OFFERING MEMORANDUM **STRICTLY CONFIDENTIAL**

US$262,664,000

INTERENERGY

UEP Penonomé II, S.A.

6.500% Senior Secured Notes due 2038

Unconditionally Guaranteed, jointly and severally, by

Tecnisol I, S.A., Tecnisol II, S.A., Tecnisol III, S.A. and Tecnisol IV, S.A.

UEP Penonomé II, S.A. (the "Issuer"), a corporation (*sociedad anónima*) organized under the laws of the Republic of Panama ("Panama"), is offering US$262,664,000 aggregate principal amount of its 6.500% Senior Secured Notes due 2038 (the "Notes"). The Issuer will pay interest on the Notes semi-annually in arrears on April 1 and October 1 of each year, commencing on April 1, 2021. Installments on principal on the Notes will be payable semi-annually on the same date as interest, commencing on April 1, 2021, as described in this offering memorandum. The final maturity of the Notes is October 1, 2038. The Issuer and the guarantors are indirect subsidiaries of InterEnergy Group Ltd. (the "Sponsor"). The Notes will be unconditionally guaranteed, jointly and severally (the "Note Guarantee"), by each of Tecnisol I, S.A., Tecnisol II, S.A., Tecnisol III, S.A. and Tecnisol IV, S.A., each a corporation (*sociedad anónima*) organized under the laws of Panama (collectively, the "Guarantors" and each, individually, a "Guarantor").

The Notes and the Note Guarantee will be the senior secured obligations of the Issuer and the Guarantors, respectively, and will rank (i) *pari passu* in right of payment with all of the Issuer's and the Guarantors' present and future senior secured obligations (other than obligations preferred by statute or by operation of law) and certain other debt, permitted to be ratably secured by the Collateral under the Indenture (ii) senior to all present and future unsecured (to the extent of the value of the collateral securing the Notes and the Note Guarantee) or subordinated obligations and (iii) subordinated to all of the Issuer's or the Guarantors' future indebtedness secured by liens on assets that do not secure the Notes or the Note Guarantee, to the extent of the value of the assets securing such indebtedness.

The Notes and the Note Guarantee will be secured by all the equity interests in the Issuer and Guarantors, and substantially all the assets of, the Issuer. The collateral securing the Notes and the Note Guarantee may also secure additional indebtedness incurred in the future, subject to certain conditions described herein. The Note Guarantee and security interests will be subject to contractual and legal limitations under relevant local laws and may be released under certain limited circumstances. See "Description of the Notes — Release of Liens."

The Issuer may redeem the Notes, in whole or in part, before October 1, 2038 at a redemption price equal to the greater of par and a make-whole amount, plus accrued and unpaid interest thereon to the redemption date. In addition, we may redeem all the Notes, in whole but not in part, at par plus accrued and unpaid interest thereon to the redemption date and any additional amounts in the event of certain tax changes. See "Description of the Notes — Optional Redemption with Make-Whole Premium" and "Description of the Notes — Optional Redemption upon Tax Event."

Upon the occurrence of certain events of loss, the Issuer and the Guarantors will be required to redeem the Notes at a redemption price equal to 100% of the outstanding principal amount of the Notes being redeemed, plus accrued and unpaid interest to the redemption date, plus any additional amounts (but without payment of any premium). See "Description of the Notes — Redemption in Connection with Events of Loss." Upon the occurrence of a change of control repurchase event, as described herein, the Issuer and the Guarantors will be required to offer to purchase the Notes at a purchase price equal to 101% of the portion of the outstanding principal balance represented by the Notes to be repurchased, plus all accrued and unpaid interest thereon, to but excluding the purchase date, plus any additional amounts. See "Description of the Notes — Repurchase Upon Change of Control Repurchase Event." Upon a foreclosure on the collateral securing the Notes, all proceeds realized in connection therewith must be applied to pay the holders of the Notes and other required amounts in accordance with the priority set forth in the Indenture. See "Description of the Notes — Priority of Payments upon Foreclosure on the Collateral."

We intend to allocate an amount equal to the net proceeds from the sale of the Notes to finance and refinance Eligible Green Projects. See "Use of Proceeds."

Application will be made for the listing and quotation of the Notes on the Singapore Exchange Securities Trading Limited (the "SGX-ST"). The SGX-ST assumes no responsibility for the correctness of any of the statements made or opinions expressed, or reports contained in this offering memorandum. Approval in principle received from the SGX-ST and admission of the Notes to the official list of the SGX-ST is not to be taken as an indication of the merits of the Issuer or the Notes. The Notes will be traded in a minimum board lot size of US$200,000 for so long as any of the Notes are listed on the SGX-ST and the rules of the SGX-ST so require. We cannot assure you that the Notes will receive final approval or will remain listed.

THE PUBLIC OFFERING OF THE NOTES HAS BEEN AUTHORIZED IN PANAMA BY THE SUPERINTENDENCIA DEL MERCADO DE VALORES DE PANAMÁ (SUPERINTENDENCE OF SECURITIES MARKET). THIS AUTHORIZATION DOES NOT IMPLY THAT THE SUPERINTENDENCE RECOMMENDS INVESTING IN THE NOTES NOR DOES IT REPRESENT A FAVORABLE OR UNFAVORABLE OPINION ON THE ISSUER'S BUSINESS PROSPECTS. SUPERINTENDENCE OF SECURITIES MARKET OF PANAMA WILL NOT BE RESPONSIBLE FOR THE ACCURACY OF THE INFORMATION PRESENTED IN THIS OFFERING MEMORANDUM OR OF THE DECLARATIONS CONTAINED IN THE REGISTRATION APPLICATION.

APPLICATION HAS ALSO BEEN MADE TO HAVE AUTHORIZATION FOR THE NOTES TO BE LISTED AND TRADED IN THE PSE. THE AUTHORIZATION DOES NOT IMPLY ANY RECOMMENDATION OR OPINION REGARDING THE NOTES, THE NOTE GUARANTEE, THE ISSUER OR THE GUARANTORS.

Investing in the Notes involves risks. See "Risk Factors" beginning on page 41.

The Notes and the Note Guarantee have not been and will not be registered under the U.S. Securities Act of 1933, as amended (the "Securities Act"). Prospective purchasers are hereby notified that the sellers of the Notes may be relying on an exemption from the provisions of Section 5 of the Securities Act provided by Rule 144A under the Securities Act. Outside the United States, the offering is being made in reliance on Regulation S under the Securities Act. For a description of certain restrictions on transfers of the Notes, see "Plan of Distribution" and "Transfer Restrictions."

Price for Notes: 100.000% plus accrued interest, if any, from December 18, 2020

We expect that delivery of the Notes will be made to investors in book-entry form through the facilities of The Depository Trust Company ("DTC"), for the accounts of its direct and indirect participants, including Euroclear Bank SA/NV, as operator of the Euroclear System ("Euroclear"), and Clearstream Banking, société anonyme ("Clearstream"), on or about December 18, 2020.

Sole Global Coordinator and Book-Runnning Manager

Citigroup

The date of this offering memorandum is December 9, 2020.

TABLE OF CONTENTS

You should rely only on the information contained in this offering memorandum. Neither we nor Citigroup Global Markets Inc. (the "Initial Purchaser") has authorized anyone to provide you with information that is different or additional to the information contained in this offering memorandum. If anyone provides you with different or additional information, you should not rely on it. You should assume that the information in this offering memorandum is accurate only as of the date on its front cover, regardless of the time it is delivered or of any sale of any Notes. Our business, financial condition, results of operations and prospects may change after the date on the front cover of this offering memorandum.

Notwithstanding anything in this offering memorandum to the contrary, except as reasonably necessary to comply with applicable securities laws, you (and each of your employees, representatives or other agents) may disclose to any and all persons, without limitation of any kind, the U.S. federal income tax treatment and tax structure of the offering and all materials of any kind (including opinions or other tax analyses) that are provided to you relating to such tax treatment and tax structure. For this purpose, "tax structure" is limited to facts relevant to the U.S. federal income tax treatment of the offering.

Neither the U.S. Securities and Exchange Commission (the "SEC"), nor any state securities commission has approved or disapproved of these securities or determined if this offering memorandum is truthful, accurate, adequate or complete. Any representation to the contrary may be a criminal offense.

We are relying upon an exemption from registration under the Securities Act for an offer and sale of securities which does not involve a public offering in the United States. By purchasing Notes, investors will be deemed to have made certain acknowledgments, representations and agreements as set forth under "Notice to Investors" in this offering memorandum. We and the Initial Purchaser are not making and have not made any offer to sell the Notes in any jurisdiction, except where such offer or sale is permitted.

The Notes are subject to restrictions on transferability and resale and may not be offered, transferred or resold except as permitted under the Securities Act and applicable state and Panamanian securities laws pursuant to registration or exemption therefrom. Investors may not sell or transfer their Notes except in compliance with applicable laws in the United States or elsewhere. See "Transfer Restrictions", "Plan of Distribution" and "Notice to Investors." Prospective investors should be aware that investors may be required to bear the financial risks of this investment for an indefinite period of time.

We have made available this offering memorandum as required by Panamanian laws and regulations in connection with the public offering of the Notes in Panama, and in the United States solely to qualified institutional buyers, and outside the United States to investors who are non U.S. persons, so they can consider a purchase of the Notes. We have not authorized the use of this offering memorandum for any other purpose. This offering memorandum may not be copied or reproduced in whole or in part. This offering memorandum may be distributed and its contents disclosed only to the prospective investors to whom it is provided. By accepting delivery of this offering memorandum, investors agree to these restrictions.

This offering memorandum is based on information provided by us, and other sources that we believe to be reliable. In making an investment decision, investors must rely on their own examination of us and the terms of this offering and the Notes, including the merits and risks involved in an investment in the Notes.

We are not making any representation to investors regarding the legality of an investment in the Notes by investors under any investment or similar laws or regulations. Investors should not consider any information in this offering memorandum to be legal, business or tax advice. Investors should consult their own counsel, accountant, business advisor and tax advisor for legal, financial, business and tax advice regarding any investment in the Notes.

We reserve the right to withdraw this offering at any time and we and the Initial Purchaser reserve the right to reject any commitment to subscribe for the Notes in whole or in part and to allot to any prospective investor less than the full amount of the Notes sought by that investor. The Initial Purchaser may acquire a portion of the Notes for its own account.

Investors must comply with all applicable laws and regulations in force in each such investor's jurisdiction and investors must obtain any consent, approval or permission required by each such investor for the purchase, offer or sale of the Notes under the laws and regulations in force in each such investor's jurisdiction to which each such investor is subject or in which each such investor makes such purchase, offer or sale, and neither we nor the Initial Purchaser will have any responsibility thereof.

Neither the delivery of this offering memorandum nor any sale made in connection herewith will, under any circumstances, create any implication that there has been no change in our affairs since the date hereof or that there has been no adverse change in our financial position since the date hereof or that this offering memorandum is correct as of any time subsequent to the date hereof.

ENFORCEMENT OF CIVIL LIABILITIES

The Issuer and the Guarantors are *sociedades anónimas* organized under the laws of Panama. Most of its directors and executive officers reside outside the United States, all of its assets are located outside the United States, and certain of the experts named in this offering memorandum also reside outside the United States. As a result, it may not be possible for investors to effect service of process within the United States upon these persons, including with respect to matters arising under the federal securities laws of the United States, or to enforce against the Issuer or them in United States courts judgments predicated upon the civil liability provisions of the federal securities laws of the United States. However, the Issuer has appointed Cogency Global Inc., with offices currently located at 122 East 42nd Street, 18th Floor, New York, NY 10168, as its authorized agent in connection with the Notes and the Indenture, upon which process may be served in any suit or proceeding arising out of or relating to the foregoing that may be instituted against the Issuer in any federal or state court located in the County of New York, State of New York.

The Issuer and the Guarantors have been advised by their Panamanian counsel that no treaty exists between the United States and Panama for the reciprocal enforcement of foreign judgments and that there is doubt as to the enforceability, in original actions in Panamanian courts, of liabilities predicated solely on the United States federal securities laws and as to the enforceability in Panamanian courts of judgments of United States courts obtained in actions predicated upon the civil liability provisions of the federal securities laws of the United States. The Issuer has also been advised by its Panamanian counsel that a judgment of a court outside Panama, including but not limited to judgments of United States courts, may only be recognized and enforced by the courts of Panama if the Supreme Court of Panama validates the judgment by the issuance of a *writ of exequatur*. Any final money judgment rendered by any foreign court will be recognized, conclusive and enforceable in the courts of Panama without reconsideration of the merits, provided that the Fourth Chamber of General Affairs (*Sala Cuarta de Negocios Generales*) of the Supreme Court of Panama shall, for purposes of issuing a *writ of exequatur* ordering such enforcement, confirm that: (i) such foreign court grants reciprocity to the enforcement of judgments of the courts of Panama; (ii) such judgment was issued by a competent court of the foreign jurisdiction (Panamanian courts have exclusive jurisdiction on matters of real estate located in Panama); (iii) the party against whom the judgment was rendered, or its agent, was personally served (not by mail) in such action within such foreign jurisdiction; (iv) the judgment arises out of a personal action against the defendant; (v) the obligation in respect of which the judgment was rendered is lawful in Panama and does not contradict the public policy of Panama; (vi) the foreign judgment, in accordance with the laws of the country where it was rendered, is final and is not subject to appeal; (vii) the judgment is properly authenticated by diplomatic or consular officers of Panama or pursuant to the 1961 Hague Convention Abolishing the Requirement of Legalization of Foreign Public Documents; and (viii) a copy of the final judgment is translated into Spanish by a translator licensed in Panama. See "Risk Factors — Risks relating to Panama — It may be difficult to enforce civil liabilities against the Issuer or its directors and executive officers and controlling persons."

NOTICE TO PANAMANIAN INVESTORS

This offering memorandum will be the *Prospecto Informativo* for purposes of the registration of the public offering of Notes with the SMV and its filing before the PSE. Any future amendments to the terms and conditions of the Notes are subject to SMV Accord 4-2003 (*Acuerdo 4-2003)* of April 11, 2003, or Accord 7-2020 of May 31, 2020 (as applicable), and must be performed in compliance with the provisions thereof. To the extent that the Spanish translation of this offering memorandum conflicts with this offering memorandum, this English language offering memorandum will govern and control.

NOTICE TO EUROPEAN ECONOMIC AREA AND UNITED KINGDOM INVESTORS

This offering memorandum has been prepared on the basis that any offer of Notes in any Member State of the European Economic Area ("EEA") or in the United Kingdom will be made pursuant to an exemption under the Prospectus Regulation from the requirement to publish a prospectus for offers of Notes. The expression "Prospectus Regulation" means Regulation (EU) 2017/1129 (as amended or superseded).

The Notes are not intended to be offered, sold or otherwise made available to and should not be offered, sold or otherwise made available to any retail investor in the EEA or in the United Kingdom. For these purposes, a retail investor means a person who is one (or more) of: (i) a retail client as defined in point (11) of Article 4(1) of Directive 2014/65/EU (as amended, "MiFID II"); or (ii) a customer within the meaning of Directive (EU) 2016/97 (as amended, the "Insurance Distribution Directive"), where that customer would not qualify as a professional client as defined in point (10) of Article 4(1) of MiFID II. Consequently, no key information document required by Regulation (EU) No 1286/2014 (as amended, the "PRIIPs Regulation") for offering or selling the Notes or otherwise making them available to retail investors in the EEA or in the United Kingdom has been prepared and therefore offering or selling the Notes or otherwise making them available to any retail investor in the EEA or in the United Kingdom may be unlawful under the PRIIPs Regulation.

References to Regulations or Directives include, in relation to the United Kingdom, those Regulations or Directives as they form part of the United Kingdom domestic law by virtue of the European Union (Withdrawal) Act 2018 or have been implemented in United Kingdom domestic law, as appropriate.

NOTICE TO INVESTORS IN CERTAIN COUNTRIES

For information for investors in certain countries, see "Plan of Distribution" and "Transfer Restrictions."

AVAILABLE INFORMATION

We are not subject to the reporting requirements of the U.S. Securities Exchange Act of 1934, as amended (the "Exchange Act"). To permit compliance with Rule 144A under the Securities Act in connection with resales of Notes, we will furnish to any holder which so requests and any prospective purchaser designated by such holder the information required to be delivered under Rule 144A(d)(4) under the Securities Act, unless we are either subject to the exemption from reporting under Rule 12g3-2(b) under the Exchange Act or furnish information to the SEC pursuant to Section 13 or 15(d) of the Exchange Act. In addition, certain additional data related to the Independent Engineering Report is available upon request. Any such request may be made to us in writing at P.H. Plaza 58, 9th Floor, Calle Ricardo Arango & Calle 58 Este, Panama, Republic of Panama.

We will be required to comply with any undertakings given by us from time to time to the SGX-ST and the PSE in connection with the Notes, and to furnish all such information as the rules of the SGX-ST and the PSE may require in connection with the listing of the Notes.

FORWARD-LOOKING STATEMENTS

This offering memorandum includes "forward-looking statements" within the meaning of the securities laws of certain applicable jurisdictions. The words "believe", "anticipate", "expect", "intend", "estimate", "plan", "project," "assume", "will", "may", "should" and other similar expressions, which are predictions of or indicate future events and future trends, identify forward-looking statements. In addition, this offering memorandum includes forward-looking statements relating to our potential exposure to various types of market risks, such as interest rate risk and foreign exchange rate risk. You should not rely on forward-looking statements because they involve known and unknown risks, uncertainties and other factors which are in some cases beyond our control and may cause our actual results, performance or achievements to differ materially from anticipated future results, performance or achievements expressed or implied by such forward-looking statements (and from past results, performance or achievements). Certain factors that may cause such differences include but are not limited to:

- actions and the timing of actions by legislative, legal, regulatory, governmental and environmental bodies in Panama and other countries;
- legislative and regulatory changes (including any changes in taxation laws and emergency regulations);
- our limited operating history;
- failure to comply with our obligations under our PPAs or any contractual disputes with significant customers;
- loss of significant customers;
- reliance on transmission assets and energy infrastructure and services that the Issuer or the Guarantors do not own or control;
- the accuracy of assumptions and estimates used in the preparation of the Expert Reports (as defined below);
- wars, terrorist attacks, organized crime, weather conditions, natural disasters and catastrophic accidents;
- developments in energy markets, including the timing and extent of changes and volatility in commodity prices;
- risks posed by attacks on, and cybersecurity threats to, the information and systems used to operate our businesses, the energy grid and the confidentiality of our proprietary information and the personal information of our customers and employees of our contractors and suppliers;
- government expropriation of assets, changes in contractual conditions and title and other property disputes;
- significant economic or political developments in other countries;
- risks and uncertainties discussed under "Risk Factors" and elsewhere in this offering memorandum; and
- the impact of the Coronavirus disease 2019 ("COVID-19") pandemic on our business generally, and on economic and market conditions globally, including changes in government policy.

The forward-looking statements herein are based on a number of assumptions and estimates and are subject to known and unknown risks, uncertainties and other factors that may or may not occur in the future. As such, we caution you that forward-looking statements are not guarantees of future performance and that our actual results of operations, including our financial condition and liquidity and the development of the industry in which we intend to operate, may differ materially from those expressed or implied by our forward-looking statements.

We urge you to read the sections of this offering memorandum entitled "Risk Factors," "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Business Overview" and "Regulatory, Permits and Environmental Matters" for a more complete discussion of the factors that could affect our future performance and the markets in which we intend to operate. The forward-looking statements herein speak only as of the date on which the statements were made. We undertake no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or developments or otherwise.

PRESENTATION OF FINANCIAL AND OTHER INFORMATION

General

Unless otherwise indicated or the context otherwise requires, references to (i) “we,” “us” and “our” are to, collectively the Issuer and the Guarantors; (ii) the “Issuer” is to UEP Penonomé II, S.A. and (iii) the “Guarantors” are to, collectively, Tecnisol I, S.A., Tecnisol II, S.A., Tecnisol III, S.A. and Tecnisol IV, S.A.

All references herein to “Balboas” or “B/.”are to Balboas, Panama’s national currency. All references to “U.S. dollars,” “US$” or “$” are to United States dollars.

Financial Statements

This offering memorandum includes the following financial statements:

- The Issuer’s audited financial statements as of and for the periods ended December 31, 2019, 2018 and 2017, together with the notes thereto (the “Issuer Annual Financial Statements”).
- The Issuer’s unaudited interim financial statements as of and for the nine-month periods ended September 30, 2020 and 2019, together with the notes thereto (the “Issuer Unaudited Interim Financial Statements” and, together with the Issuer Annual Financial Statements, the “Issuer Financial Statements”).
- The stand-alone financial statements of each of the Guarantors as of and for the periods ended December 31, 2019 and 2018, together with the notes thereto (each, a “Guarantors Annual Financial Statement,” and collectively, the “Guarantors Annual Financial Statements”).
- The unaudited combined financial statements of the Guarantors as of and for the nine-month period ended September 30, 2020 and 2019, together with the notes thereto (the “Guarantors Unaudited Interim Combined Financial Statements” and, together with the Issuer Financial Statements and the Guarantors Annual Financial Statements, the “Financial Statements”).

We prepare our financial statements, and have prepared the Financial Statements, in U.S. dollars. We prepared the Financial Statements in accordance with the International Financial Reporting Standards (“IFRS”), as adopted by the International Accounting Standards Board (“IASB”). The Issuer Annual Financial Statements and the stand-alone financial statements of each of the Guarantors as of and for the year ended December 31, 2019 were audited by PricewaterhouseCoopers, S.R.L., independent auditors (“PwC”). The Issuer Unaudited Interim Financial Statements have been prepared in accordance with International Accounting Standard 34 “Interim Financial Reporting.” The results for the nine month-period ended September 30, 2020 of the Issuer or the Guarantors are not necessarily indicative of results to be expected for the entire year ending December 31, 2020.

Currency

We maintain our financial books and records and publish our financial statements in U.S. dollars. Our functional currency is the U.S. dollar.

Since 1904, Panama has fixed its local currency, the Balboa, to the U.S. dollar, which is also recognized legal tender in Panama. The Balboa/U.S. dollar exchange rate has been fixed at B/.1.00 to US$1.00 since the Balboa was first introduced in 1904, and the Balboa has always circulated alongside U.S. dollars in Panama. There are no circulating Balboa bills or coins, other than with a value of B/.1.00 or less. Currency conversions contained in this offering memorandum should not be construed as representations that Balboas have been, could have been or could be converted into U.S. dollars at the indicated or any other rate of exchange.

Rounding

Certain amounts and percentages included in this offering memorandum have been subject to rounding adjustments and, accordingly, certain totals presented in this offering memorandum may not correspond to the arithmetic sum of the amounts or percentages that precede them.

Non-IFRS Financial Measures

In this offering memorandum, we disclose non-IFRS financial measures, namely Adjusted EBITDA for the Issuer EBITDA for the Guarantors and Combined Adjusted EBITDA for the Issuer and the Guarantors. With respect to the Guarantors, EBITDA is equal to the total comprehensive income for the period plus (a) total income tax, (b) finance cost, net and (c) depreciation and amortization.

With respect to the Issuer, Adjusted EBITDA is equal to the total comprehensive income (loss) for the period plus (a) total income tax, (b) other income, (c) finance cost, net and (d) depreciation and amortization, plus (f) advisory expenses related to an arbitration, minus (g) income related to the reimbursement of expenses related to an arbitration.

With respect to the Issuer and the Guarantors, Combined Adjusted EBITDA is equal the sum of, with respect to the Issuer and each of the Guarantors, (a) total comprehensive income (loss) for the period, plus (b) total income tax, (c) other income, (d) finance cost, net and (e) depreciation and amortization, plus (f) advisory expenses related to an arbitration, minus (g) income related to the reimbursement of expenses related to the arbitration with Goldwind. Combined Adjusted EBITDA for the Issuer and the Guarantors does not include any intercompany eliminations (see "Certain Relationships and Related Party Transactions") and is calculated by aggregating amounts recorded under the following line items in the applicable financial statements of the Issuer and each of the Guarantors: (a) with respect to the year ended December 31, 2019, the audited statement of comprehensive income included in the Issuer Annual Financial Statements and in each of the Guarantors Annual Financial Statements, (b) with respect to the nine-month period ended September 30, 2019 and 2020, the statement of comprehensive income included in the Issuer Unaudited Interim Financial Statements and in the Guarantors Unaudited Interim Combined Financial Statements.

For a reconciliation of each of Adjusted EBITDA of the Issuer and EBITDA of the Guarantors on a combined basis and of the Issuer and Guarantors on a combined basis to net profit, see "Summary Historical Financial and Other Data." These measures are not recognized under IFRS or any other generally accepted accounting principles as measures of financial performance and should not be considered as substitute to profit (loss) or operating cash flow in IFRS, or other measures of liquidity, since they do not reflect certain costs involved in our operations, such as finance expenses, taxes, depreciation, capital expenses and other related costs, any of which may have a significant effect on our net profit.

These measures, when used in conjunction with related IFRS financial measures, provide investors with additional financial analytical framework which management uses, in addition to historical operating results, as the basis for financial, operational and planning decisions and present measurements that third parties have indicated are useful in assessing our finances and results of operations. You should rely primarily on our IFRS results, and the non-IFRS measures in a supplemental manner. There is no standard definition for of the non-IFRS measures provided in this offering memorandum, and our definitions may not be comparable to equivalent Non-IFRS measures used by other companies.

Independent Energy Market Report

Estudios Energéticos Consultores S.A. ("Mercados Energéticos") has prepared the Independent Energy Market Report, see "Annex A." Mercados Energéticos has consented to the inclusion of a copy of the Independent Energy Market Report as Annex A to this offering memorandum. Mercados Energéticos is an independent international consulting firm that provides technical consulting services covering, among other industries, the energy and utilities sector.

For purposes of preparing its report, the Independent Energy Market Report relied on information provided by us, which included material contingencies and other matters that are not within our control, Mercados Energéticos' control or the control of any other person or entity. You should be aware that actual results may differ, perhaps materially, from those estimated or projected. We cannot give you any assurance that the assumptions used are correct or that the estimates and projections will match actual results of operations. See "Risk Factors — Risks Relating to Our Business — The projections of the wind and solar generation and related revenues of the Projects could prove to be materially incorrect" for more information on the risks related thereto. The summary of and conclusions stated in the Independent Energy Market Report that follow are qualified in their entirety by the report itself, which you should read before making an investment in the Notes.

The Independent Energy Market Report is divided into four chapters and includes the following topics:

- General context to the Panamanian and regional energy market, including supply and demand forecasts, the regulatory framework, as well as drivers of price and the impact of the regional electricity market on domestic prices.
- Mercados Energéticos' view on forward looking electricity prices (on a 2020 real U.S. dollar basis), factoring in fuel prices, demand, generation expansion plans, cost of the new entrants, the regional energy market, and the penetration of renewables into the Panamanian energy market.
- Mercados Energéticos' views on the UEP II PPAs (as defined below) and the Tecnisol Intercompany Energy Reserve Agreements (as defined below), as well as, the Tecnisol PPAs (as defined below), the UEP II Energy Reserve Agreements (as defined below) and the Tecnisol Third-Party Energy Reserve Agreements (as defined below).
- Forecast and validation of the prices (Regulated Tariffs and the PPA price known as Cargo por Energia de Generacion — CEG) of the Projects.
- Identification of the main opportunities and risks incurred by the Projects (as defined below), as well as proposed mechanisms, actions to mitigate them.

According to the Independent Energy Market Report, conclusions stated in the Independent Energy Market Report include the following:

- The generation installed capacity in Panama has a high component of hydroelectricity (the rainy season runs from May to October), representing approximately 44% of total energy generation in 2019 and approximately 70% in 2018. The electricity demand in Panama has grown at an average rate of 4.6% since 2000, having an average annual growth from 2016 to 2019 of 2.4%, and such electricity demand includes a high percentage of contracted energy by the Distribution Companies (90.5% of the total contracted energy in 2019).
- In the last five years, the expansion of the system has been dominated by thermal power plants and renewables. The main drivers of spot price in Panama was the variation of the crude oil prices (WTI), since most thermal plants uses fuel, and the availability of hydroelectric generation, which is affected by general hydrological conditions.
- In Panama, the Distribution Companies sell energy to Regulated Customers at Regulated Tariffs set by adding charges for transmission grid usage, charges for distribution network usage, and commercialization costs to the electric power purchase cost component.
- According to the National Energy Plan 2015-2050, Panama aims to generate 70% of its energy from alternative renewable sources. The National Energy Plan objective is to have generation of 15% and 30% of Panama's electricity deriving from both renewable and non-hydraulic energy by 2030 and 2050, respectively.
- The Stochastic Dual Dynamic Programming model is used to determine the generation of each wind farm and dispatch depends on merit order. The model breaks the hours of the day into 5 blocks to capture intraday volatility in demand and resource availability, in the case of Panama as the peak demand tends to be during the midday, the highest demand tends to be block 2 instead of block 1. Mercados Energéticos is able to model Panama's solar generation peak in terms of block 2.
- In Panama, the CND centrally dispatches all the available power units in the generation fleet by ranking them in ascendant order of variable costs aiming to assure to supply demand at the minimum

possible cost. The renewable assets have very low variable costs, thus, is ranked first in the merit order of dispatch (versus thermal generation and hydro power plants with reservoirs).

- Mercados Energéticos' view on the energy prices per different horizons of time. In the short-term, energy prices remain low in the context of low prices for commodities and relatively low demand (impact of the COVID-19 pandemic). As from 2025, marginal costs show an average upward trend, in a context of demand growth, relatively limited quantity of additions of new generation projects and increasing fuel prices in the international markets. In the long-term, it is assumed that a highly efficient thermal project (CCGTs running on LNG) are added to achieve energy prices that are compatible with the self-sustained development of the electricity market.
- To determine the prices and demand of the Guarantors' energy, Mercados Energéticos notes the following assumptions: (i) price of the existing contracts significantly decreases between years 2019 and 2021 given (x) the beginning of the new CCGT's contract (350 MW in total) with prices below the average price of the existing contracts and (y) the expiration by year 2020 of near 200 MW of costly existing contracts, (ii) the existing contracts that expire during the time period between 2020 and 2025 are renewed at a lower price because of an increasing competition among generators (supply surplus) and (iii) from 2030 onwards, the contract market reaches the long term equilibrium price, giving the economic signal to develop new capacity to meet the demand growth.
- Sales to the Tecnisol Customers under the Tecnisol PPAs are valued at the CEG, for which Mercados Energéticos projects the evolution of the CEG (PPA price) of each Tecnisol PPA taking into consideration the base price (initial price), the variations of the Regulated Tariff (calculated on 6-month basis for specific categories of tariffs) and the ceiling and floor prices specified in each Tecnisol PPA.
- The Issuer and the Guarantors commercializes their energy output through long-term energy PPAs with Distribution Companies and Large Customers, respectively. The Issuer does not carry resource risk given that they follow the generation production profile of the generator, while the Guarantors do. If the Guarantors' resources at a given hour are not enough to meet the contracted energy, the Guarantors will purchase energy deficit in the spot market at the hourly spot price, to mitigate this they have entered into energy reserve agreements with other generators and with the Issuer (Rosa de los Vientos, 50 MW).

Independent Engineer Report

UL Services Spain, S.L., a company of AWS Truepower S.L.U. ("UL") has prepared an independent engineer report dated November 30, 2020 (the "Independent Engineer Report" and, together with the Independent Energy Market Report, the "Expert Reports"). UL has consented to the inclusion of a copy of the Independent Engineer Report as Annex B to this offering memorandum. UL is an international consulting firm that provides technical and environmental consulting services to the energy industry. The Independent Engineer Report assesses the principal aspects of the Projects including plant design review, energy production report, technology review, review of critical contracts, financial model inputs review and lifetime extension analysis.

For purposes of preparing its report, UL relied on information, including estimates and projections, provided by us, which included information based upon assumptions about various matters that are not within our control. You should be aware that actual results would likely differ, perhaps materially, from those estimated or projected. No one can assure you that the assumptions used are correct or that the estimates and projections will match actual results of operations. Therefore, we do not make, nor intend to make, nor should you infer, any representation with respect to the likelihood of any future outcome. If actual results are materially less favorable than those shown, or if the assumptions used in formulating the estimates and projections prove to be incorrect, our ability to meet our obligations under the Notes could be materially and adversely affected. See "Risk Factors — Risks Relating to Our Business — The projections of the wind and solar generation and related revenues of the Project could prove to be materially incorrect." and "Annex B — Independent Engineer Report".

The Independent Engineer Report attached as Annex B to this offering memorandum is current only as of the date of such report. The delivery of the Independent Engineer Report as an annex to this offering memorandum does not imply that there has been no change in our affairs since the date of the Independent Engineer Report or that the information contained in this offering memorandum relating to the Independent Engineer Report is current as of any time after the date of the Independent Engineer Report and neither we nor any other person will update the Independent Engineer Report or the contents of this offering memorandum relating to the Independent Engineer Report to reflect developments after the date of the Independent Engineer Report.

Market Information

This offering memorandum contains and refers to information and statistics regarding the Panamanian electricity industry. This market data was obtained from independent public sources, including publications and materials from participants in the electricity industry and from governmental entities such as the Panamanian Ministry of Economy and Finance (*Ministerio de Economía y Finanzas*), the Secretariat of Energy (*Secretaria de Energía*), the Office of the Comptroller (*Contraloría General de la República*), the CND, ETESA, ASEP and the Ministry of the Environment (*Ministerio de Ambiente*), among others. Some data are also based on our estimates, which are derived from our review of internal reports, as well as independent sources. Although these sources are believed to be reliable, neither we nor the Initial Purchaser have independently verified such data, and neither we nor the Initial Purchaser make any representations as to the accuracy of such information. Where information in this offering memorandum has been sourced from third parties this information has been accurately reproduced and as far as we are aware and are able to ascertain from the information published by such third parties no facts have been omitted which would render the reproduced information inaccurate or misleading. The source of third-party information is identified where used.

Description of Contracts and Permits

This offering memorandum contains summary descriptions of material provisions of various commercial agreements, permits and other contracts, including the generation licenses, resolutions that approve the environmental impact studies for the Projects, interconnection agreements, EPC agreements related to the Tecnisol Solar Project (as defined below), the Turbine Supply Agreement (as defined below) related to the UEP II Wind Project (as defined below), service and maintenance agreements related to the Projects, PPAs between the Issuer and the Distribution Companies (as defined below), PPAs between the Guarantors and certain Tecnisol Customers (as defined below), energy reserve agreements entered into by the Issuer and the Guarantors, and the other agreements described under "Business — Certain Material Agreements," "Description of Principal Financial Documents," and "Description of Collateral." Such descriptions do not purport to be complete or exhaustive, and, as with any contract or legal instrument, the terms thereof may be subject to interpretation. Copies of the agreements described under "Business — Certain Material Agreements," "Description of Principal Financial Documents," and "Description of Collateral," as well as copies of our organizational documents, will be made available for inspection upon request to us at our address listed on the inside back cover page of this offering memorandum. As such, reference is hereby made to the actual agreements and documents for complete information contained in those agreements and documents. All summaries to such agreements and documents are qualified in their entirety by this reference.

DEFINED TERMS AND CONVENTIONS

All capitalized terms used in this offering memorandum and not defined have the meanings assigned to them below, except as otherwise defined under "Business Overview — Certain Material Agreements," "Description of Principal Financial Documents", "Description of Collateral", "Description of the Notes," and "Description of Principal Financial Documents":

"ASEP"	The National Authority of Public Services (*Autoridad Nacional de los Servicios Públicos*), an autonomous agency of the Panamanian Government tasked with overseeing, regulating and organizing the supply of public services throughout Panama and that regulates power generation,

	transmission, interconnection and distribution activities in the electric sector in Panama. For more information on ASEP, see "Regulatory, Permits and Environmental Matters."
"Balboas"	Official monetary unit of Panama.
"Commercial Rules"	The commercial rules governing the wholesale electricity market in Panama, including Resolution No. JD-605 of April 24, 1998, as amended by Resolutions No. JD-3207 of February 22, 2002, No. JD-3463 of August 21, 2002, No. JD- 4812 of June 22, 2004, No. JD-5864 of February 17, 2006, AN No. 2821-ELEC of July 29, 2009, AN No. 2969-ELEC of September 23, 2009, AN No. 3476-ELEC of May 10, 2010, AN No. 4581-ELEC of July 11, 2011, AN No. 5061- ELEC of January 11, 2012, AN No. 5329-ELEC of May 15, 2012, AN No. 5849-ELEC of December 31, 2012, AN No. 6007 of March 13, 2013, AN No. 6166-ELEC of May 27, 2013, AN No. 7477-ELEC of June 19, 2014, AN No. 8451-ELEC of April 13, 2015, AN No. 10517-ELEC of October 6, 2016 and AN No. 12083-ELEC of January 30, 2018 and any amendment thereto or additional resolution adopted by ASEP on or before the date of this offering memorandum.
"CND"	The National Dispatch Center (*Centro Nacional de Despacho*), a unit within ETESA which is responsible for planning, supervising and controlling the integrated operation of the SIN. For more information on the CND, see "Regulatory, Permits and Environmental Matters."
"COD"	The commercial operation certificate from the CND.
"Distribution Companies"	EDECHI, EDEMET and ENSA. For more information, see "Regulatory, Permits and Environmental Matters."
"EDECHI"	Empresa de Distribución Eléctrica Chiriquí, S.A.
"EDEMET"	Empresa de Distribución Eléctrica Metro-Oeste, S.A.
"Electricity Law"	Conformed Copy of Law No. 6 of February 3, 1997 (as published in Gaceta No. 26871-C on September 14, 2011), as modified by Law No. 43 of August 9, 2012, Law No. 18 of March 27, 2013, Supreme Court Ruling dated May 4, 2015, as published in Gaceta No. 28017 of April 25, 2016, Law No. 67 of December 9, 2016 and Law No. 2 February 6, 2018.
"ENSA"	Elektra Noreste, S.A.
"ERISA"	Employee Retirement Income Security Act of 1974, as amended.
"ETESA"	The Empresa de Transmisión Eléctrica, S.A., the sole transmission company of Panama. For more information on ETESA, see "Regulatory, Permits and Environmental Matters."
"Firm capacity"	As defined in the market rules of the ASEP, the measurement of the capacity of a generating unit or group of units that can be guaranteed in maximum requirement conditions and that is a function of its operating and technical characteristics, reliability requirements and the commitment assumed by the market participant.
"Fitch"	Fitch Ratings Ltd.
"GW"	One gigawatt, 1,000 megawatts or 1,000,000,000 watts, 10^9 watts, a unit of power.
"Gigawatt hour (GWh)"	One gigawatt of power supplied or demanded for one hour, or one billion-watt hours; it is a unit of energy.
"IFC Hedge Agreement"	The floating interest rate swap by and among the Issuer and the International Finance Corporation (the "IFC") subject to the terms of the Confirmation dated March 10, 2015 and the ISDA Master Agreement dated

	December 9, 2014 by and among the Issuer and the IFC.
"IFC Loan"	Collectively, the loans granted by the IFC, The Netherlandse Financierings-Maatschappij Voor, Ontwikkelingslanden N.V., Societe de Promotion et de Participation pour la Cooperation Economique S.A., Oesterrichische Entwicklungsbank A.G., Central American Bank for Economic Integration; Banco Nacional de Panama and Banco General, as lenders (the "Lenders") pursuant to the terms of (a) that certain Common Terms Agreement dated as of December 9, 2014 (the "Common Terms Agreement"), the Issuer, as Borrower and as successor in interest of IEH Penonomé Panamá S.A. which merged into UEP Penonomé II, S.A., the entities described as lenders party thereto and the IFC, as the Administrative Agent for the Lenders, and (b) the Loan Agreements entered into with each of the Lenders, secured by a pledge over substantially all the assets of the Issuer, the assignment in trust of certain assets to a Panamanian Trust and a pledge over the shares of the Issuers. For more information about the IFC Loan, see Note 13 to the Issuer Annual Financial Statements.
"IRHE"	Institute of Hydraulic Resources and Electricity (*Instituto de Recursos Hidráulicos y Electrificación*). For more information on IRHE, see "Regulatory, Permits and Environmental Matters."
"ITBMS"	Tax on transfers of tangible moveable assets and the provision of services (in Spanish, *impuesto sobre la transferencia de bienes corporales muebles y la prestación de servicios*).
"Kilovolt (kV)"	One thousand volts, a unit of electric voltage.
"Kilovolt Amperes (kVa)"	One thousand volt-ampere, a unit of apparent power.
"Kilowatt (kW)"	One thousand watts, a unit of power.
"Kilowatt hour (kWh)"	One kilowatt of power supplied or demanded for one hour, or one thousand-watt hours, a unit of energy.
"Large Customers"	Any individual or legal entity with a maximum demand that exceeds a regulated threshold, currently set at 100 kW.
"Latinclear"	Central Latinoamericana de Valores, S.A.
"MVA"	One megavolt-ampere.
"Megawatt (MW)"	One million watts, a unit of power.
"Megawatt (MWh)"	One million watts of power supplied or demanded for one hour, or one million-watt hours, a unit of energy.
"MER"	Regional Electric Market (*Mercado Eléctrico Regional*), a seventh market superimposed over the six existing markets of Central America.
"Ministry of the Environment"	Ministry of the Environment (*Ministerio de Ambiente*) created by way of Law No. 8 of March 25, 2015 to replace the National Environmental Authority (*Autoridad Nacional del Ambiente*), as the Panama's governing body for matters of the protection, conservation, preservation and restoration of the environment and the sustainable use of natural resources and to ensure compliance with and application of laws, regulations and the national environmental policy.
"NCF"	Means Net Capacity Factor, which is the unitless ratio of an actual electrical energy output over a given period of time to the maximum possible electrical energy output over that period.
"Panama"	The Republic of Panama.
"Panamanian government"	Government of Panama.
"PPAs"	Power Purchase Agreements are contracts between an electricity generating company as provider and a power purchaser as buyer.

"Projects"	Collectively, the UEP II Wind Project owned by the Issuer and the Tecnisol Solar Project owned by the Guarantors.
"Prospectus Regulation"	Directive 2003/71/EC.
"PSE"	Panama Stock Exchange (*Bolsa de Valores de Panamá*).
"Purchase Rules"	The commercial rules approved by the ASEP under Resolution AN No. 991-ELEC of July 11, 2007, as amended by Resolution No. AN No. 1094-ELEC of August 28, 2007, Resolution AN No. 593-ELEC of April 10, 2008, Resolution AN No. 1998-ELEC of August 14, 2008, Resolution AN No. 3477-ELEC of May 10, 2010, Resolution AN No. 5044-ELEC of December 30, 2011, Resolution AN No. 4275-ELEC of April 23, 2012, Resolution AN No. 5635-ELEC of October 3, 2012, Resolution AN No. 5848-ELEC of December 31, 2012, Resolution AN No. 8711-ELEC of June 24, 2015, Resolution AN No. 10922-ELEC of February 8, 2017, Resolution AN No. 13242- ELEC of April 4, 2019, and any amendment hereto or additional resolution adopted by ASEP on or before the date of this offering memorandum.
"PV modules"	Photovoltaic modules that consist of photovoltaic cells sealed in an environmentally protective laminate.
"Regulated Tariff"	The tariff established by the ASEP according to the applicable electricity regulations.
"Regulated Consumers"	Pursuant to the Electricity Law, consumers that purchase electricity at the Regulated Tariff.
"S&P"	S&P Global Ratings, a division of S&P Global Inc.
"SEC"	U.S. Securities and Exchange Commission.
"Securities Act"	U.S. Securities Act of 1933, as amended.
"SIN"	The *Sistema Interconectado Nacional*, is composed of all generation facilities, transmission lines, distribution grids and related infrastructure, which are interconnected in a single national system.
"SNE"	The National Secretariat of Energy (*Secretaría Nacional de Energía*). For more information on SNE, see "Regulatory, Permits and Environmental Matters."
"SIEPAC"	Electrical Interconnection System for Central America (*Sistema de Interconexión Eléctrica de los Países de América Central*) a regional transmission system covering Guatemala, Honduras, Nicaragua, El Salvador, Costa Rica and Panama.
"SMV"	Panama Securities Market Superintendence (*Superintendencia del Mercado de Valores de Panamá*).
"Substation"	Electrical plant, containing or comprising one or more transformers and/or switchgear, that steps down electricity voltage between transmission cables and distribution cables.
"switchgear"	Electrical plant or equipment in a transmission and distribution network used to connect components of that network and which can disconnect parts of that network automatically if overload or a fault occurs.
"TBTU"	One trillion British Thermal Units.
"transformer"	Electrical plant or equipment in a transmission and distribution network used to alter the level of voltage.
"Transmission Rules"	The transmission rules approved by the ASEP under Resolution JD-5216 of April 14, as amended by Resolution JD-5351, JD-5352 and JD-5353 of June 14, 2005, Resolution AN No. 1802-ELEC of June 16, 2008, Resolution AN No. 2504- ELEC of March 18, 2009, Resolution AN No. 2720-ELEC of

	July 3, 2009, Resolution AN No. 4156-ELEC of January 5, 2011, Resolution AN No. 4398-ELEC of April 18, 2011, Resolution AN No. 4524-ELEC of June 23, 2011, Resolution AN No. 5847-ELEC of December 31, 2012, Resolution AN No. 6637-ELEC of September 27, 2013, Resolution AN No. 6957-ELEC of December 26, 2013, Resolution AN No.7405-ELEC of June 2, 2014, Resolution AN No. 12112-ELEC of February 9, 2018, Resolution AN No. 12231-ELEC of March 28, 2018, Resolution AN No. 12307-ELEC of April 20, 2018, Resolution AN No. 13117-ELEC of February 11, 2019 and any amendment hereto or additional resolution adopted by ASEP on or before the date of this offering memorandum.
"UEP I Wind Farm"	The wind project adjacent to the UEP II Wind Project owned by AES Panama, S. de R.L. ("AES Panama").
"United States or U.S."	United States of America.
"U.S. dollars or US$"	United States dollars, the legal currency of the United States.
"V"	A volt, the standard measure used for measuring electrical potential, electrical pressure or electromotive force which forces an electrical current to flow within a circuit. One volt is equal to the difference of electric potential between two points on a conducting wire carrying a constant current of one ampere when the power dissipated between the points is one watt.
"Var"	One volt-ampere reactive or a unit of reactive power.
"watt"	A common measure of electrical power equal to one joule per second or the power dissipated by a current of one ampere flowing across a resistance of one ohm.
"watt-hour"	A measure of energy production or consumption equal to one watt produced or consumed for one hour.

SUMMARY

This summary highlights certain information about us described elsewhere in this offering memorandum. This summary is not complete and does not contain all the information you should consider before investing in the Notes. The summary should be read in conjunction with, and is qualified in its entirety by, the more detailed information included elsewhere in this offering memorandum, including the Financial Statements. You should carefully read the entire offering memorandum to understand our business, the nature and terms of the Notes and other considerations, which are important to your decision to invest in the Notes, including without limitation, the risks discussed under the section titled "Risk Factors."

Overview

As indirect subsidiaries of InterEnergy Group Ltd., our Sponsor, we are diversified clean energy companies that own and operate wind and solar power generation plants in Panama with an aggregate installed generation capacity of 255MW, the biggest unconventional renewable energy producer in Panama in terms of installed capacity. We are among the top five power generators in Panama and are one of the largest diversified clean energy companies in Central America. During 2019, the Issuer and Guarantors generated 546.2 GWh (4.9%) and 70.3 GWh (0.6%) of energy, respectively, for a combined generation of 5.5% of the total energy generated in Panama in 2019, according to the Independent Energy Market Report. For the fiscal year ended December 31, 2019, our wind and solar power generation plants generated 81% and 19%, respectively, of our combined revenues and 89% and 11%, respectively, of our combined EBITDA.

The Issuer owns and operates the Laudato Sí wind power generation project, the largest wind farm in Central America and the Caribbean with 215 MW of installed capacity, strategically located in Penonomé, Coclé, close to the southern shores of Panama (the "UEP II Wind Project") where it benefits from the Caribbean winds. The UEP II Wind Project, is installed across 39.79 hectares of flat plains located at sea level in the central region of Panama, next to the UEP I Wind Farm, a wind power plant owned by AES Panama with an installed generation capacity of 55MW. The UEP II Wind Project is equipped with 86 Goldwind direct magnet drive turbines, each with a generation capacity of 2.5 MW. Construction of the UEP II Wind Project began in 2013 and, while the project has been in operation since January 2015 under "generation under test status" (during which the performance of the project is closely monitored and tested by the CND), the UEP II Wind Project officially achieved commercial operation in February 2018. The construction of the UEP II Wind Project was performed by Instalaciones & Servicios CODEPA, S.A. ("CODEPA"), a renowned international construction and infrastructure company with extensive experience in the renewable energy sector. The UEP II Wind Project is one of the largest construction projects in Central America to date. The UEP II Wind Project is divided into five separate wind farms: 1) Nuevo Chagres — Primera Etapa ("Nuevo Chagres"), comprised of 25 wind turbines and an installed capacity of 62.5 MW, 2) Rosa de los Vientos — Primera Etapa ("Rosa de los Vientos I"), comprised of 21 wind turbines and an installed capacity of 52.5 MW, 3) Rosa de los Vientos — Segunda Etapa ("Rosa de los Vientos II"), comprised of 20 wind turbines and an installed capacity of 50 MW, 4) Marañon, comprised of 7 wind turbines and an installed capacity of 17.5 MW ("Marañon"), and 5) Portobelo Ballestillas — Primera Etapa ("Portobelo"), comprised of 13 wind turbines and an installed capacity of 32.5 MW. In 2019, the electricity sold by the UEP II Wind Project to Distribution Companies indirectly supplied electricity to 185,000 Panamanian families.

The servicing and maintenance of the wind turbines installed at the UEP II Wind Project are performed by Goldwind International Holdings (HK), an affiliate of Xinjiang Goldwind Science and Technology Co. Ltd. ("Goldwind"), the supplier of our wind turbines. Goldwind directly performs the majority of the servicing and maintenance work at the UEP II Wind Project under the terms of a Service and Maintenance Agreement we entered into on April 23, 2014 (the "Service and Maintenance Agreement" or "SMA"). The operation of the UEP II Wind Project is performed by employees of the Issuer with the support of InterEnergy Holdings UK Limited ("IEH UK"), an affiliate of our Sponsor, who provide the Issuer with day-to-day general administration services, business management, technical asset management and operation and maintenance supervision under a Management Services Agreement (the "UEP II Management Services Agreement").

The Guarantors own and operate the Ikakos solar project, a solar energy project with 40 MW of installed capacity located in David, Chiriqui, Panama (the "Tecnisol Solar Project") over flat land and in one of the most solar resource rich areas of the country. With a total area of 97.8 hectares, the Tecnisol Solar Project is divided into four separate solar parks, *Ikako, Ikako I, Ikako II, and Ikako III* (which are owned by Tecnisol I, S.A., Tecnisol II, S.A., Tecnisol III, S.A. and Tecnisol IV, S.A., respectively), each of which is comprised of a single axis tracker of 10MW equipped with Jinko Solar JKM325PP (70%) and JKM330PP (30%) PV modules. Construction of the Tecnisol Solar Project began in August 2017 and has been operating under "generation under test status" since August 2018 pending the conclusion of the regulatory approval process in order to achieve commercial operations. The construction of the Tecnisol Solar Project was performed on a turnkey basis by a consortium (the "Consortium") formed by Gransolar Panama, S.A. ("Gran Solar") and Cobra Instalaciones y Servicios, S.A. ("Cobra", together with Gran Solar and the Consortium, the "EPC Contractor").

The servicing and maintenance of the Tecnisol Solar Project is provided for in-house by our own management in accordance with our maintenance plan, developed and implemented with the support and under the coordination of IEH UK in accordance with the terms of the Management Services Agreement dated December 1, 2018 (the "Tecnisol Management Services Agreement" and, together with the UEP II Management Services Agreements, the "Management Services Agreements"). We and IEH UK possess extensive experience and count with the help of several well qualified and dedicated technical professionals with vast experience in the field. In addition, certain manufacturers of the equipment of the Tecnisol Solar Project provide a subset of maintenance services under long-term service agreements. Under such agreements, Jema Energy, S.A. ("Jema"), the manufacturer of the inverters for the Tecnisol Solar Project, performs the maintenance of our power stations, and Gonvarri Solar Steel, S.L. ("Gonvarri"), the manufacturer of the single axis trackers for the Tecnisol Solar Project, performs the maintenance of our trackers.

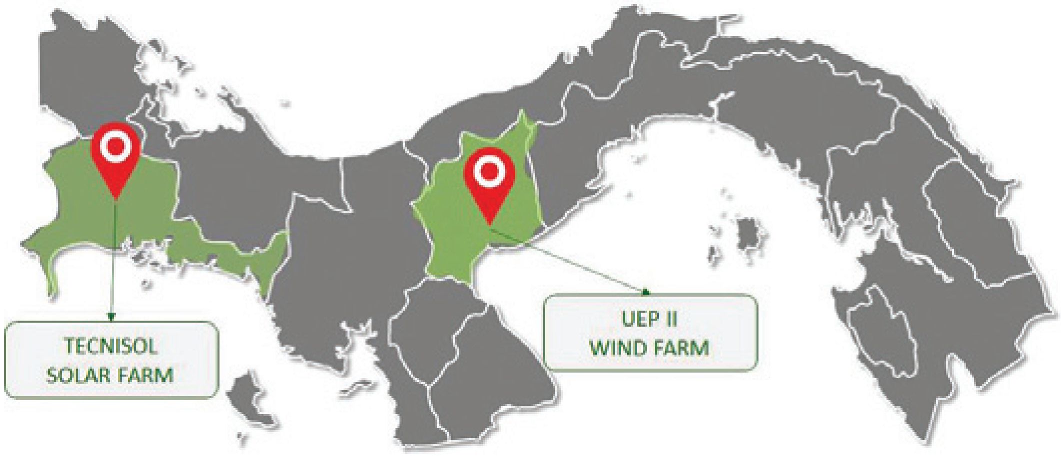
The following table sets forth the principal characteristics of our Projects:

	UEP II Wind Project	Tecnisol Solar Project
Installed Capacity	215 MW	40 MW
Turbines / PV modules	86	138,960
Manufacturer	Goldwind	Jinko Solar / Jema
		325 W JKM325PP
Nameplate Capacity	2,500 KW	330 W JKM 330PP
		JKM325PP (70%)
		JKM330PP (30%)
		Jema IFX6
Technology	Goldwind GW 109 2.5 MW	N-S single axis tracker
COD	February 2018[(1)]	Pending[(2)]
2019 Net Generation	546.2 GWh	70.3 GWh
2019 NCF (%)	29%	20.1%

(1) The project has been operating since January 2015 under "generation under test status" and reached commercial operations in February 2018.

(2) The project has been operating since August 2018 under "generation under test status."

The following map shows the location of our Projects:



Revenues

Our operating revenues from the UEP II Wind Project and the Tecnisol Solar Project derive mainly from PPAs with our customers and, to a lesser extent, sales of excess power in the spot market. As of the date of this offering memorandum, 74.9% of the combined capacity of the Issuer and the Guarantors is contracted under our PPAs with Large Customers, Distribution Companies and under the Tecnisol Intercompany Energy Reserve Agreements. The estimated remaining weighted average life of all our PPAs as of September 30, 2020 was 10.57 years.

The table below details each Project's contracted capacity as of the date of this offering memorandum and certain key details about our PPAs.

	UEP II Wind Project	Tecnisol Solar Project
Installed Capacity	215 MW	40 MW
2019 Net Generation	546.2 GWh	70.3 GWh
2019 NCF (%)	29%	20.1%
2019 PPA Energy Sold	488.8 GWh	102.2 GWh
2019 PPA Weighted Average Price	US$101.93/MWh	US$89.94/MWh
2019% of Combined Revenues	84.42%	15.58%
Weighted Average Remaining Life as of September 30, 2020	10.04 years	12.78 years

UEP II Wind Project

Our operating revenue from the UEP II Wind Project mainly derives from twelve, dollar-denominated, physical energy-only PPAs entered into with the three Distribution Companies in Panama (the "Initial UEP II PPAs"): ENSA (owned by Empresas Públicas de Medellin), and with EDEMET and EDECHI (both owned by Naturgy Energy Group, formerly Gas Natural Fenosa) (collectively, the "Distribution Companies"). In 2019, the Issuer sold 485.59 GWh of energy under the Initial UEP II PPA contracts and 49.37GWh in the Spot Market, representing 90.96% and 9.04%, respectively, of the total energy generated by the Issuer. For the year ended December 31, 2019 and for the nine-month period ended September 30, 2020, the Initial UEP II PPAs represented 69.64% and 70.97%, respectively, of the combined revenues of the Issuer and the Guarantors. Pursuant to the terms of these PPAs, the Distribution Companies are obligated to purchase all the energy generated by Nuevo Chagres, Rosa de los Vientos I, Marañon and Portobelo, which accounts for 165 MW of our aggregate installed capacity, at a price set forth in the PPAs 75% of which is fixed and 25% of which is adjusted on a monthly basis based on changes in Panama's Consumer Price Index ("Panama CPI"). These Initial UEP II PPAs have a 15-year term that commenced on July 2014 and a weighted average price paid to us by the Distribution Companies to date of US$105.41/MWh, compared to a spot price as of September 30, 2020 of US$41.60/MWh. We are currently seeking to extend our PPAs with the Distribution

Companies beyond their current maturity date given the Purchase Rules require the Distribution Companies to contract 100% of their demand projections for the next two (2) years, and for every other subsequent year this requirement decreases 10% until year 15, after which a fixed 30% of demand projections must be contracted. The closing of PPAs with Distribution Companies will be made after being awarded through public tenders organized by ETESA.

The following table sets forth the principal characteristics of our Initial UEP II PPAs:

Wind farm	Counterparty	Minimum Energy	Expected Expiration	Last PPA Price	GWh sold in 2019
Nuevo Chagres	EDEMET	13.90 GWh	June 2029	97.79	84.96
	EDECHI	4.94 GWh	June 2029	97.79	28.57
	ENSA	5.87 GWh	June 2029	97.79	38.61
Rosa de Los Vientos I	EDEMET	11.59 GWh	June 2029	100.88	81.30
	EDECHI	4.12 GWh	June 2029	100.88	27.34
	ENSA	4.89 GWh	June 2029	100.88	36.95
Marañon	EDEMET	4.23 GWh	June 2029	113.24	27.02
	EDECHI	1.50 GWh	June 2029	113.24	9.09
	ENSA	1.79 GWh	June 2029	113.24	12.28
Portobelo	EDEMET	7.10 GWh	June 2029	111.18	46.07
	EDECHI	2.52 GWh	June 2029	111.18	15.49
	ENSA	2.99 GWh	June 2029	111.18	20.94

In addition, we have entered into PPAs with the Distribution Companies on terms substantially similar to the terms of the Initial UEP II PPAs with respect to the energy generated by the Marañon and Portobelo wind farms (the "New UEP II PPAs"), which account for an aggregated installed capacity of 50 MW, for a term of four and a half years from the expiration of the applicable Initial UEP II PPAs and with a base price of US$94.9/MWh and US$91.9/MWh, respectively. While the terms of the New UEP II PPAs are substantially similar to the Initial UEP II PPAs, the following table describes the main features of the 4.5-year forward starting period of our New UEP II PPAs:

Wind farm	Counterparty	Minimum Energy	Expected Expiration
Marañon	EDEMET	11.43 GWh	December 2033
	EDECHI	7.86 GWh	December 2033
	ENSA	11.17 GWh	December 2033
Portobelo	EDEMET	18.30 GWh	December 2033
	EDECHI	12.72 GWh	December 2033
	ENSA	18.05 GWh	December 2033

As of September 30, 2020, the Initial UEP II PPAs and the New UEP II PPAs (collectively, the "UEP II PPAs") entered into by the Issuer had a remaining weighted average life of 10.04 years.

Tecnisol Solar Project

The combined operating revenues of the Guarantors derive from financial energy-only PPAs (the "Tecnisol PPAs") entered into with eight credit-worthy Large Customers (the "Tecnisol Customers"), with no single Tecnisol Customer representing more than 35% of the Guarantors' 2019 combined operating revenues. Under the Tecnisol PPAs the Guarantors are contractually obligated to supply renewable energy to cover the energy requirements of the Tecnisol Customers, which, as of September 30, 2020, accounted for close to 216 GWh of contracted power. The purchase prices under the Tecnisol PPAs are adjusted based on the biannual variations of the Regulated Tariff, subject to minimum and maximum prices set out in the applicable Tecnisol PPA. As of September 30, 2020, the Tecnisol PPAs had a remaining weighted average life of 12.78 years. For the year ended December 31, 2019 and the nine-month period ended September 30, 2020, revenues from the Tecnisol PPAs represented 13.36% and 12.96%, respectively, of the combined revenues of the Issuer and the Guarantors during that period.

The following table sets forth the principal characteristics of our Tecnisol PPAs:

Counterparty	Term	Expiration	Price	GWh sold in 2019
Coca Cola Femsa de Panamá, S.A.	15 years	April 2033	Indexed to Regulated Tariff.	11.92
Ventas y Mercadeo Panamá, S.A.(1)		March 2034		0.60
Industrias Lácteas, S.A.		July 2033		29.50
Riba Smith, S.A.		July 2033		46.46
Clínica Hospital San Fernando S.A.		July 2033		6.45
The Iron Tower Corp.(2)		April 2034		5.28
ICE Gaming Corporation(2)		April 2034		2.02
Petrolera Nacional, S.A.(3)	10 years	10 years after initial supply period	Year 1-5 (fixed price); year 6-10 (indexed to Regulated Tariff)	N/A

(1) Ventas y Mercadeo S.A. is an affiliate of Coca-Cola Femsa de Panamá, S.A.

(2) As affiliates of Hilton's franchise owned by the Fashka family in Panama.

(3) The PPA has been executed but we have not begun to supply energy to Petrolera Nacional, S.A. as registration of the PPA with the ASEP is pending, as a result of the COVID-19 pandemic. Pursuant to the terms of the PPA, since the supply period did not start on May 7, 2020, Petrolera Nacional, S.A. has the option to terminate the PPA which, as of the date of this offering memorandum, had not exercised.

In the event that the energy generated by our Tecnisol Solar Project is not sufficient to cover the energy demand of the Tecnisol Customers based on the energy committed under the Tecnisol PPAs, the Issuer and the Guarantors have entered into energy reserve agreements (the "UEP II Energy Reserve Agreements") with the highest priority in the dispatch stack among the UEP II Energy Reserve Agreements and the Tecnisol Third-Party Reserve Agreements. The Guarantors have also entered into Energy Reserve Agreements with seven hydroelectric companies for this purpose (the "Tecnisol Third-Party Energy Reserve Agreements") pursuant to which the Guarantors obtain, upon demand, the energy needed to meet such commitments, with the second highest priority in the dispatch stack among the UEP II Energy Reserve Agreements and the Tecnisol Third-Party Reserve Agreements. For more information regarding the Tecnisol Third-Party Energy Reserve Agreements, see "Business Overview — Our Projects — Tecnisol Solar Project — Terms of the Tecnisol Third-Party Energy Reserve Agreements", and for more information about our UEP II Energy Reserve Agreements and Tecnisol Intercompany Energy Reserve Agreements, see "Certain Relationships and Related Party Transactions — UEP II Energy Reserve Agreements" and "Certain Relationships and Related Party Transactions — Tecnisol Intercompany Energy Reserve Agreements."

Our Market

The Panamanian wholesale electricity market has a well-established regulatory history and has operated in its current structure since regulatory reforms were instituted in 1997 that privatized the IRHE (*Instituto de Recursos Hidráulicos y Electrificación),* a vertically integrated utility. In 1997, Law 6 was passed to decouple the generation, transmission and distribution sectors, and created the current wholesale electricity market structure through the formation of eight private corporations including four generation companies, three Distribution Companies and one transmission company, ETESA. The CND was also created, as a unit of ETESA, to centrally operate the interconnected system and dispatch generation facilities based on lowest marginal cost. Additionally, as part of the MER, Panamanian generators may export up to 300 MW of generation to the five other countries serving as regional partners in the market. An expansion (of up to 600 MW) of the capacity of the SIEPAC (*Sistema de Interconexión Eléctrica de los Países de*

América Central) Transmission Line, which is the regional electric corridor from Guatemala to Panama (1,800 km), is under discussion and is estimated to be completed before 2030. The MER contributes to regional stability and provides an additional opportunity for Panamanian generators to sell power.

In 2016 Panama joined the Paris Agreement, an agreement within the United Nations Framework Convention on Climate Change, dealing with greenhouse-gas emissions mitigation, adaptation, and finance. In line with this commitment and shortly thereafter, the SNE implemented the Energetic National Plan 2015 – 2050 in which the SNE acknowledges and promotes the incorporation of renewable energies into the nation's long-term energy matrix development plan, as well as the increased participation of unconventional renewables energies in the mid and long-term. In addition, on June 10, 2020 the SNE published the national strategy for the transition of energy 2020-2030, in which the Panamanian state outlined various initiatives in order for the energy transition to occur. A number of these initiatives could positively impact us, particularly the electric mobility strategy, an initiative that promotes the use of electric vehicles and installation of charging stations in public areas at a commercial and residential level, and the innovation strategy, an initiative that encourages public institutions to purchase energy as Large Customers through a bidding mechanism exclusively available to renewable energy generator counterparties.

As of March 31, 2020, Panama has a mixed electricity system with a total installed capacity (including autogenerators) of approximately 3,767.5 MW. It has been privatized since 1998 and is a dollarized system. Panama's electricity system has historically relied heavily on hydroelectric power, with much of the generating capacity located in western Panama, close to the Costa Rican border, where the majority of Panama's hydroelectric resources are located. After experiencing one of Panama's worst droughts in 2013 and 2014, the Panamanian government implemented certain regulatory changes to reduce Panama's dependence on hydroelectric generation by promoting other sources of energy. Panama used hydroelectric power to generate 61% of its electricity in 2015. In contrast in the first three months ended March 31, 2020, 40.9% of the electricity generated in Panama was generated using hydroelectric power, 25.7% using LNG, 13.18% using wind power, 7.93% using coal, 6.08% using bunker fuel, and 3.36% using solar power. Panama experienced below average hydrology in 2017 and 2018, and it experienced its driest year on record in 2019. The diversification of the generation matrix in 2019 mitigated the effects of poor hydrology by stabilizing the supply of electricity and reducing spot market volatility during dry conditions. For the nine months ended September 30, 2020 the average spot market price was US$50.22 per MWh, a 76.8% decrease from an average spot price of US$217.05 per MWh in 2014.

Long-term contract auctions account for approximately 80% of the total energy supplied in Panama, and, under the terms of the contracts, ETESA, the government owned transmission company, coordinates the public auction tenders on behalf of the Distribution Companies. Distribution Companies are the country's distribution utilities and are obligated to enter into PPAs for 100% of the expected peak capacity and energy requirements for the next following two years for Regulated Consumers, guaranteeing supply to the country's Regulated Consumers. Panamanian Large Customers can either pay the regulated rates, purchase energy through bilateral contracts or buy energy on the spot market, which is commercially managed by the CND. By 2039 the expected peak capacity may increase up to 3,528 MW of which 2,470 MW is not contracted through PPAs as of the date of this offering memorandum. In this scenario, the Distribution Companies are obligated to contract through PPAs such uncontracted expected peak capacity and we have an opportunity to enter into new PPAs with the Distribution Companies to satisfy such capacity demand.

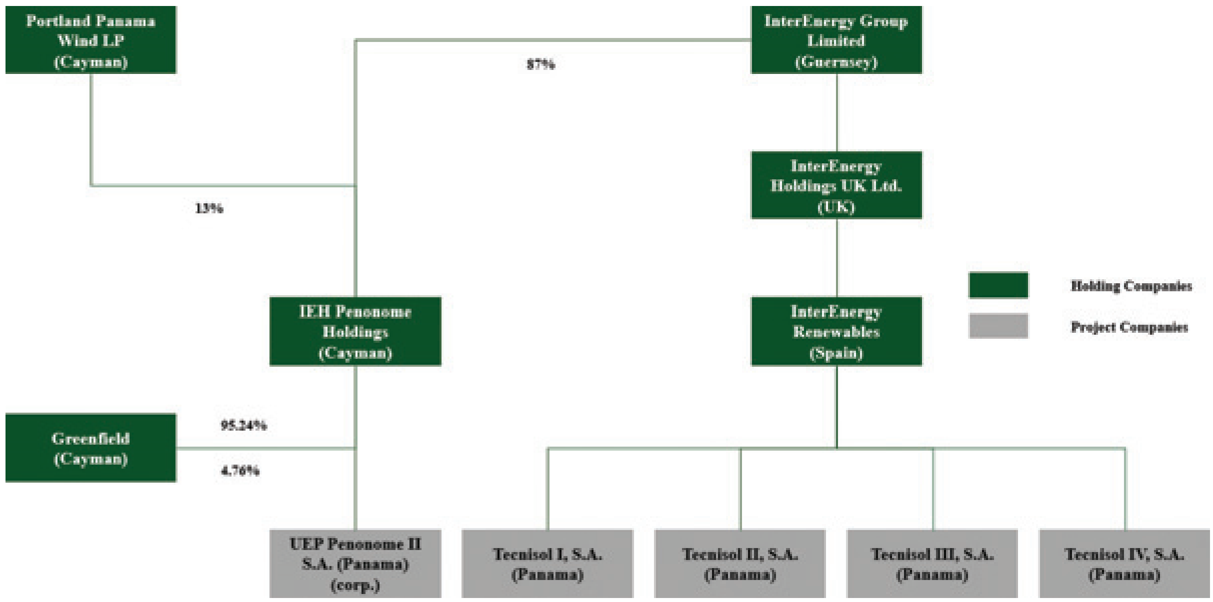
Globally, wind and solar energy have been the two fastest growing sources of electricity generation for the past decade, and projections by the International Energy Agency indicate that these energies will continue to grow at a faster rate than fossil fuels for the next two decades. According to BloombergNEF, businesses around the world signed contracts to purchase 44% more renewable energy globally in 2019 as compared to 2018, bringing the record total to approximately 20 GW of renewable energy sold under PPAs worldwide. Membership in the RE100, a global initiative of more than 200 companies making the commitment to go '100% renewable' by an average target date of 2028, grew by over one third in 2019. In addition, falling technology costs and strong public and private support for renewable energy contribute to increasing demand from purchasers, including corporate ones, and favorable government policies have created an environment supportive of such renewable energy. In its thirteenth annual report, Lazard, a major international investment bank, indicated that over time, the levelized cost of renewable energy generation technologies has continuously declined, and unsubsidized costs are now at or below the marginal costs of conventional generating technology competitors in certain cases. Given this decreased cost of technology, coupled with the increased public and private demand for renewable energy, we believe that there are substantial growth opportunities in our market.

Our Sponsor

InterEnergy Group Ltd. is a developer, owner and operator of energy assets across Latin America and the Caribbean. It manages a regional portfolio of 36 operating assets totaling 1.2 GW in 4 countries, providing reliable, cost-effective and clean energy to the Dominican Republic, Panama, Jamaica, and Chile: Tecnisol, UEP II and Pedregal (Panama), Cacao, (Jamaica), IEG Solar and Raki & Huajache (Chile), CESPM and CEPM (Dominican Republic), of which 334 MW is renewable. It has significant experience in the distribution business in the Dominican Republic as manager of the largest distribution system outside the SIN, and is also a partial owner of a Liquified Natural Gas import and transportation facility in the Dominican Republic. The IFC, a member of the World Bank Group, and the IFC African, Latin American and Caribbean Fund (the "IFC AMC") have supported the development of clean energy in the region and selected our Sponsor for an equity investment of US$100 million to develop cleaner and more efficient energy sources in the Caribbean. In addition, our Sponsor is the first wind operator in the Dominican Republic, and the UEP II Wind Project that it pioneered is the largest wind power facility in the Central American and Caribbean region. Our Sponsor holds a prominent role in the development of renewable power across Central America and the Caribbean and is a leader in renewable energy generation.

Our Corporate Structure

The following diagram illustrates our simplified corporate structure as of the date of this offering memorandum:



Our Competitive Strengths

We believe the following competitive strengths distinguish us from our competitors and are critical to the successful execution of our business strategy.

Largest wind energy company in Central America and the Caribbean

The Issuer owns and operates the UEP II Wind Project, which is the largest wind farm in Central America and the Caribbean, with 215 MW of installed capacity. As part of the SIN and the MER, we have the ability not only to sell our energy in the Panamanian energy market but may be able to export clean energy to five other countries, giving us the unique opportunity to serves as a regional clean energy generator.

Attractive Macroeconomic Fundamentals and Demand Growth Supported by a Diversified Energy Matrix & Sound Regulatory Framework

The Issuer owns its assets and operates in Panama, a country with one of the fastest growing economies in Latin America over the past decade. Panama has attractive macroeconomic fundamentals and steady energy demand growth supported by a diversified energy matrix and a sound regulatory framework. The Panama Canal and the use of the U.S. dollar (eliminating FX risk commonly faced by many of its regional peers) have promoted the strengthening of a globally-oriented and highly developed services sector, growing at an average of 4.4% in the last 5 years, and accounting for 65% of GDP. Panama has achieved an investment grade sovereign rating (Baa1 with negative outlook, BBB with stable outlook, and BBB with negative outlook by Moody's, S&P and Fitch, respectively) and has benefited from the continued access to international debt markets. Panama's strength comes in part from its strategic importance as a regional logistics and financial services hub and regional base which serves as headquarters for more than 160 multinational operations.

Additionally, Panama enjoys a position as an investment grade sovereign with continued access to international debt markets. The Panamanian government has promoted economic growth over the past decade in large part through open market policies and by supporting free trade. Moreover, the government actively encourages foreign direct investment through lax regulation and by guaranteeing ease of business. In particular, Panama has been ranked as seventh in ease of doing business in Latin America and the Caribbean, outperforming Central American peers such as Guatemala, the Dominican Republic and Honduras.

Strong and stable U.S. dollar denominated cash flows derived from long-term PPAs

Substantially all of the Issuer's revenues are derived from long-term PPAs, which provide us with stable and predictable cash flows. The Issuer has committed to sell 76.7% of its total energy generation capacity under the physical energy-only UEP II PPAs with the Distribution Companies for a fixed price (25% of which is partially adjusted based on the Panama CPI) with a weighted remaining average life of 10.04 years. In addition, we have contracted nearly all of the generation capacity of our Tecnisol Solar Project under the financial energy-only Tecnisol PPAs with credit-worthy Large Customers for a purchase price that is initially fixed and adjusted semiannually based on the variations of the Regulated Tariff. In addition, the Guarantors cover any energy supply deficiency under our Tecnisol PPAs through reserve energy agreements, pursuant to which the Guarantors purchase energy from the Issuer and other reserve energy suppliers. As of September 30, 2020, the estimated remaining weighted average life of our Tecnisol PPAs is 12.78 years and the weighted average of all our PPAs is 10.57 years.

Strategically located and highly efficient clean power generation plants

The UEP II Wind Project is located along the southern shores of Panama near the load center, Panama City, and benefits from winds coming from the natural corridor formed between the Central Range (the *Cordillera Central*) using the trade winds coming from the Caribbean Sea. No earth movements were made during the construction of this project, which reduces the risk of soil erosion, and there are no obstacles for wind, which makes this location one of the best locations in Panama for a wind farm. In addition, the transmission grid near the UEP II Wind Project was fully developed before we began construction of the project. As such, costs of connecting the UEP II Wind Project to the main ETESA transmission line were lower than in projects for which the interconnection infrastructure has to be developed from the ground up.

The Tecnisol Solar Project is located in the west of Panama on flat terrain, which allows for optimal irradiation of the panels throughout the day. Additionally, no large earth movements were made during the construction of the Project, which reduces the risk of soil erosion. In addition, the pasture covered area helps to keep the solar panels operating at an optimal temperature. We understand that the location of the Tecnisol Solar Project is one of the highest solar resource areas of the country.

The Projects provide reliable and clean energy to Panama. The generation profile of solar and wind power plants, such as ours, in Panama is advantageous, as it is inversely correlated to the generation profile of hydroelectric power plants, which are the principal source of power in Panama. This is due to increased sunshine and winds during Panama's dry season, thereby supporting Panama's transition to a carbon-neutral power generation matrix with reduced vulnerability to changing hydrological conditions. We estimate that the Projects will eliminate over 132,000 tons of CO2 emissions and save 900,000 barrels of oil per year. According to operation rules issued by ASEP, renewable generation costs are low relative to other sources, positioning renewable sources early in the dispatch stack, even ahead of hydro assets. This gives us an advantage over hydro and thermal power generators in Panama. The Projects are located in areas with strong wind and solar resource, respectively. We believe that our low generation costs compared to the higher generation cost for thermal power plants in Panama is a key contributing factor to our ability to maintain markets share and maximize margin from the sale of electricity in the spot market. In 2019, the UEP II Wind Project and the Tecnisol Solar Project had net capacity factors of 29% and 20.1%, respectively. For a more detailed description of historical wind and solar resource data, please see "Annex B — Independent Engineer Report.".

Reliable high-quality generation assets with widely-used technology

The UEP II Wind Project is comprised of 86 turbines (2.5MW each) manufactured by Goldwind with a total installed capacity of 215 MW and a net capacity factor of 29% in 2019. Goldwind also provides the maintenance of our wind turbines pursuant to the Service and Maintenance Agreement. Goldwind is a world leader in wind power with more than 20 years of experience and more than 60 GW of wind power installed capacity. Our PV modules and module inverters were manufactured by Jinko Solar Import and Export Co., Ltd. ("Jinko Solar") and Jema, respectively. Jinko Solar is a NYSE listed company and one of the largest and most innovative solar module manufacturers in the world, and Jema has more than six decades of experience in the design and manufacture of energy systems. Although we perform the operation and maintenance of the Tecnisol Solar Project with our own personnel and the support of our Sponsor, we have also retained the services of Gonvarri and Jema (who supplied parts and equipment for the construction of and, as such, are familiar with, the Tecnisol Solar Project) for the provision of certain maintenance services pursuant to service agreements with them. We believe that the world class technology we used for the construction of the Projects, coupled with the support and maintenance services rendered by the same manufacturers that provided such technology, creates synergies and advantages that distinguish us from our competitors.

Experienced and skilled strategic sponsor and management

We are owned by InterEnergy, a developer and operator of electric power generation businesses. InterEnergy manages, owns and operates an existing portfolio of 36 operating assets across four countries with 1.2 GW of installed gross capacity in operation. Our Sponsor's Board of Directors, which consists of 11 members, together with the committees of our Sponsor's Board of Directors supervise all subsidiaries that are material to our Sponsor, including us. Our Sponsor supports our operation by providing day-to-day general administration services, business management, technical asset management and operation and maintenance supervision through IEH UK under the UEP II Service Management Agreement and the Tecnisol Management Agreement, which allows us to leverage our Sponsor's managerial expertise and extensive experience in the electricity, construction and finance industries, and from our Sponsor's commitment to developing clean energy infrastructure throughout Latin America and prioritizing environmental, health, safety, compliance, risk management and high operating standards. We believe the support and active involvement of our Sponsor in our business provide us with significant advantages in operations' management. In addition, we believe benefit from our Sponsor's longstanding track record of making successful investment in cutting edge new technologies ranging from advanced gas-fired generation equipment, to smart meters, mobile access, district cooling or thermal energy solutions and electric car charging stations. In fact, we believe that the in-house operation and maintenance expertise of our Tecnisol Solar Project, coupled with the support and know how we receive from our Sponsor under the Tecnisol Management Services Agreement, allows us to save costs in comparison to other generators that fully outsource the service and maintenance of their assets. In addition, we have a highly experienced management team with experience in Central America and the Caribbean in addition to extensive knowledge of and vast experience in the Panamanian energy sector. Our directors and officers have an average of 24 years of experience in the energy industry and collectively 184 years of industry experience. We believe in our management team's capabilities and core understanding of both their own business and the related regulatory environment, enable them to operate efficiently and manage risk effectively.

Our Business Strategy

Continue to pursue a long-term contracting strategy

We continue to seek opportunities to contract mid to long term PPAs with the Distribution Companies and other Large Customers. During the first two years, Distribution Companies are required to contract for 100% of their projected capacity requirements through tenders that are held by ETESA periodically. After such 2-year period, Distribution Companies are required to contract for at least 10% less every two years. From year 15 to year 21, Distribution Companies are required to contract for 30% of their projected capacity. We intend to participate in such tenders to commit the portion of our generation capacity that is not currently contracted under our PPAs. In addition, we intend to sell our energy under PPAs to regulated Large Customers who currently rely on the Distribution Companies to cover their energy needs. Under the current regulations, regulated Large Customers are being incentivized to convert into non-regulated Large Customers since, as non-regulated Large Customers, they are able to negotiate the price of the energy with generators instead of covering their energy needs with the Distribution Companies at the Regulated Tariff. According to the Association of Large Customers of the Electricity Sector (AGRANDEL, by its acronym in Spanish), there is still a potential market to enter into PPAs with regulated Large Customer equal to 30% of the Distribution Companies' demand.

Maintain the sound and efficient operation of our wind and solar power plants

We are committed to maintaining the sound and efficient operation and maintenance of our wind and solar projects to generate predictable and stable cash flows. We have developed an Operation and Maintenance

Plan ("O&M" Plan), which includes all the requisites to operate and maintain the assets correctly. It includes a detailed description of all annual preventive maintenance tasks, the detail of the activities and frequency that need to be contracted to a third part and the corrective maintenance procedures. It also contains the templates for the daily, monthly and annual reports that need to be generated and the notification of incidents. For the servicing and maintenance of the UEP II Wind Project, we have entered into a Service and Maintenance Agreement with Goldwind, the provider of our turbines, and, with the support of IEH UK, an affiliate of our Sponsor, we believe we have developed a sound in-house maintenance program for the Tecnisol Solar Project. Upon the expiration of the current Service and Maintenance Agreement with Goldwind, we currently expect to be able to negotiate and obtain a more competitive contract with Goldwind or another provider given the increased competition for these services in Panama. In addition, we secured certain services agreements with Jema and Gonvarri to ensure that we have services available as needed. We are focused on continuing to achieve high efficiency and availability factors at our Projects and to invest in technology, systems and equipment to further improve efficiency and availability.

Our O&M Plan is further supported by the strategy of the Renewable Division of our Sponsor. Our Sponsor has a long history of experience in the operation and maintenance of power plants including renewable assets in Central and South America that allowed us to leverage on their extensive know-how and allows us the opportunity to continuously improve our procedures and the results of our Projects.

Promote the use of clean energy in Panama

We plan to promote and offer to customers committed to environmental and green goals the possibility of supporting their operations with 100% renewable energy through our Suministro Energia Renovable ("SER") initiative. To service such clients with a sense of commitment to the environment, we developed a web-based platform/interface where our customers can visualize energy consumption, savings and other data that support them in their efforts to achieve their environmental goals. Also, in the services provided to our customers we include detailed information on their energy consumption and pricing that is intended to help them achieve energy savings in their operations We believe that the SER will enable us not only to better serve our current clients, but also to capture new customers with a commitment to clean energy.

As part of our Sponsor's group, we follow strict corporate governance and environmental and social responsibility standards that seek to ensure transparency, accountability and responsibility in the operation of our business set forth by our Sponsor. In terms of sustainability, we seek to be good corporate citizens and operate our business in a manner which complies with applicable legal and environmental regulations. The registration and issuance of certificates of our energy sources through the I-Rec process, once completed, will allow us to credibly demonstrate that the energy consumed derives from renewable sources. Our Sponsor has invested and developed clean energy projects in the Dominican Republic, Jamaica, Chile and Panama and has recently announced a strategic partnership with AES Dominicana to form Energía Natural Dominicana, a company that will commercialize natural gas throughout the Eastern region of the Dominican Republic. The Projects are part of a commitment made by InterEnergy at the Clinton Global Initiative Latin America meeting in 2013.

Moreover, we understand that our Sponsor's environmental and social standards and policies were factors that contributed significantly to the decision by IFC (a member of the World Bank Group), and the IFC African, Latin American and Caribbean Fund, to make a US$100 million equity investment in our Sponsor to develop cleaner and more efficient energy sources in the Caribbean and expand its operations in Latin America. Such high standards uniquely position us to compete, as well as to help our customers transition to clean energy sources and support our customers with their clean energy initiatives.

Summary of Certain Material Agreements

We have entered into several agreements that are material to the ownership, development and operation of our power plants. For a more complete description of these material agreements and related documents, see "Business Overview — Certain Material Agreements."

Experts

Independent Energy Market Report

Mercados Energéticos has prepared the Independent Energy Market Report, see "Annex A." Mercados Energéticos has consented to the inclusion of a copy of the Independent Energy Market Report as Annex

A to this offering memorandum. Mercados Energéticos is an independent international consulting firm that provides technical consulting services covering, among other industries, the energy and utilities sector.

For purposes of preparing its report, the Independent Energy Market Report relied on information provided by us, which included material contingencies and other matters that are not within our control, Mercados Energéticos' control or the control of any other person or entity. You should be aware that actual results may differ, perhaps materially, from those estimated or projected. We cannot give you any assurance that the assumptions used are correct or that the estimates and projections will match actual results of operations. See "Risk Factors — Risks Relating to Our Business — The projections of the wind and solar generation and related revenues of the Projects could prove to be materially incorrect" for more information on the risks related thereto. The summary of and conclusions stated in the Independent Energy Market Report that follow are qualified in their entirety by the report itself, which you should read before making an investment in the Notes.

The Independent Energy Market Report is divided into four chapters and includes the following topics:

- General context to the Panamanian and regional energy market, including supply and demand forecasts, the regulatory framework, as well as drivers of price and the impact of the regional electricity market on domestic prices.
- Mercados Energéticos' view on forward looking electricity prices (on a 2020 real U.S. dollar basis), factoring in fuel prices, demand, generation expansion plans, cost of the new entrants, the regional energy market, and the penetration of renewables into the Panamanian energy market.
- Mercados Energéticos' views on the UEP II PPAs and the Tecnisol Intercompany Energy Reserve Agreements, as well as, the Tecnisol PPAs, the UEP II Energy Reserve Agreements and the Tecnisol Third-Party Energy Reserve Agreements.
- Forecast and validation of the prices (Regulated Tariffs and the PPA price known as Cargo por Energia de Generacion — CEG) of the Projects.
- Identification of the main opportunities and risks incurred by the Projects, as well as proposed mechanisms, actions to mitigate them.

According to the Independent Energy Market Report, conclusions stated in the Independent Energy Market Report include the following:

- The generation installed capacity in Panama has a high component of hydroelectricity (the rainy season runs from May to October), representing approximately 44% of total generation installed capacity in 2019 and approximately 70% in 2018. The electricity demand in Panama has grown at an average rate of 4.6% since 2000, having an average annual growth from 2016 to 2019 of 2.4%, and such electricity demand includes a high percentage of contracted energy by the Distribution Companies (90.5% of the total contracted energy in 2019).
- In the last five years, the expansion of the system has been dominated by thermal power plants and renewables. The main drivers of spot price in Panama was the variation of the crude oil prices (WTI), since most thermal plants uses fuel, and the availability of hydroelectric generation, which is affected by general hydrological conditions.
- In Panama, the Distribution Companies sell energy to Regulated Customers at Regulated Tariffs set by adding charges for transmission grid usage, charges for distribution network usage, and commercialization costs to the electric power purchase cost component.
- According to the National Energy Plan 2015-2050, Panama aims to generate 70% of its energy from alternative renewable sources. The National Energy Plan objective is to have generation of 15% and 30% of Panama's electricity deriving from both renewable and non-hydraulic energy by 2030 and 2050, respectively.
- The Stochastic Dual Dynamic Programming model is used to determine the generation of each wind farm and dispatch depends on merit order. The model breaks the hours of the day into 5 blocks to capture intraday volatility in demand and resource availability, in the case of Panama as the

peak demand tends to be during the midday, the highest demand tends to be block 2 instead of block 1. Mercados Energéticos is able to model Panama's solar generation peak in terms of block 2.

- In Panama, the CND centrally dispatches all the available power units in the generation fleet by ranking them in ascendant order of variable costs aiming to assure to supply demand at the minimum possible cost. The renewable assets have very low variable costs, thus, is ranked first in the merit order of dispatch (versus thermal generation and hydro power plants with reservoirs).
- Mercados Energéticos' view on the energy prices per different horizons of time. In the short-term, energy prices remain low in the context of low prices for commodities and relatively low demand (impact of the COVID-19 pandemic). As from 2025, marginal costs show an average upward trend, in a context of demand growth, relatively limited quantity of additions of new generation projects and increasing fuel prices in the international markets. In the long-term, it is assumed that a highly efficient thermal project (CCGTs running on LNG) are added to achieve energy prices that are compatible with the self-sustained development of the electricity market.
- To determine the prices and demand of the Guarantors' energy, Mercados Energéticos notes the following assumptions: (i) price of the existing contracts significantly decreases between years 2019 and 2021 given (x) the beginning of the new CCGT's contract (350 MW in total) with prices below the average price of the existing contracts and (y) the expiration by year 2020 of near 200 MW of costly existing contracts, (ii) the existing Tecnisol PPAs that expire during the time period between 2020 and 2025 are renewed at a lower price because of an increasing competition among generators (supply surplus) and (iii) from 2030 onwards, the contract market reaches the long term equilibrium price, giving the economic signal to develop new capacity to meet the demand growth.
- Sales to the Tecnisol Customers under the Tecnisol PPAs are valued at the CEG, for which Mercados Energéticos projects the evolution of the CEG (PPA price) of each Tecnisol PPA taking into consideration the base price (initial price), the variations of the Regulated Tariff (calculated on 6-month basis for specific categories of tariffs) and the ceiling and floor prices specified in each Tecnisol PPA.
- The Issuer and the Guarantors commercializes their energy output through long-term energy PPAs with Distribution Companies and Large Customers, respectively. The Issuer does not carry resource risk given that they follow the generation production profile of the generator, while the Guarantors do. If the Guarantors' resources at a given hour are not enough to meet the contracted energy, the Guarantors will purchase energy deficit in the spot market at the hourly spot price, to mitigate this they have entered into energy reserve agreements with other generators and with the Issuer (Rosa de los Vientos, 50 MW).

Independent Engineer Report

UL has prepared the Independent Engineer Report, see "Annex B." UL has consented to the inclusion of a copy of the Independent Engineer Report as Annex B to this offering memorandum. The Independent Engineer Report assesses, among other things, the Projects' site conditions, design, technology, equipment, estimated useful life, guarantees, performance tests and expected performance; operation and maintenance; required environmental and regulatory permits and approvals; and construction cost and schedule. UL is an international firm that provides technical and environmental advisory services to the energy industry.

The summary of conclusions of the Independent Engineer Report that follows is qualified in its entirety by the report itself, which you should read before making an investment in the Notes. Capitalized terms used in the summary below have the meanings ascribed thereto in the Independent Engineer Report. For purposes of preparing its report, the Independent Engineer relied on information provided by us, which included information based upon assumptions about material contingencies and other matters that are not within our control, UL's control or the control of any other person or entity. You should be aware that actual results may differ, perhaps materially, from those estimated or projected. We cannot give you any assurance that the assumptions used are correct or that the estimates and projections will match actual results of operations. See "Risk Factors — Risks Relating to Our Business — The projections of the wind and solar generation and related revenues of the Projects could prove to be materially incorrect" for more information on the risks related thereto".

Subject to the information and qualifications contained and the assumptions made in the Independent Engineer Report, UL expressed a number of findings and conclusions with respect to the Projects, which opinions are set forth in full in the Independent Engineer Report attached as Annex B hereto. For a complete understanding of the estimates, assumptions, considerations, and calculations upon which these opinions are based, the Independent Engineer Report should be read in its entirety and the below conclusions are only valid when considering the Independent Engineer Report in its entirety.

In summary, UL is of the opinion that:

I. UEP II — Laudato Si Wind Project Summary

- UL evaluated the long-term energy production potential of the UEP II Wind Project based on operational data as of October 5th, 2020. The report presents the results of this analysis and discusses the methods used to develop the future availability, losses, gross and net energy production, as well as uncertainty estimates. UL found that the P90 Annual Energy Production scenario for the evaluation period of 20 years was 471.4 GWh/year with a capacity factor of 25.0%, while P50 was 498.7 GWh/year with 26.5% capacity factor. These numbers are average values provided for the full evaluation period term of 20 years.
- The Project employs Goldwind 109-2.5MW turbines with Sinoma 52.5m blades. UL notes that the operational time-based availability of Laudato Si was impacted from 2016 to 2019 due to blade defects that UL considers mitigated by including preventive actions within our Blades Strategy Plan, including annual inspection as well as tip reinforcements, a global external repair plan, monitoring system to manage risk, and the purchase of 7 sets of blades.
- Analysis performed by UL as of June 18, 2020, assesses the asset life on 20 years which can be extended to 30 years with appropriate maintenance.
- UL performed general wind turbine inspections and blades strategy plan evaluation for the wind project. A general wind turbine inspection was completed and no critical issues found, and no serial defects have been identified and all discrepancies have been noted on a punch list provided to us, by means of summary results per each specific inspection. Discrepancies on the punch list are expected to be addressed by OEM, during the claim process, or by us during the next maintenance cycle. For the blade strategy plan evaluation, specific actions were recommended according to the level of damage of external inspections. All blade repair costs are reflected in the operating expenses assumption. A more thorough review of the blade replacement plan can be found in the report.
- UL finds the foundations, geotechnical, and hydrological conditions acceptable for the design and considers the electrical design typical with some particular comments and clarifications explained in the Independent Engineer Report.
- UL reviewed the executed interconnection agreement and concludes that it is a standard agreement used for renewable energy projects in Panama with ETESA.
- UL finds Goldwind HK services provisions pursuant to the Turbine O&M Agreement in terms of predictive, preventive and corrective works to be suitable for the Project, however it notes that claims relating to the blades are excluded and thus must be contemplated in the operating expenses estimates. Considering the blades are excluded from the SMA's first amendment, UL considers the scope of services provided under the SMA to be comprehensive and suitable for the Project. This is due to the fact that reasonable operating expenses and US$1 million have been proposed for O&M maintenance reserve accounts.
- The available contract for the O&M of the BOP is currently being negotiated in order to address UL's recommendations regarding the scope, price and warranties.
- From a technical perspective UL considers that the project is in compliance with the local permits with the exception of the official response from Panama's National Authority of Civil Aviation regarding a construction expansion or structure modification for 20 wind turbines. We have requested a copy of this document from the National Authority of Civil Aviation.

II. Tecnisol — Tecnisol Solar Project Summary

- UL performed the energy production estimate for the Tecnisol Solar Project and UL estimated the energy production for the repowering scenario as per the information provided by us. Details of repowering strategy are included, with an additional capacity to be installed every 5 years of 1.7 MWp. UL found that for a 25-year evaluation period the P90 Annual Energy Production scenario was 79.63 GWh/year with an AC capacity factor of 22.3%, while P50 was 87.51 GWh/year with 24.8% capacity factor.
- While the Tecnisol Solar Project is an operating project and dispatches to Large Customers pursuant to their PPAs since August 2018, the Final Acceptance certificate was issued on February 1, 2020, while COD acceptance certificate under the Tecnisol Solar Project EPC Agreement was issued on October 2, 2020. UL notes that the COD certificate from CND, defined as CEOC under the Tecnisol Solar Project EPC Agreement, is still pending due to a requirement of the grid code compliance test (response time required). UL was informed that the EPC Contractor proposed solution is pending to be approved by the inverter manufacturer, which is going to provide a PSS simulation to verify the grid code compliance by November 2020. UL notes that the Project is under normal operation since the COD certificate from CND is not required to operate. However, UL recommends a follow up on the grid code compliance solution to obtain the COD from the CND.
- In regard to performance ratio, UL noted that the main issue detected during construction was the isolating failure detected on part of the DC cabling. There are two brands of DC cabling, one of them represents 65% of the total cabling, 13% of which generated energy production losses. To avoid further issues, the Tecnisol Solar Project is expected to replace all 65% with new DC cabling by November 30, 2020. As of the report date, 50% of the total cabling has been replaced, with the remaining 15% pending. Only 2.6% of DC cabling is generating isolation failure. UL considers the issue as a risk that should be solved by the replacement of the affected DC cabling.
- The Tecnisol Solar Project employs Jinko solar modules with a 10-year workmanship and 25 years performance warranty which is considered to be industry standard and a Jema inverter with a 10-year warranty (industry standard) which the Guarantors are planning to extend to 25 years, UL considers the TracSmart warranty for the trackers to be industry standard.
- Analysis performed by UL assumed the asset life to be 25 years, which is considered to be industry standard.
- UL considers the hydrological investigation to be aligned with good practices. In regard to civil documentation, UL notes that it was not possible to determinate the soil structure stability due to the lack of information. Sponsor confirmed that a complimentary geotechnical investigation has been performed during October 2020 in order to determine the pending characteristics of the soil. UL concludes that the study demonstrates that the soil has swell and shrinking properties that need to be monitored during the entire operational period of the Tecnisol Solar Project.
- UL considers the O&M price to be aligned with industry standard based on the scope of services included and the project characteristics.

III. Financial Assessment

- UL reviewed our inputs considered in the financial model, with particular focus on the operating expenses, generation (P50(1), P90(1) and P99(1)), and revenue assumptions associated with the UEP II Wind Project and Tecnisol Solar Project. UL has not performed any review of other inputs like indexation or financial aspects and did not check our financial model formulation, audit, or further considerations beyond the review of the mentioned inputs.
- With regard to operating expenses, UL considers that the maintenance structure and scope of services are aligned with the industry standards. Long-term operating expenses assumptions consider, apart from the indexation (not reviewed by UL), blade replacement costs and future turbine O&M agreement costs for UEP II Wind Project and future corrective costs for the Tecnisol Solar Project after the inverter warranty (10 years) expiration. All in all, UL considers that spare part cost is reasonable and aligned with industry standard.

- Repowering of Tecnisol's assets is being considered every 5 years by installing additional 1.7 MWp capacity to compensate the normal degradation of the PV modules.
- Portfolio benefit analysis including the Tecnisol's repowering, provides an incremental generation for a 15-year evaluation period of 1.3% equivalent to 6.7 GWh on a P90 Annual basis and incremental 0.6% equivalent to 3.5 GWh on P75 Annual basis.
- For the Issuer and the Guarantors, the evaluation period assumed is 20 years and 25 years, respectively. The UEP II Wind Project and the Tecnisol Solar Project capacity is consistent with information provided.
- UL states that revenue assumptions and the UEP II PPAs and the Tecnisol PPAs capacity align with the UEP II PPAs and the Tecnisol PPAs' payment rate stated in the UEP II PPAs and the Tecnisol PPAs reviewed by UL.
- The financial model considers a single reserve account of US$1 million to cover maintenance and unexpected O&M costs that are excluded from the O&M contracts for the UEP II Wind Project and Tecnisol Solar Project, that may be constituted by a letter of credit and will be replenished each year if used. UL considers that this reserve account is reasonable.

Recent Developments

The COVID-19 Pandemic in Panama

In December 2019, the novel COVID-19 virus was reported in Wuhan, China. The COVID-19 virus has since spread to more than 175 countries, and the World Health Organization declared COVID-19 a global pandemic. The magnitude and duration of the COVID-19 pandemic and its impact on Panama's economy, social and public health situation is uncertain as this continues to evolve domestically and globally. As of November 1st, 2020, Panama reported 134,336 cases and 2,706 fatalities.

- On March 9, 2020, the Panamanian Ministry of Health reported the first confirmed case of COVID-19 in Panama.
- On March 13, 2020, Cabinet Resolution No. 11 declared a national state of emergency and directed government agencies to address this public health emergency.
- On March 17, 2020, the Panamanian government instituted a curfew throughout Panama for the entire population, from 9:00 p.m. to 5:00 a.m., as a preventive measure against the COVID-19 pandemic. On March 24, 2020, a 24-hour curfew was implemented, starting at 5:01 a.m. on March 25.
- On March 19, 2020, Executive Decree No. 499 declared the provinces of Panama, Panama West and Colón to be epidemic zones subject to sanitary control.
- On March 19, 2020, President Laurentino Cortizo ordered the suspension of all international passenger flights into and out of Panama, beginning on Sunday, March 22, 2020, for a period of 30 days that was later extended until June 23, 2020 and further extended to August 21, 2020.
- On March 24, 2020, President Laurentino Cortizo decreed a total curfew throughout Panama starting on March 25, 2020 at 5:01 A.M., pursuant to which non-essential businesses were closed and citizens are allowed to leave their homes for a maximum of two hours per day to buy food, medicine and basic necessities. Schools and universities were closed nationwide and gatherings of more than 50 people were prohibited. Businesses engaged in the provision of public services, hospitals, pharmacies, gas stations, supermarkets, food delivery services, the energy sector and emergency services, among others, were exempt from the curfew. The curfew also imposed travel and mobility restrictions based on people's gender and ID number. As of the date of this offering memorandum, the curfew has been lifted except for every day of the week between 11p.m. and 5a.m., which as of the date of this offering memorandum continues to be maintained without any official termination or expiration date. Nevertheless, a more limiting curfew has been implemented in certain cities and provinces.
- On March 31, 2020, Cabinet Resolution No.19 mandated the Distribution Companies to provide discounts on energy bills to certain consumers and provided for the funding of a tariff stabilization

fund (*Fondo de Estabilización Tarifaria*) through which the Panamanian government is expected to compensate the Distribution Companies for discounts provided to consumers.

- On May 4, 2020, Law 152 mandated a moratorium on payment of certain basic services, including electricity, for a period of four months for people and businesses meeting certain criteria. During this period, service providers are not permitted to disconnect these consumers' service for failure to pay or charge them late fees or interest on late payments.
- On May 11, 2020, a phased reopening was declared, and the second economic block, which includes public construction, non-metal mining, industry, places of worship and social sporting areas were opened on June 1, 2020.
- On May 21, 2020, ASEP issued Resolution No. 16094-Elec prohibiting service providers from disconnecting any end consumer's service, regardless of whether the consumer satisfies the criteria established by Law 152, issuing a moratorium on payments for the period between March and June 2020, and allowing the end customers to cancel the debt in 36 months without surcharges.
- On May 21, 2020, ASEP issued Resolution No. 16095-Elec that provides that payments under any PPA may be reduced in proportion to the deficit in income incurred by the Distribution Companies and imposes a moratorium on electricity generators' right to terminate PPAs for non-payment.
- On August 25, 2020, the Panamanian government announced that by October 12, 2020 the following activities or industries were allowed to open: cultural and creative industry, schools of music and art, hotels, other accommodation places and related services, libraries, pools, international aviation, tourism activities, non-essential transport, and the national lottery.
- In response to the COVID-19 pandemic, the Panamanian government has adopted a series of measures which involve:
  - the construction of new hospitals and procurement of medical supplies;
  - the distribution of free food packages and a US$80/month "solidarity payment", which as of April 16, 2020, had reached more than 588,736 families in need; and
  - tax relief through extended payment deadlines.

These measures are funded by the government through facilities including a US$2.5 billion sovereign bond issuance and up to US$1.3 billion available from the Panama Savings Fund (*Fondo de Ahorro de Panamá*). Multilateral organizations have also provided financial support for these measures, including the IMF, through a SDR 376.8 million (about US$515 million) rapid financing instrument loan.

Certain of Panama's neighboring countries and trade partners have imposed similar measures in an attempt to contain the spread of the COVID-19 virus, but others have not taken action. There can be no assurance that the measures taken by Panama and these other countries will successfully contain the spread or mitigate the social, health and economic impact of the COVID-19 pandemic. The COVID-19 pandemic has led to increased volatility and decreased economic activity, which has negatively impacted the financial condition of the Panamanian public and Panamanian businesses, including certain of our customers and has reduced the overall demand for electricity. When comparing the third quarter of 2020 against the first quarter of that same year, the COVID-19 pandemic reduced Panamanian power demand by 9.9%, 9.2% in generation and 38.2% in spot prices. Between April and September 2020, electricity demand decreased by 9.48% compared to demand in 2019 within the same months, although since April a slow upside trend is observed, and by October 2020, demand has nearly reached 2019 values. Spot prices in Panama during the COVID-19 pandemic have also decreased 30.94% by August, 2020, since Panama entered total lockdown on March 25, 2020. Electricity demand in September began to increase, but with arrival of the wet season and the corresponding increase in hydroelectric plant generation, prices continue to be low reflecting the increased supply. In addition, as a result of government measures, the Distribution Companies have temporarily reduced tariffs to consumers and suspended shut-offs for non-payment, which has reduced the Distribution Companies' revenue and impacted their ability to make timely payments to generators under their PPAs, including our UEP II PPAs. For example, we have been able to collect 74.51% of the aggregate amount invoiced to the Distribution Companies under the UEP II PPAs between March and June. These government measures have also allowed any outstanding payments due to generators under their PPAs to be paid by Distribution Companies on an interest-free basis. For more information, see "Risk Factors — Risks Relating to our Business — The outbreak of the COVID-19 pandemic has had and may continue to have, and a further severe outbreak or an outbreak of another contagious disease could have, a material adverse impact on our operations and financial condition."

We are currently conducting good faith negotiations with the Distribution Companies and the government of Panama to reach a mutual beneficial solution for the collection of the outstanding 25.49% of the aggregate amount invoiced to the Distribution Companies under the UEP II PPAs between March and June 2020. For additional information regarding the impact of the COVID-19 pandemic on our business, see "Risk Factors — Risks relating to our Business — The outbreak of the COVID-19 pandemic has had and may continue to have, and a further severe outbreak or an outbreak of another contagious disease could have, a material adverse impact on our operations and financial condition" and "Management's Discussion and Analysis of Financial Condition and Results of Operation — Trends and Factors affecting our Results of Operations — Effects of the COVID-19 Pandemic."

Our Response to the COVID-19 Pandemic

We adopted a number of measures to maintain the continuous and uninterrupted operation our businesses and the well-being of their employees, including:

- implementing remote working for corporate and administrative employees;
- issuing and implementing a health and safety protocol in compliance with the legal framework of Panama and the World Health Organization;
- creating a detailed plan to reopen office and workspaces gradually depending on the status of transmission;
- treatment and prevention of COVID-19 infections;
- requiring that employees who work on site use masks and observe social distancing guidelines and limiting;
- contractor site visits to those which are essential to the business;
- issuing a temporary ban on business travel;
- issuing a protocol for notifying our management of COVID-19 infections; and
- establishing clear quarantine procedures before allowing employees to return to work.

We will follow the global corporate guidelines as well as guidelines and regulations issued by the Panamanian Government and the World Health Organization before permitting corporate and administrative employees to return to work.

The Refinancing and Recapitalization Transaction

As described in more detail under "Use of Proceeds," we intend to use the proceeds from the issuance of the Notes to repay in full the IFC Loan and the mark-to-market amounts required to be paid to IFC in order to unwind the IFC Hedge Agreement (the "Refinancing and Recapitalization Transaction"), which currently hedges the floating interest rate risk associated with the IFC Loan. The Common Terms Agreement entered into with the Lenders party to the IFC Loan requires a 30-day irrevocable advanced notice in connection with any voluntary prepayment of the IFC Loan and includes certain limitations on the Issuer's ability to incur into new debt and grant new liens over the Issuer's assets. To facilitate the issuance of the Notes, the creation and perfection of the Collateral securing the Notes (which requires the release of the existing collateral securing the IFC Loan and the IFC Hedge Agreement), the prepayment of the IFC Loan and the unwinding of the IFC Hedge Agreement, the Issuer, the Lenders and the Administrative Agent under the IFC Loan have entered into a Consent Agreement, dated as of November 24, 2020 (the "Consent Agreement"), pursuant to which the Lenders have consented and agreed, subject to certain terms and conditions defined therein, to (a) reduce the prepayment notice period for the prepayment of the IFC Loan from 30 days to 6 business days, (b) amend the Original Panamanian Trust Agreement (as defined below) to allow the Panamanian Trust (as defined below) to secure additional debt (including the Notes), and permit the Panamanian Trust to survive the repayment of the IFC Loan and the unwinding of the IFC Hedge Agreement, (c) grant waivers to certain covenants in the Common Terms Agreement that would prevent the issuance of the Notes prior to repaying in full the IFC Loan and unwind the Hedge Agreement, and (d) grant waivers to certain technical defaults under the IFC Loan related to, among other things, the failure by the Issuer to meet certain construction milestones for physical completion of the UEP II Wind Project, the incurrence of certain expenditures associated with payments to Goldwind related to the arbitration proceedings with Goldwind (see "Business — Legal Proceedings — Arbitration with Goldwind"). All of these amendments and waivers will become effective upon repayment in full of the IFC Loan and unwind the IFC Hedge Agreement. In addition, pursuant to the terms of the Consent Agreement, the Lenders have consented to the unwinding and termination of the IFC Hedging Agreement, which we expect to terminate on or before the issue date of the Notes. For additional information regarding the IFC Loan and the IFC Hedge Agreement, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Indebtedness — The Issuer — The IFC Facility."

As part of the Refinancing and Recapitalization Transaction, as soon as practicable following the consummation of this offering and the repayment in full of the IFC Loan and unwinding of the IFC Hedge Agreement, the Issuer intends to:

(a) repay in full the UEP II Shareholders Loan Agreements (as defined below) with our affiliates IEH Penonomé Holdings (Cayman) and Green Field Panamá, S.A. for approximately US$50 million (For more information on the UEP II Shareholders Loan (as defined below), see "Certain Relationships and Related Party Transactions — The Issuer — UEP II Shareholders Loan Agreements.");

(b) reduce the Issuer's capital and pay a distribution to the Issuer's shareholders for an approximate amount of $14.4 million;

(c) pay US$4.8 million to our Sponsor for overdue fees under that certain Service and Management Agreement dated October 2, 2014 by and between the Issuer and the Sponsor (which has been replaced by the UEP II Management Services Agreement) which the Issuer was not permitted to pay due to the restrictions under the IFC Loan documentation;

(d) grant intercompany loans to the Guarantors to provide the Guarantors with sufficient cash to fund the repayment in full by the Guarantors of the Tecnisol Shareholders Loan (as defined below) for an approximately $41.0 million dollars (For a description of the Tecnisol Shareholders Loan, see "Certain Relationships and Related Party Transactions — The Guarantors — Tecnisol Shareholder Loan Agreement."); and

(e) enter into a fixed-for-floating interest rate swap with an initial notional amount of approximately US$69.21 million with Citibank, N.A., pursuant to which the Issuer will periodically pay an amount calculated using a fixed rate of 3.40% in exchange for a payment from Citibank, N.A. of an amount calculated using a floating rate based on the 6-month London Interbank Offered Rate (the "Citi Swap"). The notional amount of the swap would reduce by approximately US$3.7 million to US$11.9 million per year, have a final maturity date of September 15th, 2031, and a mandatory early termination date on September 15th, 2025, which will result in a termination payment equal to the prevailing mark-to-market on that date. The payment of amounts owed by the Issuer under the Citi Swap will be guaranteed by the Issuer's parent company, InterEnergy Group Ltd., and not secured by the Collateral. Pursuant to the Citi Swap, the Issuer expects to receive an upfront payment from Citibank, N.A. in the approximate amount of US$8.5 million.

Sponsor Corporate Restructuring

Following the issuance of the Notes, our Sponsor intends to reorganize its corporate structure in order to streamline the management of its renewable energy assets portfolio. We expect that, following such reorganization, our Sponsor shall maintain its current beneficial ownership over the Projects and that the security arrangements entered into in connection with the Collateral securing the Notes will remain in full force and effect.

Green Bond Principles

We anticipate that our allocation of an amount equal to the net proceeds from this offering to Eligible Green Projects will be in alignment with the "Green Bond Principles," which are a set of voluntary guidelines for the issuance of green bonds developed by a committee made up of issuers, investors and intermediaries in the green bond market and are intended to promote integrity in the green bond market through guidelines that recommend transparency, disclosure and reporting. The Green Bond Principles have four components:

- use of proceeds for qualifying projects with environmentally sustainable benefits;
- disclosure and use of a process for project evaluation and selection;
- management of proceeds through a formal process to ensure they are allocated to qualifying projects; and
- reporting on the use of proceeds, including on the projects for which funds have been used and their expected environmentally sustainable impacts.

For additional information, see "— Use of Proceeds."

THE OFFERING

The following is a brief summary of certain terms of this offering. For a more complete description of the terms of the Notes, see "Description of the Notes" in this offering memorandum.

Issuer	UEP Penonomé II, S.A.
Guarantors	Tecnisol I, S.A., Tecnisol II, S.A., Tecnisol III, S.A. and Tecnisol IV, S.A., jointly and severally.
Sponsor	InterEnergy Group Ltd.
Notes Offered	US$262,664,000 in aggregate principal amount of 6.500% Senior Secured Notes due 2038 to be issued under the Indenture.
Maturity Date	The Notes will mature on October 1, 2038.
Interest	The Notes will bear interest at 6.500% per annum from December 18, 2021 or from the immediately preceding interest payment date to which interest has been paid, payable semi-annually in arrears on April 1 and October 1 of each year commencing on April 1, 2021 (each a "Scheduled Payment Date") to the holders of record of the Notes at the close of business on March 12 or September 12, respectively, immediately preceding the corresponding interest payment date (each, a "Regular Record Date"). Interest on the Notes will be computed on the basis of a 360-day year of twelve 30-day months.
Amortization	Installments of principal on the Notes will be payable semi-annually on each Scheduled Payment Date of each year beginning on April 1, pro rata (subject to the procedures of the depositary for the Notes) to the registered holder thereof on the immediately preceding Regular Record Date in accordance with the following schedule:

Principal Payment Date	Principal Amount Payable	Percentage of Original Principal Amount Payable
April 1, 2021	US$3,685,000	1.4%
October 1, 2021	US$6,318,000	2.4%
April 1, 2022	US$3,492,000	1.3%
October 1, 2022	US$6,657,000	2.5%
April 1, 2023	US$4,129,000	1.6%
October 1, 2023	US$7,127,000	2.7%
April 1, 2024	US$4,900,000	1.9%
October 1, 2024	US$7,949,000	3.0%
April 1, 2025	US$5,358,000	2.1%
October 1, 2025	US$8,638,000	3.3%
April 1, 2026	US$5,711,000	2.2%
October 1, 2026	US$9,331,000	3.6%
April 1, 2027	US$6,043,000	2.3%
October 1, 2027	US$10,058,000	3.8%
April 1, 2028	US$6,104,000	2.3%
October 1, 2028	US$10,745,000	4.1%

Principal Payment Date	Principal Amount Payable	Percentage of Original Principal Amount Payable
April 1, 2029	US$6,639,000	2.5%
October 1, 2029	US$11,326,000	4.3%
April 1, 2030	US$3,525,000	1.4%
October 1, 2030	US$8,197,000	3.1%
April 1, 2031	US$4,996,000	1.9%
October 1, 2031	US$8,790,000	3.3%
April 1, 2032	US$5,537,000	2.1%
October 1, 2032	US$10,355,000	4.0%
April 1, 2033	US$5,531,000	2.1%
October 1, 2033	US$12,391,000	4.7%
April 1, 2034	US$2,980,000	1.1%
October 1, 2034	US$11,395,000	4.4%
April 1, 2035	US$1,587,000	0.6%
October 1, 2035	US$12,157,000	4.6%
April 1, 2036	US$2,903,000	1.1%
October 1, 2036	US$12,954,000	4.9%
April 1, 2037	US$3,216,000	1.2%
October 1, 2037	US$13,701,000	5.2%
April 1, 2038	US$3,573,000	1.4%
October 1, 2038	US$14,666,000	5.6%

Note Guarantees . . . .

Following the Issue Date, the due and punctual payment of all amounts payable under the Notes, including principal, premium, if any, and interest, together with all other payment obligations of the Issuer and the Guarantors under the Indenture and the Notes, will be unconditionally and irrevocably guaranteed on a senior secured basis by the Guarantors and the future Guarantors.

The Guarantors will guarantee the Notes on the Issue Date. The Indenture will limit the obligations of each Guarantor under its Note Guarantee to an amount not to exceed the maximum amount that can be guaranteed by such Guarantor by law or without resulting in its obligations under its Note Guarantee being voidable or unenforceable under applicable laws relating to fraudulent transfer, or under similar laws affecting the rights of creditors generally.

Ranking . . . .

The Notes will constitute the Issuer's direct and unconditional senior secured obligations, secured by the Collateral, and will rank *pari passu* in right of payment without any preference among themselves and with all Additional Notes (as defined herein), if any, and certain other Indebtedness permitted to be ratably secured by the Collateral under the Indenture, if any, the Issuer and the Guarantors may issue in the future. The Issuer's payment obligations under the Notes will, other than in the case of certain of its tax, labor or other obligations, which are granted preferential treatment over the Notes pursuant to law, at all times rank at least *pari passu* in priority of payment with all of its other present and future Indebtedness from time to time outstanding, except that such obligations will be effectively subordinated to any future Indebtedness of the Issuer and the Guarantors that is secured by Liens on assets that do not secure the Notes, to the extent of the value of the assets securing such Indebtedness, and will rank senior in priority of payment to all its present and future unsecured (to the extent of the value of the Collateral) or subordinated obligations from time to time outstanding.

The Note Guarantees will constitute the Guarantors' direct and unconditional senior secured obligations and will rank *pari passu* in right of payment without any preference among themselves and certain other Indebtedness permitted to be ratably secured by the Collateral under the Indenture, if any, that any such Guarantor may issue in the future. Each Guarantor's payment obligations under its Note Guarantee will, other than in the case of certain of its tax, labor or other obligations, which are granted preferential treatment over the Note Guarantee pursuant to law, at all times rank at least *pari passu* in priority of payment with all of its other present and future senior secured obligations from time to time outstanding, except that such obligations will be effectively subordinated to any future Indebtedness of the Guarantors that is secured by Liens on assets that do not secure the Note Guarantees, to the extent of the value of the assets securing such Indebtedness, and will rank senior in priority of payment to all its present and future unsecured (to the extent of the value of the Collateral) or subordinated Indebtedness from time to time outstanding.

All obligations in connection with the Notes are solely obligations of the Issuer and the Guarantors, secured under the Security Documents by the Collateral, with no recourse to any other Person or entity.

As of the Issue Date, and after application of the proceeds of this offering and the Refinancing and Recapitalization Transaction, the Issuer and the Guarantors will have no principal amount of Indebtedness for borrowed money other than the Notes.

Collateral . . . . The obligations of the Issuer with respect to the Notes and the performance of all other obligations of the Issuer under or relating to the Indenture and the Secured Debt Documents will be secured by the following Collateral package:

(i) Funds from the Issuer and the Guarantors to be deposited in the Panamanian Trust accounts as described in "Description of the Notes-Summary of Panamanian Trust Accounts Structure;"

(ii) A Panama-law governed mortgage over all current and future or additional real property of the Issuer as well as all of the improvements thereon and also a usufructuary right over the proceeds of the mortgaged assets;

(iii) A Panama-law governed chattel mortgage over certain moveable assets of and agreements entered into by the Issuer, future moveable assets belonging to the Issuer the value of which exceeds individually US$50,000, as well as over the rights of the Issuer to receive payments under the mortgaged agreements for the benefit the Issuer;

(iv) A Panama-law governed chattel mortgage over certain moveable assets of and agreements entered into by the Guarantors (including land lease agreements), future moveable assets belonging to each Guarantor the value of which exceeds individually US$50,000;

(v) One Panama-law governed pledge over all the shares of the Issuer;

(vi) One Panama-law governed pledge over all the shares of the Guarantors;

(vii) A Panama-law governed assignment agreement providing for the (i) unconditional assignment of certain accounts receivable and other contractual rights of the Guarantors to receive payments under certain contracts to which the Guarantors are a party and (ii) the conditional assignment of certain contractual rights, including the Tecnisol PPAs; and

(viii) A Panama-law governed assignment agreement providing for the (i) unconditional assignment of certain accounts receivable and other contractual rights of the Issuer to receive payments under certain contracts to which the Issuer is a party and (ii) conditional assignment of certain contractual rights, including the UEP II PPAs.

For a description of the Collateral, see "Description of Collateral." The rights and interest of the holders of the Notes in the Collateral are subject to certain risks. See "Risk Factors — Risk related to the Notes."

Intercreditor Agreement	The security over the Collateral is subject to the provisions of an intercreditor agreement, to be entered into on or around December 18, 2020, among the Issuer and the Guarantors, Citibank, N.A., as Intercreditor Agent and Indenture Trustee, The Bank of Nova Scotia (Panamá), S.A., as Collateral Trustee and the other parties thereto from time to time (the "Intercreditor Agreement").
Mandatory Redemption	The Notes will be subject to mandatory redemption prior to their Stated Maturity at a redemption price equal to 100% of the outstanding principal amount of the Notes being redeemed, plus accrued and unpaid interest to the redemption date, plus Additional Amounts, if any (but without payment of any premium), payable in respect of the Notes. The proceeds being applied to a mandatory redemption of the Notes will also be applied pro rata to the repayment and/or redemption of principal, accrued and unpaid interest, and Additional Amounts, if any, payable in respect of any

	Additional Debt that is permitted to be ratably secured by the Collateral and, by its terms, requires such redemption. In case of a redemption in connection with an Event of Loss, the Issuer and the Guarantors will be required to effect a mandatory redemption of the Notes; provided that notwithstanding any other provision contained in "Description of the Notes — Redemption in Connection with Events of Loss" section, any redemption of the Notes shall be conducted in accordance with the Intercreditor Agreement, including any required sharing of proceeds of any Event of Loss with other Secured Obligations. If the Issuer and the Guarantors are required to effect the mandatory redemption of Notes, the Net Available Proceeds from any such Event of Loss or series of Events of Loss shall be applied to redeem all or a portion of the Notes, as applicable, at a redemption price equal to 100% of the principal amount of the Notes being redeemed, plus accrued and unpaid interest and Additional Amounts, if any, on the Notes being redeemed to the date of redemption on a pro rata basis (or such other basis as required by the applicable depositary for the Notes). See "Description of the Notes — Mandatory Redemption Provisions."
Optional Redemption	Prior to October 1, 2038, the Notes will be redeemable, in whole or in part, at the Issuer's option at any time and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of the Notes to be redeemed or (ii) the sum of the present values of the remaining scheduled payments of principal and interest thereon that would have been payable if redemption had not been made (exclusive of any interest accrued and unpaid to the date of redemption) discounted from the dates on which the principal and interest would have been payable if the redemption had not been made, to the date of redemption on a semi-annual basis (assuming a 360-day year consisting of twelve 30 day months) at the applicable Treasury Rate plus 50 basis points, plus, in either case, Additional Amounts, if any, and accrued and unpaid interest, if any, to, but not including, the date of redemption. See "Description of the Notes — Optional Redemption with Make-Whole Premium."
Optional Redemption upon Tax Event . .	The Issuer may at any time redeem the Notes, at its option, in whole, but not in part, at a redemption price equal to 100% of the then outstanding principal amount of the Notes, plus accrued and unpaid interest thereon to, but excluding, the date of redemption and any Additional Amounts payable with respect thereto, if, as a result of certain changes in tax laws, there is an increase in the additional amounts the Issuer is obligated to pay under the Notes. See "Description of the Notes — Optional Redemption upon Tax Event."
Repurchase Upon a Change of Control Repurchase Event	Except as otherwise described, by no later than 30 days after the occurrence of a Change of Control Repurchase Event,

the Issuer and the Guarantors must give notice thereof to the Indenture Trustee and the holders of the Notes (which notice may be delivered by the Indenture Trustee, upon the written request and at the expense of the Company and the Guarantors) a notice (a "Change of Control Notice") offering to purchase all of the Notes then outstanding on a selected date that is no earlier than 30 days and no later than 60 days (or such additional time as may be required by Applicable Laws) after the date of such notice, which selected date must be a Business Day (such offer, a "Change of Control Offer"). In connection with any Change of Control Offer, the Issuer and the Guarantors will hold such offer open for at least 20 (but not more than 30) Business Days (or such additional time as may be required by Applicable Laws). The Change of Control Notice must advise each holder of the Notes in sufficient detail as to how to tender its Notes should it elect to accept such Change of Control Offer.

The Issuer and the Guarantors will: (a) accept (except to the extent such would violate Applicable Laws) for purchase all or any part (equal to US$200,000 and multiples of US$1,000 in excess thereof) of the Notes that have been tendered in (but not withdrawn from) such Change of Control Offer, and (b) pay (such payment to be made in Dollars) each applicable holder for its Notes a purchase price equal to 101% of the portion of the outstanding principal balance represented by such Notes plus all accrued and unpaid interest (if any) thereon to but excluding the purchase date plus Additional Amounts, if any, payable in respect of such Notes.

In any such Change of Control Offer, a holder may elect to condition its tender of its Notes subject to the condition that a minimum percentage (selected by such holder) of the outstanding principal balance of the Notes has been tendered in (but not withdrawn from) the offer; it being understood that, in determining whether such percentage has been achieved, the Notes of such holder and other holders that have so conditioned their tenders with the same or a higher percentage will not be considered to have been tendered.

If the Issuer and the Guarantors purchase only a portion of an outstanding Note in connection with a Change of Control Offer, the Issuer and the Guarantors will, promptly upon cancellation of the original Note, issue in the name of the holder thereof a new Note in a principal amount equal to the portion thereof not purchased. The unpurchased portion of any Note will not be less than the minimum denomination of a Note specified in Section "Book-Entry; Settlement and Clearance".

If holders of not less than 90% in aggregate principal amount of the outstanding Notes validly tender and do not withdraw such Notes in a Change of Control Offer and the Issuer and the Guarantors, or any third party making a Change of Control Offer in lieu of the Issuer and the Guarantors as described below, purchases all of the Notes validly tendered and not withdrawn by such holders, the Issuer and the Guarantors will have the right, upon not less than 30 nor more than 60 days' prior notice, given not more than 30 days following such purchase pursuant to the Change of Control Offer described above, to redeem all Notes that remain outstanding following such purchase at a redemption price in cash equal to the applicable payment in the Change of Control Offer plus, to the extent not included in such payment, accrued and unpaid interest, if any, thereon, to, but not including, the date of redemption, plus Additional Amounts, if any, payable in respect of such Notes.

The Issuer and the Guarantors will not be required to make a Change of Control Offer upon a Change of Control Repurchase Event if (1) a third party makes the Change of Control Offer in the manner, at the times and otherwise in compliance with the requirements set forth in the Indenture applicable to a Change of Control Offer made by the Issuer and the Guarantors and purchases all Notes properly tendered and not withdrawn under the Change of Control Offer, or (2) notice of redemption has been given pursuant to the Indenture as described above under the caption "Description of the Notes — Optional Redemption with Make-Whole Premium," "Description of the Notes — Optional Redemption upon Tax Event," "Description of the Notes — Redemption in Connection with Events of Loss" or "Description of the Notes — Priority of Payments upon Foreclosure on the Collateral" unless and until there is a default in payment of the applicable redemption price. A Change of Control Offer may be made in advance of a Change of Control Repurchase Event, with the obligation to pay and the timing of payment conditioned upon the occurrence of a Change of Control Repurchase Event, if a definitive agreement to effect a Change of Control is in place at the time the Change of Control Offer is made.

See "Description of the Notes — Repurchase Upon Change of Control Repurchase Event."

Priority of Payments upon Foreclosure on the Collateral . . . . If the maturity of the Notes has been accelerated and if the Collateral Trustee foreclose on or sell substantially all of the Collateral at any time pursuant to the terms of the Security Documents, all proceeds realized in connection therewith must be applied to pay the holders of the Notes for the Notes and other required amounts in accordance with the priority set forth in the Indenture, irrespective of whether such proceeds are sufficient to pay all amounts then due under the Notes but excluding, for the avoidance of doubt, application of any such proceeds to the payment of any premium.

Additional Amounts . . . . If the Issuer and the Guarantors or any paying agent is required to deduct or withhold any amount in respect of Taxes for the account of Panama (or any political subdivision thereof or any authority therein or thereof having the power to tax) or any other jurisdiction (or any political subdivision or any authority thereof or therein) from or through which such payments are made (each, a "Relevant Jurisdiction"), the Issuer and the Guarantors will pay to a holder of a Note such additional amounts as may be necessary so that the net amount received by such holder will not be less than the amount such holder would have received if such Taxes had not been withheld or deducted subject to certain exceptions described under "Description of the Notes — Additional Amounts."

Use of Proceeds	The Issuer and the Guarantors intends to allocate an amount equal to the net proceeds from the sale of the Notes (after deduction of certain fees, expenses and commissions) to finance and refinance Eligible Green Projects. See "Use of Proceeds."
Certain Negative Covenants	The Issuer and the Guarantors will agree under the Indenture to, and will cause the Restricted Subsidiaries to comply with, certain negative covenants, which will significantly limit its ability to, among other things: • incur any debt; • make any restricted payments; • grant, create, incur, assume or suffer to exist any liens; • change the nature of its business; • consolidate or merge into any other person; • sell, assign, convey, transfer, lease or otherwise dispose of its properties and assets substantially as an entirety; • make investments; • enter into certain agreements or arrangements with any affiliate; • cancel, terminate or modify any material project document; and • enter into any hedge agreement other than in the ordinary course of business and not for speculative purposes. All of these covenants are subject to a number of significant qualifications and exceptions. See "Description of the Notes — Negative Covenants of the Issuer and Restricted Subsidiaries."
Certain Affirmative Covenants	The Issuer and the Guarantors will agree under the Indenture to, and will cause the Restricted Subsidiaries to comply with, certain affirmative covenants, including requirements to, among other things: • preserve and maintain corporate existence; • maintain proper books of record and account; • permit representatives of the holders of the Notes, the Indenture Trustee, and any Collateral Agent under guidance of officers of the Issuer and the Guarantors,

to visit and inspect any of the properties of the Issuer and the Guarantors or the Restricted Subsidiaries and to examine the Issuer and the Guarantors or such Restricted Subsidiary's corporate, financial, operating and other records, no more than one time per year at the expense of the holders of the Notes and at such reasonable times during normal business hours, upon reasonable advance written notice to the Issuer and the Guarantors and with the Issuer and the Guarantors consent (such consent not to be unreasonably withheld);

- comply with all applicable laws (including any environmental laws);
- shall use the net proceeds from the offering of the Notes in the manner set forth in this offering memorandum under "Use of Proceeds;"
- maintain insurance coverage in such amounts and covering such risks consistent with Prudent Industry Practices, subject to any Applicable Laws;
- maintain in full force and effect all consents, approvals or permits of any Governmental Authority required under Applicable Law to be obtained or maintained by it in connection with the construction, operation and maintenance of its respective business and the performance of its obligations under the Material Project Documents and under the Notes, the Indenture and the other Financing Documents to which it is a party, in each case, to the extent failure to so maintain would not reasonably be expected to have a Material Adverse Effect;
- cause all properties used or useful in the Projects and the conduct of its respective business to be maintained and kept in good condition, repair and working order as in its judgment may be necessary so that its respective property and assets may be constructed, acquired, maintained and developed in conformity with the Material Project Documents and the Annual Budget consistent with Prudent Industry Practices and so that its respective business may be properly and advantageously conducted at all times, in each case, except to the extent failure to so comply would not reasonably be expected to have a Material Adverse Effect;
- (i) perform and observe all terms and provisions of the Material Project Documents to be performed or observed by it, (ii) maintain the Material Project Documents to which it is a party in full force and effect, and (iii) exercise all its rights, discretion and remedies, if any, under the Material Project Documents to which it is a party in accordance with their terms and in a manner consistent with (and subject to) the Issuer and the Guarantors and the Restricted Subsidiaries' obligations under the Indenture and the Security Documents, in each case of clauses (i) through (iii) above, except to the extent that

failure to do any of the foregoing could not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect;

- undertake all actions that are necessary to enable the Collateral Agents, on behalf of the Secured Parties, to exercise and enforce their respective rights, powers, remedies and privileges under the Security Documents; and
- prepare, give, execute, deliver, file and/or record any notice, financing statement, continuation statement, public deed, instrument or agreement necessary under Applicable Law to maintain, preserve or perfect any Lien granted under the Security Documents.

All of these limitations and restrictions are subject to a number of significant qualifications and exceptions. See "Description of the Notes — Affirmative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries."

Events of Default	For a discussion of certain events of default that will permit acceleration of the principal of the Notes plus accrued interest, and any other amounts due with respect to the Notes, see "Description of the Notes — Events of Default."
Governing Law	The Notes, the Intercreditor Agreement and the Indenture, will be governed by, and construed in accordance with, the laws of the State of New York, except that certain Security Documents will be governed by Panamanian law, as applicable.
Transfer Restrictions	The Notes have not been and will not be registered under the Securities Act or any applicable United States federal or state securities laws and may not be offered or sold within the United States or to, or for the account or benefit of, any U.S. person (as defined in Regulation S) except in transactions exempt from, or not subject to, the registration requirements of the Securities Act. The Notes are subject to restrictions on transferability and resale and may not be offered, transferred or resold except as permitted under the Securities Act. See "Transfer Restrictions."
Form and Denominations	The Notes will be issued in registered form only, without interest coupons, in denominations of US$200,000 and integral multiples of US$1,000 in excess thereof. The Notes will be initially registered in the name of DTC or its nominee and deposited with the Indenture Trustee as custodian for DTC.
Listing	Application will be made for the listing and quotation of the Notes on the SGX-ST. The Notes will be registered with the SMV and will be listed on the PSE.
Indenture Trustee, Registrar, Transfer Agent, Paying Agent, and, Intercreditor Agent	Citibank, N.A.
Collateral Trustee	The Bank of Nova Scotia (Panamá), S.A.

Singapore Listing Agent	CNPLaw LLP.
Risk Factors	Investing in the Notes involves substantial risks and uncertainties. See “Risk Factors” and other information included in this offering memorandum for a discussion of factors you should carefully consider before deciding to purchase any Notes.

SUMMARY HISTORICAL FINANCIAL AND OTHER OPERATION DATA

The following tables present our summary historical financial and other operation data for each of the periods presented.

The audited balance sheet data of the Issuer as of December 31, 2019, 2018 and 2017, and the audited statement of comprehensive income and loss data of the Issuer for the years ended December 31, 2019, 2018 and 2017 are derived from the Issuer Annual Financial Statements included elsewhere in this offering memorandum. The unaudited balance sheet data of the Issuer as of September 30, 2020, and the unaudited statement of comprehensive income data of the Issuer for the nine months ended September 30, 2020 and 2019 are derived from the Issuer Unaudited Interim Financial Statements included elsewhere in this offering memorandum.

The unaudited combined balance sheet data of the Guarantors as of September 30, 2019, and the unaudited combined statement of comprehensive income and loss data of the Guarantors for the nine months ended September 30, 2020 and 2019 are derived from the Guarantors Unaudited Interim Combined Financial Statements included elsewhere in this offering memorandum. The balance sheet data of the Guarantors as of December 31, 2019 and 2018, and the statement of comprehensive income and loss data of each of the Guarantors for the years ended December 31, 2019 and 2018 are derived from the Guarantors Annual Financial Statements included elsewhere in this offering memorandum.

The Issuer Annual Financial Statements and the stand-alone financial statements of each of the Guarantors as of and for the year ended December 31, 2019 were audited by PwC.

The following tables should be read in conjunction with "Presentation of Financial and Other Information," "Use of Proceeds," "Capitalization," "Management's Discussion and Analysis of Financial Condition and Results of Operations," and the Financial Statements included in this offering memorandum. The results of operations for the historical periods included in the following tables are not necessarily indicative of the results to be expected for future periods. In addition, see "Risk Factors" for a discussion of risk factors that could impact our future financial condition and results of operations.

The Issuer

Statement of Comprehensive Income

	For the nine months ended September 30,		For the year ended December 31,		
	2020	2019	2019	2018	2017
	(in millions of US$)				
Energy revenues	40.337	49.802	56.070	50.310	42.404
Costs of goods and services	(11.812)	(12.256)	(16.289)	(19.572)	(29.150)
Gross profit	28.525	37.546	39.781	30.738	13.254
Administrative expenses	(3.101)	(3.236)	(4.278)	(5.773)	(10.870)
Operating expenses	(4.218)	(4.453)	(6.378)	(5.455)	(4.129)
Total expenses	(7.319)	(7.689)	(10.656)	(11.228)	(14.999)
Operating profit	21.206	29.857	29.125	19.510	(1.745)
Finance cost amortization	(0.598)	(0.598)	(0.797)	(0.797)	(0.797)
Finance cost, net	(24.546)	(27.035)	(28.631)	(20.096)	(24.117)
Total finance cost	(25.144)	(27.633)	(29.428)	(20.893)	(24.914)
Other income	(0.006)	(0.064)	0.561	8.879	—
Profit (loss) before income tax	(3.944)	2.160	0.258	7.496	(26.659)
Income tax	0.176	(2.551)	(1.644)	(2.313)	1.698
Total comprehensive income (loss) for the period and year	(3.768)	(0.391)	(1.386)	5.183	(24.961)

Balance sheet

	As of September 30, 2020	As of December 31, 2019	2018	2017
		(in millions of US$)		
Assets				
Current assets				
Cash and cash equivalents	17.421	25.126	60.837	2.003
Restricted cash	51.165	51.165	—	11.964
Trade and other receivables	7.184	6.988	9.708	5.682
Prepaid expenses	0.690	0.574	0.646	0.591
Total current assets	76.460	83.853	71.191	20.240
Non-current assets				
Plant and equipment, net	233.383	243.796	249.149	317.835
Deferred Income Tax Asset	0.000	—	—	1.041
Derivative financial instrument	0.000	—	0.894	—
Restricted cash	17.272	17.272	17.272	17.272
Goodwill	20.000	20.000	20.000	20.000
Total non-current assets	270.655	281.068	287.315	356.148
Total assets	347.115	364.921	358.506	376.388
Liabilities and Equity				
Current liabilities				
Current portion of long-term debt	12.296	12.803	14.451	15.324
Trade and other payables	26.266	34.248	30.644	36.801
Total current liabilities	38.562	47.051	45.095	52.125
Non-current liabilities				
Shareholders loans	50.000	50.000	50.000	50.000
Derivative financial instrument	18.759	7.822	—	2.962
Lease liabilities long term	8.253	8.385	—	—
Deferred income tax	2.048	2.224	0.580	—
Long-term debt	203.844	220.003	232.009	245.663
Total non-current liabilities	282.904	288.434	282.589	298.625
Total liabilities	321.466	335.485	327.684	350.750
Equity				
Common shares with US$1 par value each authorized and issued 1,050 shares	0.001	0.001	0.001	0.001
Capital Contribution	74.999	74.999	74.999	74.999
Prepaid dividend tax	(0.019)	—	—	—
Accumulated Deficit	(49.332)	(45.564)	(44.178)	(49.362)
Total equity	25.649	29.436	30.822	25.638
Total liabilities and equity	347.115	364.921	358.506	376.388

The Guarantors

Guarantors' Combined Financial Information

Statement of Comprehensive Income

	For the nine months ended September 30, 2020	2019
	(in millions of US$)	
Energy revenues	7.696	9.239
Other income	0.047	0.000
Costs of goods and services	(5.639)	(6.759)
Gross profit	2.104	2.480
Administrative expenses	(0.597)	(0.643)
Operating expenses	(0.241)	(0.008)
Total expenses	(0.838)	(0.651)
Operating profit	1.266	1.829
Finance costs	(0.955)	(1.167)
Loss before income tax	0.311	0.662
Income tax	(0.141)	(0.251)
Profit for the period	0.170	0.411

Balance sheet

	As of September 30, 2020	2019
	(in millions of US$)	
Assets		
Current assets		
Cash and cash equivalents	4.376	7.333
Trade and other receivables	1.368	4.943
Prepaid expenses and other assets	0.782	0.505
Total current assets	6.526	12.781
Non-current assets		
Plant and equipment, net	38.554	41.391
Intangible assets, net	0.241	0.235
Total non-current assets	38.795	41.626
Total assets	45.321	54.407
Liabilities and Equity		
Current liabilities		
Lease liabilities short-term debt	0.033	0.031
Shareholder's loan	39.944	47.812
Trade and other payables	4.305	5.523
Total current liabilities	44.282	53.366
Non-current liabilities		
Lease liabilities long term	0.963	0.980
Total liabilities	45.245	54.346
Equity		
Common shares with US$100 par value each authorized and issued 400 shares	0.040	0.040
Retained earnings	0.095	0.039
Prepaid dividend tax	(0.059)	(0.018)
Total equity	0.076	0.061
Total liabilities and equity	45.321	54.407

Tecnisol I, S.A.

Statement of Comprehensive Loss

	For the year ended December 31,	
	2019	2018[(1)]
	(in millions of US$)	
Revenues	4.621	2.380
Costs of goods and services	(3.934)	(1.855)
Gross profit	0.687	0.525
Administrative expenses	(0.607)	(0.702)
Operating expenses	(0.082)	—
Total expenses	(0.689)	(0.702)
Operating loss	(0.002)	(0.177)
Finance costs	(0.611)	(0.001)
Loss before income tax	(0.613)	(0.178)
Income tax	(0.040)	—
Total comprehensive loss for the year	(0.653)	(0.178)

(1) Unaudited.

Balance sheet

	As of December 31,	
	2019	2018[(1)]
	(in millions of US$)	
Assets		
Current assets		
Cash and cash equivalents	1.046	5.257
Trade and other receivables	0.623	1.314
Prepaid expenses and other assets	0.312	—
Total current assets	1.981	6.571
Non-current assets		
Plant and equipment, net	12.822	13.460
Intangible assets, net	0.248	0.243
Total non-current assets	13.070	13.703
Total assets	15.051	20.274
Liabilities and Equity		
Current liabilities		
Lease liabilities short-term debt	0.007	—
Shareholder's loan	14.697	19.726
Trade and other payables	0.952	0.717
Total current liabilities	15.656	20.443
Non-current liabilities		
Lease liabilities long term	0.222	—
Total liabilities	15.878	20.443
Equity		
Common shares with US$100 par value each authorized and issued 100 shares	0.010	0.010
Accumulated deficit	(0.832)	(0.179)
Prepaid tax	(0.005)	—
Total equity	(0.827)	(0.169)
Total liabilities and equity	15.051	20.274

(1) Unaudited.

Tecnisol II, S.A.

Statement of Comprehensive Income

	For the year ended December 31,	
	2019	2018[1]
	(in millions of US$)	
Revenues	1.563	0.379
Costs of goods and services	(0.752)	(0.134)
Gross profit	0.811	0.245
Administrative expenses	(0.099)	(0.355)
Operating profit (loss)	0.712	(0.110)
Finance costs	(0.299)	—
Income (loss) before income tax	0.413	(0.110)
Income tax	(0.108)	(0.002)
Total comprehensive income (loss) for the year	0.305	(0.112)

(1) Unaudited.

Balance sheet

	As of December 31,	
	2019	2018[1]
	(in millions of US$)	
Assets		
Current assets		
Cash and cash equivalents	0.552	0.135
Trade and other receivables	0.194	0.245
Prepaid expenses and other assets	0.025	—
Total current assets	0.771	0.380
Non-current asset		
Plant and equipment, net	9.157	9.599
Total assets	9.928	9.979
Liabilities and Equity		
Current liabilities		
Lease liabilities short-term debt	0.008	—
Shareholder's loan	8.558	9.248
Trade and other payables	0.906	0.834
Total current liabilities	9.472	10.082
Non-current liability		
Lease liabilities long term	0.257	—
Total liabilities	9.729	10.082
Equity		
Common shares with US$100 par value each authorized and issued 100 shares	0.010	0.010
Retained earnings (accumulated deficit)	0.192	(0.113)
Prepaid tax	(0.003)	—
Total equity	0.199	(0.103)
Total liabilities and equity	9.928	9.979

(1) Unaudited.

Tecnisol III, S.A.

Statement of Comprehensive Income

	For the year ended December 31	
	2019	2018[(1)]
	(in millions of US$)	
Revenues	4.996	1.611
Costs of goods and services	(4.151)	(1.204)
Gross profit	0.845	0.407
Administrative expenses	(0.042)	(0.491)
Operating expenses	(0.001)	—
Total expenses	(0.043)	(0.491)
Operating profit (loss)	0.802	(0.084)
Finance costs	(0.310)	—
Income (loss) before income tax	0.492	(0.084)
Income tax	(0.171)	—
Total comprehensive income (loss) for the year	0.321	(0.084)

(1) Unaudited.

Balance sheet

	As of December 31,	
	2019	2018[(1)]
	(in millions of US$)	
Assets		
Current assets		
Cash and cash equivalents	0.861	0.760
Trade and other receivables	0.734	0.751
Prepaid expenses and other assets	0.260	—
Total current assets	1.855	1.511
Non-current asset		
Plant and equipment, net	9.931	10.473
Total assets	11.786	11.984
Liabilities and Equity		
Current liabilities		
Lease liabilities short-term debt	0.007	—
Shareholder's loan	8.955	9.714
Trade and other payables	2.362	2.344
Total current liabilities	11.324	12.058
Non-current liability		
Lease liabilities long term	0.222	—
Total liabilities	11.546	12.058
Equity		
Common shares with US$100 par value each authorized and issued 100 shares	0.010	0.010
Retained earnings (accumulated deficit)	0.237	(0.084)
Prepaid tax	(0.007)	—
Total equity	0.240	(0.074)
Total liabilities and equity	11.786	11.984

(1) Unaudited.

Tecnisol IV, S.A.

Statement of Comprehensive Income

	For the year ended December 31, 2019	2018(1)
	(in millions of US$)	
Revenues	1.575	0.372
Costs of goods and services	(0.717)	(0.128)
Gross profit	0.858	0.244
Expenses		
Administrative expenses	(0.122)	(0.239)
Operating profit	0.736	0.005
Finance costs	(0.297)	—
Income before income tax	0.439	0.005
Income tax	(0.115)	(0.001)
Total comprehensive income for the year	0.324	0.004

(1) Unaudited.

Balance sheet

	As of December 31, 2019	2018(1)
	(in millions of US$)	
Assets		
Current assets		
Cash and cash equivalents	0.509	0.150
Trade and other receivables	0.233	0.222
Prepaid expenses and other assets	0.030	—
Total current assets	0.772	0.373
Non-current asset		
Plant and equipment, net	8.723	9.109
Total assets	9.495	9.481
Liabilities and Equity		
Current liabilities		
Lease liabilities short-term debt	0.009	—
Shareholder's loan	8.444	9.125
Trade and other payables	0.430	0.343
Total current liabilities	8.883	9.468
Non-current liability		
Lease liabilities long term	0.278	—
Total liabilities	9.161	9.468
Equity		
Common shares with US$100 par value each authorized and issued 100 shares	0.010	0.010
Retained earnings	0.327	0.003
Prepaid tax	(0.003)	—
Total equity	0.334	0.013
Total liabilities and equity	9.495	9.481

(1) Unaudited.

Non-IFRS information

Net Profit to adjusted EBITDA Reconciliation

The Issuer

	For the period of nine months ended September 30,		For the year ended of December 31,		
	2020	2019	2019	2018	2017
	(in millions of US$)				
Net profit (loss)	(3.768)	(0.391)	(1.386)	5.183	(24.961)
Total income tax	(0.176)	2.551	1.644	2.313	(1.698)
Other income	0.006	0.064	(0.561)	(8.879)	—
Financial cost, net	25.144	27.632	29.428	20.893	24.914
Depreciation and amortization	10.456	10.362	13.969	17.535	25.644
EBITDA	31.662	40.218	43.094	37.045	23.899
Adjustment(1)	—	—	—	(6.605)	5.757
Adjusted EBITDA	31.662	40.218	43.094	30.440	29.656

(1) Related to one off adjustments related to the Settlement Agreement (as defined below). For more information regarding the Settlement Agreement, see "Business — Legal Proceedings — Arbitration with Goldwind."

The Guarantors (on a combined basis)

	For the period of nine months ended September 30,	
	2020	2019
	(in millions of US$)	
Net profit	0.170	0.411
Total income tax	0.141	0.251
Financial cost, net	0.955	1.167
Depreciation and amortization	2.165	2.514
EBITDA	3.431	4.343

Issuer and Guarantors (on a combined basis)(1)

	For the period of nine months ended September 30,		For the year ended of December 31, 2019
	2020	2019	
	(in millions of US$)		
Net profit (loss)	(3.598)	0.020	(1.089)
Total income tax	(0.035)	2.802	2.078
Other Income	0.006	0.064	(0.561)
Financial cost, net	26.099	28.799	30.945
Depreciation and amortization	12.621	12.876	17.203
Combined EBITDA	35.093	44.561	48.576

(1) Combined Adjusted EBITDA for the Issuer and the Guarantors does not include any intercompany eliminations (see "Certain Relationships and Related Party Transactions") required for the combination of financial statements under IFRS and is calculated solely by aggregating amounts recorded under

the following line items in the applicable financial statements of the Issuer and each of the Guarantors: (a) with respect to the year ended December 31, 2019, the audited statement of comprehensive income included in the Issuer Annual Financial Statements and in each of the Guarantors Annual Financial Statements, (b) with respect to the nine-month period ended September 30, 2019 and 2020, the statement of comprehensive income included in the Issuer Unaudited Interim Financial Statements and in the Guarantors Unaudited Interim Combined Financial Statements. This information is included only for information purposes and investors are urged to review the financial statements of the Issuer and the Guarantors included elsewhere in this offering memorandum.

Other Operating Data

	For the nine months ended September 30,		For the year ended December 31,		
Energy Generation (GWh)	**2020**	**2019**	**2019**	**2018**	**2017**
UEP II Wind Project	422.8	485.1	546.2	490.6	396.3
Tecnisol Solar Project	54.6	54.8	70.3	N/A	N/A

	For the nine months ended September 30,		For the year ended December 31,		
Availability Factor	**2020**	**2019**	**2019**	**2018**	**2017**
UEP II Wind Project	94.8%	89.9%	90.7%	93.3%	94.6%
Tecnisol Solar Project	98.9%	97.2%	97.8%	N/A	N/A

	For the nine months ended September 30,		For the year ended December 31,		
Net Capacity Factor	**2020**	**2019**	**2019**	**2018**	**2017**
UEP II Wind Project	29.9%	34.4%	29.0%	26.0%	21.0%
Tecnisol Solar Project	20.8%	20.9%	20.1%	N/A	N/A

	For the nine months ended September 30,		For the year ended December 31,		
Energy Sales (GWh)	**2020**	**2019**	**2019**	**2018**	**2017**
UEP II Wind Project	422.8	487.3	549.4	496.5	406.5
Tecnisol Solar Project	97.4	99.5	132.7	N/A	N/A

RISK FACTORS

An investment in the Notes involves significant risks. In addition to the other information contained in this offering memorandum, you should carefully consider the following risk factors before making an investment in the Notes. Any of the following risks below could adversely affect our business, financial condition, results of operations, cash flows, prospects and our ability to repay the Notes, which, in turn, could have an adverse effect on our ability to make payments under the Notes. The risks described below are not the only ones we are facing, or other companies may face in Panama. Additional risks and uncertainties of which we are not aware or that we currently believe are immaterial may also have an adverse effect on our business, financial condition, results of operations, cash flows, prospects and our ability to repay the Notes. If any of the risks described below materializes or occurs, the value of the Notes could decline, and you may lose some or all your investment.

Risks Relating to Our Business

Electricity generated from wind and solar energy depends heavily on suitable wind and solar conditions, respectively. If such conditions are unfavorable or below our expectations, our Projects' electricity generation and the revenue generated from our Projects may be substantially below our expectations.

The revenue generated by our Projects is principally dependent on the number of MWh generated in a given time period. The electricity generated by our Projects depends heavily on wind and solar conditions, which can vary significantly from period to period depending on the wind and solar resource available in a particular period.

The locations where the Projects are built considered wind and solar available resources and other meteorological and soil conditions when they were selected. Critical items such as wind's speed, prevailing direction, seasonal variations, wind turbulence, and salinity corrosion for the UEP II Wind Project and solar irradiation, weather conditions and cloud coverage for the Tecnisol Solar Project were contemplated. Even though we have actual production data for more than five years for UEP II Wind Project and one year for the Tecnisol Solar Project, future production data for wind and solar conditions at these sites, may be affected by variations in weather patterns, including any potential impact of climate change. While an increase in generation from UEP II Wind Project may cause our revenues under our UEP II PPAs to increase, for example, when the "El Niño" phenomenon happens, this results in an increase in the spot price due to dry conditions and we may incur additional costs if we need to purchase energy from other sources to cover our obligations under our Tecnisol PPAs. To the contrary, when the "La Niña" phenomenon occurs, the rainy season is extended which causes a reduction of the high wind season. Conversely, our generation capacity decreases causing a decrease in revenues derived from our PPAs but, since there is an increase in hydroelectric generation, the spot price usually decreases which allows us to cover our obligations under our Tecnisol PPAs at a lower price, if needed. In some periods, the wind or solar resources may fall within the range of our long-term estimates but not within the averages expected for such period. If either the wind or solar resources at the Projects are below P90 probability, our financial results would be below our expectations and we would be adversely affected. Projections of wind and solar resources contained in the Independent Engineer Report included in this offering memorandum as Annex B also rely upon assumptions, which involve uncertainty and require us to exercise considerable judgment. The Independent Engineer Report and the Independent Market Report contain important discussions of the projections and of the assumptions, estimates, and forecasts used in preparing them and we urge you to read the Expert Reports in their entirety. We, or our consultants, may also make mistakes in conducting these studies. Any of these factors could cause the Projects to have less wind or solar potential than expected or cause us to have developed our Projects in ways that do not optimize their potential. If our wind and/or solar energy assessments turn out to be significantly wrong, our business could suffer a number of material adverse consequences, including:

- our energy production and therefore our sales may be significantly lower than we predict; and
- the Projects may not generate sufficient cash flow to make payments of principal and interest as they become due on the Notes.

Operation and maintenance problems at our renewable energy projects, including as a result of natural events, may cause our electricity generation to fall below our expectations.

Our electricity generation production depends upon our ability to maintain the working order of our wind turbines, solar arrays, transmission lines and balance of the plant. A natural disaster, severe weather, accident, failure of major equipment, shortage of or inability to acquire critical replacement or spare parts, failure in the operation of any transmission facilities that we may operate or utilize, including the failure of interconnection to the transmission networks, could require us to shut down or curtail our turbines, solar arrays or related equipment and facilities, impeding our ability to operate our facilities and decreasing electricity generation production and our associated revenues. For example, spare parts for the Projects and key pieces of equipment and know-how related to such equipment may be hard to acquire or unavailable to us. Sources for some significant spare parts, transformers and other equipment are located outside of Panama, which can cause delays in procuring such materials. If we were to experience a shortage of or inability to acquire critical spare parts or know-how related to them, we could incur significant delays in returning to full operation.

We have previously experienced failures in the UEP II Wind Project turbines and the Tecnisol Solar Project and no assurances can be given that potential equipment deficiencies will not in fact continue to occur, that we will always have warranty coverage for any such defects, that the warranty provider would fulfill its obligations under such warranty coverage (including any liquidated damages compensation provisions), that we will have adequate insurance (or insurance at all) to cover business interruption or other costs incurred, or that these or any other such effects will not have a material adverse effect on our business prospects, financial condition and results of operation.

We typically receive warranty protections from our providers and contractor with respect to the turbines, the solar plants components and other civil works performed in our facilities. However, there can be no assurance that such manufacturers or contractors, or other third-party service provider, will be able to fulfill their contractual obligations. In addition, these agreements can vary as to what equipment maintenance risks are fully assumed by the service provider and what equipment failure risks will be repaired at the owner's cost, and disputes can arise as to the interpretation and terms of these agreements. For example, following the installation of the wind turbines in the UEP II Wind Project, we discovered a defect in the blades designed and manufactured by Sinoma Wind Power Blade Co Ltd ("Sinoma") and supplied to us by Goldwind under the Turbine Supply Agreement with Goldwind. Due to the fact that the materials used for manufacturing the blade tips were not consistent with the technical specifications provided by Sinoma, we concluded that such inconsistencies could have created safety issues and additional wear and tear in the operation of our wind project. As a result of such manufacturing defects, we reduced the expected useful life of the blades from 20 years to 10 years and we commenced arbitration proceedings against Goldwind. These arbitration proceedings concluded on May 15, 2018 with the signing of a settlement and release agreement that terminated all pending claims and counterclaims between Goldwind and us on a mutually satisfactory basis, and we have continued to work with Goldwind to develop a tailored maintenance program for our wind turbines and related equipment that take into account all necessary technical and operational considerations. For more information see "Business Overview — Certain Material Agreements — Service and Maintenance Agreement" and "Business Overview — Legal Proceedings." In addition, we recently identified certain cable insulation issues in a portion of the PV modules located at our Tecnisol Solar Project. These insulation issues were detected by us during the commissioning of the project and, after working constructively with the manufacturer of the cables to solve this issue, the manufacturer acknowledged that the cables were partially defective and agreed to replace them. The cost of replacing these cables is covered by the warranties under the Tecnisol Solar Project EPC Agreement.

In the course of our operations, direct or indirect losses may be caused by inadequate internal processes, technological defects, human error or as a consequence of certain external events. The control and management of such risks is normally based on adequate information and personnel training and on the existence of operational procedures and prevention maintenance plans that minimize the likelihood and impact of any of these events. In addition, operational problems such as the degradation of turbine components due to wear or weather or capacity limitations on the electrical transmission network, can also affect the amount of energy we are able to deliver.

The occurrence of any of the foregoing events could significantly reduce revenues or delay collections expected to be received by us, significantly increase the costs of operating the Projects, require substantial capital expenditures or reduce the electricity output of the Projects, any of which could materially adversely affect our ability to make payments on the Notes.

Failure to perform under our PPAs, the early termination or the inability to renew our PPAs upon termination will result in reduced revenue and could materially adversely affect our results of operations and ability to make payments on the Notes.

Our principal assets are the Projects. As a result, in order to make payments on the Notes, we are dependent upon the cash flows produced from the Projects, which are mainly derived from their respective PPAs. These PPAs are subject to termination prior to expiration in certain circumstances, including default by us. In particular, with respect to the PPA with Petrolera Nacional, S.A., registration of the PPA with the applicable regulatory authorities in Panama has not been completed. As such, and because the supply period did not begin on May 7, 2020, Petrolera has the option to terminate the PPA. As of the date of this offering memorandum, Petrolera has not exercised such option.

In addition, under certain Tecnisol PPAs, such PPAs may be terminated by certain Tecnisol Customers upon the payment of a penalty. Our Initial UEP II PPAs have an initial term of 15 years, as well as our Tecnisol PPAs (except for Petrolera Nacional, S.A. which has a PPA term of 10 years) although some Tecnisol PPAs grant the option to renew the agreement or to keep supplying under the terms of the PPAs on a month-to-month basis, our Tecnisol Customers may decide not to renew the applicable Tecnisol PPAs upon expiration. Additionally, if a Tecnisol Customer demands less than 100kW for four consecutive months, such Tecnisol Customer may be classified as a Regulated Customer and the applicable PPA will be terminated. Since such Tecnisol Customer will not be a Large Customer we will not be able supply our energy to such customer under a PPA for at least one (1) year.

When a PPA expires or if it is terminated, it may be difficult for us to secure a new PPA on acceptable terms or timing, if at all. The price received under subsequent arrangements may be reduced significantly, there may be a delay in securing a new PPA until a significant time after the expiration of the original PPA and, in the case of certain Tecnisol PPAs, the penalty for early termination may not compensate us for the loss of future revenues, any of which could materially adversely affect our ability to make payments on the Notes.

Our business depends on a limited number of customers with which we have entered into long-term agreements.

During the nine months ended September 30, 2020 and the years ended December 31, 2019 and 2018, the revenue generated under the UEP II PPAs represented approximately 70.97%, 69.54% and 79.23%, respectively, of our total revenues during such periods. In addition, our installed capacity of our Tecnisol Solar Project is contracted with 8 Large Customers. Therefore, a substantial portion of our revenues derives from the sales of energy under such PPAs. Depending on market conditions and regulatory requirements, it may be difficult for us to secure long-term PPAs with Distribution Companies or other Large Customers, or renew the existing PPAs as they expire. These agreements are in general subject to:

- early termination provisions for the failure of a party to perform its obligations under the agreement;
- suspension or termination provisions for *force majeure* events beyond the control of the parties; and
- standard liability limitations with no specific limit.

There can be no assurance that the Distribution Companies or the Tecnisol Customers that we supply will fulfill their obligations under the applicable UEP II PPAs or the Tecnisol PPAs, or that they will remain solvent. If the Distribution Companies or the Tecnisol Customers were to fail or refuse to perform or become unable to meet their contractual obligations on a timely basis, or if any of these agreements is prematurely terminated, it could have an adverse effect on our business, financial condition, results of operations, cash flows, prospects or our ability to repay the Notes and affect our ability to make payments on the Notes.

We could lose business to competitors, which could adversely affect their operations and financial condition.

We face significant competition from other energy generators for market share for new projects, renewing or entering into new PPAs. Under Law No. 6 of 1997, or the Electricity Law, and ASEP regulations, the Panamanian electricity industry is market-driven and competitive. In this environment, we compete with international private sector operators as well as government-owned entities. New entrants to the market may have certain competitive advantages over us as these new entrants may not obligated to pay certain taxes or to comply with certain employment regulations applicable to us. If we do not compete effectively with other energy generators, our results of operations and financial condition could be adversely affected.

The outbreak of the COVID-19 pandemic has had and may continue to have, and a further severe outbreak or an outbreak of another contagious disease could have, a material adverse impact on our operations and financial condition.

Our facilities may be impacted by the outbreak of certain public health issues, including epidemics, pandemics and other contagious diseases. If a severe outbreak were to occur in or near Panama, it could adversely impact our operations and financial condition. In December 2019, the novel COVID-19 virus affected China, then spread across the globe in the first quarter of 2020. A growing number of cases have been identified in the Americas and the Caribbean, including Panama, its neighboring countries and trade partners.

Panama and certain neighboring countries and trade partners have imposed measures in an attempt to contain the spread of the COVID-19 virus, and others have not taken action. There can be no assurance that the measures taken by Panama and these other countries will successfully contain the spread or mitigate the social, health and economic impact of the COVID-19 pandemic. As further described in "Summary — Recent Developments — the COVID-19 pandemic in Panama," the Panamanian government has taken measures to address the COVID-19 pandemic, some of which have had a negative impact on the financial condition of the Distribution Companies and their ability to make timely payments under PPAs. In addition, the resolutions that institute the payment moratorium permit the Distribution Companies to reduce payments they make under the PPAs in proportion to the reduction in the income they receive as a result of the payment moratorium. There can be no certainty as to whether these measures will be extended or expanded in ways that would aggravate the impact on the Distribution Companies and, by extension, us. In addition, the COVID-19 pandemic has led to increased volatility and decreased economic activity, which has negatively impacted the financial condition of the Panamanian public and Panamanian businesses, including certain of our Tecnisol Customers.

On May 4, 2020, the Panamanian government issued Law No. 152 ("Law 152"), which suspended, for four months, the obligation to pay for electricity, telephone and internet, if the payor satisfied certain conditions, including having had reductions in income because of the COVID-19 pandemic. Considering that several participants in the wholesale electricity market, including the Distribution Companies, may be affected by Law 152, on May 21, 2020 the ASEP issued the Resolution AN No. 16095-Elec that allowed certain market participants, including the Distribution Companies, to take certain temporary measures until July 1, 2020. For more information on these regulations, see "Regulatory, Permits and Environmental Matters — The COVID-19 pandemic."

Pursuant to such regulations, if there is a decrease in the income of a Distribution Company as a consequence of the moratorium granted by Law 152 and such decrease is demonstrated to the ASEP, the Distribution Companies may reduce its monthly payments obligations under its PPAs, such as the UEP II PPAs, proportionally to such Distribution Company's decrease in monthly revenue. If the suppliers under such PPAs, such as us, do not agree with such reduction, the parties may resolve their dispute in an arbitration proceeding with the ASEP.

A substantial portion of our revenues derive from the UEP II PPAs with Distribution Companies so a reduction on the payments owed by the Distribution Companies under our UEP II PPAs pursuant to the terms of the emergency regulations described above, or any extension or new regulation that the Panama government may issue in response to the COVID-19 pandemic, could have an adverse effect on our business, financial condition, results of operations, cash flows, prospects and affect our ability to make payments on the Notes. In fact, between March and June, we have been able to collect 74.51% of the aggregate amount invoiced to the Distribution Companies, who have cited Law 152 to withhold the payment of the remaining 25.49% of the amounts invoiced. We are currently discussing a mutually beneficial solution to this claim.

The Panamanian government is expected to fund the Tariff Stabilization Fund to compensate Distribution Companies for any mismatch between the payments they receive from consumers and the payments they owe to generation companies as a result of these measures. See "Regulatory, Permits and Environmental Matters — The COVID-19 Pandemic."

In addition, our Tecnisol Customers under the Tecnisol PPAs could be affected by the effects of the COVID-19 pandemic or the measures taken by the government. For example, as a consequence of the shutdown regulations, Hilton, one of our Tecnisol Customers, had to close its hotel and casinos. Since Hilton has been unable to operate in Panama they have decreased their consumption and have defaulted upon their payment obligations under the applicable PPA, which, as of September 30, 2020, amounted to US$0.261 million. Following such default, Hilton proposed repaying the total amount due in ten (10) monthly installments, starting in November 2020. Such proposal was accepted by us and as of the date of this offering memorandum, the first installment had been paid by Hilton. While we are proactively working with them to solve this situation, an increase in defaults under our Tecnisol PPAs could have a negative adverse effect on our results of operations and financial condition. For a discussion of the effect of the COVID-19 pandemic on our results of operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Trends and Factors Affecting Our Results of Operations — Effects of the COVID 19 Pandemic."

Should the COVID-19 pandemic continue, the Distribution Companies or our Tecnisol Customers could become unable to make payments under their PPAs, which would have a negative impact on our results of operations. The extent to which the COVID-19 pandemic and its lingering economic effects will impact our results will depend on future developments, which are highly uncertain and cannot be predicted.

The projections of the wind and solar generation and related revenues of the Projects could prove to be materially incorrect.

The Independent Engineer Report attached to this offering memorandum as Annex B contains important discussions, estimates and forecasts, including degradation of the machinery and site weather conditions used in preparing the forecasted energy Production at our Projects' sites. We urge you to read the reports in their entirety. The Independent Energy Market Report contains projections of the spot price and Regulated Tariff based on assumptions about the Panamanian wholesale electricity market such as future demand growth, capacity additions to the system, growth of the transmission capacity in the country, hydrology conditions, among others. We urge you to read the reports in their entirety.

Without limiting the generality of the foregoing, electricity generated and revenues produced by wind and solar energy projects depend heavily on wind and solar conditions, which are variable and difficult to predict. It is possible that the future wind and solar patterns and electricity production at the Projects will not reflect the historical wind and solar patterns at the Projects' sites or the projections set forth in the Independent Engineer Report.

If in the future the wind and solar resources in the areas where the Projects are located are lower than expected, electricity production at the Projects and our operating cash flows will be lower than expected, perhaps significantly so, and consequently could materially adversely affect our ability to make payments on the Notes.

Seasonality may cause fluctuations in our revenue and operating results.

The electricity and revenue generated by our equipment at the Projects are highly dependent on climatic conditions, particularly wind and solar conditions, which vary across seasons and are difficult to predict. Operating results for wind and solar projects can vary significantly from period to period depending on resource availability during the periods in question. For example, the high wind season in Panama is usually from December until April, so generation of electricity from the UEP II Wind Project in the first quarter is usually higher than the rest of the quarters. In addition, weather in Panama is highly affected by the "El Niño" and "La Niña" phenomena, which cause for electricity generation by the Projects and the spot price in the Panamanian wholesale electricity market to significantly vary during the occurrence of such phenomena. While an increase in generation from UEP II Wind Project may cause our revenues under our UEP II PPAs to increase, we may incur additional costs if we need to purchase energy from other sources to cover our obligations under our Tecnisol PPAs. To the contrary, when the "La Niña" phenomenon occurs, the rainy season is extended which causes a reduction of the high wind season. Conversely, our generation capacity decreases causing a decrease in revenues derived from our PPAs but, since there is an increase in hydroelectric generation, the spot price usually decreases which allows us to cover our obligations under our Tecnisol PPAs at a lower price, if needed. This seasonality may result in quarter-to-quarter volatility in our operating results.

It may not be possible for us to fulfill our obligations under our Tecnisol PPAs and we may need to purchase energy from the spot market at a price which may be higher than the price at which we sell energy under our Tecnisol PPAs.

Under our Tecnisol PPAs we have assumed the obligation to supply certain amounts of energy to our Tecnisol Customers. If the electricity dispatched from our Tecnisol Solar Project is less than the amount we have contracted under our Tecnisol PPAs, the Guarantors will have to purchase the difference from our suppliers under the Tecnisol Third-Party Energy Reserve Agreements or the UEP Energy Reserve Agreements in order to fulfill our obligations under the Tecnisol PPAs or, if the suppliers under such energy reserve agreements are not able to deliver such energy, we will have to purchase the energy in the spot market. This can negatively or positively impact our results of operations since the costs to purchase the energy under such energy reserve agreements or in the spot market could be substantially higher or lower than the average price at which we sell under our Tecnisol PPAs. Spot prices for energy can be affected by a number of factors that are beyond our control, such as the variable cost of the marginal generator, market demand, weather conditions, seasonality, new market entrants, transmission congestion and new regulations.

Coverage under major equipment warranties may be limited.

Since the warranties under the Turbine Supply Agreement entered with Goldwind have expired, we have extended the term of the existing Service and Maintenance Agreement with an affiliate of Goldwind and amended that agreement to include warranties and guarantees related to our turbines. Such warranties, the warranties that we received from our EPC contractor related to the Tecnisol Solar Project under the Tecnisol Solar Project EPC Agreement, and the warranties granted by manufacturers of equipment of the Tecnisol Solar Project, such as Jema, Gonvarri and Jinko, are subject to certain conditions that, if not satisfied, would limit the coverage of the warranties and guarantees, thus requiring us to incur additional costs to repair the equipment or improve its efficiency, which could have an adverse effect on our financial condition and our ability to make payments on the Notes. For more information of the Turbine Supply Agreement and the Service and Maintenance Agreement, see “Business Overview — Certain Material Agreements — UEP II Wind Project.”

Our ability to operate effectively could be impaired if we lose key personnel or are unable to attract and retain skilled technical personnel.

Our business depends upon the continued efforts, abilities and expertise of our officers and directors, as well as our other key employees and our specialized technical personnel. We believe that the unique combination of skills and experience possessed by our officers, directors, other key employees and specialized technical personnel would be difficult to replace, and that the loss of our officers, directors and key employees or specialized technical personnel could have a material adverse effect on us, including the impairment of our ability to execute our business strategy. There is no assurance that such individuals will continue to be employed by us or that we will be able to attract and retain qualified personnel in the future.

We are not able to insure against all potential risks and our insurance, guarantee and warranty coverage may not be adequate.

We currently maintain customary insurance of the types and amounts that are generally consistent with industry practice and applicable legal requirements. See “Business — Insurance.” Our insurance policies do not, however, fully cover losses as a result of certain events of force majeure or natural disasters, including earthquakes, volcanic eruption, tsunamis, among other things. Our insurance coverage also does not protect against war, terrorist attacks or sabotage, damage due to corrosion, and limits recoveries on serial losses. We generally do not maintain insurance for certain risks such as radioactive contamination, electronic data destruction, and political risk. In addition, our insurance policies are subject to annual review by our insurers and may not be renewed at all or on similar or favorable terms. A serious uninsured loss or a loss significantly exceeding the limits of our insurance policies could have a material adverse effect on our business, financial condition, operational results and our ability to make payments on the Notes.

Additionally, we insure certain of our risks with Panamanian insurance companies as is required by Panamanian law. Although we maintain insurance from Panamanian insurers consistent with industry practice to protect against certain operating and other risks, such as risk of sudden physical loss or damage and business interruption, not all risks are insured or insurable. See "Business — Insurance."

There can be no assurance that such insurance coverage will continue to be available on commercially reasonable terms or at commercially reasonable rates or that the amounts for which we are insured, or that the proceeds of such insurance, will compensate us fully for our losses. In the event there is a total or partial loss of our assets, any insurance proceeds that we may receive in respect thereof may not be sufficient in any particular situation to perform a restoration of such assets to their previous condition. Furthermore, we are subject to a liability limit of US$400 million per occurrence, further limiting our ability to replace a total or partial loss of our assets if multiple assets are damaged at the same time.

In the event of a total or partial loss of our main assets, certain items of equipment may not be easily replaced because they are not insured or may be excessively expensive or so system specific that they are not readily available. Accordingly, notwithstanding that we may have insurance, guarantee or warranty coverage, the location of our assets or limitations on our ability to procure replacement equipment may give rise to significant delays in replacement and thereby cause service interruption which could have a material adverse effect on our cash flows, financial condition and results of operations and could impair our ability to make payments under the Notes.

We depend on information and processing systems to operate our business, the disruption or failure of which could adversely affect our financial condition and results of operations.

Information and processing systems are vital to our ability to monitor the operation and performance of our power assets, to generate adequate invoices to customers, achieve operating efficiencies and meet service targets and standards.

Any disruption or failure of any of these information and processing systems to operate properly could have a material adverse effect on our financial condition and results of operations and, as a result, could impair our ability to make payments under the Notes. Non-scheduled and non-justified disruptions could be subject to administrative fines by our regulators.

We are subject to cybersecurity risks.

Information and processing systems are vital to us and our ability to monitor the operation and performance of our Projects, achieve operating efficiencies and meet service targets and standards. We are subject to cybersecurity risks including unauthorized access to privileged information, technological assaults on our infrastructure aimed at stealing information, fraud or interference with regular service and interruption of our services resulting from the exploitation of these vulnerabilities. Any failure to anticipate, identify or offset such threats of potential cyberattacks or breaches of our security in a timely manner could materially and adversely affect our operations, results of operations and financial condition. Non-scheduled and non-justified disruptions could also be subject to administrative fines by our regulators.

The interests of our shareholders may be contrary to our interests and the interests of the Noteholders.

We are controlled by InterEnergy, our Sponsor. Our Sponsor beneficially owns 82.5% of the Issuer's capital stock, and indirectly owns 100% of the Guarantors' capital stock and has the power to elect all of our directors and officers and has the power to determine the outcome of any action requiring shareholder approvals, except, with respect to the Issuer, for those decisions that require the approval of all the issued and outstanding shares including transactions with related parties, corporate reorganizations and the timing and modifications of the dividends policy. The Issuer's board of directors is responsible for establishing our general business policies and guidelines, as well as our long-term strategy. Pursuant to our articles of incorporation and the Panamanian General Corporations Law (*Ley Sobre Sociedades Anónimas*), our directors and executive officers may be removed at a shareholders' meeting at any time. Our shareholders, therefore, can substantially influence our policies, strategies and day-to-day management and operations. See "Management — Board of Directors," "Management — Management," "Principal Shareholders" and "Related Party Transactions."

In circumstances involving a conflict of interest between our Sponsor, on the one hand, and the holders of the Notes, on the other hand, our shareholders may exercise their ability to control us in a manner that would be adverse to the Noteholders. For example, our shareholders may direct us, or cause our board of directors and/or executive officers to direct us, not to engage in certain activities, to make certain expenditures and dividend payments and/or enter into transactions with affiliates, subject to the provisions of the Indenture and the Notes, which direction may be designed primarily to promote their own goals and not exclusively to enhance our business. We may also be the subject of political debates or be subject to public or political pressure that may change from time to time which may require our shareholders to take certain actions, including those in respect of us, which may be adverse to our interests and the interests of the holders of the Notes.

The impact of such actions and each of these factors may adversely affect our business, results of operations, financial condition and, as a result, impair our ability to make payments on the Notes.

We engage in related party transactions.

We have entered into transactions with related parties. The details of certain of these transactions are set forth in "Related Party Transactions." Related party transactions create the possibility of conflicts of interest with regard to the Sponsor and our management. Such conflicts could cause our management to seek to advance the economic interest of our Sponsor above ours.

In particular, we have entered into Management Services Agreements with IEH UK, an affiliate of our Sponsor, under which we receive several services we need to continue operating and, in the case of the Tecnisol Solar Project, IEH UK provides certain availability guarantees with respect to the Tecnisol Solar Project. We have and expect to continue to pay for the ongoing provision of these services. A portion of these payments are not dependent on our success or profitability. For more information on the Management Services Agreements, see "Certain Relationships and Related Party Transactions."

In addition, the Issuer has entered into two intercompany energy reserve agreements with Tecnisol I, S.A. and Tecnisol III, S.A. whereby the Issuer has agreed to supply energy to Tecnisol I, S.A. and Tecnisol III, S.A. on an as-needed basis. Also, the Guarantors have entered into four intercompany energy reserve agreements among themselves pursuant to which the supplier under the relevant agreement, as applicable, has agreed to supply all energy generated by such supplier that is not previously sold under other PPAs.

IN ADDITION, WE HAVE RECEIVED LOANS FROM OUR SHAREHOLDERS (THE "SHAREHOLDERS LOANS") TO FINANCE A PORTION OF THE CONSTRUCTION OF THE PROJECTS, WHICH WE PLAN TO REPAY WITH THE PROCEEDS OF THE OFFERING OF THE NOTES.

These transactions and agreements could result in a misalignment of our incentives and interests and those of our shareholders.

We are exposed to behaviors incompatible with our ethics and compliance standards.

Given the number of contracts that we are a party to with our local and foreign suppliers and other counterparties, the geographic distribution of our operations and the great variety of actors that we interact with in the course of our business, we are subject to the risk that our employees, contractors, or any person having relations with us may misappropriate our assets, manipulate our assets or information or engage in money laundering or the financing of terrorism, for such person's personal or business advantage. Our systems for identifying and monitoring these risks may not be effective to fully mitigate them in all situations. Such acts may result in material financial losses or reputational harm to us.

There is only limited historical financial information of the Guarantors and of the Projects.

The financial statements of the Issuer included in this offering memorandum are the Issuer's audited financial statements as of and for the years ended December 31, 2019, 2018 and 2017 and the unaudited interim financial statements as of and for the nine-month period ended September 30, 2020 and 2019. However, the financial information of the Guarantors included in this offering memorandum are the Guarantors stand-alone audited financial statements as of and for the year ended December 31, 2019 and the unaudited combined financial statements of the Guarantors as of September 30, 2020 and for the nine-month period ended September 30, 2020 and 2019. We have not included any combined financial statements of the Issuer and the Guarantors. Accordingly, our historical financial information does not reflect our combined results of operations or financial condition or the expected future financial condition, results of operations or cash flows.

In addition, we achieved commercial operation of the UEP II Wind Project in February 2018. While the Guarantors reached the availability required for dispatch, they have not yet achieved commercial operation of the Tecnisol Solar Project due to regulatory approvals. For more information, see "Business — History — Tecnisol Solar Project." Therefore, the limited historical financial information available with respect to the Projects may make it difficult to assess our financial position and operating results for the dates and periods presented, and such limited financial information is not indicative of our future financial position or operating results.

Our level of indebtedness may adversely affect our business, results of operations, financial condition and our ability to comply with our obligations under the notes.

Our outstanding indebtedness as of December 31, 2019, was US$241.965 million and, following the issuance of the Notes and the application of the proceeds as indicated herein, we will continue to have a substantial level of indebtedness. There can be no assurance that, subject to the terms and conditions of the Notes, we will not incur substantial additional debt in the future. A high level of indebtedness could have one or more of the following consequences:

- make it more difficult for us to satisfy our obligations with respect to the Notes;
- require us to dedicate a substantial portion of our cash flows from operations to payments on our debt, which would reduce the funds available for working capital, significant capital expenditures, acquisitions and other general corporate purposes;
- increase our vulnerability to general adverse economic conditions; and
- limit our ability to borrow additional funds and increase the cost of any such borrowing.

We may be unable to generate cash flow from operations or, if necessary, obtain financing in sufficient amounts and on favorable terms to fund our future obligations.

To the extent that we are required to fund future cash requirements, including current and future contractual commitments, from sources other than cash flow from operations and available cash, there is no guarantee that any such debt or financings will be available on reasonable terms or at all. Our access to funding may be limited by existing covenants on permitted indebtedness, and factors beyond our control, such as conditions in the international capital markets and investor perceptions of the risks of investing in Panama and in emerging markets generally. If we are unable to source sufficient funds by accessing the international capital markets on favorable terms or at all, they may not be able to implement our strategy, which could have an adverse effect on our results of operations.

Our property may be damaged and their business interrupted or impaired by the occurrence of natural disasters.

Natural disasters, such as hurricanes, floods, earthquakes or tsunamis, could severely impact our facilities or equipment or cause an interruption in their ability to generate electricity. There can be no assurance that the scope of damages we may suffer in the event of a natural disaster would not exceed the policy limits of our insurance. In addition, the effects of a natural disaster on Panama's economy could be severe and prolonged, leading to a decline in demand for electricity. The occurrence of a natural disaster, particularly one that causes damages in excess of our insurance policy limits, could have an adverse effect on its business, financial condition and results of operations. In addition, if our generation assets become damaged and we determine it will be unable to repair it, we may be required to redeem the corresponding portion of the Notes at par without a premium of any kind. Should an event of loss occur and we be required to redeem a portion of the Notes prior to their maturity, the holders of the Notes may not be able to realize their expected return on that portion of the Notes. See "Description of the Notes — Mandatory Redemption Provisions — General."

Failure to comply with applicable laws and regulations, including in respect of corruption, money-laundering and other illegal or improper activities could have a material adverse effect on our business.

We are subject to a variety of domestic and international laws and regulations, including applicable anti-bribery, anti-money laundering and anti-corruption laws and regulations and sanctions related to doing business with certain persons and countries. These laws and regulations vary by jurisdiction and may not be equally stringent. As part of Sponsor's group, we have policies and procedures specifically designed to promote and achieve compliance by us and our directors, officers, employees and agents with anti-bribery, anti-money laundering and anti-corruption laws.

Although we have implemented policies and procedures to prevent inappropriate practices or violations of law in all relevant jurisdictions, there can be no assurance that these policies, procedures and practices completely eliminate such risks. Any failure by our Sponsor, equity holders, employees, officers and affiliates, customers or suppliers to comply with any of these requirements could have an adverse effect on our business, reputation, result of operations or financial condition.

Risks Relating to Our Industry

Restrictions on transmission system and access to the SIN could affect our capacity to deliver the contracted energy.

The Projects are connected to the main grid in Panama, the SIN, and we deliver our energy at certain connection points in the grid. We provide energy using existing transmission lines that have an open access policy by law. Bottlenecks or failures in or damage to either the National Transmission System, the connection line linking the Generation Facilities to the SIN or transmission restrictions due to technical or design conditions could limit our ability to supply energy to our customers, which could have an adverse effect on our business and financial condition. The SIN is owned by ETESA, the state-owned transmission company, which, pursuant to the market rules issued by the ASEP, is required to indemnify generators for energy they purchase in the spot market when the transmission system is constrained. However, ETESA's ability to indemnify generators such as us depends on its financial condition and, ultimately, the budget or liquidity of the Panamanian government. There can be no assurance that ETESA will meet its indemnity obligations in a timely manner or at all.

In addition, the UEP II Wind Project is connected to the SIN through the El Coco substation, which is owned by UEP Penonome I, S.A. ("UEP I"), an unrelated Third-Party which is the owner of a neighboring wind project. UEP I has been acquired by AES Panama in May 2020 and was absorbed by AES Panama in June 2020. We have the right to interconnect to the SIN pursuant to an Interconnection Agreement with ETESA but we have the right to use the substation through which we connect to the SIN pursuant to the terms of a Shared Assets Access Agreement dated June 15, 2018 (the "Shared Assets Access Agreement") in exchange for a monthly rental fee. The maintenance of the substation is performed by UEP I and we share a portion of the costs incurred. For more information on the Shared Assets Access Agreement, see "Business Overview — Certain Material Agreements — UEP II Wind Project — Shared Asset Access Agreement."

The inability to use the El Coco substation or to access the SIN though our transmission lines due to physical damage, natural disasters (such as earthquakes), failure to adequately maintain the substation, a default under or termination of the Shared Assets Access Agreement or the UEP II Wind Project Interconnection Agreement, or any other reason, would impact our ability to deliver energy into the SIN which could have a material adverse effect on results of operations and our ability to make payments on the Notes.

Bottlenecks and other faults in the transmission system could affect dispatch because most of Panama's plants (including the most efficient ones) are located in western Panama and consumption is focused in eastern Panama. When the transmission infrastructure fails to deliver electricity produced in western Panama to consumers in eastern Panama, plants located in eastern Panama need to be dispatched to maintain the stability in the load center (Panama City). This is called "mandatory generation." Mandatory generation does not affect the spot price, but the party responsible for causing such congestion must pay a compensation to the mandatory generator and to the displaced generators (that is, those generators who would have been dispatched but for the congestion). The mandatory generator is compensated in an amount equivalent to the difference between its variable cost and the spot market price, and the displaced generators are compensated in an amount equivalent to the difference between their respective variable cost and the spot market price (if such difference is positive). Under the UEP II PPAs all the energy produced by the UEP II Wind Project is purchased by the Distribution Companies, but the minimum required generation is very small. If there are faults or congestions in the transmission system that affect the UEP II Wind Project, the Issuer would be a displaced generator that would receive a very small compensation, thereby reducing the UEP II PPA revenues. When the Tecnisol and reserve contracts seller's production is affected, we are also forced to purchase energy in the spot market to meet our contractual obligations thereunder. This means that bottlenecks and faults in the transmission system could negatively affect our results of operations. However, since 2018 ETESA commissioned a third transmission line (Veladero — Panama) and has not had to dispatch additional generators from eastern Panama, due to the increase in the transmission capacity from western Panama to eastern Panama.

Our industry could be subject to increased regulatory oversight or changes in government policies that could have adverse effects.

Our industry could be subject to increased regulatory oversight. All our assets and operations are located in Panama, so changes in regulatory policies and other actions by the Panamanian government or third parties with respect to electricity generation, electricity grid management restrictions, interconnection rules, wholesale electricity market design and transmission may all have the effect of limiting the revenues from, and increasing the operating costs of, our Projects which could have a material adverse effect on our business, financial condition and results of operations. For example, in connection with the recent COVID-19 emergency measures, the ASEP implemented certain temporary measures allowing for the reduction in PPA payments proportional to the deficit income incurred by Distribution Companies and also imposed a moratorium on electricity generators' right to terminate PPAs for non-payment. For more information on these measures, see "Regulatory, Permits and Environmental Matters — The COVID-19 Pandemic." We cannot assure you that subsequent changes will not have similar adverse effects against us.

Excess supply of electricity to the Panamanian market with lower variable cost could cause a decrease in energy spot prices, adversely affecting our revenues.

Low or no growth in demand, coupled with the addition of new generation capacity, could create oversupply of electricity in the Panamanian market, which may reduce prices of future bilateral contracts. Oversupply of electricity with lower variable cost could adversely affect our revenues by causing a decrease in energy spot prices. Energy spot prices could decrease if the capacity added to the system by new generators is not absorbed by corresponding demand growth. In this case, the energy spot price could decrease to the extent that the new generators displace relatively expensive generators from the dispatch stack. If an excess supply of electricity to the Panamanian market causes a decrease in our revenues from sales, our operating margins could be adversely affected.

Risks Relating to Panama

Panamanian political and economic conditions directly affect our business and the market price of the Notes.

We derive substantially all of our revenues from sales of energy to the Panamanian market and all our generating assets are located in Panama. Our business, results of operations and financial condition depend, to a considerable extent, on the economic conditions of Panama. Future adverse developments in the Panamanian economy could thus adversely affect our customer, our business, results of operations and financial condition and may impair our ability to proceed with our strategic plan of business. In addition, such developments may negatively affect the market price of the Notes.

The Panamanian government has modified in the past and maintains the ability to modify monetary, fiscal, tax and other policies to influence the Panamanian economy. We have no control over government policies and cannot predict how those policies or government intervention will affect the Panamanian economy or, directly and indirectly, our business. Changes in policies involving exchange controls, taxation and other matters related to our sector may adversely affect our business, results of operations and financial condition and the market price of the Notes.

The Panamanian economy is small and relatively undiversified, being largely focused on the services sector, which represents the largest portion of the GDP as of March 31, 2020. A significant portion of Panama's economic activity is linked directly or indirectly to the Panama Canal, shipping and port activities, a large free trade zone, an international banking center and tourism services. Due to the small size and limited focus of the Panamanian economy, adverse developments in Panama could have a more pronounced effect than would be the case if the developments occurred within the context of a larger, more diversified economy. Investing in an emerging market country, such as Panama, carries economic risks. These risks include many different factors that may affect Panama's economic results, including the following:

- interest rates in the United States and financial markets outside Panama;
- changes in economic or tax policies;
- the imposition of trade barriers;
- general economic and business conditions in Panama and the global economy;
- the ability of Panama to effect key economic reforms;
- the impact of hostilities or political unrest in other countries that may affect international trade, commodity prices and the global economy;
- the decisions of international financial institutions regarding the terms of their financial agreements with Panama; and
- the impact of epidemics such as the ongoing COVID-19 pandemic currently affecting countries and markets worldwide.

Any adverse effect on the Panamanian economy could adversely affect our business, thereby impairing the Issuer's ability to meet its payment obligations under the Notes.

The Issuer and Guarantors may be adversely affected by future political crises in Panama.

Panama has experienced different types of government and governmental policies. Prior to 1968, Panama generally had a constitutional democracy. In 1968, the military secured control over the government and military rule continued until 1989. A political crisis erupted in 1987 among the then ruling military dictator, General Manuel Antonio Noriega, civilian organizations, political parties and the business community, which had been agitating for a return to democratic rule. In December 1989, Mr. Noriega was deposed, largely as a result of United States military intervention, and Guillermo Endara, who had been elected by a majority of the Panamanian electorate in a popular vote earlier in the year, was sworn in as President. Since the end of 1989, the Panamanian government has maintained political and economic stability under successive democratically elected governments, and favorable relations with the United States have been fully restored. If Panama experiences future political crises, our financial condition and results of operations may be adversely affected.

The Issuer and Guarantors may be adversely affected by governmental policies.

The Panamanian government has exercised, and continues to exercise, significant influence over the Panamanian economy. The Panamanian government has had a significant impact on the economy through various statutory and other governmental initiatives, including the enforcement of a rigid labor code, electricity subsidies related to increases in prices of fuel, tariff policies, regulatory policy, taxation and price controls. Accordingly, the Panamanian government's actions regarding the economy could have significant adverse effects on private sector entities in general and on the Issuer and Guarantors in particular. It is not possible to determine what effect such plans or actions or the implementation thereof could have on the Panamanian economy or on our financial condition or results of operations. In addition, there can be no assurance that the Panamanian government will not interfere or intervene in certain sectors of the economy, including power generation. Any interference or intervention could have a material adverse effect on our business, and the Issuer's ability to meet its obligations under the Notes.

Because the Panamanian monetary system is dependent on the U.S. dollar, any downturns in the U.S. economy may adversely affect the Issuer and the Guarantors.

Since shortly after its independence from Colombia in 1903, Panama has used the U.S. dollar as legal tender and sole paper currency, using the balboa only as coinage and as a unit of account with an exchange rate set at parity with the U.S. dollar. Inflation was 0.9% in 2017, 0.8% in 2018, -0.4% in 2019 and -0.5% in the three months ended March 31, 2020. Given the dependence on the U.S. dollar and the United States economy, there can be no assurance that appreciation or depreciation of the U.S. dollar against other currencies or the existence of sustained higher levels of inflation in the United States economy (and the resultant effect on the value of the U.S. dollar) or increases or decreases in interest rates generally in the United States will not adversely affect the Panamanian monetary system or, indirectly, us. In addition, there are currently no exchange controls or other restrictions imposed by Panamanian law on payments in U.S. dollars by us, and capital moves freely in and out of the country, without local currency risk. However, if exchange controls or payment restrictions are imposed by the Panamanian government, the Issuer's liability to repay the Notes, or the potential liability of the Guarantors, could be adversely affected.

Because Panama is a service-based economy, fluctuation of prices in basic goods may have a significant impact on the Panamanian economy and the Issuers and Guarantors.

According to data from the Ministry of Economy and Finance, the price during December 2019 for basic consumption goods (consisting of a basket of 59 basic goods for a three and a half member family) decreased from US$306.68 in December 2019 to US$305.93 in January 2020 (-0.25%). While this same item experienced an increase during the period 2017-2019, changing from US$302.70 in December 2017 to US$305.68 in December 2018 (0.98%), and to US$306.68 in December 2019 (0.33%). If prices should begin to increase again, Panama runs the risk of deceleration of demand, consumption and employment. This, in turn, may adversely affect the growth of our industry as well as our customers' ability to meet their financial obligations, thereby potentially impacting the Issuer's ability to repay the Notes.

The perception of Panama by certain international financial regulatory bodies as a jurisdiction with increased susceptibility to shortcomings in financial compliance may result in increased international regulatory requirements or adverse publicity, which may adversely affect the Panamanian financial sector and the Panamanian economy and, consequently, the Issuer and Guarantors' financial condition and results of operation.

Supranational organizations rate jurisdictions for tax transparency, governance, real economic activity, corporate tax rate, prevention of money laundering, financing of terrorism, among others. Depending on prevailing international regulatory concerns, certain countries that are considered to less than adequately cooperate with such supranational organizations may be put on a "grey" or "black" list. From time to time in the recent past, Panama has been included or threatened with inclusion on these aforementioned lists. For example, from June 2014 until February 2016, Panama was included in the "grey" list of the FATF. Further, in June 2019, Panama was once again included on the FATF "grey" list. We cannot assure you that Panama will be able to exit the FATF "grey" list at all or, if it is able to do so, that its exit will occur in a comparable period of time, if at all. In addition, in February 2020, the Economic and Financial Affairs Council of the European Union adopted a revised European Union blacklist of non-cooperative jurisdiction for tax purposes, including Panama. Moreover, in May 2020, Panama was included in the European Union's high-risk third country (AML) list.

The government of Panama has implemented several initiatives to strengthen its regulatory framework, nevertheless and depending on international regulatory concerns, continued efforts by Panama to adopt additional regulatory reform may not be readily accepted by international financial regulatory bodies. In the event Panama is included in any such "grey" list or "black" list, even if such inclusion is later rescinded, the resulting reputational and regulatory consequences may adversely affect the Panamanian economy and, consequently, our financial condition and results of operation. Moreover, measures imposed by supranational organizations against "grey" or "black" listed jurisdictions may also include the enactment of substantive laws and regulations with which we and other participants in the Panamanian economy may be obligated to comply with. These additional laws and regulations, as well as any international standards adopted therewith, could increase regulatory costs or otherwise have a material adverse effect our business, financial condition and results of operation.

The Panamanian economy could be adversely affected by economic developments in Latin American and other emerging markets or global markets.

All of our business operations and assets are located in Panama. Our results of operations and financial condition are sensitive to, and dependent upon, the economic activity in Panama. Developments in other emerging markets, particularly in Latin America, may adversely affect the market for our securities and the availability of foreign capital in Panama. We cannot predict whether events in other markets will adversely affect the price of, or market for, our securities. Unfavorable general economic conditions, financial crisis or global slowdown, can cause a decrease in the amount of foreign capital invested in emerging markets, including Panama and Latin America. Further, significant concerns regarding the sovereign debt of numerous countries have developed recently and required some of these countries to seek emergency financing. Because international investors' reactions to the events occurring in one market sometimes affect other regions or disfavor certain investments, the Panamanian economy could be adversely affected by negative economic or financial developments in other countries. We cannot assure you that negative developments in Latin America or other emerging markets or in developed economies will not occur or that such negative developments would not adversely affect the markets in which our securities trade or affect our access to sources of financing. We cannot assure you that the Panamanian economy will continue to grow in the future at the same speed of previous years or that such slowdown will not impair our ability to proceed with our business plan or materially adversely affect our business, financial condition or results of operations.

The worldwide economic effects of the COVID-19 pandemic could adversely affect Panama's economy.

The COVID-19 pandemic is currently having an indeterminable adverse impact on the world economy. The COVID-19 virus was reportedly first detected in Wuhan, Hubei Province, China, and first reported to the WHO country office in China on December 31, 2019. On January 30, 2020, the WHO declared COVID-19 a public health emergency of international concern and on March 11, 2020, declared the outbreak a pandemic. The COVID-19 pandemic has begun to have numerous worldwide effects on general commercial activity.

In Panama, following the discovery of the first case of COVID-19 in the country, the government implemented various protective measures, including declaring a National State of Emergency, decreeing a national curfew, suspending international passenger flights, extending tax amnesty and passing Law 152. At this time, given the uncertainty of the lasting effect of the COVID-19 pandemic, the financial impact on Panama's economy cannot be determined. In the medium to long term, if the spread of the COVID-19 virus is prolonged, it could adversely affect the economies and financial markets of Panama and of many other countries, resulting in an economic downturn that could, among other effects, reduce international trade flows, including shipments through the Panama Canal and air traffic through the Tocumen Airport. The occurrence of these events could have an adverse effect on Panama's economy.

The Panamanian government could seize or expropriate our assets under certain circumstances.

Certain countries in Latin America may have in the past failed to recognize private property rights and have at times nationalized or expropriated the assets of private companies. If the Panamanian government were to do so, this would cause an adverse effect on our business and financial condition.

Pursuant to Article 48 of the Panamanian Constitution, the Panamanian government may exercise its eminent domain powers in respect of our assets in Panama for public policy reasons or where it is in the interest of society as a whole. The powers conferred upon the Panamanian government by Article 48 must be exercised through a special judicial process and requires the government to indemnify the owner of the expropriated asset. Article 51 of the Panamanian Constitution grants the executive branch of the Panamanian government additional eminent domain powers that are not subject to the aforementioned judicial process, provided, however, that such power may only be exercised in case of war, civil unrest and when deemed in the urgent public interest. Article 51 also requires the Panamanian government to indemnify the owner of the expropriated asset. Accordingly, in case of expropriation, with grounds on either constitutional provision, we would be entitled to compensation for the expropriated assets. Any such compensation shall be included in the Collateral, as described in "Description of the Notes — Collateral Arrangements." However, the compensation may be lower than the price for which the expropriated asset could be sold in a free market sale or the value of the asset as part of an ongoing business, which may adversely affect our ability to make payments under the Notes.

Panama has different corporate disclosure than those you may be familiar with in the United States.

Our securities disclosure requirements in Panama differ in certain significant respects from those required in the United States. Accordingly, the information about us available to you will not be the same as the information available to holders of notes issued by a United States company and listed in a U.S. exchange. In addition, although Panamanian law imposes restrictions on insider trading and price manipulation, applicable Panamanian laws are different from those in the United States, and the Panamanian securities markets are not as highly regulated and supervised as the U.S. securities markets.

The perception of higher risk in other countries, especially in emerging economies, may adversely affect the Panamanian economy, our businesses and the market price of Panamanian securities issued by Panamanian issuers, including the Notes.

The market price of the Notes may be adversely affected by developments in the international financial markets and world economic conditions. Panamanian securities markets are influenced, to varying degrees, by economic and market conditions in other countries, especially those in Latin America and other emerging markets. Emerging markets like Panama are subject to greater risks than more developed markets, and financial turmoil in any emerging market could disrupt business in Panama and adversely affect the price of the Notes. Moreover, financial turmoil in any important emerging market country may adversely affect prices in stock markets and prices for debt securities of issuers in other emerging market countries as investors move their money to more stable, developed markets. An increase in the perceived risks associated with investing in emerging markets could dampen capital flows to Panama and adversely affect the Panamanian economy in general, and the interest of investors in the Notes, particularly in Panama. There can be no assurance that the value of the Notes will not be negatively affected by events in other emerging markets or the global economy in general.

Risk related to the Notes

The public auction at the PSE will allow any investor to submit a bid for the full principal amount of the Notes and the bidder submitting the highest, and in the case of parity the earliest, bid would have the right to purchase the Notes. If a bidder different from the Initial Purchaser submits a higher or an equal but earlier bid, you will not receive the Notes on the Issue Date as we will abstain from selling and the offering will be cancelled in consideration to the liabilities that the Issuer could face under the purchase agreement.

The offering of the Notes on the PSE on the Issue Date will be conducted pursuant to a public auction process whereby parties other than the Initial Purchaser may also lodge bids for the full principal amount of the offering at prices other than the offer price set forth on the cover of this offering memorandum. Consequently, settlement of the Notes pursuant to the terms set forth in this offering memorandum will be conditioned upon, among other factors, the Initial Purchaser's success in securing the winning bid on the PSE for the Notes as part of such public auction process. If, as a part of such public auction process, a party other than the Initial Purchaser were either to lodge a bid for the Notes at a higher price than the price contained in the Initial Purchaser's bid and reflected on the cover of this offering memorandum, or if such other party placed an equivalently priced bid for the Notes earlier in time than the bid submitted by the Initial Purchaser, we will immediately withdraw and cancel the offering of Notes with the effect that the Initial Purchaser would be unable to purchase the Notes for subsequent resale to you. Consequently, for the foregoing reasons, we are unable to assure you that you will ultimately be able to receive Notes on the Issue Date. See "Plan of Distribution — Panamanian Settlement Process" for more information.

Investors should consider the risks of selling the notes in the secondary market prior to the Issue Date as settlement is conditioned on the Initial Purchaser having the winning bid on the PSE and even if the Initial Purchaser does have the winning bid, settlement delays may result in delivery to investors of notes on the business day following the intended settlement date.

If, as a part of the public auction process in Panama, a party other than the Initial Purchaser were either to lodge a bid for the notes at a higher price than the offer price contained in the Initial Purchaser's bid and reflected on the cover of this offering memorandum, or if such other party placed an equivalently priced bid for the notes earlier in time than the bid submitted by the Initial Purchaser, we will immediately withdraw and cancel the offering of notes. If the offering is cancelled, it would not be possible to complete settlement of any secondary market trades. Additionally, any delay in settlement as described above could cause complications for investors that conducted trades in respect of the notes in the secondary market if such trades are scheduled to settle prior to the time that they receive notes in their account.

You may be subject to withholding for Panamanian capital gains taxes upon a sale of the Notes, for which the Issuer will not indemnify you.

On June 19, 2006, Panama passed Law 18, or the 2006 Tax Law, which adopted a number of changes to Panama's tax law, which were further regulated through Executive Decree No.135 of February 6, 2012. Under the 2006 Tax Law and its regulations, if the Notes are not sold through an exchange or another organized market, (i) the seller will be subject to income tax in Panama on capital gains on the sale of the Notes at a fixed rate of 10% on the gain realized and (ii) the buyer would be required to withhold from the seller and remit to the Panamanian fiscal authorities, within the following ten days, as an advance on the seller's capital gains tax payment, an amount equal to 5% of the aggregate proceeds of the sale by withholding for the capital gains tax of the seller. The seller may, at its option, consider the amount so withheld by the buyer as definitive payment in full of the capital gains tax, or in the event of overpayment, exceeding 10% of the capital gain actually realized on the sale, the seller may file, a sworn declaration before the tax authorities claiming a tax credit or refund in respect of amounts paid in excess. See "Taxation — Panamanian Tax Considerations — Taxation of Dispositions." The capital gains income tax provisions of the 2006 Tax Law and its regulations, do not exempt from income tax in Panama capital gains on sales of Notes outside of Panama by holders not resident in Panama and, therefore, such provisions would apply to sales of Notes by "qualified institutional buyers" in the United States, including sales through the facilities of DTC.

Notwithstanding Law No. 18 of June 19, 2006, based on certain opinions issued by the Dirección General de Ingresos, any capital gains by noteholders not resident in Panama on the sale or other disposition of Notes that is executed and effected outside Panama, and which payment thereof is made outside of Panama, would not be deemed Panamanian source income and, accordingly, the income realized from that sale would not be subject to income tax in Panama. However, the Issuer's Panamanian counsel has advised the Issuer that the Tax Opinion is not a legally binding interpretation of the 2006 Tax Law.

The Issuer will not indemnify you if you are subject to withholding for Panamanian capital gains taxes under the 2006 Tax Law and its regulations upon a sale of the Notes.

The ability to transfer the Notes may be limited by the absence of an active trading market, and there can be no assurance that any active trading market will develop for the Notes.

The Issuer has not registered, and will not register, the Notes under the Securities Act or any other applicable U.S. securities laws. Accordingly, the offering of the Notes in the United States will be made pursuant to exemptions from, and in transactions not subject to, the registration provisions of the Securities Act and state securities laws. The Notes are subject to certain restrictions on resale and other transfers in the United States, and you may be required to bear the risk of your investment for an indefinite period of time. See "Notice to Investors." Consequently, a holder of Notes and an owner of beneficial interests in those Notes must be able to bear the economic risk of their investment in the Notes for the term of the Notes.

There is currently no market for the Notes in the United States. The Notes are expected to be listed on the PSE and the SGX-ST, however, there can be no assurance that the Notes will become or remain listed thereon or that active trading markets for the Notes will develop. Although the Issuer has been advised by the Initial Purchaser that it currently intends to make a market in the Notes following completion of the offering, the Initial Purchaser is not obligated to do so and may discontinue any such market-making activities at any time without notice. The Notes could trade at prices that may be higher or lower than their initial offering price depending on many factors, including some that are beyond the Issuer's control. The liquidity of, and trading market for, the Notes may be adversely affected by changes in interest rates and declines and volatility in the market for similar securities, as well as by any changes in our financial condition or results of operations and by declines in the market for investment grade and emerging market securities generally.

The Issuer cannot assure you that the market, if any, for the Notes will be free from disruptions or that any such disruptions may not adversely affect the prices at which you may sell your Notes. Therefore, the Issuer cannot assure you will be able to sell your Notes at a particular time or the price that you receive when you sell will be favorable.

It may be difficult to enforce civil liabilities against the Issuer or the Issuer's directors and executive officers and controlling persons.

The Issuer is a *sociedad anónima*, organized under the laws of Panama. Substantially all of its directors, executive officers and controlling persons reside outside of the United States. In addition, all or a substantial portion of the assets of these persons and of the Issuer's assets are located outside of the United States. As a result, it may not be possible for investors to effect service of process within the United States upon such persons, or to enforce judgments in United States courts against them or the Issuer predicated upon the civil liability provisions of the federal securities laws of the United States or otherwise obtained in United States courts. Because a substantial portion of our assets is located outside of the United States, any judgment obtained in the United States against the Issuer may not be fully collectible in the United States. The Issuer has been advised by its Panamanian counsel that no treaty exists between the United States and Panama for the reciprocal enforcement of foreign judgments and that that there is doubt as to the enforceability, in original actions in Panamanian courts, of liabilities predicated solely on the United States federal securities laws and as to the enforceability in Panamanian courts of judgments of United States courts obtained in actions predicated upon the civil liability provisions of the United States federal securities laws of the United States. In any case, judgments of courts outside Panama, including but not limited to judgments of United States courts, may only be recognized and enforced by the courts of Panama if the Supreme Court of Panama validates the judgment by the issuance of a *writ of exequatur*. Any final money judgment rendered in a foreign court (including the United States) could be recognized as conclusive and enforceable in the courts of Panama without reconsideration of the merits, provided that the Fourth Chamber of General Affairs (in Spanish, *Sala Cuarta de Negocios Generales*) of the Supreme Court of Panama shall, for purposes of issuing a *writ of exequatur* ordering such enforcement, confirm that (i) the applicable foreign courts enforce judgments of the courts of Panama (ii) the defendant or its agent was personally served with process by the applicable foreign court in connection with the action giving rise to such judgment, (iii) the judgment arose out of a personal action against the defendant, (iv) the obligation in respect of which the judgment was rendered is lawful in Panama and is not contrary to the public policy of Panama, (v) the judgment, in accordance with the laws of the country where it was rendered, is final and not subject to appeal, (vi) the judgment is properly authenticated by diplomatic or consular officers of Panama or pursuant to the 1961 Hague Convention Abolishing the Requirement of Legalization of Foreign Public Documents and (viii) a copy of the final judgment was translated into Spanish by a Panamanian licensed translator.

Enforcing your rights as a holder of Notes in Panama may prove difficult.

Your rights under the Notes (including their security interest in the Collateral) will be subject to the insolvency and administrative laws of Panama, and the Issuer cannot assure you that you will be able to effectively enforce your rights in such insolvency or similar proceedings. In addition, insolvency, administrative and other laws of Panama may be materially different from, or in conflict with, each other, including in the areas of rights of creditors, priority of government entities and related party creditors, and the ability to obtain post-bankruptcy filing loans or to pay interest. The application of these laws, or any conflict among them, could call into question what and how Panamanian laws should apply. The laws of Panama may not be as favorable to your interests as the laws of jurisdictions with which you are familiar. Such issues may adversely affect your ability to enforce your rights under the Notes and the Guarantees in Panama, as the case may be, or limit any amounts that you may receive. For further information on the bankruptcy regime in the Republic of Panama, see "Regulatory, Permits and Environmental Matters — Bankruptcy Regime".

We may not be able to effect the repayment and release of our debt obligations under the IFC Loan and the IFC Hedge Agreement, and the Notes may be effectively subordinated to the rights of the creditors under the IFC Loan and the IFC Hedge Agreement.

Although we intend to use the net proceeds of the Notes for the repayment in full of our obligations under the IFC Loan and the unwinding of the IFC Hegde Agreement on the issue date of the Notes, until the IFC Loan and the IFC Hedge Agreement are fully repaid and our obligations and security arrangements thereunder fully terminated and discharged, the rights of the holders of the Notes will be effectively subordinated to the rights of the creditors under the IFC Loan and the IFC Hegde Agreement. For more information regarding the repayment of the IFC Loan and the unwinding of the IFC Hedge Agreement, see "Summary — Recent Developments — The Refinancing and Recapitalization Transaction" and "Use of Proceeds." For additional information regarding the IFC Loan and the IFC Hedge Agreement, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Indebtedness — The Issuer — The IFC Facility."

Your interests in the Collateral securing the Notes may be adversely affected by our failure to timely record, perfect or maintain security interests.

The Collateral Trustee's ability to foreclose on some of the Collateral on the holders' behalf is subject to perfection and priority issues. The Notes will be secured by a first-priority perfected security interest on the Collateral. See "Description of Collateral." A portion of the Collateral is permitted to be perfected after the Issue Date. To the extent any security interest in the Collateral has not been perfected on or prior to the Issue Date, we will be required to have all such security interests perfected following the Issue Date in accordance with the time periods set forth in "Description of Collateral." Although we will, as described in this offering memorandum, sign certain agreements that create or amend liens in respect of the Collateral and cause perfection of such liens or amendments thereto within an agreed upon period of time following the Issue Date, no assurance can be made that the registration of such liens or amendments thereto will be properly or timely made. No assurance can be made as to our ability to obtain such registrations in a timely manner, or at all. Perfection of the security interests in the Collateral after the Issue Date increases the risk that the liens granted become avoided and subject to the liens of intervening creditors and in the absence of such registration, the liens on Collateral may not be enforceable against third parties, which could adversely affect the Collateral Trustee's rights to foreclose upon the Collateral.

The Collateral is subject to casualty risks, which may limit your ability to recover for losses of our assets.

We will maintain insurance or otherwise insure against risks to the extent customary with companies in the power generation and energy industry as agreed in the Indenture. There are, however, certain losses, including but not limited to losses resulting from natural perils, war and terrorism, defective design and wear and tear that may be either uninsurable or not economically insurable, in whole or in part. As a result, we cannot assure you that the insurance proceeds will compensate us fully for any losses. If there is a total or partial loss of any of the Collateral securing the Notes, we cannot assure you that any insurance proceeds received by us will be sufficient to satisfy all the Notes obligations.

Different disclosure requirements in Panama and the United States may provide you with different or less information about us than you expect.

Securities disclosure requirements in Panama differ from those applicable in the United States. Accordingly, the information about us that is available to you may not be the same as the information available to security holders of a United States company. There may be less publicly available information about us than is regularly published about companies in the United States and certain other jurisdictions. We are not subject to the periodic reporting requirements of the Exchange Act and, therefore, are not required to comply with the information disclosure requirements that it imposes.

Our credit ratings or the Notes may be lowered or withdrawn.

The credit ratings of the Notes may not reflect the potential impact of all risks relating to the value of the Notes. In addition, real or anticipated changes in our credit ratings or the credit ratings of the Notes will generally affect the market value of the Notes. Thus, even though we are making interest payments when due, the price of the Notes in the secondary market that may develop may be considerably less than the price you paid for your Notes.

The value of the Collateral may not be sufficient to satisfy amounts owed in respect of the Notes and any other Additional Secured Debt, and it may be difficult to realize the value of the Collateral.

We provide no assurance to investors that, if we default on the payments due on the Notes and the Collateral Agent forecloses on and sells the Collateral, holders of the Notes will receive sufficient proceeds to pay all amounts that we owe under the Notes and any Additional Secured Debt, including the amounts due under the Letters of Credit Agreement (as defined below). If the Collateral Trustee were to attempt to foreclose upon our assets, there are certain assets, including our PPAs and certain others of our material project agreements that the Collateral Agent may not be able to effectively foreclose upon without the consent of third parties, such as a governmental authority. We provide no assurance to investors that if the Collateral Trustee forecloses on our assets, the Collateral Trustee will be able to obtain all of the third-party approvals necessary to obtain or transfer ownership of all assets necessary to operate the Projects. Furthermore, if the Collateral Trustee forecloses on the Collateral, then, in connection therewith, transferring required permits to a purchaser or new operator of the Projects may require additional governmental approvals or proceedings, which could result in delays. Accordingly, there may not be sufficient proceeds from the sale of the Collateral to pay all or any of the amounts due on the Notes.

In addition, after the issuance date of the Notes, the Issuer may subsequently incur Additional Secured Debt, including the issuance of Letters of Credit under the Letter of Credit Facility. Following the incurrence of such Additional Secured Debt, the Collateral will secure both the Notes and the Additional Secured Debt. If a default occurs, any recovery derived from any foreclosure actions will be distributed pro-rata between the Notes and any other Secured Obligations. Such distribution may not be sufficient to satisfy obligations under the Notes and the Additional Secured Debt. See "Risk Factors — Risk Relating to the Notes — Your rights to make certain decisions with respect to your investment in the Notes may be limited by the intercreditor provisions under the Intercreditor Agreement."

Furthermore, by its nature, some or all of the Collateral would be illiquid and might have no readily ascertainable market value. Some of the Collateral may have no significant independent value apart from the other pledged assets or could be impaired in the future as a result of changing economic and market conditions. Some of the Collateral may not be readily saleable or, if saleable, there may be substantial delays in their liquidation. In addition, the Indenture provides only limited covenant protections with respect to the Collateral and might not protect you against actions that we could take that could impair the value of the Collateral. We also cannot assure you that the proceeds from any sale of the Collateral would be sufficient to repay holders all amounts owed under the Notes and any future obligations.

The Indenture and the instruments governing the Collateral contain, and agreements governing any Additional Secured Debt, including the Letter of Credit Agreement, may contain, cross-default clauses that may cause all debt issued under the Notes and under such agreements to become due in advance and immediately payable as a result of a noncompliance event resulting under another unrelated debt instrument.

The Indenture and the instruments governing the Collateral contain certain covenants and restrictions. Any failure to comply with these covenants could lead to an event of default with respect to the corresponding agreement, which may, in turn, result in the related debt becoming due in advance and immediately payable. In such event, we would need to obtain financial resources from alternative sources, which may not be available to us on favorable terms, on a timely basis, or at all. Alternatively, any such default could require us to sell our assets or otherwise curtail operations in order to satisfy our obligations to our creditors which could have a material adverse effect on our business, results of operations and financial condition.

Concurrently with or following the issuance of the Notes, we expect to enter into a Letter of Credit Agreement (as defined below) for purposes of issuing Letters of Credit (as defined below) to fund certain reserve accounts required to be maintained under the terms of the Panamanian Trust Agreement. See "Description of the Notes — Summary of Panamanian Trust Accounts." As of the date of this offering memorandum, the terms have not been agreed and depend on further negotiations between us and the potential letter of credit providers. If we are unable to enter into the Letter of Credit Agreement, we will be required to fund those reserve accounts with cash. If we enter into the Letter of Credit Agreement, the commitments of the lenders thereunder may expire prior to the maturity of the Notes or the Letters of Credit may be issued for terms shorter than the remining term of the Notes. If we are unable to renew such commitments or the Letters of Credit issued under the Letter of Credit Agreement, the Collateral Trustee may draw such Letter of Credit prior to its applicable expiration date which would require us to reimburse such funds or fund the reserve accounts with cash. If we are unable to refund the applicable issuing bank or fund the reserve accounts with cash, we would need to obtain financial resources from alternative sources, which may not be available to us on favorable terms, on a timely basis, or at all, which could trigger a cross-default under the Indenture and the Notes. For more information about the Letter of Credit Agreement, see "Description of Principal Financial Documents — Letter of Credit Agreement."

We may engage in hedging transactions and other risk mitigation strategies that could harm our results of operations and financial condition.

From time to time, we may enter into fixed-for-floating interest rate hedges in an attempt to partially offset the effects of interest rate risk or currency in respect of our indebtedness. In connection with the issuance of the Notes, the repayment of the IFC Loan and the unwinding of the IFC Hedge Agreement, we expect to enter into an interest rate swap with Citi. See "Summary — The Refinancing and Recapitalization Transactions." This interest rate swap will initially have negative mark-to-market value, which could either increase or decrease depending on movements in the LIBOR rate or replacement fallback floating rate underlying the swap agreement.

In addition, we may enter into interest rate or currency hedges. The financial statement impact of our hedging activities is dependent upon, among other things, the exchange rates involved and foreign exchange volatility. Hedging arrangements expose us to the risk of potential financial loss in situations where the other party to the hedging contract defaults on its contract, the hedging contract is terminated early, or, in the case of exchange-traded hedging contracts, where there is a change in the expected differential between the underlying price in the hedging agreement and the actual prices paid or received by us. In addition, our open contract positions may require cash deposits to cover margin calls, negatively impacting our liquidity. As a result, our hedging activities and fluctuations in the price of foreign exchange rates or interest rates may adversely affect our results of operations, financial condition and liquidity.

The Issuer and the Guarantors' obligations under the Notes are subordinated to the Issuer and the Guarantors' payment of certain statutory liabilities and may have different treatment from the obligations of unrelated creditors in any Panamanian reorganization proceedings.

Except with respect to the Collateral, the Notes will be the general, unsecured unsubordinated obligations of the Issuer or the relevant Guarantor. Under Panamanian law, such unsecured obligations are subordinated to certain statutory preferences. In the event of the Issuer or any Guarantor's bankruptcy, reorganization, intervention, insolvency or liquidation, such statutory preferences, such as claims for salaries, wages and credits guaranteed over assets (but up to the value of such assets), social security contributions, taxes, court fees and expenses, will have preference over any other unsecured claims, including the claims by any investor in respect of the Notes. In the event of a reorganization proceedings in Panama, the Issuer's obligations under the intercompany loans made to the Guarantors may also be deemed to be related to the Issuer (which may occur in the event that the debtor is part of the same corporate group as a creditor). As a result, the Issuer may be required to vote separately from non-debtor related creditors in order to approve any reorganization plan if such intercompany loans (together with any other creditor-linked debt) exceed 50% of the debtor's recognized indebtedness.

Your rights to make certain decisions with respect to your investment in the Notes may be limited by the intercreditor provisions under the Intercreditor Agreement.

The Intercreditor Agreement sets forth intercreditor matters with respect to the Collateral, including requiring certain notices and procedures for an intercreditor vote in connection with the taking of any enforcement action and the making of modifications to the Security Document. Generally, if an event of default occurs or is continuing under the documents for any Secured Debt, secured creditors holding more than 50% of the aggregate principal amount outstanding of combined exposure of the Secured Parties are required to instruct the Intercreditor Agent to direct any collateral agent to exercise remedies with respect to the Collateral. See "Description of the Notes — Intercreditor Arrangement — Defaults and Remedies."

The Notes will be held in book-entry form and therefore you must rely on the procedures of the relevant clearing system to exercise any rights and remedies.

The Notes will be issued in fully registered form. The Regulation S Global Notes and the Rule 144A Global Notes will be deposited, on the closing date, with, or on behalf of, the Indenture Trustee for the account of DTC registered in the name of a nominee of the DTC.

Ownership of beneficial interests in the Global Notes (the "Book-Entry Interests") will be limited to persons that have accounts with DTC ("participants") or persons that hold interests through such participants. Book-Entry Interests will be shown on, and transfers thereof will be effected only through, records maintained in book-entry form by DTC and their participants. Owners of beneficial interests in the Global Notes will not be entitled to receive definitive Notes in registered form, except under the limited circumstances described in "Book-Entry; Settlement and Clearance." So long as the Notes are held in global form, holders of Book-Entry Interests will not be considered the owners or "holders" of Global Notes.

Payments of any amounts owing in respect of the Global Notes (including principal, premium, interest and additional amounts, if any) will be made by the Issuer to the paying agents. The paying agents will, in turn, make such payments to DTC, which will in turn distribute such payments to participants in accordance with its procedures. After payment to the DTC, we will have no responsibility or liability for the payment of interest, principal or other amounts to the holders of Book-Entry Interests. Accordingly, if you hold a Book-Entry Interest, you must rely on the procedures of DTC, or the procedures of the participant through which you hold your interest, to exercise any rights and obligations of a holder of Notes under the Indenture governing the Notes.

Unlike the holders of the Notes themselves, holders of Book-Entry Interests will not have the direct right to act upon the Issuer's solicitations for consents, requests for waivers or other actions from holders of the Notes. Instead, if you hold a Book-Entry Interest, you will be permitted to act only to the extent you have received appropriate proxies to do so from DTC. The procedures implemented for the granting of such proxies may not be sufficient to enable you to vote on a timely basis and, therefore, your vote may not be counted for purposes of calculating the applicable majorities needed under the Intercreditor Agreement. Similarly, upon the occurrence of an event of default under the Indenture governing the Notes, unless and until definitive registered Notes are issued in respect of all Book-Entry Interests, if you hold a Book-Entry Interest, you will be restricted to acting through DTC. The procedures to be implemented through DTC may not be adequate to ensure the timely exercise of rights under the Notes.

We may not have the ability to raise the funds necessary to finance the Change of Control Offer required by the Indenture.

Upon the occurrence of a "Change of Control Repurchase Event," as defined in the Indenture, we will be required to offer to repurchase all outstanding Notes at 101% of the principal amount thereof plus accrued and unpaid interest and Additional Amounts, if any, to the date of repurchase. See "Description of the Notes — Repurchase Upon Change of Control Repurchase Event." However, it is possible that we will not have sufficient funds at the time of the Change of Control Repurchase Event to make the required repurchase of Notes. Third-party financing may be required in order to provide the funds necessary for us to make the Change of Control Offer for the Notes and to refinance any other indebtedness that would become payable upon the occurrence of such events. We may not be able to obtain such additional financing on terms favorable to us or at all.

The definition of "Change of Control" in the Indenture will include a disposition of all or substantially all of the properties or assets of the Issuer and the Guarantors to any person. Although there is a limited body of case law interpreting the phrase "all or substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve a disposition of "all or substantially all" of the assets of the Issuer and the Guarantors. As a result, it may be unclear as to whether a Change of Control has occurred and whether we are required to make an offer to repurchase the Notes.

A failure to make an offer to repurchase the Notes upon a Change of Control Repurchase Event would give rise to an event of default under the Indenture and could result in an acceleration of amounts due thereunder.

The Collateral may be subject to expropriation, which may limit your ability to recover as a secured creditor if any of the Collateral is expropriated.

It is possible that all or a portion of the Collateral that will secure the Notes may become subject to a proceeding for expropriation. In such event, we may be compensated for any total or partial loss of property, but it is possible that such compensation will be insufficient to fully compensate us for our losses. In addition, a total or partial expropriation may interfere with our ability to use and operate all or a portion of our business, which may have an adverse impact on our business, prospects, financial condition and results of operations.

There is no current market consensus on what constitutes a "green" or "sustainable" project and the Notes may not be a suitable investment for all investors seeking exposure to green assets.

There is no current market consensus on what precise attributes are required for a particular project to be defined as "green" or "sustainable" and, therefore, the Eligible Green Projects that we financed with the proceeds from IFC Loan and the Shareholders Loans (which we intend to repay with the proceeds from the issuance of the Notes) and/or any new Eligible Green Projects that we decide to finance with a portion of the net proceeds from the offering of the Notes may not meet the criteria and expectations of investors regarding environmental impact and sustainability performance.

There can be no guarantee that the underlying projects initially financed with indebtedness being refinanced with the net proceeds from the offering of the Notes and/or any new projects that we decide to finance with a portion of the net proceeds from the offering of the Notes will deliver the environmental benefits anticipated, or that adverse environmental and/or social impacts will not occur during or as a result of the design, construction, commissioning and operation of such projects. In addition, where any negative impacts are insufficiently mitigated, the projects may become controversial, and/or may be criticized by activist groups or other stakeholders.

Each potential purchaser of Notes should determine for itself the relevance of the information contained in this offering memorandum regarding the use of proceeds and its purchase of Notes should be based upon such investigation as it deems necessary. See "Use of Proceeds."

EXCHANGE RATE INFORMATION

Since 1904, Panama has fixed its local currency, the Balboa, to the U.S. dollar, which is also recognized legal tender in Panama. The Balboa/U.S. dollar exchange rate has been fixed at B/.1.00 to US$1.00 since the Balboa was first introduced in 1904, and has always circulated alongside U.S. dollars in Panama. There are no circulating Balboa bills or coins, other than coins with a value of B/.1.00 or less. Currency conversions contained in this offering memorandum should not be construed as representations that Balboas have been, could have been or could be converted into U.S. dollars at the indicated or any other rate of exchange.

USE OF PROCEEDS

We expect the aggregate gross proceeds from the sale of the Notes in this offering to be US$262,664,000. Consistent with the "Green Bond Principles" (see "Summary — Recent Developments — Green Bond Principles"), we intend to allocate an amount equal to the net proceeds from the sale of the Notes (after deduction of certain fees, expenses and commissions) to finance or refinance Eligible Green Projects. Eligible Green Projects include those projects and expenditures funded prior to the issue date, as described below, and at any time following the issue date until the maturity of the notes, which meet, among other, the following eligibility criteria:

- *Renewable Energy* — The development, construction and operation, as well as transmission infrastructure to support, facilities that generate solar energy or wind energy; or
- *Energy Efficiency* — Energy Optimization Programs that work to educate and provide our customers with tools to reduce energy usage and improve energy efficiency.

We currently intend to use the net proceeds of the Notes (after deduction of certain fees, expenses and commissions) to repay the IFC Loan and to unwind the IFC Hedge Agreement. For additional information regarding the IFC Loan and the IFC Hedge Agreement, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Indebtedness — The Issuer — IFC Facility."

Process for Project Evaluation and Selection

Our sustainability team will select and recommend projects that qualify as Eligible Green Projects for the review and approval of our finance team. The finance team will be responsible for the allocation of the net proceeds from the offering of the Notes to finance new or existing Eligible Green Projects, which may include the repayment of the IFC Loan, the UEP II Shareholders Loans, and to grant intercompany loans to the Guarantors for the cancelation of the Tecnisol Shareholders Loan which were used to finance our Projects. For additional information regarding the UEP II Shareholders Loan and the Tecnisol Shareholder Loan, see "Certain Relationships and Related Party Transactions."

Management of Proceeds

We will establish internal tracking systems to monitor and account for allocation of an amount equal to the net proceeds from the offering of the Notes. Pending such allocation, we intend to hold the net proceeds from the offering of the Notes in cash and/or cash equivalents.

Reporting

Within one year of issuance of the Notes, we will provide an update on our Sponsor's website regarding the allocation of an amount equal to the net proceeds of the Notes to Eligible Green Projects, detailing, at a minimum, the Eligible Green Projects funded by the net proceeds, together with key environmental features of such Eligible Green Project. The update will also contain (i) an assertion by management that the net proceeds of the Notes were allocated to qualifying Eligible Green Projects, and (ii) an attestation report from an independent accountant in respect of the independent accountant's examination of management's assertion conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. If the net proceeds are not fully allocated within one year of issuance, or in the event of material developments, we will continue to provide updates annually and provide an annual attestation report from an independent accountant until the net proceeds are fully allocated.

CAPITALIZATION

The following table sets forth the cash and cash equivalents and capitalization of the Issuer on an actual basis as of September 30, 2020 and as adjusted to reflect the issuance of US$262,664,000 of the Notes offered hereby (net of the underwriting fees and commissions), the use of the proceeds from this offering, as described under "Use of Proceeds" and the Refinancing and Recapitalization Transaction as if these events had occurred on September 30, 2020. For more information related to the Refinancing and Recapitalization Transaction, see "Summary — The Refinancing and Recapitalization Transaction." Actual amounts have been derived from the Issuer Interim Financial Statements.

You should read this table together with "Use of Proceeds" and the Issuer Financial Statements included elsewhere in this offering memorandum.

	Actual	As Adjusted
	(in millions of US$)	
Cash and cash equivalents	17.421	19.686
Restricted cash[1]	68.437	—
Total cash and Restricted cash	85.858	19.686
Financial Assets — Intercompany Loans	—	30.000[2]
DEBT		
Senior Debt	224.702[3]	—
Management fee owed to Sponsor	4.800	—
Shareholder Loan	50.000	—
Senior Secured Notes offered hereby	—	262.664
Swap Mark-to-Market	18.759	9.380[4]
Total Debt	298.261	272.044
EQUITY		
Capital	75.000	68.000[5]
Accumulated deficit	(49.332)	(49.332)
Prepaid dividend tax	(0.019)	(0.019)
Total Equity	25.649	18.649
Total Capitalization	323.910	290.693

(1) Cash deposited in the accounts pledged as collateral under the terms of the IFC Loan and the IFC Hedge Agreement. For more information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Indebtedness — The Issuer — The IFC Facility."

(2) Intercompany loans granted to the Guarantors to fund the repayment on or around the Closing Date by the Guarantors of the Tecnisol Shareholders Loan. See "Summary — The Refinancing and Recapitalization Transaction." For a description of the Tecnisol Shareholders Loan, see "Certain Relationships and Related Party Transactions — The Guarantors — Tecnisol Shareholder Loan Agreement."

(3) Includes only unpaid principal and excludes accrued and unpaid interest, and unwinding costs related to the Refinancing and Recapitalization Transaction. See "Summary — The Refinancing and Recapitalization Transaction."

(4) After giving effect to the Citi Swap. See "Summary — The Refinancing and Recapitalization Transaction."

(5) After giving effect a capital reduction and a distribution of US$7 million. "Summary — The Refinancing and Recapitalization Transaction."

SELECTED HISTORICAL FINANCIAL DATA

The following tables present our selected historical financial for each of the periods presented.

The audited balance sheet data of the Issuer as of December 31, 2019, 2018 and 2017, and the audited statement of comprehensive income and loss data of the Issuer for the years ended December 31, 2019, 2018 and 2017 are derived from the Issuer Annual Financial Statements included elsewhere in this offering memorandum. The unaudited balance sheet data of the Issuer as of September 30, 2020, and the unaudited statement of comprehensive income data of the Issuer for the nine months ended September 30, 2020 and 2019 are derived from the Issuer Unaudited Interim Financial Statements included elsewhere in this offering memorandum.

The unaudited combined balance sheet data of the Guarantors as of September 30, 2020, and the unaudited combined statement of comprehensive income and loss data of the Guarantors for the nine months ended September 30, 2020 and 2019 are derived from the Guarantors Unaudited Interim Combined Financial Statements included elsewhere in this offering memorandum. The balance sheet data of the Guarantors as of December 31, 2019 and 2018, and the statement of comprehensive income and loss data of each of the Guarantors for the years ended December 31, 2019 and 2018 are derived from the Guarantors Annual Financial Statements included elsewhere in this offering memorandum.

The Issuer Annual Financial Statements and the stand-alone financial statements of each of the Guarantors as of and for the year ended December 31, 2019 were audited by PwC.

The following tables should be read in conjunction with "Presentation of Financial and Other Information", "Use of Proceeds," "Capitalization," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Financial Statements included in this offering memorandum. The results of operations for the historical periods included in the following tables are not necessarily indicative of the results to be expected for future periods. In addition, see "Risk Factors" for a discussion of risk factors that could impact our future financial condition and results of operations.

The Issuer

	For the nine months ended September 30,		For the year ended December 31,		
Statement of Comprehensive Income	**2020**	**2019**	**2019**	**2018**	**2017**
	(in millions of US$)				
Energy revenues	40.337	49.802	56.070	50.310	42.404
Costs of goods and services	(11.812)	(12.256)	(16.289)	(19.572)	(29.150)
Gross profit	28.525	37.546	39.781	30.738	13.254
Administrative expenses	(3.101)	(3.236)	(4.278)	(5.773)	(10.870)
Operating expenses	(4.218)	(4.453)	(6.378)	(5.455)	(4.129)
Total expenses	(7.319)	(7.689)	(10.656)	(11.228)	(14.999)
Operating profit	21.206	29.857	29.125	19.510	(1.745)
Finance cost amortization	(0.598)	(0.598)	(0.797)	(0.797)	(0.797)
Finance cost, net	(24.546)	(27.035)	(28.631)	(20.096)	(24.117)
Total finance cost	(25.144)	(27.633)	(29.428)	(20.893)	(24.914)
Other income	(0.006)	(0.064)	0.561	8.879	—
Profit (loss) before income tax	(3.944)	2.160	0.258	7.496	(26.659)
Income tax	0.176	(2.551)	(1.644)	(2.313)	1.698
Total comprehensive income (loss) for the period and year	(3.768)	(0.391)	(1.386)	5.183	(24.961)

Balance sheet	As of September 30, 2020	As of December 31, 2019	2018	2017
		(in millions of US$)		
Assets				
Current assets				
Cash and cash equivalents	17.421	25.126	60.837	2.003
Restricted cash	51.165	51.165	—	11.964
Trade and other receivables	7.184	6.988	9.708	5.682
Prepaid expenses	0.690	0.574	0.646	0.591
Total current assets	76.460	83.853	71.191	20.240
Non-current assets				
Plant and equipment, net	233.383	243.796	249.149	317.835
Deferred Income Tax Asset	—	—	—	1.041
Derivative financial instrument	—	—	0.894	—
Restricted cash	17.272	17.272	17.272	17.272
Goodwill	20.000	20.000	20.000	20.000
Total non-current assets	270.655	281.068	287.315	356.148
Total assets	347.115	364.921	358.506	376.388
Liabilities and Equity				
Current liabilities				
Current portion of long-term debt	12.296	12.803	14.451	15.324
Trade and other payables	26.266	34.248	30.644	36.801
Total current liabilities	38.562	47.051	45.095	52.125
Non-current liabilities				
Shareholders loans	50.000	50.000	50.000	50.000
Derivative financial instrument	18.759	7.822	—	2.962
Lease liabilities long term	8.253	8.385	—	—
Deferred income tax	2.048	2.224	0.580	—
Long-term debt	203.844	220.003	232.009	245.663
Total non-current liabilities	282.904	288.434	282.589	298.625
Total liabilities	321.466	335.485	327.684	350.750
Equity				
Common shares with US$1 par value each authorized and issued 1,050 shares	0.001	0.001	0.001	0.001
Capital Contribution	74.999	74.999	74.999	74.999
Prepaid dividend tax	(0.019)	—	—	—
Accumulated Deficit	(49.332)	(45.564)	(44.178)	(49.362)
Total equity	25.649	29.436	30.822	25.638
Total liabilities and equity	347.115	364.921	358.506	376.388

The Guarantors

Guarantors' Combined Financial Information

Statement of Comprehensive Income	For the nine months ended September 30, 2020	2019
	(in millions of US$)	
Energy revenues	7.696	9.239
Other income	0.047	—
Costs of goods and services	(5.639)	(6.759)
Gross profit	2.104	2.480
Administrative expenses	(0.597)	(0.643)
Operating expenses	(0.241)	(0.008)
Total expenses	(0.838)	(0.651)
Operating profit	1.266	1.829
Finance costs	(0.955)	(1.167)
Income before income tax	0.311	0.662
Income tax	(0.141)	(0.251)
Profit for the period	0.170	0.411

Balance sheet	As of September 30, 2020	2019
	(in millions of US$)	
Assets		
Current assets		
Cash and cash equivalents	4.376	7.333
Trade and other receivables	1.368	4.943
Prepaid expenses and other assets	0.782	0.505
Total current assets	6.526	12.781
Non-current assets		
Plant and equipment, net	38.554	41.391
Intangible assets, net	0.241	0.235
Total non-current assets	38.795	41.626
Total assets	45.321	54.407
Liabilities and Equity		
Current liabilities		
Lease liabilities short-term debt	0.033	0.031
Shareholder's loan	39.944	47.812
Trade and other payables	4.305	5.523
Total current liabilities	44.282	53.366
Non-current liabilities		
Lease liabilities long term	0.963	0.980
Total liabilities	45.245	54.346
Equity		
Common shares with US$100 par value each authorized and issued 400 shares	0.040	0.040
Retained earnings	0.095	0.039
Prepaid tax	(0.059)	(0.018)
Total equity	0.076	0.061
Total liabilities and equity	45.321	54.407

Tecnisol I, S.A.

Statement of Comprehensive Loss	For the year ended December 31, 2019	2018[1]
	(in millions of US$)	
Revenues	4.621	2.380
Costs of goods and services	(3.934)	(1.855)
Gross profit	0.687	0.525
Administrative expenses	(0.607)	(0.702)
Operating expenses	(0.082)	—
Total expenses	(0.689)	(0.702)
Operating loss	(0.002)	(0.177)
Finance costs	(0.611)	(0.001)
Loss before income tax	(0.613)	(0.178)
Income tax	(0.040)	—
Total comprehensive loss for the year	(0.653)	(0.178)

(1) Unaudited.

Balance sheet	As of December 31, 2019	2018[1]
	(in millions of US$)	
Assets		
Current assets		
Cash and cash equivalents	1.046	5.257
Trade and other receivables	0.623	1.314
Prepaid expenses and other assets	0.312	—
Total current assets	1.981	6.571
Non-current assets		
Plant and equipment, net	12.822	13.460
Intangible assets, net	0.248	0.243
Total non-current assets	13.070	13.703
Total assets	15.051	20.274
Liabilities and Equity		
Current liabilities		
Lease liabilities short-term debt	0.007	—
Shareholder's loan	14.697	19.726
Trade and other payables	0.952	0.717
Total current liabilities	15.656	20.443
Non-current liabilities		
Lease liabilities long term	0.222	—
Total liabilities	15.878	20.443
Equity		
Common shares with US$100 par value each authorized and issued 100 shares	0.010	0.010
Accumulated deficit	(0.832)	(0.179)
Prepaid tax	(0.005)	—
Total equity	(0.827)	(0.169)
Total liabilities and equity	15.051	20.274

(1) Unaudited.

Tecnisol II, S.A.

Statement of Comprehensive Income	For the year ended December 31, 2019	2018[1]
	(in millions of US$)	
Revenues	1.563	0.379
Costs of goods and services	(0.752)	(0.134)
Gross profit	0.811	0.245
Administrative expenses	(0.099)	(0.355)
Operating profit (loss)	0.712	(0.110)
Finance costs	(0.299)	—
Income (loss) before income tax	0.413	(0.110)
Income tax	(0.108)	(0.002)
Total comprehensive income (loss) for the year	0.305	(0.112)

(1) Unaudited.

Balance sheet	As of December 31, 2019	2018[1]
	(in millions of US$)	
Assets		
Current assets		
Cash and cash equivalents	0.552	0.135
Trade and other receivables	0.194	0.245
Prepaid expenses and other assets	0.025	—
Total current assets	0.771	0.380
Non-current asset		
Plant and equipment, net	9.157	9.599
Total assets	9.928	9.979
Liabilities and Equity		
Current liabilities		
Lease liabilities short-term debt	0.008	—
Shareholder's loan	8.558	9.248
Trade and other payables	0.906	0.834
Total current liabilities	9.472	10.082
Non-current liability		
Lease liabilities long term	0.257	—
Total liabilities	9.729	10.082
Equity		
Common shares with US$100 par value each authorized and issued 100 shares	0.010	0.010
Retained earnings (accumulated deficit)	0.192	(0.113)
Prepaid tax	(0.003)	—
Total equity	0.199	(0.103)
Total liabilities and equity	9.928	9.979

(1) Unaudited.

Tecnisol III, S.A.

Statement of Comprehensive Income	For the year ended December 31	
	2019	2018[1]
	(in millions of US$)	
Revenues	4.996	1.611
Costs of goods and services	(4.151)	(1.204)
Gross profit	0.845	0.407
Administrative expenses	(0.042)	(0.491)
Operating expenses	(0.001)	—
Total expenses	(0.043)	(0.491)
Operating profit (loss)	0.802	(0.084)
Finance costs	(0.310)	—
Income (loss) before income tax	0.492	(0.084)
Income tax	(0.171)	—
Total comprehensive income (loss) for the year	0.321	(0.084)

(1) Unaudited.

Balance sheet	As of December 31,	
	2019	2018[(1)]
	(in millions of US$)	
Assets		
Current assets		
Cash and cash equivalents	0.861	0.760
Trade and other receivables	0.734	0.751
Prepaid expenses and other assets	0.260	—
Total current assets	1.855	1.511
Non-current asset		
Plant and equipment, net	9.931	10.473
Total assets	11.786	11.984
Liabilities and Equity		
Current liabilities		
Lease liabilities short-term debt	0.007	—
Shareholder's loan	8.955	9.714
Trade and other payables	2.362	2.344
Total current liabilities	11.324	12.058
Non-current liability		
Lease liabilities long term	0.222	—
Total liabilities	11.546	12.058
Equity		
Common shares with US$100 par value each authorized and issued 100 shares	0.010	0.010
Retained earnings (accumulated deficit)	0.237	(0.084)
Prepaid tax	(0.007)	—
Total equity	0.240	(0.074)
Total liabilities and equity	11.786	11.984

(1) Unaudited.

Tecnisol IV, S.A.

Statement of Comprehensive Income	For the year ended December 31, 2019	2018[(1)]
	(in millions of US$)	
Revenues	1.575	0.372
Costs of goods and services	(0.717)	(0.128)
Gross profit	0.858	0.244
Expenses		
Administrative expenses	(0.122)	(0.239)
Operating profit	0.736	0.005
Finance costs	(0.297)	—
Income before income tax	0.439	0.005
Income tax	(0.115)	(0.001)
Total comprehensive income for the year	0.324	0.004

(1) Unaudited.

Balance sheet	As of December 31, 2019	2018[(1)]
	(in millions of US$)	
Assets		
Current assets		
Cash and cash equivalents	0.509	0.150
Trade and other receivables	0.233	0.222
Prepaid expenses and other assets	0.030	—
Total current assets	0.772	0.373
Non-current asset		
Plant and equipment, net	8.723	9.109
Total assets	9.495	9.481
Liabilities and Equity		
Current liabilities		
Lease liabilities short-term debt	0.009	—
Shareholder's loan	8.444	9.125
Trade and other payables	0.430	0.343
Total current liabilities	8.883	9.468
Non-current liability		
Lease liabilities long term	0.278	—
Total liabilities	9.161	9.468
Equity		
Common shares with US$100 par value each authorized and issued 100 shares	0.010	0.010
Retained earnings	0.327	0.003
Prepaid tax	(0.003)	—
Total equity	0.334	0.013
Total liabilities and equity	9.495	9.481

(1) Unaudited.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the information below together with "Presentation of Financial and Other Information," "Summary Historical Financial and Other Data," "Capitalization," "Use of Proceeds" and "Selected Historical Financial Data" and our Financial Statements and related notes included elsewhere in this offering memorandum. The Issuer Annual Financial Statements and the Guarantors Financial Statements were prepared in accordance with IFRS.

This section contains forward-looking statements that involve risks and uncertainties. Our actual results may vary materially from those discussed in such forward-looking statements as a result of various factors, including, without limitation, those set forth in "Risk Factors" and other matters set forth in this offering memorandum.

Overview

As indirect subsidiaries of InterEnergy Group Ltd., our Sponsor, we are diversified clean energy companies that own and operate wind and solar power generation plants in Panama with an aggregate installed generation capacity of 255MW, the biggest unconventional renewable energy producer in Panama in terms of installed capacity. We are among the top five power generators in Panama and are one of the largest diversified clean energy companies in Central America. During 2019, the Issuer and Guarantors generated 546.2 GWh (4.9%) and 70.3 GWh (0.6%) of energy, respectively, for a combined generation of 5.5% of the total energy generated in Panama in 2019, according to the Independent Energy Market Report, see "Annex A." For the fiscal year ended December 31, 2019, our wind and solar power generation plants generated 81% and 19%, respectively, of our combined revenues and 89% and 11%, respectively, of our combined EBITDA.

The Issuer owns and operates the UEP II Wind Project, the largest wind farm in Central America and the Caribbean with 215 MW of installed capacity, strategically located in Penonomé, Coclé, close to the southern shores of Panama where it benefits from the Caribbean winds. The UEP II Wind Project, is installed across 39.79 hectares of flat plains located at sea level in the central region of Panama, next to the UEP I Wind Farm, a wind power plant owned by AES Panama with an installed generation capacity of 55MW. The UEP II Wind Project is equipped with 86 Goldwind direct magnet drive turbines, each with a generation capacity of 2.5 MW. Construction of the UEP II Wind Project began in 2013 and, while the project has been in operation since January 2015 under "generation under test status" (during which the performance of the project is closely monitored and tested by the CND), the UEP II Wind Project officially achieved commercial operation in February 2018. The construction of the UEP II Wind Project was performed by CODEPA, a renowned international construction and infrastructure company with extensive experience in the renewable energy sector. The UEP II Wind Project is one of the largest construction projects in Central America to date. The UEP II Wind Project is divided into five separate wind farms: 1) Nuevo Chagres, comprised of 25 wind turbines and an installed capacity of 62.5 MW, 2) Rosa de los Vientos I, comprised of 21 wind turbines and an installed capacity of 52.5 MW, 3) Rosa de los Vientos II, comprised of 20 wind turbines and an installed capacity of 50 MW, 4) Marañon, comprised of seven wind turbines and an installed capacity of 17.5 MW, and 5) Portobelo, comprised of 13 wind turbines and an installed capacity of 32.5 MW. In 2019, the electricity sold by the UEP II Wind Project to Distribution Companies indirectly supplied electricity to 185,000 Panamanian families.

The Guarantors own and operate the Tecnisol Solar Project, a solar energy project with 40 MW of installed capacity located in David, Chiriqui, Panama over flat land and in one of the most solar resource rich areas of the country. With a total area of 97.8 hectares, the Tecnisol Solar Project is divided into four separate solar parks, *Ikako, Ikako I, Ikako II, and Ikako III*, each of which is comprised of a single axis tracker of 10MW equipped with Jinko Solar JKM325PP (70%) and JKM330PP (30%) PV modules. Construction of the Tecnisol Solar Project began in August 2017 and has been operating under "generation under test status" since August 2018 pending the conclusion of the regulatory approval process in order to achieve commercial operations. The construction of the Tecnisol Solar Project was performed on a turnkey basis by.

Trends and Factors Affecting Our Results of Operations

The following are the principal factors affecting our result of operations:

Terms of our PPAs

Our revenue is primarily a function of the volume of electricity generated by our facilities and sold under our PPAs as well as, to a lesser extent, our sales to the spot market. Except for 50 MW related to Rosa de los Vientos II (which is part of the UEP II Wind Project), all the generation capacity of UEP II Wind Project is contracted under the long-term physical energy-only UEP II PPAs. In the case of the Tecnisol Solar Project, the Guarantors have long-term financial energy-only PPAs to supply all demand of our Tecnisol Customers, which demand has resulted, in the period from January 2019 to June 2020, in approximately 60% of the generation capacity of the Tecnisol Solar Project. Any remaining generation capacity is sold in the spot market. As of September 30, 2020, the weighted average remaining life of our PPAs was 10.04 years and 12.78 years, respectively.

The price for the electricity sold under the UEP II PPAs is fixed as to 75% of such price for the duration of the contract while the remaining 25% of such price is adjusted based on the Panama CPI. The price for electricity under the Tecnisol PPAs is calculated based on an initial base price adjusted every six months by variations in the Regulated Tariff set by the ASEP and minimum and maximum prices are set forth in the applicable PPA. Therefore, our results of operations may be affected by inflation or other increases in operating costs in Panama since, while costs of operation may increase as a consequence of an increase in inflation or for other reasons, our revenue derived from the UEP II PPAs or the adjustment based on the Regulated Tariff under our Tecnisol PPAs may not appropriately reflect such increases in costs.

In addition, for the Tecnisol PPAs, transmission costs are assumed by our Tecnisol Customers. These costs are mainly comprised of the fees and tolls owed to ETESA, from our point of delivery in the SIN to the point in which the energy is delivered to our customers. An increase or a decrease of the transmission costs affects the cost to deliver our energy to our Tecnisol Customers. For more information regarding our PPAs, see “Business Overview — Revenues.”

Environmental conditions and seasonality

The electricity produced and revenues generated by UEP II Wind Project depend heavily on wind conditions, which are variable and difficult to predict. Operating results for renewable energy facilities vary significantly from period to period depending on the wind conditions during the periods in question. As our wind project is located in Panama, there is some flattening of the wind between May and November compensated by the high wind season between December and April. Therefore, historically, our wind generation has been greater in the first quarter of the year. During the years ended December 31, 2017, 2018 and 2019 and the nine months ended September 30, 2020, our UEP II Wind Project production was 396.33 GWh, 490.61 GWh, 546.18 GWh and 422.81 GWh, respectively.

Similarly, the amount of electricity produced and revenues generated by our Tecnisol Solar Project is dependent in part on the amount of solar irradiation where the assets are located. Cloudy weather in the rainy season, from May to November, results in less irradiation and hence a lower generation is produced by this facility. Solar irradiation can also be variable at a particular location from period to period due to meteorological patterns, which can affect operating results. During the years ended December 31, 2018 and 2019 and the nine months ended September 30, 2020, the Tecnisol Solar Project’s energy generation was 21.72 GWh, 70.28 GWh and 54.6 GWh, respectively.

In addition, weather in Panama is highly affected by the “El Niño” and “La Niña” phenomena. When the “El Niño” phenomenon occurs, there is an increase in the duration of the high wind season and a reduction of the rainy seasons. Therefore, when such phenomenon occurs, we usually experience an increase in generation from the UEP II Wind Project and the Tecnisol Solar Project but, since the “El Niño” phenomenon also causes droughts in Panama, the hydroelectric plants decrease their energy generation which usually derives in an increase in the spot price. While an increase in generation from UEP II Wind Project may cause our revenues under our UEP II PPAs to increase, we may incur additional costs if we need to purchase energy from other sources to cover our obligations under our Tecnisol PPAs. Conversely, when the “La Niña” phenomenon occurs, the rainy season is extended which causes a reduction of the high wind season. Conversely, our generation capacity decreases causing a decrease in revenues derived from our PPAs but, since there is an increase in hydroelectric generation, the spot price usually decreases which allows us to cover our obligations under our Tecnisol PPAs at a lower price, if needed. For more information, see

"Risk Factors — Risks Relating to Our Business — Seasonality may cause fluctuations in our revenue and operating results" and "Risk Factors — Risks Relating to Our Business — Electricity generated from wind and solar energy depends heavily on suitable wind and solar conditions, respectively. If such conditions are unfavorable or below our expectations, our Projects' electricity generation and the revenue generated from our projects may be substantially below our expectations."

The Independent Engineer Report contains an analysis and assessment of the wind and solar resources at the Projects. See "Annex B — Independent Engineer Report."

Operations and availability

Our revenue generation is materially affected by the volume of electricity generated and sold, but also by the availability and operational integrity of the power generation assets and equipment that we use. The volume of electricity generated and sold by our renewable energy facilities during a particular period is impacted by both scheduled and unexpected repair and maintenance required to keep our facilities operational. Thus, we selected high-quality equipment which, combined with the in-house operating capabilities developed and the support services we engaged under the Service and Maintenance Agreement and the Tecnisol Management Services Agreement, allow us to expect high availability and long-term production from our equipment.

The following table sets forth the total energy generation for each Project during the periods indicated.

	For the nine months ended September 30,		For the year ended December 31,		
	2020	**2019**	**2019**	**2018**	**2017**
UEP II Wind Project	422.8	485.1	546.2	490.6	396.3
Tecnisol Solar Project	54.6	54.8	70.3	N/A	N/A

Under the Service and Maintenance Agreement, Goldwind guarantees to the Issuer a turbine availability rate of 97% for the high wind season and 96% for the low wind season. Under the Tecnisol Management Services Agreement, IEH UK, an affiliate of our Sponsor, has guaranteed an availability rate of 98% in the inverter points. Goldwind has compensated the Issuer for the turbines' reduced availability levels in 2017 pursuant to the terms of the Settlement Agreement and for the turbines' reduced availability levels in the years 2018 and 2019. Despite these guarantees, the volume of electricity generated and sold by our facilities is impacted if any facility experiences higher than normal downtime as a result of electrical grid disruption or curtailment, weather disruptions, or other events beyond our control.

The following table sets forth the total plant availability factor for each Project during the periods indicated.

	For the nine months ended September 30,		For the year ended December 31,		
	2020	**2019**	**2019**	**2018**	**2017**
UEP II Wind Project	94.8%	89.9%	90.7%	93.3%	94.6%
Tecnisol Solar Project	98.9%	97.2%	97.8%	N/A	N/A

The costs we incur to operate, maintain, and manage our renewable energy facilities also affect our results of operations. As mentioned, equipment performance represents an essential factor affecting our operating results because equipment downtime impacts the volume of the electricity that we are able to generate from our renewable energy facilities. UEP II Wind Project is operated by the Issuer and supervised by IEH UK, an affiliate of our Sponsor, while the maintenance of the wind turbines is performed by Goldwind under the Service and Maintenance at a fixed price for regular work and variable price for additional work. Ingenieria y Productos Electromecanicos S.A. is currently responsible for providing maintenance to the UEP II Wind Project internal mid voltage transmission grid until December 2020. As to the Tecnisol Solar Project, we operate and maintain our facilities in-house under the supervision of IEH UK, an affiliate of our Sponsor, and Mantenimientos de Sistemas Eléctricos de Chiriquí, S.A. is currently responsible for providing maintenance to the Tecnisol Solar Project transmission line until August 31, 2021.

While we maintain all manufacturer warranties for all equipment (inverters, modules, tracking structure and other components) and we maintain a complete inventory of spare parts to reduce repair or replacement lead time, we have also entered into agreements with Jema and Gonvarri to provide us with technical assistance as needed. For more information, see "Risk Factors — Risks Relating to Our Business — Operation and maintenance problems at our renewable energy projects, including for natural events causes, may cause our electricity generation to fall below our expectations" and "Risk Factors — Risks Relating to Our Business — Electricity generated from wind and solar energy depends heavily on suitable wind and solar conditions, respectively. If such conditions are unfavorable or below our expectations, our projects' electricity generation and the revenue generated from our projects may be substantially below our expectations."

The Independent Engineer Report also contains the mechanical availability of the wind turbines and PV modules and their performance and efficiency. See "Annex B — Independent Engineer Report."

Wake Effect Agreement

Upon the commencement of construction of UEP II Wind Project, the Issuer entered into a Wake Effect Agreement with Unión Eólica Panameña, S.A. and Goldwind (which later assigned its rights and obligations thereunder to UEP I) pursuant to which we agreed to compensate UEP I for the MWh that UEP I Wind Farm would have generated and sold under UEP I's PPAs and to the spot market but for the downstream influence and reduced wind speed and flow created by the upstream location of the UEP II Wind Project when in operation. The wake effect created by the UEP II Wind Project on the UEP I Wind Farm was calculated by an independent wind consultant designated by the Issuer and UEP I and the compensation is calculated on a monthly basis based on a formula that contemplates the hourly generation of the UEP I Wind Farm, the sale price set forth in UEP I's then existing PPAs and the hourly spot market price. UEP I was acquired by AES Panama on May 13, 2020 and absorbed by AES Panama in June 2020.

Effects of the COVID-19 Pandemic

The COVID-19 pandemic has taken a substantial toll on the Panamanian economy. The Panamanian government has enacted measures to mitigate the economic effect on the economy, including a prohibition on shutting off electricity services for non-payment and mandating the Distribution Companies to provide discounts to certain customers on their electricity bill. The discounts are to be funded through a tariff stabilization fund (*Fondo de Estabilización Tarifaria*), which has not yet been funded. This has caused the Distribution Companies to make only partial payments on our invoices during April, May and June. Nevertheless, there can be no certainty as to when the Panamanian government will fund the Tariff Stabilization Fund, and continued payment delays and shortfalls could adversely affect our financial condition and results of operation. For more information on the measures taken by the Panamanian Government, see "Summary — Recent Developments"

The COVID-19 pandemic has also caused a downturn in consumer demand for certain goods and services as well as the temporary closure of businesses and industries. The Issuer, however, has not been affected by this downturn since, except for the 50 MW of energy generated by Rosa de los Vientos II, all of the energy generated by the UEP II Wind Project is fully contracted. However, the COVID-19 pandemic has adversely affected the financial condition of some Tecnisol Customers and has lowered their overall demand for electricity. For example, due to the measures taken by the Panamanian government, Hilton, one of our Tecnisol Customers, had to temporarily close its hotel and casinos. As a consequence, Hilton defaulted on payment obligations under the applicable PPA, which, as of September 30, 2020, amounted to US$0.261 million. Following such default, Hilton proposed repaying the total amount due in ten (10) monthly installments, starting in November 2020. Such proposal was accepted by us and as of the date of this offering memorandum, the first installment had been paid by Hilton. Although the remaining Tecnisol Customers have been making timely payments as of the date of this offering memorandum, there can be no assurance that they will be able to continue making timely payments in the future. Although no official data has been published, we expect that electricity demand will fall, which could also lower the average price for energy in the spot market.

Critical Accounting policies

For a discussion of the significant accounting policies of the Issuer see Note 4 to the Issuer Annual Financial Statements and Note 4 to the Issuer Unaudited Interim Financial Statements, included in this offering memorandum. For a discussion of the significant accounting policies of the Guarantors see Note 2 to each Guarantor Annual Financial Statement and Note 2 to the Guarantor Combined Financial Statements, included in this offering memorandum.

Restatements

During 2018, the Issuer received cash compensation of US$51.165 million in connection with the Settlement Agreement (as defined below) that was accounted as a liability (other current liabilities and accrued expenses) to purchase the related assets that were part of such Settlement Agreement. For more information on the Settlement Agreement, see "Business — Legal Proceedings — Arbitration with Goldwind." On further detailed analysis performed by the Issuer's management during the third quarter of 2020, it was determined that the appropriate accounting treatment of the compensation received should be reflected as a reduction of plant and equipment that cause an adjustment to the depreciation expense of the associated assets. The US$51.165 million payment was restated in the Issuer's financial statements as of and for the years ended December 31, 2019 and 2018 to present the figures as a reduction of plant and equipment and the reduction of the related depreciation expense and accumulated depreciation for the years 2019 and 2018. The related deferred tax liability was adjusted accordingly to the figures presented in the table below.

In addition, the Issuer evaluated and determined at the inception of the IFC Loan and the hedging agreement to fix rate disclosed in Note 12 to the Issuer Annual Financial Statements, were considered as closely related at the inception as it is established that the borrower would have to repay both simultaneously and is required to have the debt hedged. Although, in subsequent analysis of the contracts during the third quarter of 2020, it was determined that from a legal perspective there are both separate contracts that required that the derivative financial instrument from the interest rate swap should be accounted at fair value, since the hedge accounting option was not adopted in the inception of the IFC Loan. The transaction resulted in the restatement for the recognition of the derivative financial instrument separately in the balance sheet and recognizing the corresponding fair value losses (gains) on interest rate swap for the 2019 and prior financial years. The amount of US$3.462 million was recognized as the initial adjustment to accumulated deficit as of December 31, 2016.

For more information, see Note 22 to the Issuer Annual Financial Statements.

Changes in accounting policies

Management has initially applied IFRS 16, for the first time for their annual reporting period commencing January 1, 2019. It has applied using the cumulative effect method, under which the comparative information is not restated. For more information on the application of IFRS 16, see Note 2 to the Issuer Annual Financial Statements and Note 2 to the Issuer Unaudited Interim Financial Statements, included in this offering memorandum, and Note 2 to each Guarantor Annual Financial Statement and Note 2 to the Guarantor Combined Financial Statements, included in this offering memorandum.

Results of Operations

The Issuer's results of operations for the nine-month period ended September 30, 2020 compared to the nine-month period ended September 30, 2019

	For the nine months ended September 30,			
	2020	2019	Variation	
	(in millions of US$)			
Energy revenues	40.337	49.802	(9.465)	(19.01)%
Costs of goods and services	(11.812)	(12.256)	0.444	(3.62)%
Gross profit	28.525	37.546	(9.021)	(24.03)%
Administrative expenses	(3.101)	(3.236)	0.135	(4.17)%
Operating expenses	(4.218)	(4.453)	0.235	(5.28)%
Total expenses	(7.319)	(7.689)	0.370	(4.81)%
Operating profit	21.206	29.857	(8.651)	(28.97)%
Finance cost amortization	(0.598)	(0.598)	—	0.00%
Finance cost, net	(24.546)	(27.035)	2.489	(9.21)%
Total finance cost	(25.144)	(27.633)	2.489	(9.01)%
Other loss	(0.006)	(0.064)	0.058	(90.63)%
Profit (loss) before income tax	(3.944)	2.160	(6.104)	(282.59)%
Income tax	0.176	(2.551)	2.727	(106.90)%
Loss for the period	(3.768)	(0.391)	(3.377)	863.68%

Energy revenues

The Issuer's energy revenues for the nine months ended September 30, 2020 were US$40.337 million, a decrease of US$9.465 million, or 19.01%, compared to the Issuer's energy revenues of US$49.802 million for the nine months ended September 30, 2019. This decrease was primarily attributable to a decrease of US$8.371 million, or 19.02%, in the Issuer's energy revenues under the Issuer's PPAs due to (a) a decrease in the amount of electricity generated by our generating assets contracted under our PPAs as a consequence of adverse weather conditions at our Projects caused by the transition from the "El Niño" phenomenon to the "La Niña" phenomenon (generation in the period of nine months ended September 30, 2020 was 422.8 GWh compared to 487.3 GWh generated in the same period of 2019); and (b) a decrease of US$0.957 million, or 20.02%, in the Issuer's revenues from sales in the spot market due to the decrease in the average spot sales price by 43.59% (US$60.61/MWh in the nine months ended September 30, 2020 compared to US$104.19/MWh in the same period in 2019) mostly due to the decreased demand caused by the COVID-19 pandemic, a decrease in the international Fuel Oil Prices and an increment on the hydroelectric generation caused by additional water inflows.

Costs of goods and services

The Issuer's cost of goods and services for the nine months ended September 30, 2020 was US$11.812 million, a decrease of US$0.444 million, or 3.62%, compared to the Issuer's cost of goods and services of US$12.256 million for the nine months ended September 30, 2019, mostly driven by a decrease of US$0.457 million related to energy purchases in the spot market as consequence of the expiration of certain short-term financial PPAs between the Issuer and certain Distribution Companies.

Gross profit

The Issuer's gross profit for the nine months ended September 30, 2020 was US$28.525 million, a decrease of US$9.021 million, or 24.03%, compared to the Issuer's gross profit of US$37.546 million for the nine months ended September 30, 2019, mostly driven by the decrease in revenues during the nine months ended September 30, 2020.

Administrative expenses

The Issuer's administrative expenses for the nine months ended September 30, 2020 were US$3.101 million, a decrease of US$0.135 million, or 4.17%, compared to the Issuer's administrative expenses of US$3.236 million for the nine months ended September 30, 2019. This decrease was primarily attributable to:

- a decrease of US$0.313 million in professional fees due to lower technical advisory fees derived from the advisory services related to the repair of the blades' tips completed in 2019; and
- a decrease of US$0.261 million from lower fees incurred under the Wake Effect Agreement as a consequence of lower generation by UEP I and lower spot prices during the period.

These decreases were partially offset by an increase of US$0.242 million in accrued management services expenses under the UEP II Management Services Agreement during 2020 compared to 2019, an increase of US$0.159 million in costs related to the cleaning of the UEP II Wind Project site, the transportation of the staff and other expenses related to filings with the Superintendencia del Mercado de Valores.

Operating expenses

The Issuer's operating expenses for the nine months ended September 30, 2020 were US$4.218 million, a decrease of US$0.235 million, or 5.28%, compared to the Issuer's operating expenses of US$4.453 million for the nine months ended September 30, 2019. This decrease was attributable to a decrease of US$0.136 million in security expenses due to a reduction in the price paid for security as a consequence of change of provider, and a decrease of US$0.098 million repairs and maintenance expenses due to indexation and taxes.

Total finance cost

The Issuer's finance costs, net for the nine months ended September 30, 2020 were US$25.144 million, a decrease of US$2.489 million, or 9.01%, compared to the Issuer's finance cost, net of US$27.633 million for the nine months ended September 30, 2019. This decrease was primarily attributable to a reduction of the fair market valuation under the IFC Hedge Agreement of US$0.802 million, and a decrease of US$1.757 million in interest expenses under the variable tranches of the IFC Loan due to a decrease of the 6 month US$ LIBOR rate during the period.

Profit (loss) before income tax

The Issuer's loss before income tax for the nine months ended September 30, 2020 was US$3.944 million, a decrease of US$6.104 million, or (282.59)%, compared to the Issuer's profit before income tax of US$2.160 million for the nine months ended September 30, 2019.

Income tax

The Issuer's income tax for the nine months ended September 30, 2020 was US$0.176 million, a decrease of US$2.727 million, compared to the Issuer's income tax of US$2.551 million for the nine months ended September 30, 2019. This decrease is attributable to the deferred tax liability computation of US$2.419 million and current tax of US$0.308 million.

Loss for the period

The Issuer's loss for the nine-months ended September 30, 2020 was US$3.768 million, an increase of US$3.377 million, compared to the Issuer's loss for the period of US$0.391 million for the nine months ended September 30, 2019. The Issuer's net income as a percentage of revenue was (9.34)% for the nine months ended September 30, 2020 compared to (0.79)% for the nine months ended September 30, 2019.

The Issuer's results of operations for year ended December 31, 2019 compared to year ended December 31, 2018.

	For the year ended December 31,			
	2019	**2018**	**Variation**	
	(in millions of US$)			
Energy revenues	56.070	50.310	5.760	11.45%
Costs of goods and services	(16.289)	(19.572)	3.283	(16.77)%
Gross profit	39.781	30.738	9.043	29.42%
Administrative expenses	(4.278)	(5.773)	1.495	(25.90)%
Operating expenses	(6.378)	(5.455)	(0.923)	16.92%
Total expenses	(10.656)	(11.228)	0.572	(5.09)%
Operating profit	29.125	19.510	9.615	49.28%
Finance cost amortization	(0.797)	(0.797)	—	0.00%
Finance cost, net	(28.631)	(20.096)	(8.535)	42.47%
Total finance cost	(29.428)	(20.893)	(8.535)	40.85%
Other income	0.561	8.879	(8.318)	(93.68)%
Profit (loss) before income tax	0.258	7.496	(7.238)	(96.56)%
Income tax	(1.644)	(2.313)	0.669	(28.92)%
Total comprehensive income (loss) for the year	(1.386)	5.183	(6.569)	(126.74)%

Energy revenues

The Issuer's energy revenues for the year ended December 31, 2019 were US$56.070 million, an increase of US$5.760 million, or 11.45%, compared to the Issuer's energy revenues of US$50.310 million for the year ended December 31, 2018. This increase was primarily attributable to (a) an increase of sales under the Issuer's PPAs by 12.8%, due to favorable weather conditions as a consequence of the "El Niño" phenomenon resulting in higher generation of our assets contracted under PPAs (488.8 GWh in 2019 compared to 433.2 GWh in 2018), and (b) an increase in spot sales by 2.4% due to higher generation of our assets not contracted under PPAs (49.4 GWh in 2019 compared to 48.2 GWh in 2018) and the increase of the spot sales price by 21.0% (average sport price increased to US$102.5/MWh in 2019 from US$84.9/MWh in 2018), due to lower hydroelectric generation as a result of the "El Niño" phenomenon.

Cost of goods and services

The Issuer's cost of goods and services for the year ended December 31, 2019 was US$16.289 million, a decrease of US$3.283 million, or 16.77%, compared to the Issuer's cost of goods and services of US$19.572 million for the year ended December 31, 2018. This decrease was primarily attributable to:

- a lower depreciation expense of US$4.027 million derived from the compensation received from Goldwind in June 2018 pursuant to the terms of the Settlement Agreement which decreased the value of property, plant and equipment in the balance sheet which, in turn, caused a decrease in depreciation expense.
- US$0.106 million decrease in repairs and maintenance, or 78.93% due to the termination of an agreement with an external provider for the operation of the El Coco substation (such operation is currently done in-house).

These decreases were partially offset by:

- an increase of US$0.461 million in amortization, mostly driven by the adoption and implementation of IFRS16;
- an increase of US$0.206 million in fee transmission cost, due to the increase in the generation of 10.7% during 2019 compared to 2018; and

- an increase of US$0.166 million in energy purchases to meet energy obligations under a short term PPA, due to an increase in the average spot purchase price from US$115.7/MWh to US$136.7/MWh due to lower hydroelectric generation as a result of the "El Niño" phenomenon.

Gross profit

The Issuer's gross profit for the year ended December 31, 2019 was US$39.781 million, an increase of US$9.043 million, or 29.42%, as compared to the Issuer's gross profit of US$30.738 million for the year ended December 31, 2018.

Administrative expenses

The Issuer's administrative expenses for the year ended December 31, 2019 were US$4.278 million, a decrease of US$1.495 million, or 25.90%, as compared to the Issuer's administrative expenses of US$5.773 million for the year ended December 31, 2018. This decrease was primarily attributable to:

- a decrease of US$1.200 million in management fee expenses, due to the waiver by our Sponsor to receive payment of the fees owed in 2019 under the Service and Maintenance Agreement;
- a decrease of US$0.734 million in land expenses as a consequence of the adoption and application to IFRS16; and
- a decrease of US$0.130 million in substation rent, given that, while it incurred in the same expenses under the Share Asset Access Agreement as compared to 2018, the Issuer made certain one-time payments in 2018 that were required by the Settlement Agreement.

These decreases were partially offset by:

- an increase of US$0.271 million in professional fees expenses, due to an increase in technical consultant expenses related to blades inspection and generation improvement analysis of the wind project incurred in 2019; and
- an increase of US$0.251 million in wake effect expenses due to an increase in generation by UEP I's wind project and higher spot prices as a consequence of the "El Niño" phenomenon.

Operating expenses

The Issuer's operating expenses for the year ended December 31, 2019 were US$6.378 million, an increase of US$0.923 million, or 16.92%, compared to the Issuer's operating expenses of US$5.455 million for the year ended December 31, 2018. This increase was primarily attributable to:

- an increase of US$0.827 million in repairs and maintenance expenses, as a consequence of the performance of certain delayed maintenances of services due in 2018 that were performed in 2019; and
- an increase of US$0.103 million in security expenses, as a consequence of the new agreement entered into with a new security contractor.

Finance cost, net

The Issuer's finance cost, net for the year ended December 31, 2019 was US$28.631 million, an increase of US$8.535 million, or 42.47%, compared to the Issuer's finance cost, net of US$20.096 million for the year ended December 31, 2018. This increase was primarily attributable to a higher fair market valuation under the IFC Hedge Agreement of US$12.572 million, and a decrease of US$4.037 million in interest expenses under the variable tranches of the IFC Loan due to a decrease of the 6 month US$ LIBOR rate during the period.

Other income

The Issuer's other income for the year ended December 31, 2019 was US$0.561 million, a decrease of US$8.318 million, or 93.68%, compared to the Issuer's other income of US$8.879 million for the year ended December 31, 2018, and is primarily attributable to the reimbursement of expenses received under the Settlement Agreement in 2018.

Income tax

The Issuer's income tax for the year ended December 31, 2019 was US$1.644 million, a decrease of US$0.669 million, or 28.92%, compared to the Issuer's income tax of US$2.313 million for the year ended December 31, 2018. This decrease was primarily attributable to the current tax expense of US$0.691 million incurred on 2018.

Net income

The Issuer's net income or loss for the year ended December 31, 2019 was a loss of US$1.386 million, a decrease of US$6.569 million, compared to the Issuer's net income of US$5.183 million in 2018. The Issuer's net income as a percentage of revenue was (2.47%) for the year ended December 31, 2019 compared to 10.30% for the year ended December 31, 2018.

The Issuer's results of operations for year ended December 31, 2018 compared to year ended December 31, 2017.

	For the year ended December 31,			
	2018	2017	Variation	
	(in millions of US$)			
Energy revenues	50.310	42.404	7.906	18.64%
Costs of goods and services	(19.572)	(29.150)	9.578	(32.86)%
Gross profit	30.738	13.254	17.484	131.91%
Administrative expenses	(5.773)	(10.870)	5.097	(46.89)%
Operating expenses	(5.455)	(4.129)	(1.326)	32.11%
Total expenses	(11.228)	(14.999)	3.771	(25.14)%
Operating profit	19.510	(1.745)	21.255	(1,218.05)%
Finance cost amortization	(0.797)	(0.797)	—	0.00%
Finance cost, net	(20.096)	(24.117)	4.021	(16.67)%
Total finance cost	(20.893)	(24.914)	4.021	(16.14)%
Other income	8.879	—	8.879	N/A
Profit (loss) before income tax	7.496	(26.659)	34.155	(128.12)%
Income tax	(2.313)	1.698	(4.011)	(236.22)%
Total comprehensive income (loss) for the year	5.183	(24.961)	30.144	(120.76)%

Energy revenues

The Issuer's energy revenues for the year ended December 31, 2018 was US$50.310 million, an increase of US$7.906 million, or 18.64%, compared to the Issuer' energy revenues of US$42.404 million for the year ended December 31, 2017. This increase was primarily attributable to (a) an increase of sales under the Issuer's PPAs by 22.1%, due to favorable weather conditions as a consequence of "El Niño" phenomenon resulting in higher generation of our assets contracted under PPAs (433.2 GWh in 2018 compared to 336.1 GWh in 2017) and (b) an increase in spot physical sales by 3.3% due to the increase of the average spot sales price by 25% (US$84.9/MWh in 2018 compared to US$67.7/MWh in 2017) caused lower hydroelectric generation as a result of the "El Niño" phenomenon.

Cost of goods and services

The Issuer's cost of goods and services for the year ended December 31, 2018 was US$19.572 million, a decrease of US$9.578 million, or 32.86%, compared to the Issuer's cost of goods and services of US$29.150 million for the year ended December 31, 2017. This decrease was primarily attributable to:

- a US$8.108 million lower depreciation expense, mainly due to (a) the reduction of the expected useful life of our blades from 20 years to 10 years as a consequence of the defect claims made to

Goldwind (See "Business Overview — Legal Proceedings — Goldwind Arbitration Proceedings") that resulted in a higher depreciation expense of US$6.912 million in 2017, and (b) a lower depreciation expense of US$3.936 million derived from the compensation received from Goldwind in June 2018 pursuant to the terms of the Settlement Agreement which decreased the value of property, plant and equipment in the balance sheet which, in turn, caused a decrease in depreciation expense;

- US$1.493 million lower energy purchases, due to higher generation of our assets not contracted under PPAs during 2018 as compared to 2017 which decreased the energy needed to cover the energy shortfall under the short-term financial PPA entered with respect to Rosa de Los Vientos II and the Distribution Companies; and

- US$0.221 million decrease or 19.58% in fee transmission cost, due a decrease by US$1.00/MWh in the toll owed to ETESA fees compared to the prior year.

Gross profit

The Issuer's gross profit for the year ended December 31, 2018 was US$30.738 million, an increase of US$17.484 million, or 131.91%, compared to the Issuer's gross profit of US$13.254 million for the year ended December 31, 2017.

Administrative expenses

The Issuer's administrative expenses for the year ended December 31, 2018 were US$5.773 million, a decrease of US$5.097 million, or 46.89%, compared to the Issuer's administrative expenses of US$10.870 million for the year ended December 31, 2017. This decrease was primarily attributable to:

- a decrease of US$5.324 million in professional fees and expenses given the one-off expense incurred in 2017 related to the arbitration process with Goldwind;

partially offset by:

- an increase of US$0.608 million in substation rent, given that, while it incurred in the same expenses under the Share Asset Access Agreement as compared to 2018, the Issuer made certain one-time payments in 2018 required by the Settlement Agreement; and

- an increase of US$0.431 million related to the commencement of payments under the Wake Effect Agreement following the commercial operation date of UEP I and the Issuer with respect to the UEP II Wind Project in February 2018.

Operating expenses

The Issuer's operating expenses for the year ended December 31, 2018 were US$5.455 million, an increase of US$1.326 million, or 32.11%, compared to the Issuer's operating expenses of US$4.129 million for the year ended December 31, 2017. This increase was primarily attributable to millions higher in repairs and maintenance expenses following the execution of a new Service and Maintenance Agreement with Goldwind and adjustments to the price therein. Base price was increased to US$45,000 per turbine indexed annually based on the U.S. consumer price index, partially offset by lower costs associated to a decrease in the spot market sales.

Finance cost, net

The Issuer's finance cost, for the year ended December 31, 2018 was US$20.096 million, a decrease of US$4.021 million, or 16.67%, compared to the Issuer's finance cost of US$24.117 million for the year ended December 31, 2017. This decrease was primarily attributable to a reduction of the fair market valuation under the IFC Hedge Agreement of US$3.357 million, and an increase of US$0.664 million in interest expenses under the variable tranches of the IFC Loan due to an increase of the 6 month US$ LIBOR rate during the period.

Financial results, net

The Issuer's financial results, net for the year ended December 31, 2018 was US$20.893 million, a decrease of US$4.021 million, or 16.14%, compared to the Issuer's financial results, net of US$24.914 million for the year ended December 31,2017, primarily due to the decrease in finance cost, net as explained above.

Other income

The Issuer's other income for the year ended December 31, 2018 was US$8.879 million, an increase of US$8.879 million, compared to the Issuer's other income of US$0.000 million for the year ended December 31, 2017 primarily attributable to the result of the Settlement Agreement.

Income tax

The Issuer's income tax for the year ended December 31, 2018 was a tax expense of US$2.313 million, an increase of US$4.011 million, compared to the Issuer's income tax of US$1.698 million for the year ended December 31, 2017. This increase was primarily attributable to the reassessment of the deferred tax position given the application of different amortization methodologies by accounting and tax (the application of linear methodology versus accelerated methodology). The Issuer's effective tax rate in the year ended December 31, 2018 was 30.86% compared to 0% in the year ended December 31, 2017.

Net income

The Issuer's net income for the year ended December 31, 2018 was US$5.183 million, an increase of US$30.144 million, or 120.76%, compared to the Issuer's net loss of US$24.961 million in 2017.

The Guarantors' combined results of operations for the nine-month period ended September 30, 2020 compared to the nine-month period ended September 30, 2019

	For the nine months ended September 30,		Variation	
	2020	2019		
	(in millions of US$)			
Energy revenues	7.696	9.239	(1.543)	(16.70)%
Other income	0.047	—	0.047	100%
Costs of goods and services	(5.639)	(6.759)	1.120	(16.57)%
Gross profit	2.104	2.480	(0.376)	(15.16)%
Administrative expenses	(0.597)	(0.643)	0.046	(7.15)%
Operating expenses	(0.241)	(0.008)	(0.233)	2,912.50%
Total expenses	(0.838)	(0.651)	(0.187)	28.73%
Operating profit	1.266	1.829	(0.563)	(30.78)%
Finance cost	(0.955)	(1.167)	0.212	(18.17)%
Profit (loss) before income tax	0.311)	0.662	(0.351)	(53.02)%
Income tax	(0.141)	(0.251)	0.110	(43.82)%
Total comprehensive income for the year	0.170	0.411	(0.241)	(58.64)%

Energy Revenues

The Guarantors' combined energy revenues for the nine months ended September 30, 2020 were US$7.696 million, a decrease of US$1.543 million, or 16.70%, compared to the Guarantors' combined energy revenues of US$9.239 million for the nine months ended September 30, 2019. This decrease was primarily attributable to a decrease of: (a) US$0.581 million in the Guarantors' sales under the Tecnisol PPAs due to a decrease in the average sales price (US$87.7/MWh during nine months ended September 30, 2020 compared to US$91.3/MWh during the nine months ended September 30, 2019) and (b) US$0.618 million in the Guarantors' spot sales due to lower average spot sales price (US$53.4/MWh during the nine months ended September 30, 2020 compared to US$82.4/MWh during the nine months ended September 30, 2019).

Other income

The Guarantors' combined other income for the nine months ended September 30, 2020 was US$0.047 million compared to the Guarantors' other income of US$0 for the nine months ended September 30, 2019, relating to an extraordinary reimbursement from a supplier.

Costs of goods and services

The Guarantors' combined cost of goods and services for the nine months ended September 30, 2020 was US$5.639 million, a decrease of US$1.120 million, or 16.57%, compared to the Guarantors' combined cost of goods and services of US$6.759 million for the nine months ended September 30, 2019. This decrease was primarily attributable to: (a) a decrease of US$2.055 million in energy purchases in the spot market as a consequence of lower prices and a decrease of US$0.349 million in depreciation and amortization, mostly driven by the reassessment the useful life of certain assets on 2019, (b) partially offset by an increase of US$1.085 million of energy purchase quantity from energy reserve agreements, and an increase of US$0.198 million of repairs and maintenance expenses.

Gross profit

The Guarantors' combined gross profit for the nine months ended September 30, 2020 was US$2.104 million, a decrease of US$0.376 million, or 15.16%, compared to the Guarantors' combined gross profit of US$2.480 million for the nine months ended September 30, 2019.

Administrative expenses

The Guarantors' combined administrative expenses for the nine months ended September 30, 2020 were US$0.597 million, a decrease of US$0.046 million, or 7.15%, compared to the Guarantors' combined administrative expenses of US$0.643 million for the nine months ended September 30, 2019. This decrease was primarily attributable to one-time expenses incurred in relation to the Tecnisol Solar Project launching event and lower professional fees expenses caused by the completion of the inspection in construction related to the definitive acceptance certificate under the Tecnisol Solar Project EPC Agreement.

Operating expenses

The Guarantors' combined operating expenses for the nine months ended September 30, 2020 were US$0.241 million, an increase of US$0.233 million, compared to the Guarantors' combined operating expenses of US$0.008 million for the nine months ended September 30, 2019. This increase was primarily attributable to:

- US$0.180 million in higher repairs and maintenance expenses that refer to the maintenance of the interconnection line, the contract includes the transmission line between the Tecnisol Solar Project and the "Mata de Nance" substation and started in 2020; and
- US$0.053 million in higher security expenses since we assumed the security expenses since February 2020 following the completion of the construction process.

Finance cost

The Guarantors' combined finance cost for the nine months ended September 30, 2020 was US$0.955 million, a decrease of US$0.212 million, compared to the Guarantors' combined finance cost of US$1.167 million for the nine months ended September 30, 2019, primarily attributable to the interests expense under the Tecnisol Shareholder Loans.

Income tax

The Guarantors' combined income tax for the nine months ended September 30, 2020 was US$0.141 million, a decrease of US$0.110 million, compared to the Guarantors' combined income tax of

US$0.251 million for the nine months ended September 30, 2019. This decrease was primarily attributable to a US$0.110 million decrease in current income tax related to lower pre-tax results. The Guarantors' combined effective tax rate in the nine months ended September 30, 2020 was 45% compared to 38% in the nine months ended September 30, 2019.

Net income

The Guarantors' combined net income for the nine months ended September 30, 2020 was US$0.170 million, a decrease of US$0.241 million, compared to the Guarantors' combined net income of US$0.411 million for the nine months ended September 30, 2019. The Guarantors' combined net income as a percentage of revenue was 2.21% for the nine months ended September 30, 2020 compared to 4.45% for the nine months ended September 30, 2019.

Liquidity and Capital Resources

Overview

Our sources of liquidity for the construction of UEP II Wind Project were the initial contribution of our Sponsor and shareholders through the Shareholders' Loans and equity together with the IFC Loan; while the capital provided for the construction of the Tecnisol Solar Project was provided solely by our Sponsor through construction loans and equity. Now that our Projects are in operation, we rely on cash flows from operations.

Liquidity

The Issuer

	For the nine months ended September 30,		Year Ended December 31,		
	2020	2019	2019	2018	2017
	(in millions of US$)				
Net cash provided by operating activities	9.721	29.593	30.033	11.043	7.934
Net cash (used in) provided by investing activities	(0.043)	(0.028)	(0.049)	63.115	(0.147)
Net cash used in financing activities	(17.383)	(14.513)	(14.530)	(15.324)	(14.377)
Net (decrease) increase in cash and cash equivalents	(7.705)	15.052	15.454	58.834	(6.590)
Cash and cash equivalents at end of period	68.586	75.889	76.291	60.837	2.003

The Issuer's cash flows for the nine months ended September 30, 2020 compared to the nine months ended September 30, 2019

For each of the nine months ended September 30, 2020 and 2019, considering the Issuer's cash flows from operations, cash flows, from investing activities and cash flows from financing activities, the Issuer generated net cash outflow of US$7.705 million and net cashflow of US$15.052 million, respectively. The variation of such net cash is explained below:

Operating Activities

For each of the nine months ended September 30, 2020 and 2019, the Issuer's net cash provided by operating activities was US$9.721 million and US$29.593 million, respectively. The main driver for this decrease is explained by a reduction in account payables of US$5.905 million as the Issuer cancelled fees under the Service and Maintenance Agreement and US$6.104 million less profit before income tax due to a decrease in revenue as a consequence of lower generation in the nine months ended September 30, 2020 compared to the same period in 2019.

Investing Activities

For each of the nine months ended September 30, 2020 and 2019, the Issuer's net cash used in investing activities was US$0.043 million and US$0.028, respectively. There was no material deviation between these periods.

Financing Activities

For each of the nine months ended September 30, 2020 and 2019, the Issuer's net cash used in financing activities was US$17.383 million and US$14.513 million, respectively. The main driver for this increase is the payments made in connection with the IFC Loan during the nine months ended September 30, 2020.

The Issuer's cash flows for the year ended December 31, 2019 compared to year ended December 31, 2018

For each of the years ended December 31, 2019 and 2018, taking into account the Issuer's cash flows from operations, cash flows from investing activities and cash flows from financing activities, the Issuer had generated net cash of US$15.454 million and US$58.834 million respectively. The variation of such net cash is explained below:

Operating Activities

For each of the years ended December 31, 2019 and 2018, the Issuer's net cash provided by operating activities was US$30.033 million and US$11.043 million, respectively. The main driver for this increase in 2019 compared to 2018 was the payment of the last installment under the Turbine Supply Agreement in 2018 and an increase in revenues in 2019.

Investing Activities

For the year ended December 31, 2019, the Issuer's net cash used in investing activities was US$0.049 million compared to the net cash provided by investing activities for the year ended December 31, 2018 of US$63.115 million. This decrease was due to the release of restricted cash for US$11.964 million to cancel the last installment under the Turbine Supply Agreement and the receipt of the US$51.165 million cash compensation payment under the Settlement Agreement in 2018.

Financing Activities

For each of the years ended December 31, 2019 and 2018, the Issuer's net cash flows used in financing activities was US$14.530 million and US$15.324 million, respectively. There was no material deviation between these periods.

The Issuer's cash flows for the year ended December 31, 2018 compared to the year ended December 31, 2017

For each of the years ended December 31, 2018 and 2017, taking into account the Issuer's cash flows from operations, cash flows from investing activities and cash flows from financing activities, the Issuer had generated net cash of US$58.834 million and a cash outflow of US$6.590 million, respectively. The variation is explained below:

Operating Activities

For each of the years ended December 31, 2018 and 2017, the Issuer's net cash derived from operating activities was US$11.043 million and US$7.934 million, respectively. The main driver for the increase in 2018 was attributable to higher revenues by US$7.906 million partially offset by working capital variations.

Investing Activities

For the year ended December 31, 2018, the Issuer's net cash provided by investing activities was US$63.115 million compared to net cash used in investing activities for the year ended December 31, 2017 of US$0.147 million. This increase was due to the release of restricted cash for US$11.964 million to cancel the last installment under the Turbine Supply Agreement and the receipt of the US$51.165 million cash compensation payment under the Settlement Agreement in 2018.

Financing Activities

For each of the years ended December 31, 2018 and 2017, the Issuer's net cash flows used in financing activities was US$15.324 million and US$14.377 million, respectively. There was no material deviation between these periods.

The Guarantors

	For the nine months ended September 30,	
	2020	2019
	(in millions of US$)	
Net cash provided by operating activities	2.253	1.294
Net cash used in investing activities	(0.078)	(0.216)
Net cash used in financing activities	(0.767)	(0.047)
Net increase in cash and cash equivalents	1.408	1.031
Cash and cash equivalents at end of period	4.376	7.333

The Guarantors' combined cash flows for the nine months ended September 30, 2020 compared to nine months ended September 30, 2020

For each of the nine months ended September 30, 2020 and 2019, taking into account the Guarantors' combined cash flows from operations, cash flows from investing activities and cash flows from financing activities, the Guarantors' had generated net cash of US$1.408 million and US$1.031 million respectively. The cash flow variation is explained below:

Operating Activities

For each of the nine months ended September 30, 2020 and 2019, the Guarantors' combined net cash provided by operating activities was US$2.253 million and US$1.294 million, respectively. The main driver for this increase in 2020 compared to 2019 was a payment made on behalf of the Sponsor and interest paid to the shareholders under the Shareholders Loans.

Investing Activities

For each of the nine months ended September 30, 2020 and 2019, the Guarantors' combined net cash used in investing activities was US$0.078 million and US$0.216 million, respectively. There was no material deviation between these periods.

Financing Activities

For each of the nine months ended September 30, 2020 and 2019, the Guarantors' combined net cash flows used in financing activities was US$0.767 million and US$0.047 million, respectively. This decrease was caused by the repayment of US$0.710 million of principal and interest under the Shareholders' Loans.

Indebtedness

The Issuer

	As of September 30, 2020	As of December 31,		
		2019	2018	2017
	(in millions of US$)			
Current debt, net	12.296	12.803	14.451	15.324
Long-term debt	203.844	220.003	232.009	245.663
Total debt facilities	216.140	232.806	246.460	260.987

The following table described the main financial terms of the Issuer's facilities:

Type of borrowing	Date Incurred	Maturity date	Currency	Rate	Outstanding as of September 30, 2020	Initial disbursement
					(in millions of US$)	
IFC Loan						
Tranche A	2014	2031	US dollar	Partially Float	US$187.790	US$250.000
Tranche B	2014	2031	US dollar	Float	US$ 24.208	US$ 34.000
Subordinated loan	2015	2030	US dollar	Fixed	US$ 12.704	US$ 16.000
Loan with IEH Penonome Holdings	2014	2031	US dollar	Fixed	US$ 47.619	US$ 47.619
Loan with Green Field Panama, S.A.	2014	2031	US dollar	Fixed	US$ 2.381	US$ 2.381

For a description of the UEP II Shareholders' Loans, see "Certain Relationships and Related Party Transactions — The Issuer — UEP II Shareholders Loan Agreements."

IFC Facility

On December 9, 2014, the Issuer, IEH Penonomé Panama, S.A. (which was subsequently merged into the Issuer), the Lender parties thereto, and the IFC, as administrative agent for such Lenders, executed the Common Terms Agreement pursuant to which the parties agreed to certain terms and conditions in common to each of the following loans for the purpose of financing the development of UEP II Wind Farm:

- On December 9, 2014, the Issuer, as Borrower entered into a senior debt facility loan agreement, as borrower, with certain Lenders parties thereto (the "Tranche A"). The total original amount of the Tranche A consisted of US$250 million and the maturity of the Tranche A is of 17 years (total door-to-door tenor). The principal amount due under the Tranche A accrues interest at an annual rate equal to 6 month US$ LIBOR plus 4.75%. The amortization is scheduled to be stepping up from 2.4% in average for the first 22 semesters (53% of total amount), 3.66% for the following 6 semesters (22% of total amount) and 6.27% for the last 4 semesters (25% of total amount).
- On December 9, 2014, the Issuer entered into a senior debt facility loan agreement, as borrower, with Banco General and Corporación Interamericana para el Financiamiento de Infraestructura, S.A., as lenders (the "Tranche B"). The total original amount of Tranche B was US$34 million and the maturity is of 15 years (total door-to-door tenor). The principal amount due under the Tranche B accrues interest at an annual rate equal to 6 month US$ LIBOR plus 4.50%. The amortization is scheduled to be stepping up from 2.91% in average for the first 16 semesters (47% of total amount), and 4.45% for the following 12 semesters (53% of total amount).
- On December 9, 2014, the Issuer entered into a subordinated C-Loan agreement, as borrower, with the IFC, as lender (the "Subordinated Loan"). The total original amount of the Subordinated Loan was US$16 million and the maturity of the agreement is of 17 years (total door-to-door tenor). The tailored amortization is scheduled to be step up from 2.17% in average for the first 18 semesters (39% of total amount); 3.50% for the following 10 semesters (35% of total amount) and 6.5% for the last 4 semesters (26% of the total amount). The principal amount due under the Subordinated Loan accrues interest at an annual fixed rate of 12% but, of C-Loan deficiency (as defined in the applicable agreement) occurs the rate is increased to 13% per annum. On the same date, the Sponsor executed a C-Loan Guaranty Agreement pursuant to which the Sponsor guaranteed UEP II's obligations under the Subordinated Loan.

On March 9, 2015, the Issuer entered into the IFC Hedge Agreement, a floating interest rate swap agreement by which the Issuer agreed to exchange the difference between fixed and floating interest rate amounts calculated on agreed notional principal amounts for a total of US$180 million. The IFC Hedge Agreement enabled the Issuer to mitigate the risk of changing interest rates on the cash flow exposures under variable rate debt tranches of the IFC Loan.

For purposes of securing the obligations under the IFC Loan and the IFC Hedge Agreement, the Issuer, IEH Penonomé Panama, S.A. (which was subsequently merged into the Issuer) and the IFC executed (a) a series of offshore security agreements whereby such entities granted: (i) a first priority security interest in all of its rights titles and interest of major contracts and agreements related to UEP II Wind Project, (ii) proceeds from asset disposals; and (iii) insurance proceeds. Citibank, N.A. acted as offshore security agent to such security agreements, (b) certain security agreements, including an irrevocable collateral trust agreement in which The Bank of Nova Scotia (Panama) S.A. acts as security agent and trustee, a real property mortgage over certain assets of the Issuer, a first priority chattel mortgage over all material movable assets of the Issuer, certain share pledge agreements and certain master assignment agreement in benefit of the lenders under the IFC Loan and the providers under the IFC Hedge Agreement, as beneficiaries of such collateral trust and for the payment of certain secured obligations. Such security documents include the pledge on the shares of the Issuer, a real estate mortgage on generation licenses, a collateral assignment of power purchase agreements, and ANATI lease titles, as well as a mortgage over movable assets of the Issuer.

The Issuer executed certain master account and security agreements whereby it certified that it had established offshore accounts with Citibank, N.A., as offshore account bank, and with The Bank of Nova Scotia (Panama) S.A., as account bank in accordance with the Collateral Trust agreement. Offshore accounts include senior debt service reserve account and C-Loan debt service reserve accounts representing the debt service amount on each loan. The agreement states the procedures to transfer from the revenue account in accordance with the Common Term Agreement; including restricted payments.

We intend to repay in full the IFC Loan and unwind the IFC Hedge Agreement with the proceeds of this offering. See "Use of Proceeds." The Issuer's assets that are subject to security interests that secure the obligations under the IFC Loan and the IFC Hedge Agreement will, upon the repayment of the IFC Loan and the IFC Hedge Agreement, be part of the Collateral that will secure the Notes. For a description of the Collateral, see "Description of Collateral". See "Risk Factors — Risks related to the Notes — We may not be able to effect the repayment and release of our debt obligations under the IFC Loan and the IFC Hedge Agreement, and the Notes may be effectively subordinated to the rights of the creditors under the IFC Loan and the IFC Hedge Agreement."

The Guarantors

	As of September 30, 2020	As of December 31, 2019	2018	2017
	(in millions of US$)			
Current debt, net	39.944	40.654	—	—
Long-term debt	—	—	—	—
Total debt facilities	39.944	40.654	—	—

As of September 30, 2020, the Guarantors had a total of US$39.944 million in debt which is due under the Tecnisol Shareholders Loans, which we expect to repay with the proceeds of this offering and cash available. See "Use of Proceeds." For a description of the Tecnisol Shareholders Loan, see "Certain Relationships and Related Party Transactions — The Guarantors — Tecnisol Shareholder Loan Agreement."

Capital Expenditures

As the construction of the Issuer's Project was completed in 2015, we do not anticipate any additional material expenses relating to the development, equipping, permitting, commissioning, or construction of the Projects. Because the Project's construction has been completed and has achieved commercial operation, the only additional capital expenditures that are expected going forward are maintenance capital expenditures. However, we expect to invest US$4.55 million in the implementation of our Blades Strategy Plan. For a description of our Blades Strategy Plan, see "Business Overview — History — UEP II Wind Project."

Contractual Obligations

The following is a summary of the Issuer's contractual obligations as of September 30, 2020, considering undiscounted cash flows of financial liabilities based on the earliest date on which payments can be required, including both interest and principal payments:

	Less than 1 year	1 – 2 years	3 – 5 years	More than 5 years	Total
	(in millions of US$)				
Long-Term Debt Obligations[(1)]	29.601	60.326	91.796	160.063	341.786
O&M and Asset Management	5.043	9.937	1.550	3.139	19.668
Operating Lease Obligations	0.994	1.585	4.362	8.920	15.861
Total	35.638	71.848	97.708	172.122	377.315

(1) For purposes of this calculation, we assumed the exercise of the Purchase Option under the Share Assets Agreement during 2021. For more information about the Purchase Option and the Share Assets Agreement, see "Certain Material Agreements — UEP II Wind Project — Shared Asset Access Agreement — Purchase Option."

The following is a summary of the Guarantors' contractual obligations as of September 30, 2020, considering undiscounted cash flows of financial liabilities based on the earliest date on which payments can be required, including both interest and principal payments:

	Less than 1 year	1 – 2 years	3 – 5 years	More than 5 years	Total
	(in thousands of US$)				
Long-Term Debt Obligations[(1)]	39.944	—	—	—	39.944
O&M and Asset Management	0.248	0.120	0.180	0.300	0.848
Operating Lease Obligations	0.161	0.214	0.536	0.857	1.768
Total	40.353	0.334	0.716	1.157	42.561

(1) For purposes of this calculation, we assumed the exercise of the Purchase Option under the Share Assets Agreement during 2021. For more information about the Purchase Option and the Share Assets Agreement, see "Certain Material Agreements — UEP II Wind Project — Shared Asset Access Agreement — Purchase Option."

Dividend Policy

The payment of dividends by the Issuer and the Guarantors, their amount and the date of payment are determined by a majority vote of directors at a board of directors meeting. Under Panamanian law, the board of directors of the Issuer and the Guarantors may only declare and pay dividends upon the shares of its capital stock out of the excess of its assets over its liabilities.

Quantitative and Qualitative Disclosures about Market Risk

For a discussion of the market, financial, capital and liquidity risks, see Note 3 to the Issuer 2019 Financial; Statement.

BUSINESS OVERVIEW

Overview

As indirect subsidiaries of InterEnergy Group Ltd., our Sponsor, we are diversified clean energy companies that own and operate wind and solar power generation plants in Panama with an aggregate installed generation capacity of 255MW, the biggest unconventional renewable energy producer in Panama in terms of installed capacity. We are among the top five power generators in Panama and are one of the largest diversified clean energy companies in Central America. During 2019, the Issuer and Guarantors generated 546.2 GWh (4.9%) and 70.3 GWh (0.6%) of energy, respectively, for a combined generation of 5.5% of the total energy generated in Panama in 2019, according to the Independent Energy Market Report, see "Annex A." For the fiscal year ended December 31, 2019, our wind and solar power generation plants generated 81% and 19%, respectively, of our combined revenues and 89% and 11%, respectively, of our combined EBITDA.

The Issuer owns and operates the UEP II Wind Project, the largest wind farm in Central America and the Caribbean with 215 MW of installed capacity, strategically located in Penonomé, Coclé, close to the southern shores of Panama where it benefits from the Caribbean winds. The UEP II Wind Project, is installed across 39.79 hectares of flat plains located at sea level in the central region of Panama, next to the UEP I Wind Farm, a wind power plant owned by AES Panama with an installed generation capacity of 55MW. The UEP II Wind Project is equipped with 86 Goldwind direct magnet drive turbines, each with a generation capacity of 2.5 MW. Construction of the UEP II Wind Project began in 2013 and, while the project has been in operation since January 2015 under "generation under test status" (during which the performance of the project is closely monitored and tested by the CND), the UEP II Wind Project officially achieved commercial operation in February 2018. The construction of the UEP II Wind Project was performed by CODEPA. CODEPA, a renowned international construction and infrastructure company with extensive experience in the renewable energy sector. The UEP II Wind Project is one of the largest construction projects in Central America to date. The UEP II Wind Project is divided into five separate wind farms: 1) Nuevo Chagres, comprised of 25 wind turbines and an installed capacity of 62.5 MW, 2) Rosa de los Vientos I, comprised of 21 wind turbines and an installed capacity of 52.5 MW, 3) Rosa de los Vientos II, comprised of 20 wind turbines and an installed capacity of 50 MW, 4) Marañon, comprised of 7 wind turbines and an installed capacity of 17.5 MW, and 5) Portobelo, comprised of 13 wind turbines and an installed capacity of 32.5 MW. In 2019, the electricity sold by the UEP II Wind Project to Distribution Companies indirectly supplied electricity to 185,000 Panamanian families.

The servicing and maintenance of the wind turbines installed at the UEP II Wind Project are performed by Goldwind, the supplier of our wind turbines. Goldwind directly performs the majority of the servicing and maintenance work at the UEP II Wind Project under the terms of the Service and Maintenance Agreement. The operation of the UEP II Wind Project is performed by employees of the Issuer with the support of IEH UK, an affiliate of our Sponsor, who provide the Issuer with day-to-day general administration services, business management, technical asset management and operation and maintenance supervision under the UEP II Management Services Agreement.

The Guarantors own and operate the Tecnisol Solar Project, a solar energy project with 40 MW of installed capacity located in David, Chiriqui, Panama over flat land and in one of the most solar resource rich areas of the country. With a total area of 97.8 hectares, the Tecnisol Solar Project is divided into four separate solar parks, *Ikako, Ikako I, Ikako II, and Ikako III*, each of which is comprised of a single axis tracker of 10MW equipped with Jinko Solar JKM325PP (70%) and JKM330PP (30%) PV modules. Construction of the Tecnisol Solar Project began in August 2017 and has been operating under "generation under test status" since August 2018 pending the conclusion of the regulatory approval process in order to achieve commercial operations. The construction of the Tecnisol Solar Project was performed on a turnkey basis by EPC Contractor.

The servicing and maintenance of the Tecnisol Solar Project is provided for in-house by our own management in accordance with our maintenance plan, developed and implemented with the support and under the coordination of IEH UK in accordance with the terms of the Tecnisol Management Services Agreement. We and IEH UK possess extensive experience and count with the help of several well qualified and dedicated technical professionals with vast experience in the field. In addition, certain manufacturers of the equipment of the Tecnisol Solar Project provide a subset of maintenance services under long-term service agreements. Under such agreements, Jema, the manufacturer of the inverters for the Tecnisol Solar Project, performs the maintenance of our power stations, and Gonvarri, the manufacturer of the single axis trackers for the Tecnisol Solar Project, performs the maintenance of our trackers.

The following table sets forth the principal characteristics of our Projects:

	UEP II Wind Project	Tecnisol Solar Project
Installed Capacity	215 MW	40 MW
Turbines / PV modules	86	138,960
Manufacturer	Goldwind	Jinko Solar / Jema
Nameplate Capacity	2,500 KW	325 W JKM325PP 330 W JKM 330PP
Technology	Goldwind GW 109 2.5 MW	JKM325PP (70%) JKM330PP (30%) Jema IFX6 N-S single axis tracker
COD	February 2018(1)	Pending(2)
2019 Net Generation	546.2 GWh	70.3 GWh
2019 NCF (%)	29%	20.1%

(1) The project has been operating since January 2015 under "generation under test status" and reached commercial operations in February 2018.

(2) The project has been operating since August 2018 under "generation under test status."

The following map shows the location of our Projects:

History

UEP II Wind Project

The Issuer is a corporation (*sociedad anónima*) existing under the laws of Panama. The Issuer was formed on January 18, 2013 to develop, construct, own and operate wind projects, including the UEP II Wind Project. The design of the UEP II Wind Project commenced in 2013 and construction activities began shortly after in the same year (2013). The IFC agreed to grant the IFC Loan for a 17 year term for the development of the UEP II Wind Project in 2014. The first UEP II Wind Project turbines reached Panama in September 2014.

In January 2015, we energized the first circuit. In January 2016, we were awarded three short-term PPAs through the ETESA LPI 03-15 tender to sell energy to the three Distribution Companies. By April 2016, we successfully commissioned all 86 wind turbines, and on February 19, 2018 the UEP II Wind Project reached COD.

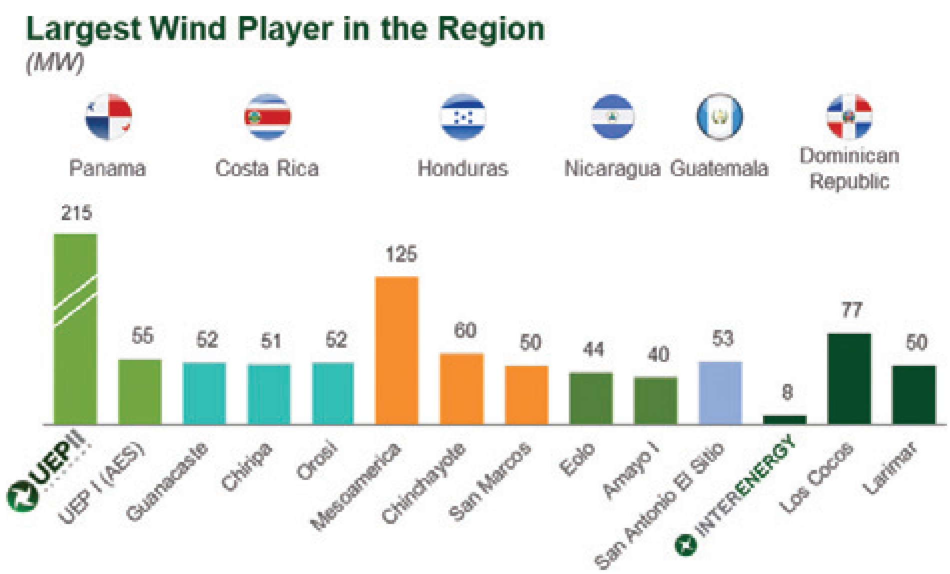
Tecnisol Solar Project

The Guarantors are corporations (*sociedades anónimas*) existing under the laws of Panama. The Guarantors were formed on February 20, 2014 to develop, construct, own and operate the Tecnisol Solar Project. The design of the Tecnisol Solar Project commenced in 2014 and construction activities began in August 2017. On August 2018, the Tecnisol Solar Plant delivered its first MWh to the grid, and in February 2020, the Guarantors issued the definitive acceptance certificate with respect to the Tecnisol Solar Project. The Tecnisol Solar Project was financed with contributions from InterEnergy.

In 2018, we completed the construction of the 40 MW Tecnisol Solar Project. Between July 2017 and April 2019, we directly entered into ten PPAs with private companies. The Tecnisol Solar Project has not yet reached COD, but it reached the availability required for dispatch on March 29, 2019 (for *Ikako*, *Ikako I* and *Ikako II*) and for *Ikako III* on May 10, 2019. In order to achieve COD, we are implementing certain adjustments to the Tecnisol Solar Project' control system to comply with certain requirements of the ASEP's regulations. We expect to complete such adjustments and to obtain COD by the first quarter 2021.

Our Sponsor

Our Sponsor owns and operates 36 power operating assets across four countries in Latin America and the Caribbean. It has 1.2 GW of installed and available capacity, of which 334 MW is renewable, providing reliable, cost-effective and clean energy to the Dominican Republic, Panama, Jamaica, and Chile. It has significant experience in the distribution business in the Dominican Republic as managers of the largest distribution system outside the SIN, and also holds a participation in Liquified Natural Gas import and transportation facility in the Dominican Republic. The IFC, a member of the World Bank Group, and the IFC AMC have supported the development of clean energy in the region and they selected our Sponsor to make an equity investment of US$100 million for the development of cleaner and more efficient energy sources in the Caribbean. Our Sponsor is the first wind operator in the Dominican Republic, and the UEP II Wind Project that it pioneered is the largest wind power facility in the Central American and Caribbean region.



Sources: Energia Limpia XXI and Tecnológico de Costa Rica

Our Sponsor has a long and successful track record. In 1988, Basic Energy, our Sponsor predecessor, invested in the Dominican Republic's first IPP in partnership with Seaboard Corp., and between 1988 and 2011 Basic Energy entered into a series of acquisitions which contributed to its growth over the years. These acquisitions include the following: 1) in 1992, Basic Energy formed CEPM, which grew into a major vertically integrated utility supplying the Dominican Republic, 2) in 1999, Basic Energy led a consortium that acquired 50% of EGE Haina in the Dominican Republic, 3) in 2006, Basic Energy acquired CESPM, a

300 MW power plant in the Dominican Republic in partnership with Soros, Citigroup and Seaboard Corp., 4) in 2007, Basic Energy acquired 55% interest in Pedregal and 100% interest in CACAO (Jamaica) and sold its interest in both in 2009, 5) in 2016, 15MW of two wind farms in Chile, named Raki and Huajache, and 6) in 2017, 45MW of a solar portfolio also in Chile.

In 2011, our Sponsor was formed through a series of acquisitions, including of the entities owned by Basic Energy above at the time of formation. At inception, our Sponsor owned 100% of CEPM, 25.6% of EGE Haina and 29.2% of CESPM. During the same year, our Sponsor also acquired an additional 10% stake in CESPM. Furthermore, in that same year, CEPM and EGE Haina inaugurated the Dominican Republic's first wind parks (Los Cocos and Quilvio Cabrera). Our Sponsor achieved a further milestone in 2013, when the IFC and IFC AMC invested US$100 million in our Sponsor, and our Sponsor invested in Gas Stream, a LNG logistics and regasification business in Chile. Of particular importance, in 2014, our Sponsor acquired the UEP II development in Panama and invested US$425 million to create the 215 MW UEP II Wind Project and exits EGE Haina.

From 2014 to 2018 our Sponsor continued to grow. In 2015, our Sponsor increased its ownership in CESPM by an additional 21%, bringing its total to 60%, and re-acquired Pedregal (Panama). In 2016, our Sponsor acquired an additional 10% of CESPM from Citigroup and 15 MW of co-located wind farms in Chile, and Barings also invested into our Sponsor. In 2017 our Sponsor expanded its business in Chile with 45 MW of solar and gas stream (Chile) is sold to ENGIE. In 2018, our Sponsor started the conversion of CESPM in the Dominican Republic from diesel to gas and initiated a new LNG terminal with connecting pipeline to CESPM.

More recently, in 2019 our Sponsor sold 60% of its participation in CESPM and through its shareholding in Energas announced a partnership with AES Dominicana to form Energia Natural Dominicana (ENADOM), a company that will commercialize natural gas throughout the Eastern region of the Dominican Republic.

Our Competitive Strengths

We believe the following competitive strengths distinguish us from our competitors and are critical to the successful execution of our business strategy.

Largest wind energy company in Central America and the Caribbean

The Issuer owns and operates the UEP II Wind Project, which is the largest wind farm in Central America and the Caribbean, with 215 MW of installed capacity. As part of the SIN and the MER, we have the ability not only to sell our energy in the Panamanian energy market but may be able to export clean energy to five other countries, giving us the unique opportunity to serves as a regional clean energy generator.

Attractive Macroeconomic Fundamentals and Demand Growth Supported by a Diversified Energy Matrix & Sound Regulatory Framework

The Issuer owns its assets and operates in Panama, a country with one of the fastest growing economies in Latin America over the past decade. Panama has attractive macroeconomic fundamentals and steady energy demand growth supported by a diversified energy matrix and a sound regulatory framework. The Panama Canal and the use of the U.S. dollar (eliminating FX risk commonly faced by many of its regional peers) have promoted the strengthening of a globally-oriented and highly developed services sector, growing at an average of 4.4% in the last 5 years, and accounting for 65% of GDP. Panama has achieved an investment grade sovereign rating (Baa1 with negative outlook, BBB with stable outlook, and BBB with negative outlook by Moody's, S&P and Fitch, respectively) and has benefited from the continued access to international debt markets. Panama's strength comes in part from its strategic importance as a regional logistics and financial services hub and regional base which serves as headquarters for more than 160 multinational operations.

Additionally, Panama enjoys a position as an investment grade sovereign with continued access to international debt markets. The Panamanian government has promoted economic growth over the past decade in large part through open market policies and by supporting free trade. Moreover, the government actively encourages foreign direct investment through lax regulation and by guaranteeing ease of business. In particular, Panama has been ranked as seventh in ease of doing business in Latin America and the Caribbean, outperforming Central American peers such as Guatemala, the Dominican Republic and Honduras.

Strong and stable U.S. dollar denominated cash flows derived from long-term PPAs

Substantially all of the Issuer's revenues are derived from long-term PPAs, which provide us with stable and predictable cash flows. The Issuer has committed to sell 76.7% of its total energy generation capacity under the physical energy-only UEP II PPAs with the Distribution Companies for a fixed price (25% of which is partially adjusted based on the Panama CPI) with a weighted remaining average life of 10.04 years. In addition, we have contracted nearly all of the generation capacity of our Tecnisol Solar Project under the financial energy-only Tecnisol PPAs with credit-worthy Large Customers for a purchase price that is initially fixed and adjusted semiannually based on the variations of the Regulated Tariff. In addition, the Guarantors cover any energy supply deficiency under our Tecnisol PPAs through reserve energy agreements, pursuant to which the Guarantors purchase energy from the Issuer and other reserve energy suppliers. As of September 30, 2020, the estimated remaining weighted average life of our Tecnisol PPAs is 12.78 years and the weighted average of all our PPAs is 10.57 years.

Strategically located and highly efficient clean power generation plants

The UEP II Wind Project is located along the southern shores of Panama near the load center, Panama City, and benefits from winds coming from the natural corridor formed between the Central Range (the *Cordillera Central*) using the trade winds coming from the Caribbean Sea. No earth movements were made during the construction of this project, which reduces the risk of soil erosion, and there are no obstacles for wind, which makes this location one of the best locations in Panama for a wind farm. In addition, the transmission grid near the UEP II Wind Project was fully developed before we began construction of the project. As such, costs of connecting the UEP II Wind Project to the main ETESA transmission line were lower than in projects for which the interconnection infrastructure has to be developed from the ground up.

The Tecnisol Solar Project is located in the west of Panama on flat terrain, which allows for optimal irradiation of the panels throughout the day. Additionally, no large earth movements were made during the construction of the Project, which reduces the risk of soil erosion. In addition, the pasture covered area helps to keep the solar panels operating at an optimal temperature. We understand that the location of the Tecnisol Solar Project is one of the highest solar resource areas of the country.

The Projects provide reliable and clean energy to Panama. The generation profile of solar and wind power plants, such as ours, in Panama is advantageous, as it is inversely correlated to the generation profile of hydroelectric power plants, which are the principal source of power in Panama. This is due to increased sunshine and winds during Panama's dry season, thereby supporting Panama's transition to a carbon-neutral power generation matrix with reduced vulnerability to changing hydrological conditions. We estimate that the Projects will eliminate over 132,000 tons of CO2 emissions and save 900,000 barrels of oil per year. According to operation rules issued by ASEP, renewable generation costs are low relative to other sources, positioning renewable sources early in the dispatch stack, even ahead of hydro assets. This gives us an advantage over hydro and thermal power generators in Panama. The Projects are located in areas with strong wind and solar resource, respectively. We believe that our low generation costs compared to the higher generation cost for thermal power plants in Panama is a key contributing factor to our ability to maintain markets share and maximize margin from the sale of electricity in the spot market. In 2019, the UEP II Wind Project and the Tecnisol Solar Project had net capacity factors of 29% and 20.1%, respectively. For a more detailed description of historical wind and solar resource data, please see "Annex B — Independent Engineer Report."

Reliable high-quality generation assets with widely-used technology

The UEP II Wind Project is comprised of 86 turbines (2.5MW each) manufactured by Goldwind with a total installed capacity of 215 MW and a net capacity factor of 29% in 2019. Goldwind also provides the maintenance of our wind turbines pursuant to the Service and Maintenance Agreement. Goldwind is a world leader in wind power with more than 20 years of experience and more than 60 GW of wind power installed capacity. Our PV modules and module inverters were manufactured by Jinko Solar Jinko Solar and Jema, respectively. Jinko Solar is a NYSE listed company and one of the largest and most innovative solar module manufacturers in the world, and Jema has more than six decades of experience in the design and manufacture of energy systems. Although we perform the operation and maintenance of the Tecnisol Solar Project with our own personnel and the support of our Sponsor, we have also retained the services of Gonvarri and Jema (who supplied parts and equipment for the construction of and, as such, are familiar with, the Tecnisol Solar Project) for the provision of certain maintenance services pursuant to service agreements with them. We believe that the world class technology we used for the construction of the Projects, coupled with the support and maintenance services rendered by the same manufacturers that provided such technology, creates synergies and advantages that distinguish us from our competitors.

Experienced and skilled strategic sponsor and management

We are owned by InterEnergy, a developer and operator of electric power generation businesses. InterEnergy manages, owns and operates an existing portfolio of 36 operating assets across four countries with 1.2 GW of installed gross capacity in operation. Our Sponsor's Board of Directors, which consists of 11 members, together with the committees of our Sponsor's Board of Directors supervise all subsidiaries that are material to our Sponsor, including us. Our Sponsor supports our operation by providing day-to-day general administration services, business management, technical asset management and operation and maintenance supervision through IEH UK under the UEP II Service Management Agreement and the Tecnisol Management Agreement, which allows us to leverage our Sponsor's managerial expertise and extensive experience in the electricity, construction and finance industries, and from our Sponsor's commitment to developing clean energy infrastructure throughout Latin America and prioritizing environmental, health, safety, compliance, risk management and high operating standards. We believe the support and active involvement of our Sponsor in our business provide us with significant advantages in operations' management. In addition, we believe benefit from our Sponsor's longstanding track record of making successful investment in cutting edge new technologies ranging from advanced gas-fired generation equipment, to smart meters, mobile access, district cooling or thermal energy solutions and electric car charging stations. In fact, we believe that the in-house operation and maintenance expertise of our Tecnisol Solar Project, coupled with the support and know how we receive from our Sponsor under the Tecnisol Management Services Agreement, allows us to save costs in comparison to other generators that fully outsource the service and maintenance of their assets. In addition, we have a highly experienced management team with experience in Central America and the Caribbean in addition to extensive knowledge of and vast experience in the Panamanian energy sector. Our directors and officers have an average of 24 years of experience in the energy industry and collectively 184 years of industry experience. We believe in our management team's capabilities and core understanding of both their own business and the related regulatory environment, enable them to operate efficiently and manage risk effectively.

Our Business Strategy

Continue to pursue a long-term contracting strategy

We continue to seek opportunities to contract mid to long term PPAs with the Distribution Companies and other Large Customers. During the first two years, Distribution Companies are required to contract for 100% of their projected capacity requirements through tenders that are held by ETESA periodically. After such 2-year period, Distribution Companies are required to contract for at least 10% less every two years. From year 15 to year 21, Distribution Companies are required to contract for 30% of their projected capacity. We intend to participate in such tenders to commit the portion of our generation capacity that is not currently contracted under our PPAs. In addition, we intend to sell our energy under PPAs to regulated Large Customers who currently rely on the Distribution Companies to cover their energy needs. Under the current regulations, regulated Large Customers are being incentivized to convert into non-regulated Large Customers since, as non-regulated Large Customers, they are able to negotiate the price of the energy with generators instead of covering their energy needs with the Distribution Companies at the Regulated Tariff. According to the Association of Large Customers of the Electricity Sector (AGRANDEL, by its acronym in Spanish), there is still a potential market to enter into PPAs with regulated Large Customer equal to 30% of the Distribution Companies' demand.

Maintain the sound and efficient operation of our wind and solar power plants

We are committed to maintaining the sound and efficient operation and maintenance of our wind and solar projects to generate predictable and stable cash flows. We have developed an Operation and Maintenance

Plan ("O&M" Plan), which includes all the requisites to operate and maintain the assets correctly. It includes a detailed description of all annual preventive maintenance tasks, the detail of the activities and frequency that need to be contracted to a third part and the corrective maintenance procedures. It also contains the templates for the daily, monthly and annual reports that need to be generated and the notification of incidents. For the servicing and maintenance of the UEP II Wind Project, we have entered into a Service and Maintenance Agreement with Goldwind, the provider of our turbines, and, with the support of IEH UK, an affiliate of our Sponsor, we believe we have developed a sound in-house maintenance program for the Tecnisol Solar Project. Upon the expiration of the current Service and Maintenance Agreement with Goldwind, we currently expect to be able to negotiate and obtain a more competitive contract with Goldwind or another provider given the increased competition for these services in Panama. In addition, we secured certain services agreements with Jema and Gonvarri to ensure that we have services available as needed. We are focused on continuing to achieve high efficiency and availability factors at our Projects and to invest in technology, systems and equipment to further improve efficiency and availability.

Our O&M Plan is further supported by the strategy of the Renewable Division of our Sponsor. Our Sponsor has a long history of experience in the operation and maintenance of power plants including renewable assets in Central and South America that allowed us to leverage on their extensive know-how and allows us the opportunity to continuously improve our procedures and the results of our Projects.

Promote the use of clean energy in Panama

We plan to promote and offer to customers committed to environmental and green goals the possibility of supporting their operations with 100% renewable energy through our SER initiative. To service such clients with a sense of commitment to the environment, we developed a web-based platform/interface where our customers can visualize energy consumption, savings and other data that support them in their efforts to achieve their environmental goals. Also, in the services provided to our customers we include detailed information on their energy consumption and pricing that is intended to help them achieve energy savings in their operations We believe that the SER will enable us not only to better serve our current clients, but also to capture new customers with a commitment to clean energy.

As part of our Sponsor's group, we follow strict corporate governance and environmental and social responsibility standards that seek to ensure transparency, accountability and responsibility in the operation of our business set forth by our Sponsor. In terms of sustainability, we seek to be good corporate citizens and operate our business in a manner which complies with applicable legal and environmental regulations. The registration and issuance of certificates of our energy sources through the I-Rec process, once completed, will allow us to credibly demonstrate that the energy consumed derives from renewable sources. Our Sponsor has invested and developed clean energy projects in the Dominican Republic, Jamaica, Chile and Panama and has recently announced a strategic partnership with AES Dominicana to form Energía Natural Dominicana, a company that will commercialize natural gas throughout the Eastern region of the Dominican Republic. The Projects are part of a commitment made by InterEnergy at the Clinton Global Initiative Latin America meeting in 2013.

Moreover, we understand that our Sponsor's environmental and social standards and policies were factors that contributed significantly to the decision by IFC (a member of the World Bank Group), and the IFC African, Latin American and Caribbean Fund, to make a US$100 million equity investment in our Sponsor to develop cleaner and more efficient energy sources in the Caribbean and expand its operations in Latin America. Such high standards uniquely position us to compete, as well as to help our customers transition to clean energy sources and support our customers with their clean energy initiatives.

Our Projects

UEP II Wind Project

UEP II Wind Project is located in Penonomé, which is part of the Coclé Province of Panama. The project is located about 10 km away from the Penonomé town and 15 km north of the coast. The project consists of 86 Goldwind 2.5 MW wind turbine generators which total 215 MW. The site is approximately 19,000 hectares, which lease under more than 25 different lease agreements, with predominantly flat terrain. UEP II Wind Project is divided into 5 wind farms named: *Nuevo Chagres*, *Portobelo*, *Marañon*, *Rosa de* *los Vientos I*, and *Rosa de los Vientos II*. The main access to the site is located right next to the Hector Conte Bermudez street and dirt roads built by UEP II Wind Project provide access to the UEP II Wind Project substation, O&M building and all wind turbine generator locations.

Our Goldwind 109-2.5MW turbines have a hub height of 90m and operate rotors with 107.5m diameters at a nominal rotor speed of 10.2 m/s. The estimated maximum tip speed is as high as 77 m/s, falling safely below the industry cautionary threshold of 80 m/s. Various platform foundation types are designed for wind turbine generator model Goldwind GW 109-2.5 MW. Our turbines use at least two shallow spread footing (one of 10m of radius and the second of 12 m radius) and one pile foundation types.

Consistent with good industry practices, we source blades from two suppliers, Sinomatech Wind Power Blade Company certified by China General Certification, and LM Wind Power certificated by DNV:

	S152.5B	LM53.2P
Manufacturer	Sinomatech Wind Power Blade Co., Ltd.	LM Wind Power Blades
Length (m)	52.5	53.2
Material	GFRP	GFRP
Swept area (m^2)	9,076	9,331

LM is a leading global supplier of wind turbine blades with more than 30 years of experience and a market share of 28%. LM supplies most major wind turbine generator manufacturers including GE and Vestas. Sinoma is one of the top three domestic suppliers in China.

The blades installed in the project correspond to the Sinoma blades, certified by CGC. The blade is made from glass fiber reinforced polymer ("GFRP") and the main beams of the blades are manufactured applying a vacuum infusion method. Each blade is equipped with a lightning protection system that extends through its tip and redirects lightnings to the ground through 3 rotating junctions: the blade bearing, rotor bearings, and yaw bearing. The protection system is designed in accordance with IEC 61400-24 Wind Turbines Part 24: Lightning Protection.

Following the arbitration process with Goldwind and the Settlement Agreement, to mitigate any possible risk derived from the condition of the blades while operating the UEP II Wind Project and to ensure the safety and health of the UEP II Wind Project, we developed a Blades Strategy Plan that results from extensive studies performed in the earlier half of 2019 by UL in three phases. In phase one, UL inspected by means of a robot 72 of our wind turbines and assessed the blades of each according to the external level of damage. UL also extracted one sample from a blade placed on the ground, and a tomography, US and sectional analysis were carried out in the bushings insert. In phase 2, the inspection protocol of this sample cut was expanded and performed on 10 additional sample blades. In phase 3, which was conducted parallel to the studies performed on the sample blades, UL performed the following studies: LifeTime Wind turbines Evaluation, Operational Energy Production Report, Performance Assessment, and Energy Production Report for the new blades (LM 53.2m). Based on the results obtained, a few long term actions that the plan includes are: 1) annual visual external inspections using a high-resolution camera, including blades and tips, and where further inspection is desirable, rope-access inspection of defects detected during visual inspections; 2) partial repair works in some blades, initial assumption: 10 wind turbines per year, as necessary 3) tip reinforcement is planned to be applied in 20 wind turbines per year; 4) the purchase of seven new sets of three blades to be available at the UEP II Wind Project as spare parts, to reduce response time if blade replacement is necessary, thus reducing potential unavailability; and 5) implementation of a monitoring system to manage risk. In the last quarter of 2020, we will begin major repair work on the blades, including additional inspections and repair works for all the blades of all 86 wind turbines from September to November of 2020.

Each wind turbine generator generates power at 690 V and requires an external Pad Mount Transformer ("PMT") to increase this voltage to 34.5 kV. Once at 34.5 kV, the energy, via feeder cables, exits the PMTs in conduits to the internal mid voltage transmission grid of the wind farm, through 11 circuits, of which four are underground and the rest are aerial lines. From the collection system, it then travels to the 34.5/230 kV step up El Coco substation, configured in a breaker and a half arrangement. At the El Coco Substation, voltage is again increased from 34.5 KV to 230 kV for interconnection to the ETESA transmission system via two 230 KV power transformers, each with 140 MVA of capacity. In the El Coco Substation there are 6 SMECs (power meters) installed, one for each wind farm with the exception of Rosa de los Vientos II which has two SMECs. Each SMEC has a backup, in case the main SMEC is damaged.

Tecnisol Solar Project

The Tecnisol Solar Project is located in San José de David in the Chiriquí province of Panama. The project site covers an area of approximately 97.8 hectares, which lease under several lease agreements, with a relatively flat terrain, having only a slight slope from north to south. The Tecnisol Solar Project is divided into 4 sub-plants of 10 MW each: *Ikako*, *Ikako I*, *Ikako II*, and *Ikako III*. It boasts a GHI of 2,007kWh/m2/year, with pitch varying from 7.15m to 8.0m.

The general area surrounding the Tecnisol Solar Project consists of agricultural and farmland, and includes high vegetation presence in the east. Twenty year land lease agreements are in place, which include the option to extend with the written consent of the Guarantors and the lessors. The site is located approximately 15 km north of the sea; however, the surrounding area has a high presence of water streams to the sea. Approximately 35 km north of the Tecnisol Solar Project are Panama's central highlands. The principal access road to the site is the Panamericana road, an exit road of Agronomy University at Chiriquí town. A dirt road of approximately 2 km interconnects the Tecnisol Solar Project site with the Panamericana road.

The Tecnisol Solar Project PV array consists of 4 power blocks of 10.2 MW and four 34.5 kV medium voltage collection systems, 34.5 kV transmission line and a 34.5 kV grid connection substation, that each perform according to industry standard. The redundancy across each block allows for continued power generation if one inverter goes offline. The Tecnisol Solar Project uses the Jema IFX6, with a maximum DC input voltage of 1,500 V_{DC} and a power output of 2,675 kVA at 25C and 2,550 at 50C. Jema IFX6 inverters comply with IEC 610000 for Electromagnetic Compatibility and EN 6210901:2011 for Safety of PV inverters. They also meet the requirements and are tested to IEC 61683:1999 for measuring inverter efficiency. The inverter converts the direct current electricity produced by the PV module into alternating current that can be fed into the grid. Jema is a Spanish manufacturer founded in 1953 and acquired by Irizar Group, a Spanish transportation equipment conglomerate, in 2009.

The Tecnisol Solar Project is also equipped with Hiasa-Grupo Gonvarri / Solar Steel TracSmart 3.0 single axis trackers that each support 60 modules mounted in a 3 column landscape configuration. The trackers are separated by a pitch distance between 7.15m (Ikako) and 8 m (Ikako I). Each axis consists of a main beam with maximum height of 1.7m, further supported by 2 secondary beams and 7 piles driven into the soil. In the center of each main beam is a dedicated drive motor and control unit that calculates the position of the sun by algorithm, ensuring that the module moves following the sun's movement from East to West. The foundation of some trackers reaches a depth of 1.5m while others yet reached a depth of 2m. The trackers conform to the European EN-1090 standard, meet ASCE 7-05, "Minimum Design Loads for Structures" and EUROCODE-3 "Design of Steel Structures" standards, and are certified to IEC 62817:2014, the best practice in the market. Gonvarri's parent company is a well-established Spanish company founded in 1958 with over 6,000 employees and 45 factories across 19 countries.

The PV modules installed on each single axis tracker are Jinko Solar JKM325PP (70%) and JKM330PP (30%), 72 polycrystalline cells with a nominal output power rating of 325 Wp and 330 Wp, respectively. The Jinko Solar PV modules have been tested and found to meet the requirements of IEC 61730, which tests the modules for safety against electrical shock, fire, and other incidents. The modules have also been tested and certified against the IEC 61215, which governs the field performance of PV modules and have also been tested according to the IEC 62804 Ed. 1.0 standard for evaluating PV module resistance to Potential Induced Degradation. Jinko Solar is a vertically integrated, Tier 1 Chinese module manufacturer, as ranked by Bloomberg New Energy Finance and has been one of the top 10 module manufacturers since 2011.

The PV modules are connected by cables to array boxes and inverters anchored directly below the trackers. The power generated by the PV modules is channeled to and collected at the project collection substation, or switching station, consisting of a medium voltage PV feeder, Hicaco IV substation, with 2 busbar A and B connecting 4 JEMA inverters. The output voltage from the JEMA inverters are stepped up from 620 V to 34.5 kVAC through 2.85 MVA transformers installed on the inverter skids. The 34.5 kV output from the transformers is connected in a daisy chain to bring the full power capacity to the switchyard substation in 4 medium voltage circuits. There, a LT with two circuits leaves the sectioning center in underground cable for 50m before continuing route overhead by a 13.5 km transmission line. This transmission line connects to the Mata de Nance substation owned by the state capital company (ETESA). The Mata de Nance substation connects to the SIN through 34.5 kV, 115 kV and 230 kV transmission lines. The transmission line is composed of 269 concrete and metallic towers for the 13.6 km length.

A grounding system protects workers and equipment against inadvertent contact with energized components and consists of a grid of conductors horizontally buried within trenches, supplemented in some cases by a series of vertical rods connected to the grid if necessary. This system, along with surge protectors installed on both the DC and AC sides of the system, also provide protection from lightning.

Revenues

Our operating revenues from the UEP II Wind Project and the Tecnisol Solar Project derive mainly from PPAs with our customers and, to a lesser extent, sales of excess power in the spot market. As of the date of this offering memorandum, 74.9% of the combined capacity of the Issuer and the Guarantors is contracted under our PPAs with Large Customers, Distribution Companies and under the Tecnisol Intercompany Energy Reserve Agreements. The estimated remaining weighted average life of all our PPAs as of September 30, 2020 was 10.57 years.

The table below details each Project's contracted capacity as of the date of this offering memorandum and certain key details about our PPAs.

	UEP II Wind Project	Tecnisol Solar Project
Installed Capacity	215 MW	40 MW
2019 Net Generation	546.2 GWh	70.3 GWh
2019 NCF (%)	29%	20.1%
2019 PPA Energy Sold	488.8 GWh	102.2 GWh
2019 PPA Weighted Average Price	US$101.93/MWh	US$89.94/MWh
2019% of Combined Revenues	84.42%	15.58%
Weighted Average Remaining Life as of September 30, 2020	10.04 years	12.78 years

UEP II Wind Project

Our operating revenue from the UEP II Wind Project mainly derives from twelve, dollar-denominated, physical energy-only PPAs entered into with the three Distribution Companies in Panama: ENSA (owned by Empresas Públicas de Medellin), and with EDEMET and EDECHI (both owned by Naturgy Energy Group, formerly Gas Natural Fenosa). In 2019, the Issuer sold 485.59 GWh of energy under the Initial UEP II PPA contracts and 49.37GWh in the Spot Market, representing 90.96% and 9.04%, respectively, of the total energy generated by the Issuer. For the year ended December 31, 2019 and for the nine-month period ended September 30, 2020, the Initial UEP II PPAs represented 69.64% and 70.97%, respectively, of the combined revenues of the Issuer and the Guarantors. Pursuant to the terms of these PPAs, the Distribution Companies are obligated to purchase all the energy generated by Nuevo Chagres, Rosa de los Vientos I, Marañon and Portobelo, which accounts for 165 MW of our aggregate installed capacity, at a price set forth in the PPAs 75% of which is fixed and 25% of which is adjusted on a monthly basis based on changes in Panama CPI. These Initial UEP II PPAs have a 15-year term that commenced on July 2014 and a weighted average price paid to us by the Distribution Companies to date of US$105.41/MWh, compared to a spot price as of September 30, 2020 of US$41.60/MWh. We are currently seeking to extend our PPAs with the Distribution Companies beyond their current maturity date, given the Purchase Rules require the Distribution Companies to contract 100% of their demand projections for the next two (2) years, and for every other subsequent year this requirement decreases 10% until year 15, after which a fixed 30% of demand projections must be contracted. The closing of PPAs with Distribution Companies will be made after being awarded through public tenders organized by ETESA.

The following table sets forth the principal characteristics of our Initial UEP II PPAs:

Wind farm	Counterparty	Minimum Energy	Expected Expiration	Last PPA Price	GWh sold in 2019
Nuevo Chagres	EDEMET	13.90 GWh	June 2029	97.79	84.96
	EDECHI	4.94 GWh	June 2029	97.79	28.57
	ENSA	5.87 GWh	June 2029	97.79	38.61
Rosa de Los Vientos I	EDEMET	11.59 GWh	June 2029	100.88	81.30
	EDECHI	4.12 GWh	June 2029	100.88	27.34
	ENSA	4.89 GWh	June 2029	100.88	36.95
Marañon	EDEMET	4.23 GWh	June 2029	113.24	27.02
	EDECHI	1.50 GWh	June 2029	113.24	9.09
	ENSA	1.79 GWh	June 2029	113.24	12.28
Portobelo	EDEMET	7.10 GWh	June 2029	111.18	46.07
	EDECHI	2.52 GWh	June 2029	111.18	15.49
	ENSA	2.99 GWh	June 2029	111.18	20.94

In addition, we have entered into the New UEP II PPAs with the Distribution Companies on terms substantially similar to the terms of the Initial UEP II PPAs with respect to the energy generated by the Marañon and Portobelo wind farms, which account for an aggregated installed capacity of 50 MW, for a term of four and a half years from the expiration of the applicable Initial UEP II PPAs and with a base price of US$94.9/MWh and US$91.9/MWh, respectively. While the terms of the New UEP II PPAs are substantially similar to the Initial UEP II PPAs, the following table describes the main features of the 4.5-year forward starting period of our New UEP II PPAs:

Wind farm	Counterparty	Minimum Energy	Expected Expiration
Marañon	EDEMET	11.43 GWh	December 2033
	EDECHI	7.86 GWh	December 2033
	ENSA	11.17 GWh	December 2033
Portobelo	EDEMET	18.30 GWh	December 2033
	EDECHI	12.72 GWh	December 2033
	ENSA	18.05 GWh	December 2033

As of September 30, 2020, the UEP II PPAs entered into by the Issuer had a remaining weighted average life of 10.04 years.

The Issuer and Tecnisol I and Tecnisol III, have also entered into the UEP II Energy Reserve Agreements by which UEP II Wind Project sells energy to the Tecnisol Solar Project on an as-needed basis. This contract is allocated to *Rosa de Los Vientos II*, which is not contracted by the UEP II PPAs described above and has a total capacity of 50MW. For more information about the UEP II Energy Reserve Agreements, see "Certain Relationships and Related Party Transactions — The Issuer — UEP II Energy Reserve Agreements." Any overproduction of energy not purchased by the Tecnisol Solar Project is usually sold on the spot market.

Terms of the UEP II PPAs

The UEP II PPAs are entered into by the Issuer and the Distribution Companies, EDEMET, EDECHI, and ENSA. Each Distribution Company has entered into six PPAs, one PPA for each wind farm from which it purchases energy that expires in 2029 and an additional PPA for each of Portobelo and Marañon that expires in 2033, as described in the tables above. The total amount contracted under the UEP II PPAs amounts to 165 MW of the 215 MW total wind energy produced by the Project, or 76.7% of the total capacity of the UEP II Wind Project. The Initial UEP II PPAs have a start date of July 2014 and a term of 15 years. The average base energy price across all UEP II PPAs is US$102.75/MWh. The Average Price PPA during the first nine months of 2020 was US$105.78/MWh.

Under each of the UEP II PPAs:

- Pricing terms are fixed for 75% of the price, with Panama CPI indexation for the remaining 25% of the price;
- The Distribution Companies are required to pay for contracted energy on a monthly basis upon receipt of our invoices. The payments to be made by Distribution Companies under the UEP II PPAs are calculated by multiplying the price contemplated in the relevant UEP II PPAs by the applicable consumption indicator determined by the CND. These payments are made for the production of all the energy generated by the seller and delivered at the delivery point;
- We have issued an aggregate of approximately US$18 million in performance bonds in order to secure our commitments to supply our contracted energy under those agreements. We have a 30-day cure period to remedy any defaults;
- In the event that we materially breach our obligations under a PPA and do not remedy the breach within the cure periods provided therein (ranging from 24 hours to 30 days), the purchaser has the right to terminate its power purchase agreement, in which case we may forfeit the performance bond to the purchaser;
- The Distribution Companies are required to provide a security deposit guaranteeing approximately one month's payment;
- Any conflict or disagreement which arises among the parties and is not resolved by direct negotiation among the parties must be resolved through arbitration by the ASEP; and
- The parties have the right to terminate the PPAs upon the occurrence of a material breach or an event of default, such as (i) the bankruptcy, assignment in favor of creditors that could materially affect the performance under the contracts, or dissolution of any of the parties; (ii) the seizure of the assets of any of the parties; (iii) the assignment of the UEP II PPAs without the consent of the other party (except in favor of financial institutions); and (iv) cancelation of the generation or distribution permits of any of the parties.

Tecnisol Solar Project

The combined operating revenues of the Guarantors derive from financial energy-only Tecnisol PPAs entered into with eight credit-worthy Tecnisol Customers, with no single Tecnisol Customer representing more than 35% of the Guarantors' 2019 combined operating revenues. Under the Tecnisol PPAs the Guarantors are contractually obligated to supply renewable energy to cover the energy requirements of the Tecnisol Customers, which, as of September 30, 2020, accounted for close to 216 GWh of contracted power. The purchase prices under the Tecnisol PPAs are adjusted based on the biannual variations of the Regulated Tariff, subject to minimum and maximum prices set out in the applicable Tecnisol PPA. As of September 30, 2020, the Tecnisol PPAs had a remaining weighted average life of 12.78 years. For the year ended December 31, 2019 and the nine-month period ended September 30, 2020, revenues from the Tecnisol PPAs represented 13.36% and 12.96%, respectively, of the combined revenues of the Issuer and the Guarantors during that period.

The following table sets forth the principal characteristics of our Tecnisol PPAs:

Counterparty	Term	Expiration	Price	GWh sold in 2019
Coca Cola Femsa de Panamá, S.A.		April 2033		11.92
Ventas y Mercadeo Panamá, S.A.(1)		March 2034		0.60
Industrias Lácteas, S.A.		July 2033		29.50
Riba Smith, S.A.	15 years	July 2033	Indexed to Regulated Tariff.	46.46
Clínica Hospital San Fernando S.A.		July 2033		6.45
The Iron Tower Corp.(2)		April 2034		5.28
ICE Gaming Corporation(2)		April 2034		2.02

Counterparty	Term	Expiration	Price	GWh sold in 2019
Petrolera Nacional, S.A.[3]	10 years	10 years after initial supply period	Year 1 – 5 (fixed price); year 6 – 10 (indexed to Regulated Tariff)	N/A

(1) Ventas y Mercadeo S.A. is an affiliate of Coca-Cola Femsa de Panamá, S.A.

(2) As affiliates of Hilton's franchise owned by the Fashka family in Panama.

(3) The PPA has been executed but we have not begun to supply energy to Petrolera Nacional, S.A. as registration of the PPA with the ASEP is pending, as a result of the COVID-19 pandemic. Pursuant to the terms of the PPA, since the supply period did not start on May 7, 2020, Petrolera Nacional, S.A. has the option to terminate the PPA which, as of the date of this offering memorandum, had not exercised.

In the event that the energy generated by our Tecnisol Solar Project is not sufficient to cover the energy demand of the Tecnisol Customers based on the energy committed under the Tecnisol PPAs, the Issuer and the Guarantors have entered into the UEP II Energy Reserve Agreements with the highest priority in the dispatch stack among the UEP II Energy Reserve Agreements and the Tecnisol Third-Party Reserve Agreements. The Guarantors have also entered into the Tecnisol Third-Party Energy Reserve Agreements with seven hydroelectric companies for this purpose pursuant to which the Guarantors obtain, upon demand, the energy needed to meet such commitments, with the second highest priority in the dispatch stack among the UEP II Energy Reserve Agreements and the Tecnisol Third-Party Reserve Agreements. For more information regarding the Tecnisol Third-Party Energy Reserve Agreements, see "Business Overview — Our Projects — Tecnisol Solar Project — Terms of the Tecnisol Third-Party Energy Reserve Agreements", and for more information about our UEP II Energy Reserve Agreements and Tecnisol Intercompany Energy Reserve Agreements, see "Certain Relationships and Related Party Transactions — UEP II Energy Reserve Agreements" and "Certain Relationships and Related Party Transactions — Tecnisol Intercompany Energy Reserve Agreements."

Terms of the Tecnisol PPAs

Pursuant to the Electricity Law, generators may sell energy to Large Customers at freely agreed prices. Such Large Customers are free to purchase energy from any generator as long as its demand is higher than 100 kW and the applicable PPA complies with the provisions set forth in the "Procedure to Sell energy and Capacity to Large Customers of the Power Market Wholesale" and some of the provisions in the "Commercial Rules", both issued by the ASEP.

We entered into eight PPAs with respect to the Tecnisol Solar Project. The Tecnisol PPAs start dates vary from April 2018 to April 2019 and have a term of 15 years, except for the PPA with Petrolera Nacional, S.A. which has a term of 10 years. We may extend these PPAs following negotiations with the Large Customers that take place prior to the PPA maturity date on a PPA by PPA basis. Certain Tecnisol PPAs allow us to sell, and the Tecnisol Customer to purchase, energy after the expiration date of such Tecnisol on the terms set forth in the Tecnisol PPAs on a month-to-month basis (in such cases the Tecnisol Customer or us may terminate such automatic extension by giving notice to the other party). We also have the option to participate in future tenders of Distribution Companies or capture new Large Customers should any of our current PPA contracts not be extended beyond their maturity date. The supply period of the PPA with Petrolera Nacional, S.A. has not started because, in light of the COVID-19 pandemic, its registration has not been possible due to a suspension of the ASEP's administrative procedures. All of the Tecnisol Solar Project's 40 MW capacity is committed to supply energy to its Tecnisol Customers. Such customers use a portion of the total capacity of the Tecnisol Solar Project when it is at full load, and when the sun goes down such energy is acquired from energy reserve agreements (or the spot, if necessary). Panamanian regulations allow the generators to commit to sell beyond their capacity, since the generators sell "only energy" in these types of PPAs.

Under the Tecnisol PPAs, the purchaser may terminate the contract without liability at its expense under certain circumstances set forth in each Tecnisol PPA, which includes, the following: (i) fraudulent alteration or modification of the SMEC; (ii) bankruptcy or dissolution of the applicable supplier; (iii) seizure of the supplier's property; (iv) assignment of the supplier's assets to creditors or (v) partial or total cessation of supply for causes attributable to the supplier. In addition, some of our Tecnisol PPAs contain a voluntary termination clause that allows certain Tecnisol Customers to voluntarily terminate their Tecnisol PPAs after a specified number of years, provided that the relevant Tecnisol Customer pays a penalty, in certain cases, calculated as the present value of the remaining payments for the term of the applicable Tecnisol PPA and, in other cases, equivalent to the invoiced amount of the year immediately prior to the termination notice date multiplied by two.

The Tecnisol Customers may also terminate the Tecnisol PPAs without penalty if there is an interruption of the supply of energy for a period of time of more than 30 or 45 days (subject to the applicable Tecnisol PPA) due to "force majeure" or an "act of God" as described in Article 34d of the Civil Code and Article 5 of Executive Decree No. 22 of June 19, 1998, but only if the force majeure or act of God impairs the ability of the Tecnisol Solar Project to comply with its obligations under the applicable Tecnisol PPA. See "Risk Factors — Risks Relating to Our Business — Our business depends on a limited number of customers with which we have entered into long-term agreements."

Certain Tecnisol PPAs include a contractual equilibrium provision that establishes that in case there are any changes or amendments to the applicable laws or regulations within the energy industry, applicable taxes, general social and economic disturbance locally or regionally, among other unforeseeable situations that may affect the ability of a party to comply with its obligations under the Tecnisol PPA, or may cause material damages to the financial situation of a party and as a consequence cause a contractual imbalance, the parties may modify the agreement to restore such contractual balance, provided that the original conditions of the Tecnisol PPA are preserved, including amounts, payments and other conditions of additional expenses, and acknowledgment of financial costs and interests, if any.

Terms of the Tecnisol Third-Party Energy Reserve Agreements

We have entered into fourteen energy reserve agreements with seven hydroelectric power plants that supply energy to Tecnisol I, S.A. and Tecnisol III, S.A. pursuant to which the suppliers sell to Tecnisol I, S.A. or Tecnisol III, S.A., as applicable, energy upon energy demand (the "Tecnisol Third-Party Energy Reserve Agreements"). The purpose of the Tecnisol Third-Party Energy Reserve Agreements are to supply energy to our customers under the Tecnisol PPAs when we are unable to generate such energy with our Tecnisol Solar Project or obtain such energy from our UEP II Wind Project. The weighted average purchase price for all the Third-Party Reserve Agreements is 68.26 US$/MWh.

Under each of the Tecnisol Third-Party Energy Reserve Agreements:

- The parties have the right to terminate the Tecnisol Third-Party Energy Reserve Agreements upon the occurrence of a material breach or an event of default, such as (i) the bankruptcy, assignment in favor of creditors that could materially affect the performance under the contracts, or dissolution of any of the parties and (ii) the assignment of the Tecnisol Third-Party Energy Reserve Agreements without the consent or notification of the other party as applicable in the respective contracts;
- The suppliers under the Tecnisol Third-Party Energy Reserve Agreements are not liable for failure to deliver the energy if the contracted energy is not available; and
- Any controversy or claim arising out of the Tecnisol Third-Party Energy Reserve Agreements is required to be settled by binding arbitration.

The following chart lists the Tecnisol Third-Party Energy Reserve Agreements that we have entered into.

Seller	Offtaker	Supply Period
Generadora Alto Valle, S.A.	Tecnisol I, S.A.	May 2020 – Dec. 2021
Generadora Alto Valle, S.A.	Tecnisol III, S.A.	May 2020 – Dec. 2021
Generadora del Istmo, S.A.	Tecnisol I, S.A.	Jan. 2018 – Dec. 2020

Seller	Offtaker	Supply Period
Generadora del Istmo, S.A.	Tecnisol III, S.A.	Jan. 2018 – Dec. 2020
Hydro Caisán, S.A.	Tecnisol I, S.A.	May 2020 – Dec. 2021
Hydro Caisán, S.A.	Tecnisol III, S.A.	May 2020 – Dec. 2021
Generadora Pedregalito, S.A.	Tecnisol I, S.A.	May 2020 – Dec. 2021
Generadora Pedregalito, S.A.	Tecnisol III, S.A.	May 2020 – Dec. 2021
Generadora Río Chico, S.A.	Tecnisol I, S.A.	May 2020 – Dec. 2021
Generadora Río Chico, S.A.	Tecnisol III, S.A.	May 2020 – Dec. 2021
Saltos del Francolí, S.A.	Tecnisol I, S.A.	Nov. 2019 – Dec. 2020
Saltos del Francolí, S.A.	Tecnisol III, S.A.	Nov. 2019 – Dec. 2020
Electron Investment, S.A.	Tecnisol I, S.A.	July 2020 – Dec 2020
Electron Investment, S.A.	Tecnisol III, S.A.	July 2020 – Dec 2020
UEP Penonomé II, S.A.	Tecnisol I, S.A.	Nov.2017 – Mar.2025
UEP Penonomé II, S.A.	Tecnisol III, S.A.	Feb.2018 – Mar.2025

Certain Material Agreements

UEP II Wind Project

Interconnection Agreement

Introduction

UEP II Wind Project is interconnected to the SIN through the El Coco substation under an interconnection agreement number GG-019-2012 executed with ETESA and Unión Eólica Panameña, S.A. on April 16, 2012 which was partially assigned to the Issuer on July 21, 2014 (as amended the "UEP II Wind Project Interconnection Agreement").

Term

The UEP II Wind Project Interconnection Agreement has a term of fifteen (15) years counted from April 16, 2012.

Our obligations

Under the UEP II Wind Project Interconnection Agreement, the Issuer must pay for the interconnection services provided by ETESA, such as the interconnection to the SIN, the use of the interconnection equipment, and the operation services (which includes access to international interconnections and the spot market and the administration of the market by the CND).

Assignment

The Issuer may assign the UEP II Wind Project Interconnection Agreement to financial institutions, provided that no new obligations arise or obligations cease to exist as consequence of such assignment.

Termination

The UEP II Wind Project Interconnection Agreement can be terminated by (i) mutual agreement, (ii) written notice by the Issuer to ETESA for a breach by ETESA to the contract or by the Issuer unilaterally with a prior written notice to ETESA at least six months prior to the date of cancellation, provided that the Issuer pays for all the expenses that ETESA deems necessary to maintain the operation of the SIN after the disconnection or (iii) by ETESA for failure by the Issuer to pay for the interconnection services or other breach of the contract by the Issuer, subject to the ASEP's approval.

Law and Dispute Resolution

The UEP II Wind Project Interconnection Agreement is governed by the laws of Panama and disputes will be resolved by arbitration through the ASEP.

Service and Maintenance Agreement

Introduction

The Issuer entered into the Service and Maintenance Agreement with Goldwind on April 23, 2014, and on October 1, 2020 the parties agreed to an amendment to the Service and Maintenance Agreement (the "SMA Amendment") which provides, among other things, for the assignment of the Service and Maintenance Agreement by Goldwind to Goldwind Service Company Panama, S. de R.L. (the "Service Company") and that the term is extended until December 31, 2023. The description of the Service and Maintenance Agreement that follows includes terms agreed under the SMA Amendment.

Term

The Service and Maintenance Agreement was originally scheduled to expire on the date when the warranties expire under the Turbine Supply Agreement. However, under the SMA Amendment the expiration date of the Service and Maintenance Agreement has been extended to December 31, 2023. Prior to the expiration date of the Service and Maintenance Agreement, the Issuer intends to either extend such agreement again or to enter into a new service and maintenance agreement with another third party.In case a new provider is selected, the SMA Amendment guarantees the supply of spare parts until December 31, 2035.

Scope of Service

Under the Service and Maintenance Agreement, the Service Company is required to perform the services necessary for the proper operation and maintenance of the wind turbine generators, except for: (i) operation and maintenance of components comprising the balance of plant work, (ii) obtaining any authorizations otherwise necessary or appropriate for the erection, ownership or operation of the Project, or (iii) obtaining any rights or authorizations necessary for the production, delivery or sale of electrical power produced by the wind turbines, including any real property rights and rights under any power purchase agreements. Under the SMA Amendment, the Service Company has also agreed to extend the warranties under the Turbine Supply Agreement and replace, repair or retrofit defective parts, with the exception of the blade sets, at no additional cost to the Issuer.

Compensation

As compensation for the Service Company's services under the Service and Maintenance Agreement, we have agreed to pay the Service Company an annual fee of US$48,500 per turbine, plus applicable taxes, payable in identical quarterly installments in advance, which is adjusted annually based on the U.S. CPI. The Service Company is entitled to fees for additional services, if any, that are provided under the Service and Maintenance Agreement.

Minimum annual average availability guarantee

The Service Company has provided a minimum availability of the turbines of at least 97% for the high wind season and 96% for the low wind season (the "SMA Annual Guaranteed Availability"). If on average the Projects fail to meet the SMA Annual Guaranteed Availability in any year, the Service Company will pay the Issuer a penalty pursuant to a specified formula. If, on the contrary, the SMA Annual Guaranteed Availability is exceeded in any year, the Issuer will pay to the Service Company a bonus, calculated pursuant to a separate formula set forth in the SMA.

Force Majeure

The Issuer and the Service Company have the right to suspend the obligations under the Service and Maintenance Agreement upon the occurrence of certain events beyond control of the parties.

Termination

The Service and Maintenance Agreement may be terminated by the Issuer prior to its expiration under certain conditions, including insolvency events involving the Service Company, breach of representations, breach of contract and unpermitted assignment. The Service and Maintenance Agreement may be terminated by the Service Company prior to its expiration under certain conditions, including Issuer's failure to pay fees, denial of access to the Project's sits, insolvency events involving the Issuer, breach of representations, breach of contract and unpermitted assignment.

Exclusion of Liability

The annual liability of the Service Company under the Service and Maintenance Agreement is limited to 100% of the annual fee for the applicable year. In addition, there are certain events that release the Service Company from its obligation to replace, repair or retrofit defective parts, such as alterations or repairs made to the wind turbine generators by unauthorized persons, failure of a tower foundation, hazardous substances not in the control of the Service Company.

Assignment

The Service and Maintenance Agreement may not be assigned by any party without the prior written consent of the other parties, except that the Issuer may assign the Service and Maintenance Agreement to its financing parties in guaranty of its obligations under such financing.

Law and Dispute Resolution

The Service and Maintenance Agreement is governed by New York law and disputes are to be resolved in New York courts.

Maintenance Agreement — UEP II Project Transmission Line

Introduction

The Issuer entered into a Maintenance Agreement with Ingenieria y Productos Electromecanicos, S.A., (IPELSA) (the "UEP II TL Service Company") on December 1, 2019 (the "UEP II TL Maintenance Agreement").

Term

The UEP II TL Maintenance Agreement expires on December 1, 2020. The Issuer and the UEP II TL Service Company are negotiating the renewal of the UEP II TL Maintenance Agreement.

Scope of Service

Under the UEP II TL Maintenance Agreement, the UEP II TL Service Company is required to perform the preventive and corrective services necessary for the proper operation of the transmission line of the UEP II Wind Project, including supplying of all materials, equipment and manpower necessary for the services.

Compensation

As a compensation for the UEP II TL Service Company's services under the UEP II TL Maintenance Agreement, the Issuer currently pays a monthly fee of US$7,900.00 to the UEP II TL Service Company.

Termination

The UEP II TL Maintenance Agreement may be terminated prior to its expiration under certain conditions, including by breach of contract by any party, abandonment by the UEP II TL Service Company, and mutual consent of the parties.

Additional Service and Maintenance Works

The El Coco Substation service and maintenance is performed by Ingeteam as a subcontractor of UEP I and we assume 80% of such service and maintenance through the Shared Asset Access Agreement dated as of June 15, 2018 that we entered into with UEP I. See "— Shared Asset Access Agreement" below. Grass cutting and pest control, including of bees in wind turbines, and cleaning of the drainage system are performed by DRBG Services, and contracted for on an annual basis.

Shared Asset Access Agreement

Introduction

The El Coco substation, through which the Issuer interconnects to the SIN, does not belong to the Issuer. It belongs to UEP I, which is also the owner of the neighboring wind farm. Until May 13, 2020, UEP I belonged to Goldwind, and on that date it was acquired by AES Panama, S. de R.L. However, some of the assets in the El Coco substation are necessary for the operation of the UEP II Wind Project. Those assets are known as the "Shared Assets." In order for the Issuer to use and access the Shared Assets and the Issuer's transformer located in the El Coco substation, the Issuer and UEP I have entered into a series of agreements. Currently, UEP I and the Issuer are parties to that certain Shared Assets Access Agreement dated as of June 15, 2018 pursuant to which UEP I grants the Issuer access and the right to use the Shared Assets in exchange for a monthly rental fee of US$27,129.85. In addition, UEP I agreed to manage, operate and maintain the Shared Assets against reimbursement of approximately 80% of fees and expenses incurred because the Issuer's nameplate capacity is 80% of the capacity currently connected to the El Coco substation. UEP I also reserved the right to transfer the Shared Assets and the remainder of the high-voltage portion of the El Coco substation to ETESA, as required by Panamanian law and as of the date of this offering memorandum, the sale of a portion of the Shared Assets to ETESA is under negotiation. Once such sale of a portion of the Shared Assets is perfected, the monthly rental fee will decrease to US$22,361.17.

Purchase Option

UEP I granted the Issuer an option to purchase the Shared Assets at an agreed price, after ETESA acquires the remainder of the high-voltage portion of the El Coco substation, or sooner if UEP I terminates its obligation to manage, operate and maintain the Shared Assets. The option price is US$1,512,396.48 plus any applicable transfer taxes, ITBMS, sales taxes or any other taxes, duties and fees that may be charged by any Panamanian governmental authority in connection with transfer and sale of the Shared Assets. Once the Purchase Option is executed and after ETESA acquires the remainder of the high-voltage portion of the El Coco substation, the rental fee will decrease to US$1,980.95.

Transfer of O&M Building Property

Under the Shared Assets Access Agreement, UEP I agreed to transfer for free the land on which the O&M Building sits, which as agreed was built by the Issuer on land belonging to UEP I. In consideration for that transfer, the Issuer will permit the permanent use by UEP I of a portion of the O&M Building proportional to UEP I's wind farm nameplate capacity with respect to the total capacity connecting to the El Coco substation, currently approximately 20%.

Term

The Shared Assets Access Agreement will remain in effect for as long as the UEP II Wind Project operates, unless terminated earlier by mutual agreement of the parties.

Assignment

Each of the parties may assign the Shared Assets Access Agreement to its respective lenders, and to any transferee of the Shared Assets (in the case of UEP I) or the UEP II Wind Project (in the case of the Issuer).

Termination

The Shared Assets Access Agreement does not contain early termination provisions, but may be terminated by mutual agreement of the parties.

Law and Dispute Resolution

The Shared Assets Access Agreement is governed by Panamanian law, and disputes are to be settled by arbitration in Panama City, Republic of Panama pursuant to the rules of arbitration of the International Chamber of Commerce.

Wake Effect Agreement

On December 10, 2014, the Issuer signed a Wake Effect Agreement (the "Wake Effect Agreement") with Unión Eólica Panameña, S.A. and Goldwind (who later assigned its rights and obligations thereunder to UEP I) pursuant to which the Issuer agreed to compensate UEP I for the energy losses caused by the wind restriction created by the turbines installed in UEP II Wind Project. The Issuer agreed to pay a monthly payment beginning with the Commercial Operation Date, which occurred on February 19, 2018, for a term of 25 years.

Expired Construction Agreements

Introduction

The UEP II Wind Project was built pursuant to three contracts with different contractors. The obligations of the parties under those contracts have been fulfilled or have expired and there are no pending obligations of the parties thereto outstanding.

Turbine Supply Agreement

On April 23, 2014, the Issuer and Goldwind entered into an Amended and Restated Turbine Supply Agreement (the "Turbine Supply Agreement") pursuant to which Goldwind agreed to supply and install the wind turbine generators of the UEP II Wind Project against the payment of an agreed price. The term of the Turbine Supply Agreement, and therefore the warranties under it, will expire on October 31, 2020 and certain warranties provided by Goldwind have been extended until December 31, 2023 under the Service and Maintenance Agreement described above.

Balance of Plant Agreement

On October 14, 2013, the Issuer and Instalaciones y Servicios CODEPA, S.A. (the "BOP Contractor") entered into a balance of plant agreement (the "BOP Agreement") pursuant to which the BOP Contractor agreed to build the civil works of the UEP II Wind Project against the payment of an agreed price. The original BOP Agreement was amended on April 23, 2014 and, on July 7, 2016, after construction of the civil works was completed and the UEP II Wind Project was in operation, it was terminated pursuant to a settlement agreement after a subcontractor sued another subcontractor, the BOP Contractor and the Issuer.

Logistics Services Agreement

On April 23, 2014, the Issuer and Tree Logistics Corp. (the "Transporter") entered into a Logistics Services Agreement (the "Transportation Agreement") pursuant to which the Transporter agreed to transport all components of the wind turbine generators from the place where they were built to the Projects' site against the payment of an agreed price. The Transportation Agreement expired when the Transporter completed its transportation obligations.

Tecnisol Solar Project

Tecnisol Solar Project Interconnection Agreements

Introduction

The Tecnisol Solar Project is interconnected to the SIN through the Mata de Nance substation. Tecnisol I, S.A. and Tecnisol III, S.A. entered into two separate direct interconnection agreements with ETESA dated September 28, 2015 and Tecnisol II, S.A. and Tecnisol IV, S.A. entered into two separate indirect interconnection agreements with ETESA dated September 28, 2015 (collectively the "Tecnisol Solar Project Interconnection Agreements")

Term

The Tecnisol Solar Project Interconnection Agreements have a term of fifteen (15) years each.

Our obligations

Under each Tecnisol Solar Project Interconnection Agreement, each Guarantor must pay for the interconnection services provided by ETESA, such as the interconnection to the SIN, the use of the interconnection equipment, and the operation services (which includes access to international interconnections and the administration of the market by the CND).

Assignment

We have authorized the assignment of the Tecnisol Solar Project Interconnection Agreements to the concessionaire that replaces ETESA as holder of the transmission concessions relating to the Mata de Nance substation. ETESA has authorized us to assign the Tecnisol Solar Project Interconnection Agreements to the entity that would replace us as owner of the Projects.

Termination

The Tecnisol Solar Project Interconnection Agreements can be terminated by (i) mutual agreement, or (ii) written notice by the applicable Guarantor to ETESA for a breach by ETESA to the contract or by the applicable Guarantor unilaterally with a prior written notice to ETESA at least six months prior to the date of cancellation, provided that the applicable Guarantor pays for all the expenses that ETESA deems necessary to maintain the operation of the SIN after the disconnection or (iii) by ETESA for failure by the Issuer to pay for the interconnection services or other breach of the contract by the Issuer, subject to the ASEP's approval.

Law and Dispute Resolution

The Tecnisol Solar Project Interconnection Agreements are governed by the laws of Panama and disputes will be resolved by arbitration through the ASEP.

Tecnisol Intercompany Interconnection Agreements

Introduction

Tecnisol II, S.A. and Tecnisol IV, S.A. have access to the SIN through the HICACO IV substation, property of Tecnisol I, S.A. On August 1, 2018, Tecnisol I, S.A. entered into two separate intercompany interconnection agreements with Tecnisol II, S.A. and Tecnisol IV, S.A. (collectively the "Tecnisol Intercompany Interconnection Agreements").

Term

The Tecnisol Intercompany Interconnection Agreements have an indefinite term.

Our obligations

Under each Tecnisol Intercompany Interconnection Agreements, Tecnisol II, S.A. and Tecnisol IV, S.A. must pay a fee to Tecnisol I, S.A. for the use of the HICACO IV substation. The fee is set by Tecnisol I, S.A., and Tecnisol I, S.A. notifies Tecnisol II, S.A. and Tecnisol IV, S.A. of the fee amount no later than December 31 of the immediately prior year.

Assignment

The parties may assign their rights and obligations under the Tecnisol Intercompany Interconnection Agreements upon prior written notification to the other party.

Termination

The Tecnisol Intercompany Interconnection Agreements can be terminated by mutual agreement or written notice at least six months prior to the date of cancellation.

Law and Dispute Resolution

The Tecnisol Intercompany Interconnection Agreements are governed by the laws of Panama and disputes will be resolved by arbitration through the ASEP.

Substation Operation Agreement

Introduction

On July 16, 2018, Tecnisol I, S.A. and ETESA entered into an operation agreement (the "Operation Agreement") for the operation and maintenance of switch yard No. 4 of the Mata de Nance substation.

Term

The Operation Agreement will be in force until Tecnisol I, S.A. successfully transfers the switch yard No. 4 of the Mata de Nance substation to ETESA.

Our obligations

Under the Operation Agreement, Tecnisol I, S.A. must pay for the operation and maintenance services provided by ETESA.

Termination

The Operation Agreement may be terminated by (i) mutual agreement or (ii) by Tecnisol I, S.A. unilaterally by written notification to ETESA at least one month prior to the termination.

Law and Dispute Resolution

Any dispute arising in connection with the Operation Agreement must be resolved by arbitration at the ASEP.

Tecnisol Solar Project EPC Agreement

Introduction

The Guarantors entered into an EPC Agreement dated August 23, 2017 with the EPC Contractor for the design, construction and commissioning of the Tecnisol Solar Project (the "Tecnisol EPC Agreement"). Such EPC Agreement was modified by a Project Acceptance Agreement dated February 1, 2020 (the "Project Acceptance Agreement") and the Tecnisol EPC Agreement, as amended by the Project Acceptance Agreement (the "Tecnisol Solar Project EPC Agreement").

Outstanding Obligations

Pursuant to the Tecnisol Solar Project EPC Agreement, subject to compliance of certain milestones by the EPC Contractor, the Guarantors will issue acceptance certificates and make the applicable payments to the EPC Contractor. As of the date of this offering memorandum, the Guarantors have issued all acceptance certificates, and the outstanding obligations of the EPC Contractor are the following:

- Obtaining the COD; and
- Compliance with the warranties described below (the "Warranty Obligations").

Warranties

Under the Tecnisol Solar Project EPC Agreement, the EPC Contractor provided to the Guarantor the following warranties which are valid from February 1, 2020 until February 1, 2022, except as provided below (the "Warranty Period"):

- Warranty against Defects: the EPC Contractor warrants that all services performed under the Tecnisol Solar Project EPC Agreement are free from any defects and are in compliance with the Tecnisol Solar Project EPC Agreement, the applicable laws and the Tecnisol Solar Project permits. If all or part of the Tecnisol Solar Project cannot be used by the Guarantors due to a defect, the warranty period shall be extended for a period equivalent to the period in which the Tecnisol Solar Project or the applicable part is not being used. In addition, any repairs or replacements shall benefit from an extended warranty period until February 1, 2023. The warranty of defect is granted notwithstanding any applicable manufacturing warranties granted by the manufacturer;
- Warranty of Performance Ratio: the EPC Contractor warrants that the Tecnisol Solar Project will achieve the guaranteed performance ratio of 100% of the theoretical value (the "Guaranteed Performance Ratio"), subject to compliance with the operation and maintenance manual delivered by the EPC Contractor to the Guarantors. If the EPC Contractor does not comply with the Guaranteed Performance Ratio the Guarantors may impose penalties to the EPC Contractor up to 15% of the price of the EPC Contract; and

- Warranty of subcontractors and manufacturers. With respect to the warranties granted by the manufacturers and subcontractors, the EPC Contractor has the obligation to make the necessary claims under such warranties during the Warranty Period.

Warranty for Concealed Defects

If after the termination of the Warranty Period, the Guarantors discover any mistake, omission, defect or deficiency in the works performed by the EPC Contractor under the Tecnisol Solar Project EPC Agreement that is not disclosed to the Guarantors during the Warranty Period the EPC Contractor shall repair or replace such work if such mistake, omission, defect or deficiency is notified by the Guarantors within eight years after the date in which the Guarantors issued the last acceptance certificate.

Performance Bond

The EPC Contractor has delivered the performance bond No. 070-001-00021186-000000 issued by Compañía Internacional de Seguros, S.A. (the "Performance Bond") valid until February 1, 2022 to guarantee the compliance of the EPC Contractor's obligations during the Warranty Period.

Penalties

The Guarantors may impose penalties on the EPC Contractor for up to 15% of the price of the Tecnisol Solar Project if the EPC Contractor does not repair any defect within the period specified by the Guarantors and such penalties may be paid through deductions from the price or the enforcement of the Performance Bond.

Limitation of Liability

The EPC Contractor's liability cannot exceed 100% of the price of the Tecnisol Solar Project EPC. The EPC Contractor is not liable for indirect or consequential damages due to non-compliance with its obligations under the Tecnisol Solar Project EPC.

Force Majeure and Acts of God

The EPC Contractor may be excused from compliance with its obligations due to a force majeure or an act of God.

Termination

The Tecnisol Solar Project EPC Agreement has standard termination provisions.

Assignment

The Guarantors may assign the Tecnisol Solar Project EPC Agreement to their respective lenders.

Law and Dispute Resolution

The Tecnisol Solar Project EPC Agreement is governed by Panamanian law, and disputes are to be settled by arbitration in Panama City, Republic of Panama pursuant to the rules of arbitration of the International Chamber of Commerce.

Project Acceptance Agreement

The EPC Contractor and the Guarantors had some differences with respect to certain matters of the Tecnisol EPC Agreement, including the issuance by the Guarantors to the EPC Contractor of certain acceptance certificates and the payments corresponding to such certificates. Considering such discrepancies, the EPC Contractor and the Guarantors signed the Project Acceptance Agreement, under which, among other terms, the parties agreed that subject to the compliance of the EPC Contractor's obligations for the issuance of such acceptance certificates and the payments by the Guarantors to the EPC Contractor under the Project Acceptance Agreement, (i) each party released the other party from any liability with respect to such other party's obligations under the Tecnisol EPC Agreement, except in the case of the EPC Contractor of certain obligations including: obligations related to obtaining the COD and the Warranty Obligations and (ii) the EPC Contractor waived any right to claim against the Guarantors in relation to the Tecnisol Solar

Project EPC Agreement. As of the date of this offering memorandum, the Guarantors have issued all acceptance certificates and made to the EPC Contractor the payments corresponding to such certificates.

EPC Agreement — The Tecnisol Solar Project Transmission Line and Interconnection

Introduction

Tecnisol I entered into an EPC Agreement dated August 24, 2017 with Instalaciones y Servicios Inserpa S.A. ("TL EPC Contractor") for the design and construction of the transmission line and interconnection of the Tecnisol Solar Project (the "TL EPC Agreement"). No liabilities of Tecnisol I remain outstanding under the TL EPC Agreement. The warranties granted by the TL EPC Contractor under the TL EPC Agreement expire on May 30, 2021.

Maintenance Agreement — Tecnisol Solar Project Transmission Line.

Introduction

Tecnisol I entered into a Maintenance Agreement with Mantenimiento de Sistemas Eléctricos de Chiriquí, S.A., "Manselect" (the "Tecnisol TL Service Company") on August 28, 2019, as amended on August 31, 2020 (the "Tecnisol TL Maintenance Agreement").

Term

The Tecnisol TL Maintenance Agreement expires on August 31, 2021. However, Tecnisol I is entitled but not obligated to renew the Tecnisol TL Maintenance Agreement on the same terms and conditions upon delivery of a notice 90 calendar days before the expiration date.

Scope of Service

Under the Tecnisol TL Maintenance Agreement, the Tecnisol TL Service Company is required to perform the preventive and corrective services necessary for the proper operation of the transmission line of the Tecnisol Solar Project, including supplying of all materials, equipment and manpower necessary for the services.

Compensation

As a compensation for the Tecnisol TL Service Company's services under the Tecnisol TL Maintenance Agreement, Tecnisol has agreed to pay the Tecnisol TL Service Company a monthly fee of US$13,615.75.

Termination

The Tecnisol TL Maintenance Agreement may be terminated prior to its expiration under certain conditions, including breach of contract by any party, abandonment by the Tecnisol TL Service Company, the mutual consent of the parties, expiration of the term of the Tecnisol TL Maintenance Agreement without a notification by any of the parties to renew the contract and bankruptcy of any party.

Jinko Solar Warranty

Jinko Solar has granted (i) a warranty over the PV Modules of the Tecnisol Solar Project that expires between December 2027 and March 2028 and (ii) a power warranty that expires between December 2042 and March 2043 (no less than 80.7% of power output). These warranties have exclusions including the following: (i) damages due to transportation and installation, (ii) failure to comply with the instructions of use, installation and maintenance, (iii) interventions, modifications and intents of repairs without the prior written consent of Jinko Solar or otherwise inconsistent with Jinko Solar's written instructions, or (iv) force majeure events, among others.

Jema Warranty

On December 21, 2018 Jema granted a warranty over the inverters of the Tecnisol Solar Project of 10 years that expires on December 21, 2028 (extendable subject to certain conditions). The warranty includes spare parts and all replacement works and has exclusions including the following: (i) damages due to transportation and installation, (ii) failure to comply with the instructions of use, installation and maintenance, (iii) interventions, modifications and intents of repairs by the unauthorized personnel, (iv) improper use of the equipment, (v) insufficient ventilation where the equipment is placed, or (vi) force majeure events, among others.

Gonvarri Warranty

On March 9, 2019 Gonvarri granted a warranty over the structures of the PV modules of the Tecnisol Solar Project of 10 years that expires on March 9, 2029; Gonvarri also granted a warranty over the corrosion of the structures of the PV modules of the Tecnisol Solar Project of 20 years that expires on March 9, 2039; and Gonvarri granted a warranty over third-part components of the structures of the PV modules of the Tecnisol Solar Project of 5 years that expires on March 9, 2024. The warranty has exclusions including the following: (i) damage to the materials or coating caused by mishandling, improper or negligent assembly of the materials and/or misuse from their intended purpose by the Guarantors or any other third party, (ii) regular wear and tear, (iii) inadequate maintenance, (iv) failure to comply with the instructions of maintenance, or (v) force majeure events, among others.

Jema Services Agreement

The Guarantors entered into a maintenance services agreement with Jema under which Jema is required to perform preventive maintenance services to the inverters of the Tecnisol Solar Project, with a term between February 2020 until January 2021. The Guarantors must pay an annual fee of €22,155 for such services provided by Jema.

Gonvarri Services Agreement

The Guarantors entered into a maintenance services agreement with Gonvarri under which Gonvarri is required to perform preventive maintenance services to the trackers of the Tecnisol Solar Project, with a term between February 2020 until January 2021. The Guarantors must pay an annual fee of €18,825 for such services provided by Gonvarri.

Health, Safety, Environmental and Security Standards

We have established health, safety, and environmental policies and procedures and we regularly undertake monitoring of the Project's compliance with applicable environmental policies, local laws and permit requirements, with oversight and audit through our operations and environmental, health and safety departments. We also utilize third-party contractors to conduct regular health, safety and environmental audits.

We will, for all controlled facilities produce and distribute electricity according to the local laws, rules and regulations, IFC Performance Standards on Environmental and Social Sustainability (2012), and applicable aspects of the IFC general and sectoral Environmental, Health, and Safety Guidelines. The eight Performance Standards (PS) that InterEnergy is to meet throughout the life of an investment are:

PS1 — Assessment and Management of Environmental and Social Risks and Impacts: the environmental and social management system enables us to anticipate environmental and social risks posed to the business activities and avoid, minimize, and compensate for such impacts, if applicable.

PS2 — Labor and Working Conditions: the management of the relationship between workers and managers to provide a fair, safe and healthy conditions to everyone, and the identification of risks in the primary supply chain.

PS3 — Resource Efficiency and Pollution Prevention: integration of good practices and technologies to promote energy efficiency, use of resources in a sustainable way and reduction of greenhouse gas emissions.

PS4 — Community Health, Safety and Security: the adoption of responsible practices to reduce risks related to worksite accidents, hazardous materials and spread of diseases including emergency preparedness and response, security force management, and design safety measures.

PS5 — Land Acquisition and Involuntary Resettlement: to minimize the impact of involuntary resettlement or displacement, through mitigation measures such as fair compensation and improvements to and living conditions.

PS6 — Biodiversity Conservation and Sustainable Management of Living Natural Resources: protection and conserving of biodiversity, maintenance of ecosystem services, and managing living natural resources for a sustainable development.

PS7 — Indigenous Peoples: assurance that our business activities minimize negative impacts fosters respect for human rights, dignity and culture of indigenous populations, and promotion of development benefits in culturally appropriate ways; plus, informed consultation and participation with indigenous people throughout the project process.

PS8 — Cultural Heritage: protection of cultural heritage from adverse impacts of project activities and supporting its preservation, also promoting equitable sharing of benefits from the use of cultural heritage.

Insurance

InterEnergy Group secures three global insurance policies as part of its risk management strategy that provide risk coverage to its subsidiaries, including the Issuer and the Guarantors:

- All Risk of Direct Physical Damage and Business Interruption Insurance Program;
- General Liability Insurance; and
- Directors and Officer's Liability Insurance.

All policies are in USD currency.

All Risk of Direct Physical Damage and Business Interruption Insurance

Mapfre Panama, S.A. is the insurer of our All Risk of Direct Physical Damage and Business Interruption Insurance. This insurance has a maximum combined single limit of US$400,000,000, each and every occurrence.

The policy insures against "All Risks" of direct physical loss, destruction or damage to interests and insured property referred to in the Property and Insured Interest clause, including mechanical and machinery breakdown. InterEnergy's program defines total insured value of the assets for property damage as replacement value or market value. Business interruption considers a 12-month indemnity period.

	Guarantors	**Issuer**
	Property Damage	*Property Damage*
Insured Value	US$48,000,000	US$303,197,681
Deductibles	US$50,000, each and every occurrence, except 2% of insured values each and every occurrence in respect of Earthquake, Volcanic Eruption, Tsunami subject to a minimum of US$50,000.	US$100,000, each and every occurrence
	Business Interruption	*Business Interruption*
Insured Value	US$7,120,893	US$50,672,700
Deductibles	30 days waiting period, each and every occurrence	30 days waiting period, each and every occurrence

The policy defines certain sublimit to property damage that apply as part of, and not in addition to, the overall policy limit for an occurrence insured. Each sublimit is the maximum amount potentially recoverable from all insurance layers combined for all insured loss, damage, expense, time element or other insured interest arising from or relating to that aspect of the occurrence, including but not limited to type of property, construction, geographic area, zone, location, or peril.

General Liability Insurance

Chubb Panama is the insurer of our General Liability Insurance. This policy covers Non-Marine General Liability up to US$50,000,000, any one occurrence for general liability and in the policy period aggregate for all other covers (combined single limits for all locations). The insured retains liability for US$10.000, on each and every loss.

Coverage includes:

- Legal Liability derived from injury or physical or material damage and its consequences, occurring during the period of insurance and caused to third parties by acts or omissions in the exercise of the insured business activity;
- The insured's legal liability as promoter of or contractor or builder for inland new building works, maintenance, repair, extension or reconstruction works on existing buildings and installations, provided that the total value of the project does not exceed US$5,000,000, excluding damages to works themselves;
- Legal liability for company medical services, fire-fighting services, games and sports, company travels, educational visits, presence at and participation in trade shows, exhibitions and the like, accommodation, sports, hospitality and recreation facilities, bar and dining facilities or food and drink vending machines, company stores, watchman and security services, whether its own or of third parties and whether armed or not, and with the use of any technical measures or animals;
- The insured's legal liability for damage which may be caused to the goods or property of its employees, kept or situated within or in the vicinity of its installations;
- The insured's legal liability for damage to the property of third parties in its safe-keeping, custody or control, not under housekeepers contract, with a sublimit of US$5,000,000 per event. This does not cover damages to property being worked upon;
- Sudden & accidental pollution 72 hours discovery period, including clean-up or third parties damaged premises;
- Failure to supply: property damage or injury derived from failure to supply arising directly from accidental damages to the installations and equipment of the insured. This does not include pure financial losses derived from FTS;
- Subsidiary legal liability arising from the use of vehicles owned by employees or used by third parties on behalf of the insured's activity or hired vehicles for the insured activity: this cover operates in excess of statutory insurance or any other valid or collectible policy or US$100,000, whichever is greater;
- The insured's subsidiary legal liability as a result of the use of vehicles owned by its employees, third parties or of hired vehicles, when they are placed at the disposal of the company or used for its benefit is covered. Subsidiary auto liability in the USA operates in XS of US$1,000,000;
- Products liability and completed operations: indemnities which the insured shall be required to pay for legal liability arising from injury, material damage and the consequences thereof caused to third parties by products and/or services designed, manufactured, sold, supplied, distributed and installed shall be deemed to be covered by this policy, provided the products and/or services have been delivered to third parties;
- Employers liability: insured's legal liability arising out of bodily injury or material damage and the consequences thereof suffered accidentally employees of the insured, including apprenticeships. This cover does not include: contributions laid down by legislation relating to accidents at work, social security and/or the like, and penalties, fines and surcharges on indemnities, which may be required by such legislation, nor professional illness, that shall be excluded; and

- Defense costs and bonds: The insurers shall also meet costs, fees and expenses, which the insured may have incurred with the consent of the insurers for the defense or settlement of any claim under this policy in front of any courts, including legal expenses and bonds and deposits. Defense costs are covered in excess of the limit of indemnity except for claims in the USA/Canada and its territories, that will be comprised within the total limit of indemnity stated in the policy.

Directors' and officers' liability insurance

Our Sponsor secures directors and officer's liability insurance through a primary policy with a primary all risk cover with a limit of indemnity of US$10 million, in the aggregate; and an excess all risk cover with a limit of indemnity of US$20 million in the aggregate.

Performance bonds

Pursuant to the terms of our UEP II PPAs, the Issuer must deliver to the energy Distribution Companies a performance bond (one for each PPA) to guarantee the obligations contracted in the UEP II PPAs. The performance bond must be issued by an insurance company or a bank accepted by the buyer and must be equal to two months of energy billing. The validity of the performance bonds corresponds to the duration of the contracts, with annual renewals.

The Issuer currently has 18 performance bonds in force contracted with the International Insurance Company (*Compañía Internacional de Seguros, S.A.*) as follows:

PPA	Wind farm	Value
EDEMET	Nuevo Chagres	US$2,848,504.09
EDEMET	Rosa de los Vientos I	US$2,322,948.15
EDEMET	Portobelo	US$1,619,149.69
EDEMET	Marañon	US$826,579.29
EDEMET	Portobelo	US$1,251,507.98
EDEMET	Marañon	US$712,860.34
EDECHI	Nuevo Chagres	US$842,517.89
EDECHI	Rosa de los Vientos I	US$706,981.17
EDECHI	Portobelo	US$478,910.42
EDECHI	Marañon	US$250,483.00
EDECHI	Portobelo	US$671,540.88
EDECHI	Marañon	US$395,477.45
ENSA	Nuevo Chagres	US$1,163,478.01
ENSA	Rosa de los Vientos I	US$976,310.67
ENSA	Portobelo	US$661,339.87
ENSA	Marañon	US$350,671.70
ENSA	Marañon	US$644,968.87
ENSA	Portobelo	US$1,159,934.23

UEP II Payment Guarantees

Pursuant to the terms of our UEP II PPAs, the Distribution Companies must maintain during the supply period a payment guarantee (one for each UEP II PPA) to guarantee the payment obligations contracted in such PPAs. The payment guarantee can be in cash, or issued by an insurance company and must be equal to approximately one month of energy billing. The validity of the guarantee payments corresponds to the duration of the contracts, with annual renewals.

The Issuer currently has 12 payment guarantees in force as follows:

PPA	Wind farm	Value
EDEMET	Nuevo Chagres	US$1,424,252.04
EDEMET	Rosa de los Vientos I	US$1,161,474.07
EDEMET	Portobelo	US$809,574.84
EDEMET	Marañon	US$413,289.64
EDECHI	Nuevo Chagres	US$421,258.94
EDECHI	Rosa de los Vientos I	US$353,490.58
EDECHI	Portobelo	US$239,455.21
EDECHI	Marañon	US$125,241.50
ENSA	Nuevo Chagres	US$581,739.00
ENSA	Rosa de los Vientos I	US$488,155.33
ENSA	Portobelo	US$330,669.93
ENSA	Marañon	US$175,335.85

Tecnisol Payment Guarantees

Pursuant to the terms of the Tecnisol PPAs, the Tecnisol Customers must deliver to the Guarantors a payment guarantee (one for each Tecnisol PPA) to guarantee the payment obligations contracted in such PPAs. The payment guarantee must be issued by an insurance company or, under certain PPAs, a financial institution accepted by us and must be equal to approximately two months of energy billing. The validity of the guarantee payments corresponds to the duration of the contracts, with annual renewals.

The Guarantors currently have 8 payment guarantees in force as follows:

Counterparty	Value
Coca Cola Femsa de Panamá, S.A.	US$189,023.10
Ventas y Mercadeo Panamá, S.A.	US$ 13,339.20
Industrias Lácteas, S.A.	US$466,700.10
Riba Smith, S.A. (Delirys)	US$ 13,965.14
Riba Smith, S.A.	US$181,541.60
Clínica Hospital San Fernando S.A.	US$146,047.42
The Iron Tower Corp.	US$ 98,551.37
ICE Gaming Corporation	US$ 42,247.20

Employee and Pension Matters

As of September 30, 2020, we had approximately 17 full-time employees, consisting of operators, engineers, project and site managers. The Sponsor also dedicated 19 full time employees plus 2 subcontracted personnel to manage us, which are not employees of the Issuer or the Guarantors.

Legal Proceedings

We are subject to various legal contingencies, including legal proceedings and claims arising out of the normal course of business. These proceedings primarily involve commercial claims and tax disputes. The outcome of these lawsuits, legal proceedings and claims cannot be predicted with certainty. Nevertheless, we believe the outcome of any of these currently existing proceedings, even if determined adversely, would not have a material adverse effect on our financial condition or results of operations.

Goldwind Arbitration Proceedings

Following the installation of the wind turbines in the UEP II Wind Project, we discovered a defect in the blades designed and manufactured by Sinoma and supplied to us by Goldwind under the Turbine Supply Agreement with Goldwind. Due to the fact that the materials used for manufacturing the blade tips were not consistent with the technical specifications provided by Sinoma, we concluded that such inconsistencies could have created safety issues and additional wear and tear in the operation of our wind project. As a result of such manufacturing defects, we reduced the expected useful life of the blades from 20 years to 10 years and we commenced arbitration proceedings against Goldwind. These arbitration proceedings included claims for these defects of the blades tips and the payment of certain availability guarantees for the years 2017 and 2018. These arbitration proceedings concluded on May 15, 2018 with the signing of a settlement and release agreement (the "Settlement Agreement") that terminated all pending claims and counterclaims between Goldwind and us on a mutually satisfactory basis, and we have continued to work with Goldwind to develop a tailored maintenance program (which is set out under the Service and Maintenance Agreement) for our wind turbines and related equipment that take into account all necessary technical and operational considerations. For a description of our Blades Strategy Plan, see "— UEP II Wind Project" above and for additional information on the settlement with Goldwind, see Note 19 to the Issuer Annual Financial Statements.

Tecnisol PV Modules

In addition, we recently identified certain cable insulation issues in a portion of the PV modules located at our Tecnisol Solar Project. These insulation issues were detected by us during the commissioning of the Tecnisol Solar Project and, after working constructively with the manufacturer of the cables to solve this issue, the manufacturer acknowledged that the cables were partially defective and agreed to replace them. The cost of replacing these cables is covered by the warranties under the Tecnisol Solar Project EPC Agreement. Additionally, the replacement work started on September 23, 2020 and is planned to be finalized by November 30, 2020, according to the Contractor's schedule.

OVERVIEW OF THE PANAMANIAN ELECTRICITY INDUSTRY

Panama

Macroeconomic indicators

Panama has an upper-middle-income economy. Panama's dollar-based economy (since 1904) rests primarily on a well-developed services sector growing at an average of 4.2% in the last 5 years and accounting for approximately 74% of GDP. Services include operating the Panama Canal, logistics, banking, the Colon Free Trade Zone, insurance, container ports, flagship registry, and tourism and Panama is a center for offshore banking. Furthermore, Tocumen International Airport is the regional hub for several commercial and cargo airlines. It connects passengers to 38 countries and 89 destinations all around the world.

Bordering the South Pacific Ocean and the North Atlantic Ocean and located between Costa Rica and Colombia, Panama is rich in natural resources, including timber, precious metals, and hydropower.

Political stability has also contributed to economic growth. The Panamanian government is a constitutional democracy and since 1994 every presidential election, which is held every five years, has been regarded as fair. The president is directly elected by a simple majority popular vote, in two rounds if needed, for a single five-year term. The current head of government is President Laurentino Cortizo, who was sworn in on July 1, 2019. Panama does not have a regular, active military but it does have several public forces, including the Panamanian National Police, the National Air-Naval Service, and the National Border Service.

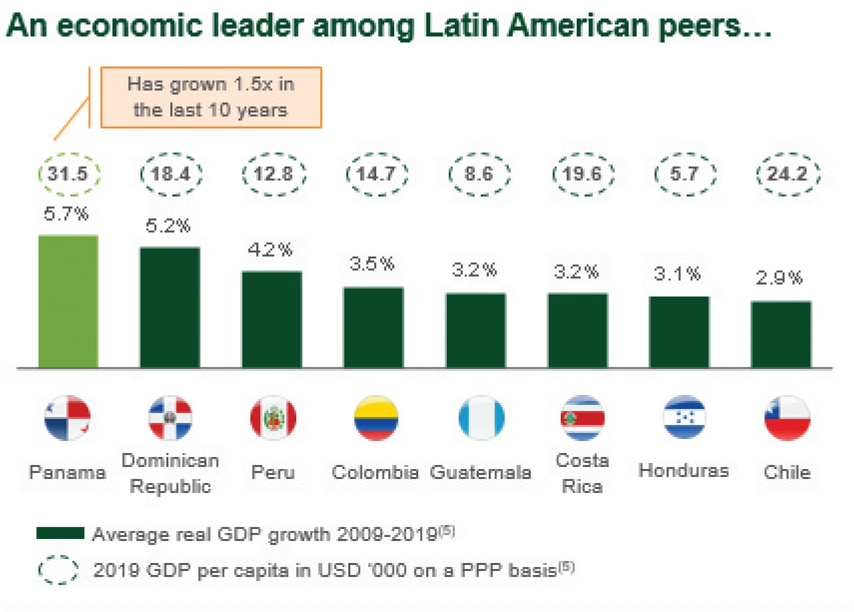
Indicator Name	2019
Population, total	4,246,439
GDP (constant 2010 US$)	50,575,748,118
GDP growth (annual %)	3
GDP (current US$)	66,800,800,000
GDP per capita (constant 2010 US$)	11,910

Source: World Bank (Data base)

As of July 1, 2020, Panama's estimated total population was 4,333,351. As of 2020 the median age is 29.7 years. Panama has an educated and healthy population. As of 2018, its population had a literacy rate of 95.41% and a life expectancy at birth of 78.32 years of age.

Panama continues to make progress in decreasing its poverty rate. Between 2015 and 2018 the population living in poverty (on less than US$3.20 per day) decreased from 6.7% to 5.1%.

Panama has been one of the most dynamic economies in Latin America and in the Western Hemisphere. Panama experienced economic expansion with average annual growth of 5.66% in the last 25 years. The high growth episode was supported by an investment boom, which included the expansion of the Panama Canal, of good performance, transportation and logistics services sectors, along with others infrastructure development projects, making Panama among the most attractive FDI destinations in the region over the last decade. Panama has a dollarized economy, eliminating FX risks common across its regional peers. In addition, it has a highly developed services sector, growing at an average of 4.4% in the last 5 years and accounting for 65% of national GDP. However, growth slowed in 2019 amid declining productivity and weaknesses in construction and commerce.



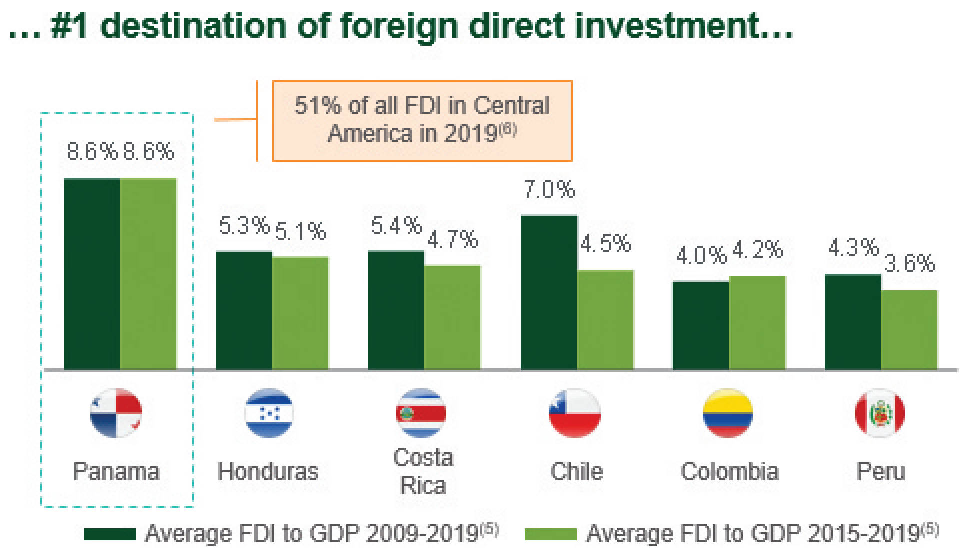
Source: World Bank

Metric	Units	2016	2017	2018	2019	2020	2021
Gross domestic product, constant prices	Percent change	5.0	5.6	3.7	3.0	(2.1)	4.0
Gross domestic product, current prices	Purchasing power parity; international dollars (Billions)	93.5	100.6	106.9	112.0	110.4	117.1
Gross domestic product per capita, constant prices . .	Purchasing power parity; percent change	3.4	4.0	2.2	1.5	(3.4)	2.0
Inflation, average consumer prices	Percent change	0.7	0.9	0.8	(0.4)	(0.9)	0.5
Inflation, end of period consumer prices	Percent change	1.5	0.5	0.2	(0.1)	(1.0)	1.0
Unemployment rate	Percent of total labor force	5.5	6.1	6.0	7.1	8.8	8.4
General government net lending/borrowing	Percent of GDP	(2.0)	(2.2)	(3.2)	(3.1)	(6.2)	(2.5)
Current account balance . .	Percent of GDP	(7.8)	(5.9)	(8.2)	(5.2)	(6.8)	(6.0)

Source: International Monetary Fund, World Economic Outlook Database, April 2020

In addition, strong economic performance has not translated into broadly shared prosperity, as Panama has the second worst income distribution in Latin America. Nevertheless, Panama has made significant progress in reducing poverty in recent years in part due to economic growth and public transfers. Between 2015 and 2018, poverty at US$5.5 fell from 15.4 to 12.6 percent while extreme poverty at US$3.2 declined from 6.7 to 5.2 percent.

Panama has a market-oriented economy characterized by a high level of foreign trade, with 14 free trade agreements, four partial trade agreements, and 21 bilateral investment treaties in force. The country's stable growth over the past decade has contributed to Panama having the highest GDP per capita in Central America. Exports of goods and services account for approximately 42.5% of GDP in 2018. Panama's top exports in 2018 were Refined Petroleum, Coal Tar Oil, Passenger and Cargo Ships, Bananas, and Gold. The World Bank ranked Panama #7 in ease of doing business in Latin America and the Caribbean. Also, the country has a strategic importance as a regional logistics and financial services hub and regional headquarter for over 160 multinational operations.



Source: World Bank.

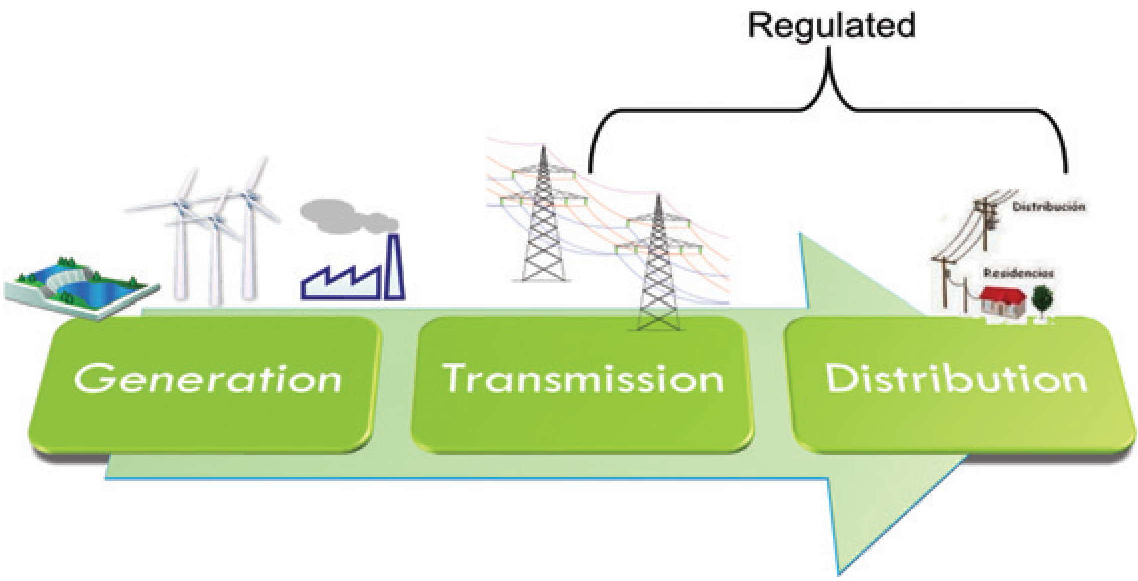
The 2019 estimate of GDP per capita stands at US$11,910, with private consumption accounting for 51.5% of this GDP. This level of consumption is aided by an unemployment rate of 7.07% in 2019, and a slightly negative inflation rate of -0.36% in 2019. Panama has developed an infrastructure network that affords the population great energy accessibility, with 95% of the total population having access to electricity in 2015. The total electricity production for the country stood at 11,141 GWh in 2019 (including energy exports), with 10,726 GWh total consumption in that year.

Moreover, Panama is an investment grade sovereign with continued access to international debt markets, rated Baa1 with negative outlook, BBB with stable outlook and BBB with negative outlook by Moody's, S&P and Fitch, respectively.

Electricity market

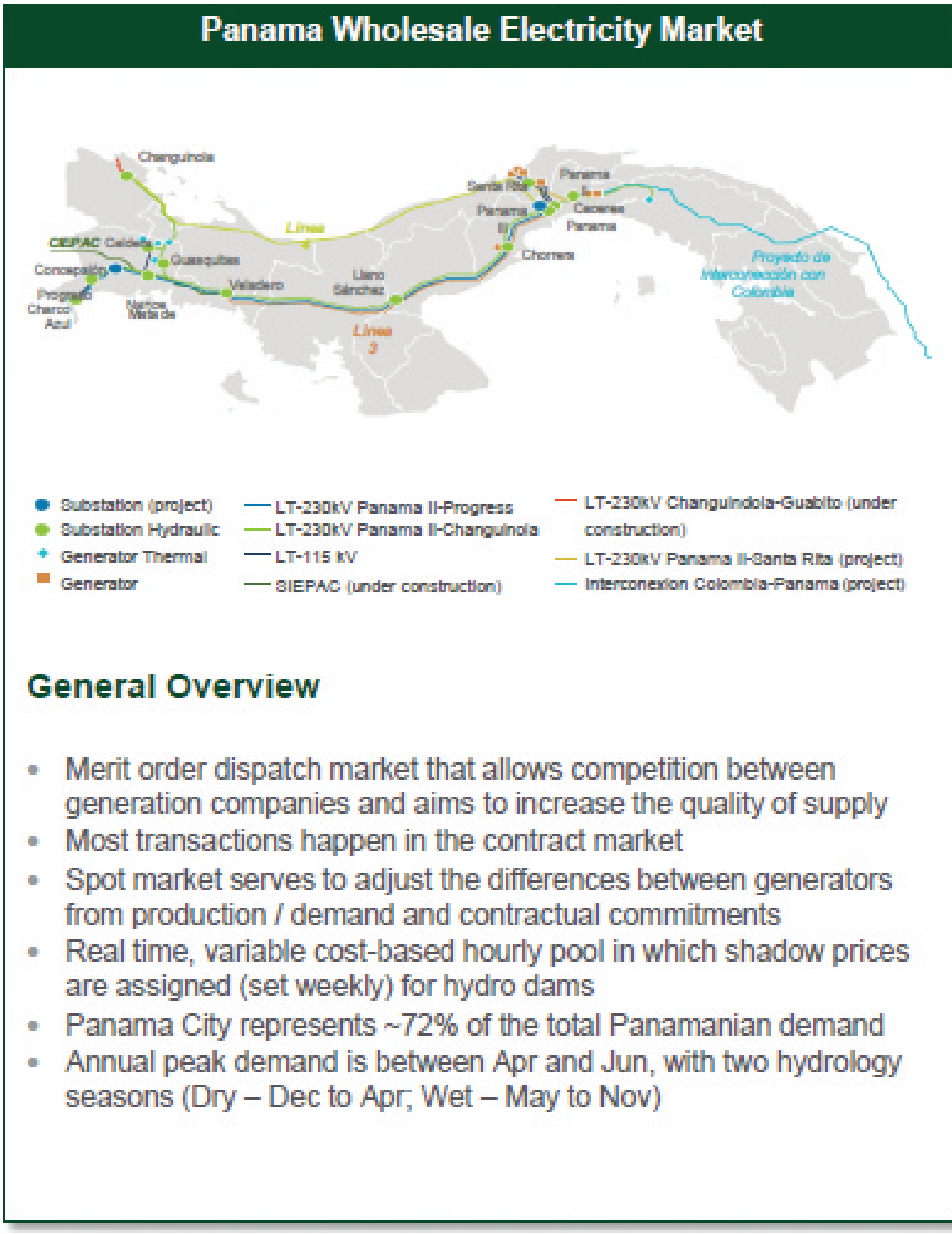
In 1997, the Government of Panama started a reform process of the power sector with the privatization of its vertically integrated electricity utility (IRHE). The privatization of IRHE was part of a broader reform program that involved establishing a new regulatory framework, introducing a wholesale electricity market, adopting a new tariff regulation, and separating IRHE activities in three different sectors: Generation, Transmission and Distribution. The generation part of IRHE was restructured in four companies (Bayano, 192 MW; Bahia Las Minas, 292 MW; Fortuna, 300 MW; and Chiriqui, 222 MW); the distribution part in three companies (EDEMET, ENSA, EDECHI) geographically divided; and one transmission company that would remain in state hands (ETESA).

Law No. 6 of February 3, 1997 set the broad parameters underlying the privatization process and the new regulatory guidelines. The new wholesale electricity market in Panama began its operations as such in 1999. Generation, transmission, and distribution activities were unbundled, and the generation segment was structured as a competitive market while transmission (state owned) and distribution (state-privately owned) activities were considered public services and thus regulated.

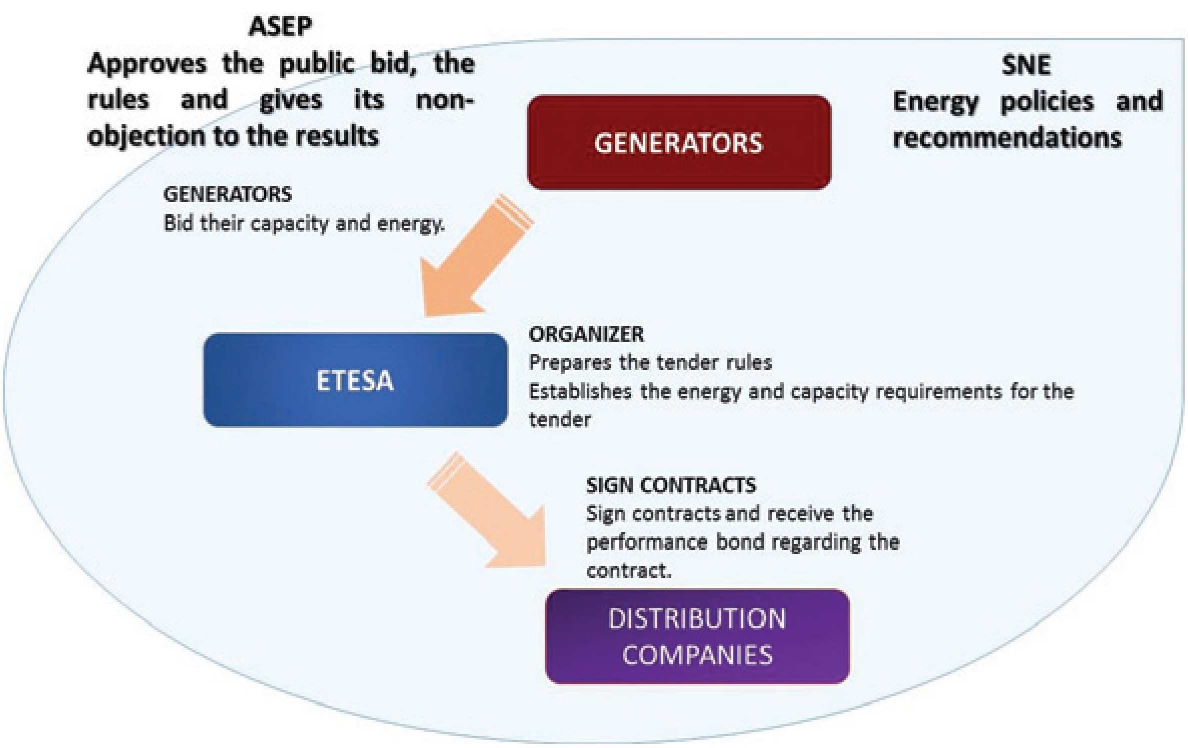


The wholesale electricity market in Panama is divided in the contract (PPA) market and the spot market. During 2019, the PPAs accounted for 91% of the energy supply, while the spot market accounted for 9%.

Distribution Companies must contract (through PPAs) in advance 100% of their two-year expected peak demand (and regulatory reserve) and energy needs to guarantee the supply of their Regulated Consumers. This percentage of obligation is reduced for following years in accordance with the Purchase Rules. Prices under PPAs with the Distribution Companies are passed through to end user tariffs and Distribution companies can self-generate up to 15% of their demand. The PPAs by which the Distribution companies contract their energy and peak demand are awarded in public tenders organized by ETESA where the generation companies bid their capacity and energy to supply the energy and peak demand of the Distribution Companies. In the public tenders, generators can be awarded firm capacity PPAs, capacity and energy PPAs or energy PPAs, although generators cannot enter into firm capacity PPAs for more than their firm capacity, they can have a combination of firm capacity PPAs up to their firm capacity, and only energy PPAs for the period of the year when production is higher, so as to cover energy surpluses.

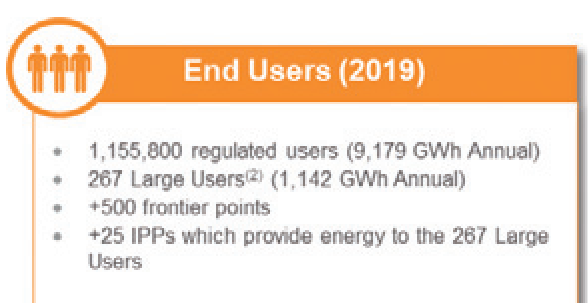


ETESA, the transmission company, acts as a single buyer and coordinates the public tenders on behalf of the Distribution Companies, following the criteria established by ASEP for such tenders. The PPA prices that result from public tenders are fully passed through to end user tariffs.



Two products are traded in the spot market: energy (hourly) and capacity (daily and yearly through the long-term reserve service). The energy spot market is conceived for generators to buy the energy not produced by their units to fulfill their PPA requirements, for Distribution Companies to purchase the energy needed and not contracted through PPAs, for generators without PPAs to sell their energy and for generators with PPAs to sell their energy surplus. A generator receives the hourly spot price (short run marginal cost of the system) for energy produced during such hour. If it is not dispatched, it does not receive energy payments. In addition, if a generator participates in the long-term reserve service (where the product traded is capacity), it receives a capacity payment whether it is being dispatched or not. The long-term reserve service is like a one-year firm capacity PPA awarded through a public auction. The system operator aggregates all demands not yet contracted for the year ahead (for the Distribution Companies and Large Customers) and carries out a public auction for the generators to offer their firm capacity (not yet committed in PPAs). There is a cap price for the capacity offered which is the regulated capacity price, currently at US$8.96 per kW a month.

The following chart shows relevant statistics about end users:



Source: ASEP, CND (2019).

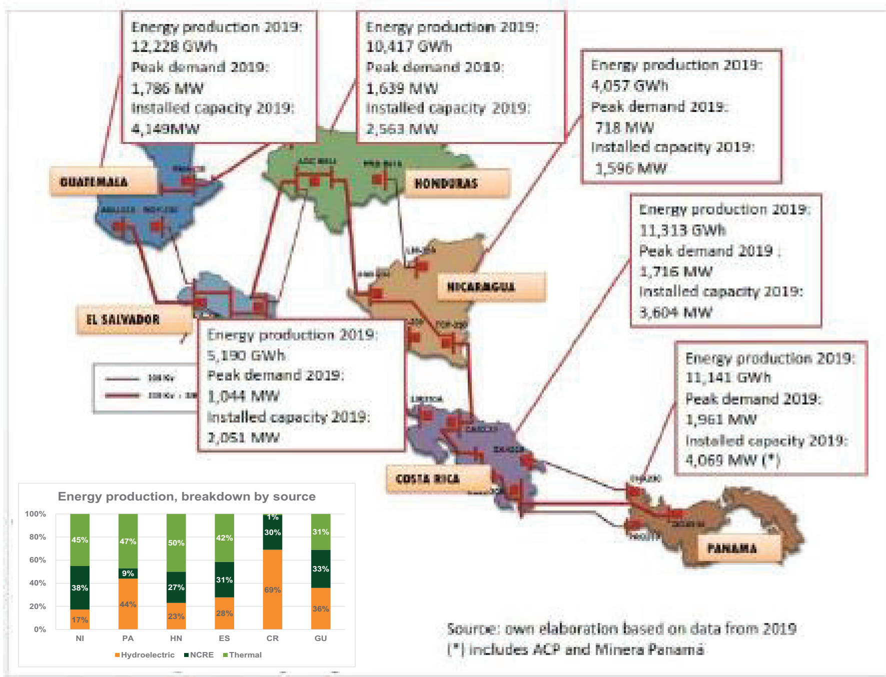
Large Customers can either purchase their energy needs in the wholesale market (through PPAs and/or on a spot basis) or they can be supplied by the Distribution Companies at a Regulated Tariff. Large Customers are divided in active or passive, active Large Customers are those that can purchase energy in PPAs or the spot market and represent themselves in the wholesale electricity market while passive Large Customers are those that purchase all their energy in PPAs to secure their supply and are represented in the wholesale electricity market by the generator with whom they have the energy PPA.

Panama also participates in the MER with a trend towards energy exports. The country members of MER are the six interconnected countries of the isthmus (Panama, Costa Rica, Nicaragua, Honduras, El Salvador, and Guatemala). A generator located in Panama can sell its energy production to any other country member of the MER through the regional transmission lines that have a transmission capacity of 300 MW.

Regional Electricity Market

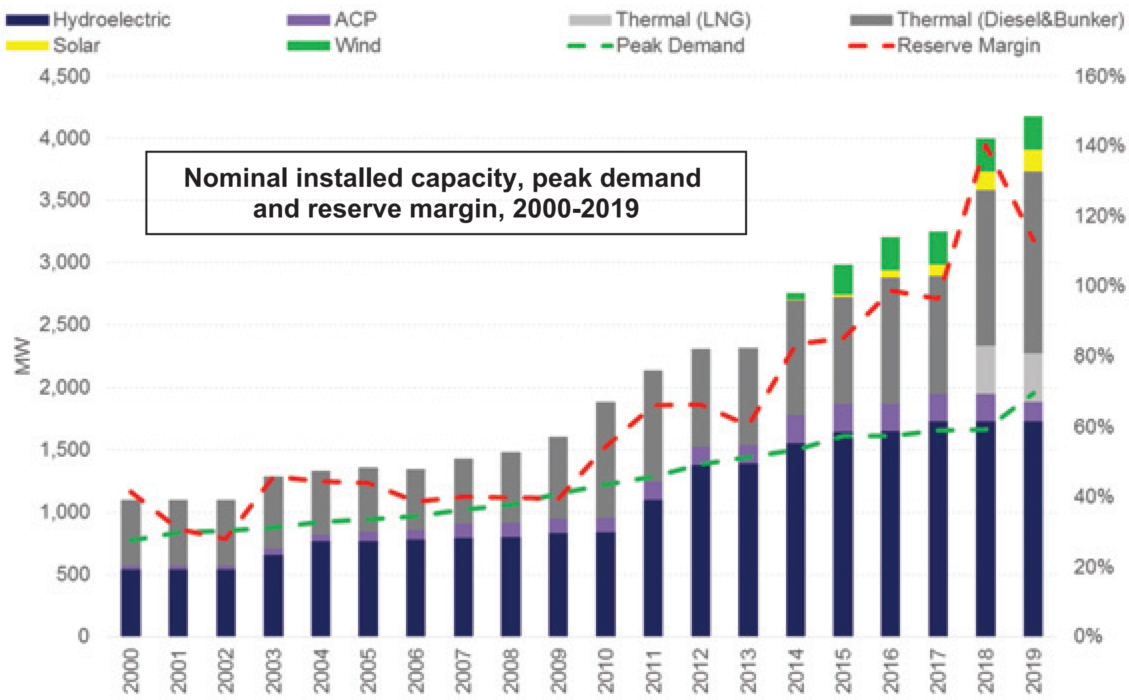
General Overview

- Regional electricity market is governed by the Regional Electricity Interconnection Commission ("CRIE") and the Regional Operating Entity ("EOR") to ensure legal compliance with global standards
- Panama is interconnected to the regional market through SIEPAC (Central American Electrical Interconnection System)
- Completion of the SIEPAC first circuit line has strengthened some weak interconnection lines from 60 MW to 300 MW and is expected to increase further when the second circuit is enabled
- SIEPAC currently has 7,069 MW in generation and 7,293 MW in demand
- Panama is the leading country with 1,686MW (24%) in generation and 1,651 MW (23%) in demand



Installed Capacity and Supply

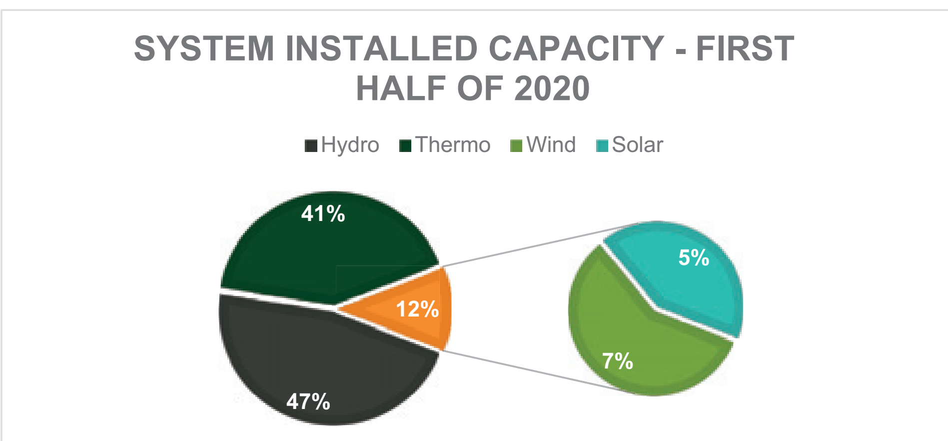
Historically, Panama had a system composed primarily of Hydro and Thermal generating assets, with a significant proportion of hydro resources that have continued to increase their share of production during the 2010s. The majority of the hydro capacity is derived from run-of-river plants, but also includes two major reservoir plants, Fortuna (300 MW) and Bayano (260 MW) that complement the dispatch during the dry season, when the system depends on the thermal generation. Thermal generation counts with low and mid velocity engines, steam turbines and combines cycles distributed in coal fired plants, Heavy Fuel Oil (bunker), diesel and LNG plants (this last, since 2018). The system includes participation of the Panama Canal Authority (ACP, for its acronym in Spanish), which is considered as a self-generator, having an installed capacity of 223 MW (of which 27% is Hydro and 73% thermo), adding capacity to the system, offering the surplus of the energy from their generation units used for their operations. Since 2012 the Non-Conventional Renewable Energy has been increasing the participation in the generation matrix, introducing solar and wind capacity.



Source: Independent Energy Market Report, Mercados Energéticos (November 2020)

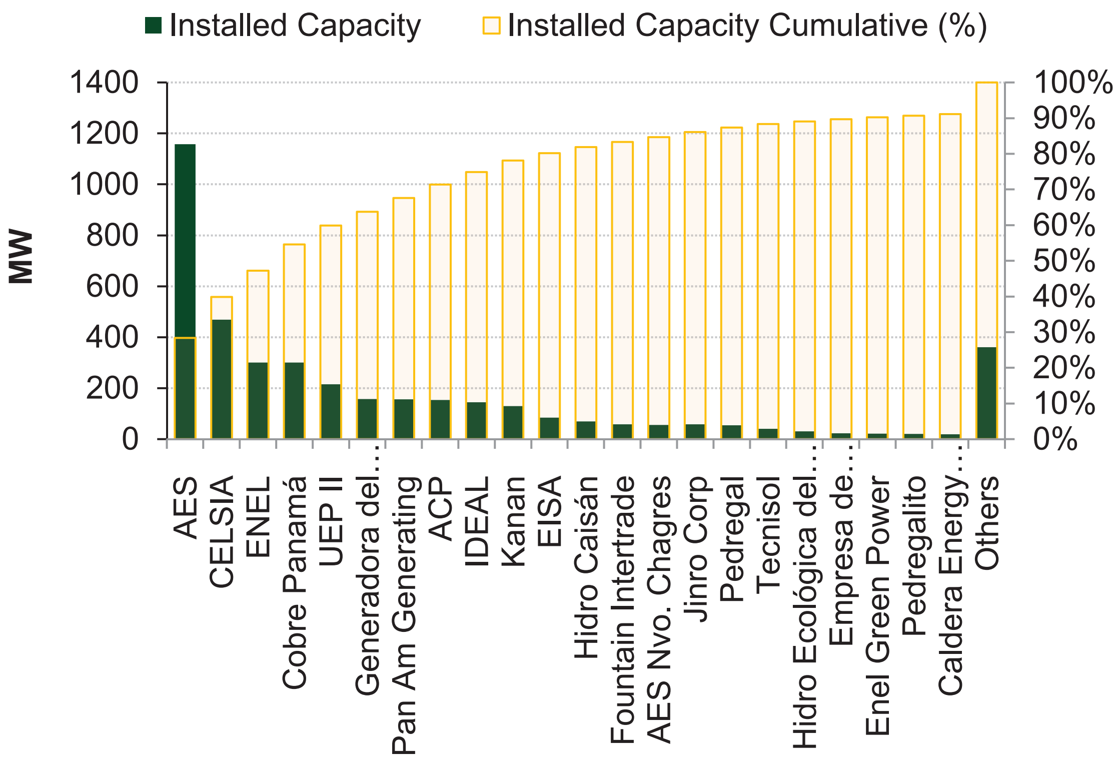
According to ASEP's report of the Generation Offer for the first half of 2020, the total installed capacity in Panama was 3,854 MW, of which 3,605 MW (94%) corresponds with power plants that supply the electricity public service, 213 MW (6%) to self-generators and 36 MW (less than 1%) to isolated systems, which are portions not connected to the main system, such as Darien and Guna Yala Province.

Out of this installed capacity, 1,791 MW (47%) are hydroelectric plants, 1,598 MW (41%) are thermoelectric (including coal, bunker, diesel and LNG plants), 270 MW (7%) from wind and 195 MW (5%) from solar.



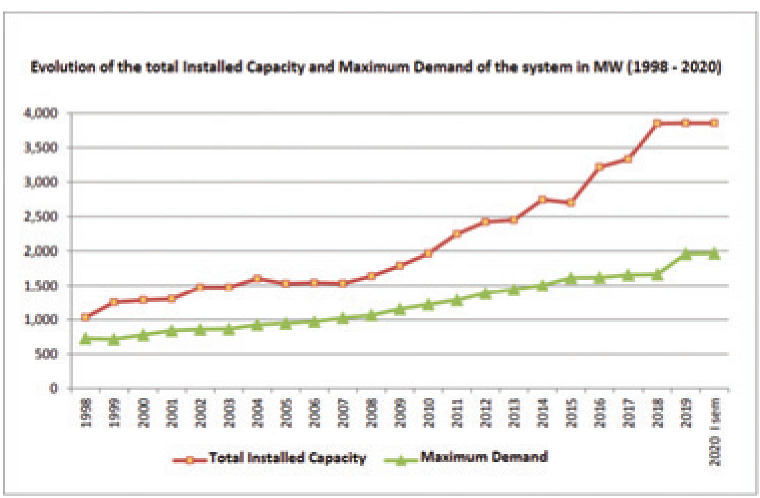
Source: Statistic from ASEP, Offer Report for the First Half of 2020.

60% of the Installed Capacity of the country is concentrated within the main five players in the generation sector: AES Panama, Celsia, Enel, Quantum Minerals (Minera Panamá, S.A.) and InterEnergy (UEP II), as follows:



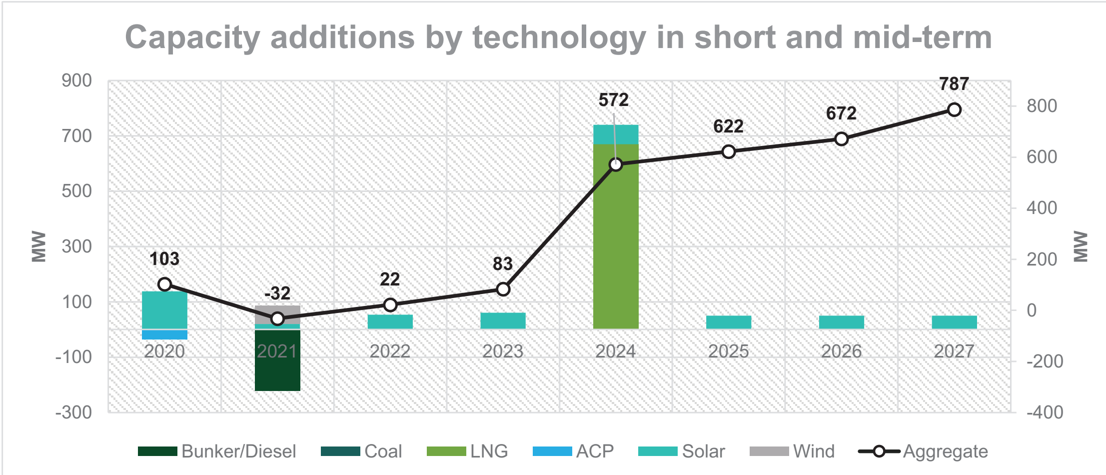
Source: Independent Energy Market Report, Mercados Energéticos (November 2020)

The following chart shows the evolution of the total installed capacity of the system against the historical maximum demand registered, since 1998 until the first semester of 2020:



Source: Statistic from ASEP, Offer Report for the First Half of 2020.

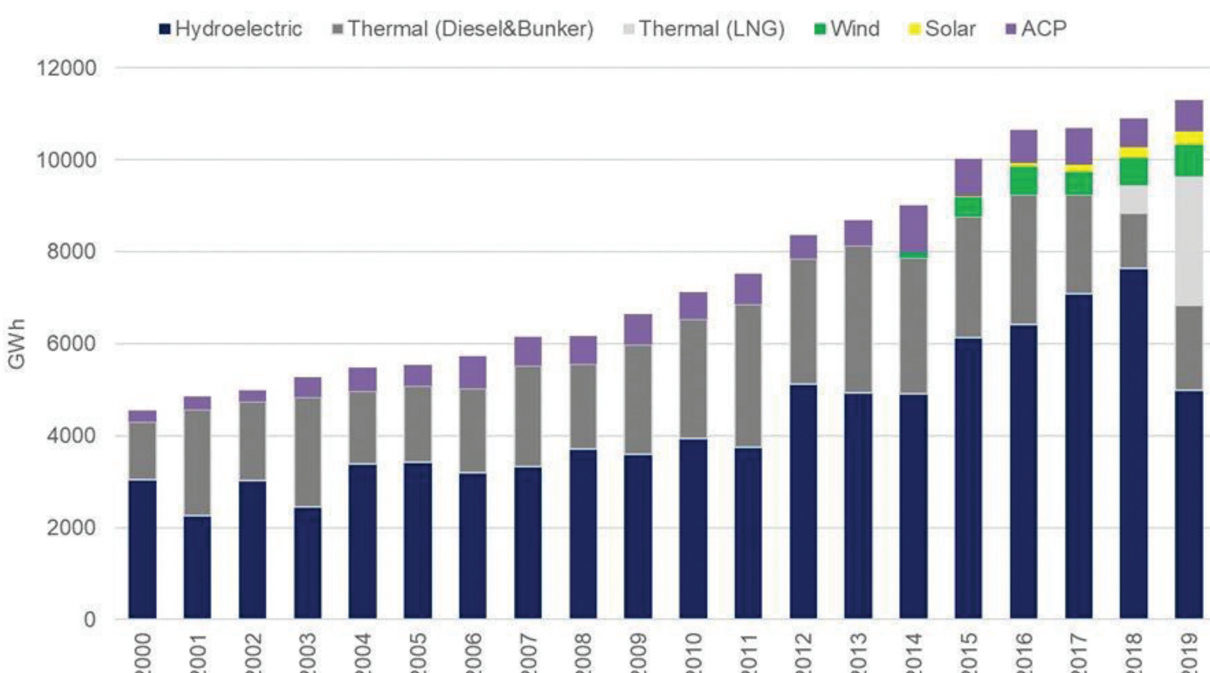
The projections of the capacity additions for the Panamanian system, shows LNG power plants in the mid-term (considering already the infrastructure required by such projects) with 670 MW, complemented with renewables additions from solar (493 MW) and wind (66 MW). Minor additions in hydroelectric power plants (66 MW) mainly caused by the socio-environmental complications that these projects entail, taking into account the opposition that has developed among nearby communities (aboriginal peoples) to the projects, which has been identified in recent years. For the 2020-2027 period the addition of 787 MW of energy is forecasted, considering the retirement of 257 MW Bunker/Diesel power plants. The following chart shows the additional capacity in generation offered by technology:



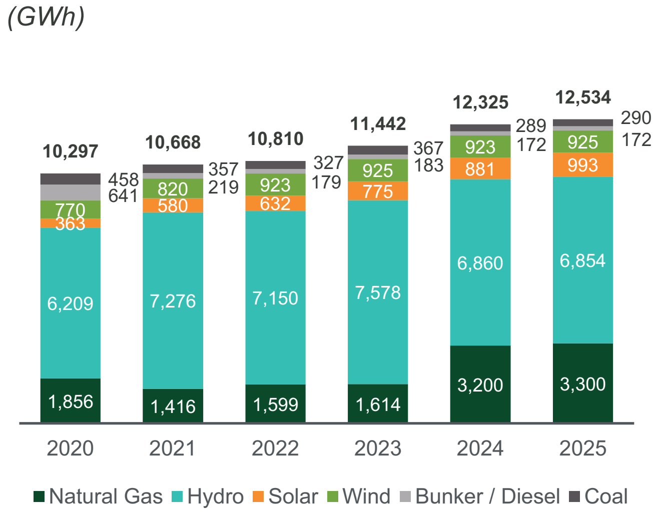
Source: Independent Energy Market Report, Mercados Energéticos (November 2020)

Generation

The Panamanian electricity system has a high hydroelectric component and, as a result, the composition of the participation of different generation technologies in the annual energy matrix depends to a great extent on weather phenomena such as El Niño and La Niña. During periods where the *El Niño* phenomenon occurs, droughts happen and with them a reduction in hydroelectric generation, an increase in average wind speeds (greater wind generation), as well as an increase in incident radiation for solar plants. During periods where the *La Niña* phenomenon occurs, Panama experiences higher rainfall and, consequently, an increase in total hydroelectric generation, thereby decreasing the production of wind and solar generation. As a result of these cyclical phenomenon, depending on the hydrology conditions, the participation of hydro technology in the annual energy matrix can range from as high as 70% to as low as 45%. The following chart presents the energy supply by technology during the period from 2000 to 2025:



Source: Independent Energy Market Report, Mercados Energéticos (November 2020)



Type	'20 – '25 CAGR
Coal	(8.7%)
Bunker / Diesel	(23.1%)
Wind	3.7%
Solar	22.3%
Hydro	2.0%
Natural Gas	12.2%

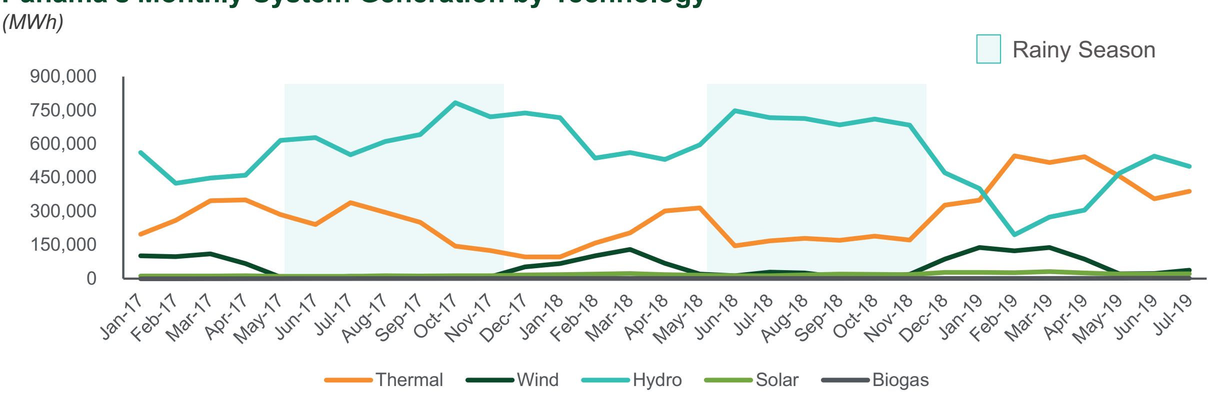
Source: Independent Energy Market Report, Mercados Energéticos (November 2020)

The energy supply responds to the system operator, the CND, who based on a reliable economic criteria, plans the dispatch of the system on a weekly basis. For that purposes, the CND considers the variable cost of each unit in the system and commands the entrance from lower to higher cost, until the demand is met, known as merit order.

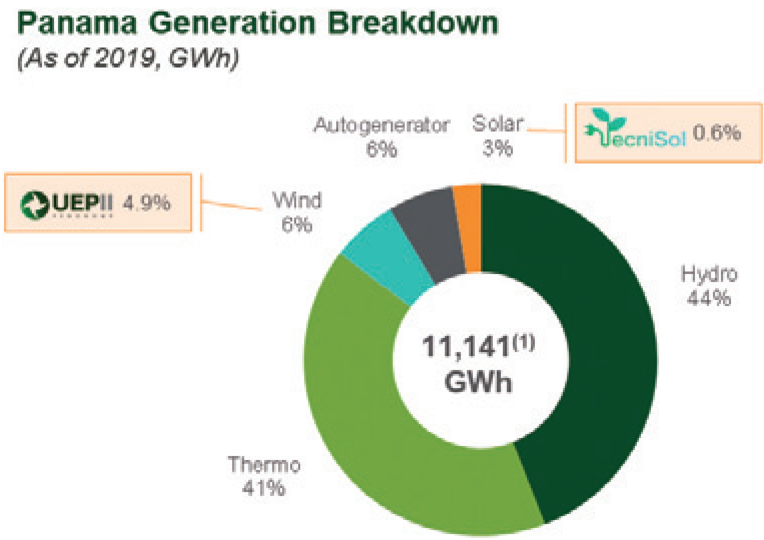
The total gross generation for 2019 in Panama was 11,141 GWh. This includes the consumption of the Distribution Companies (82%), supply for Large Costumers (10%), generation companies' consumption (1%), exports to Central America (4%) and energy losses (2%). Electricity generation by plant type was 4,902 GWh by hydroelectric plants, 4,568 GWh by thermal plants, 668 GWh by wind power plants, 668 GWh by autogenerators, and 334 GWh by solar or photovoltaic plants.

The charts below show monthly GWh generation by source in Panama from 2017 to 2019 and the percentage of generation by source in 2019:

Panama's Monthly System Generation by Technology



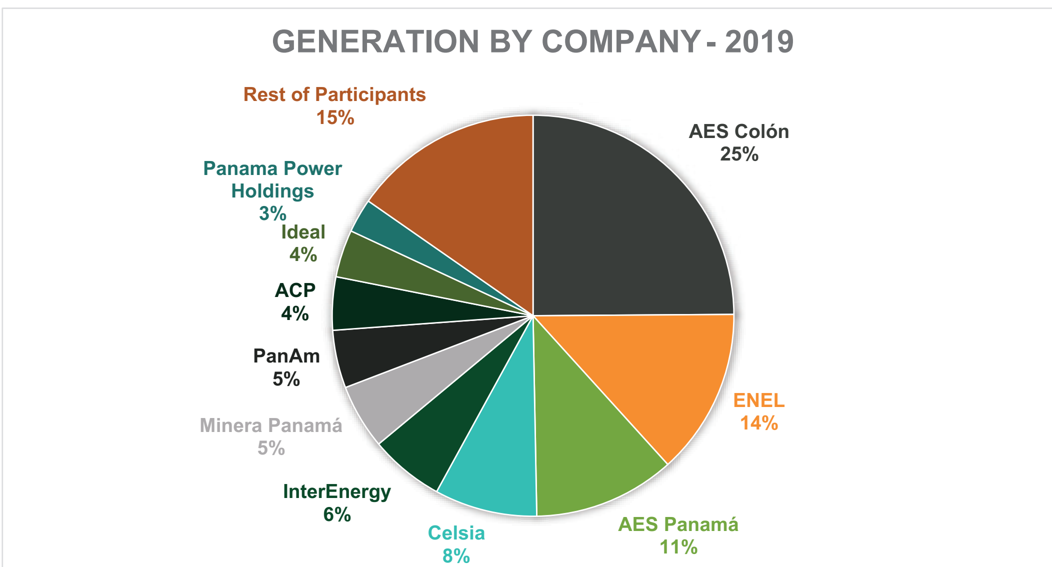
Source: CND Monthly Generation Report



Source: Independent Energy Market Report, Mercados Energéticos (November 2020)

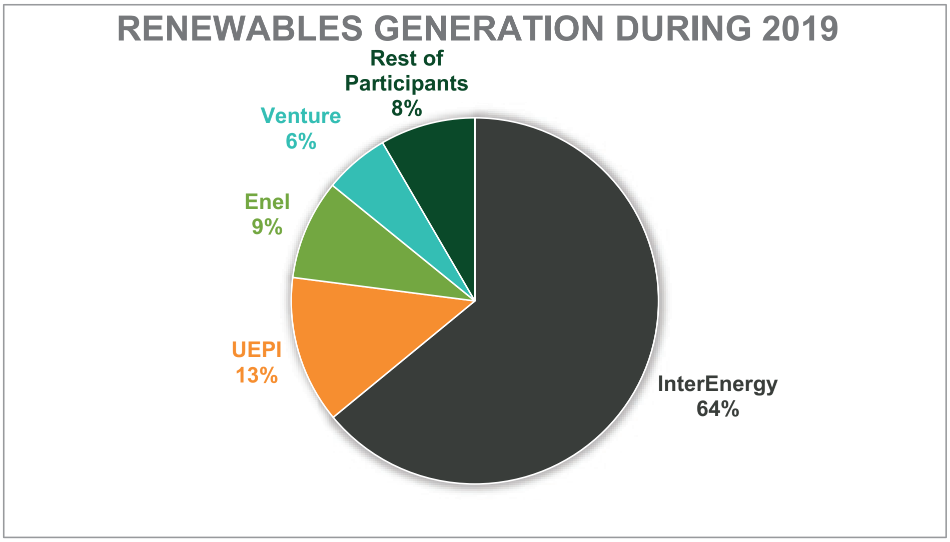
The largest generation companies by share of total power generation during 2019 (excluding imports from Central America) are AES Colon with 24.89%, ENEL with 13.41%, AES Panama with 11.40%, Celsia with 8.26% and InterEnergy with 5.98%, Collectively, these top five market players produce 63.95% of the annual generation.

The chart below shows generation in Panama by company in 2019:



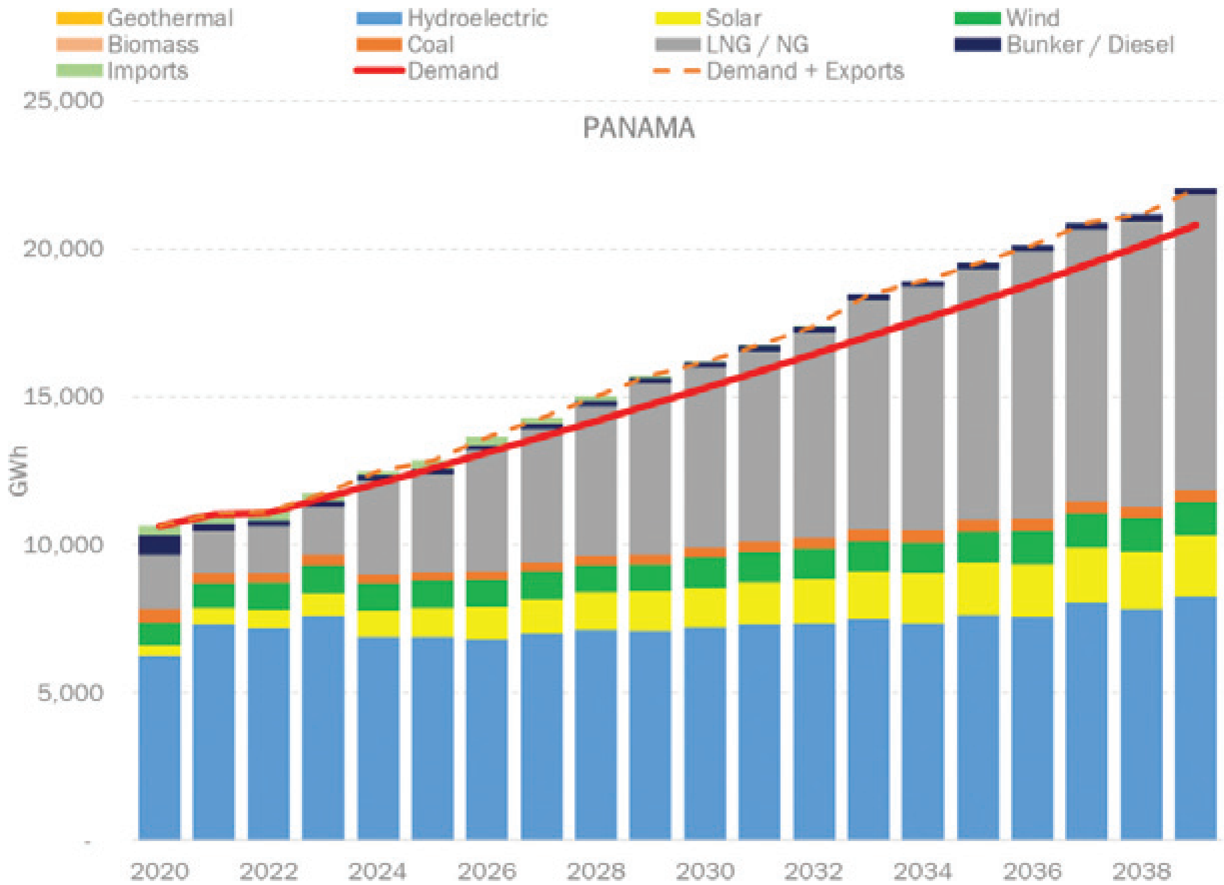
Source: CND, Generation Report for 2019.

The chart below provides generation companies' share of renewable energy generated in Panama in 2019. In total, 973 GWh of renewable energy was generated in 2019, of which InterEnergy generated 632 GWh, or 64%, of such renewable energy, while UEP I (AES) wind farm generated 127 GWh (13%), Enel 86 GWh (8.8%), Venture Group 56 GWh (5.7%) and the rest of the participants 82 GWh (8.4%).



Source: CND, Generation Report for 2019.

The chart below provides electricity generation projections until the year 2039, projected by Mercados Energéticos using official sources of information such as ETESA, the CND, and ASEP. For forecasting purposes, Mercados Energéticos used the SDDP software, which is highly used in the Central American markets for planning and energetic analysis. There is no assurance that such projections will in fact materialize, and actual outcomes may be materially different.



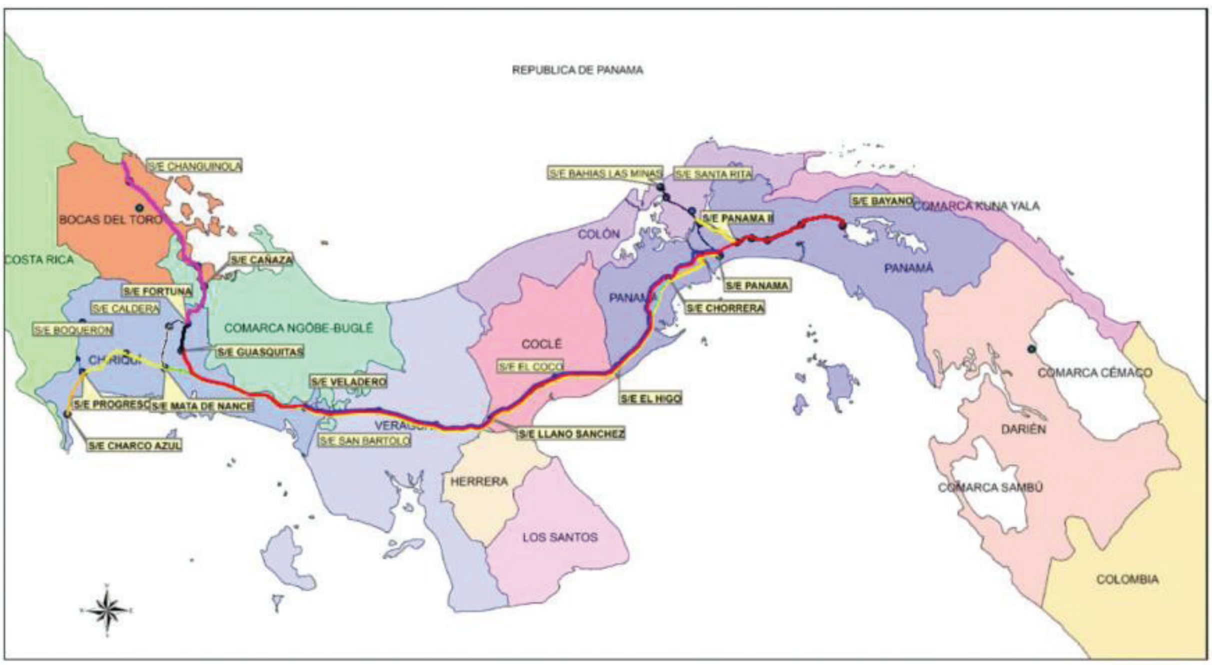
Source: Independent Energy Market Report, Estudios Energéticos Consultores (November 2020)

Transmission

In accordance with Article 66 of the Electricity Law, the electric power transmission network in the SIN is made up of high-voltage transmission lines, substations, transformers and other electrical elements necessary for transporting energy from the point of delivery of said energy by the generator to the point of reception by the Distribution Company or Large Customer. The electric power transmission network also includes international interconnections.

ETESA oversees the operation, maintenance, planning, and expansion of the SIN in accordance with the provisions established in the Transmission Rules. The transmission system voltage is from 230 kV (maximum operating voltage), up to 34.5 kV level.

According to the 2019 ETESA transmission expansion plan, the transmission system has a total length of 2,712.95 Km in double circuit 230 kV transmission lines, and 94.58 km in 230 kV single lines. For the 115 KV lines, the total length of double circuit lines and single circuit lines is 267.80 km and 39.90 km, respectively. The following chart shows the Panamanian transmission system:



Source: ETESA's 2019 Transmission Expansion Plan

ETESA has seventeen (17) substations; two (2) of them at 115 kV level, Cáceres and Santa Rita (the whole northern transmission system is in 115 kV), and four (4) sectioning substation (does not have transformation) at 230 kV level, Guasquitas, Veladero, Cañazas and El Higo. The remaining eleven (11) substations are reducers (change the voltage from 230 kV to lower levels) Panamá II, Panamá, Chorrera, Llano Sánchez, Mata de Nance, San Bartolo, Boquerón III, Progreso, Caldera, Charco Azul and Changuinola. The two principals' substations are Panama and Panama II which serve the main load center, Panama City, where, according to ETESA, is concentrated approximately 70% of the demand of the country.

Regarding the transformation capacity, the system has 2,641 MVA in 230 kV, 2,511 MVA in 115 kV, 922 MVA in 34.5 kV and 300 MVA in 13.8 kV, as shown in the table below:

TRANSFORMADORES DE ETESA

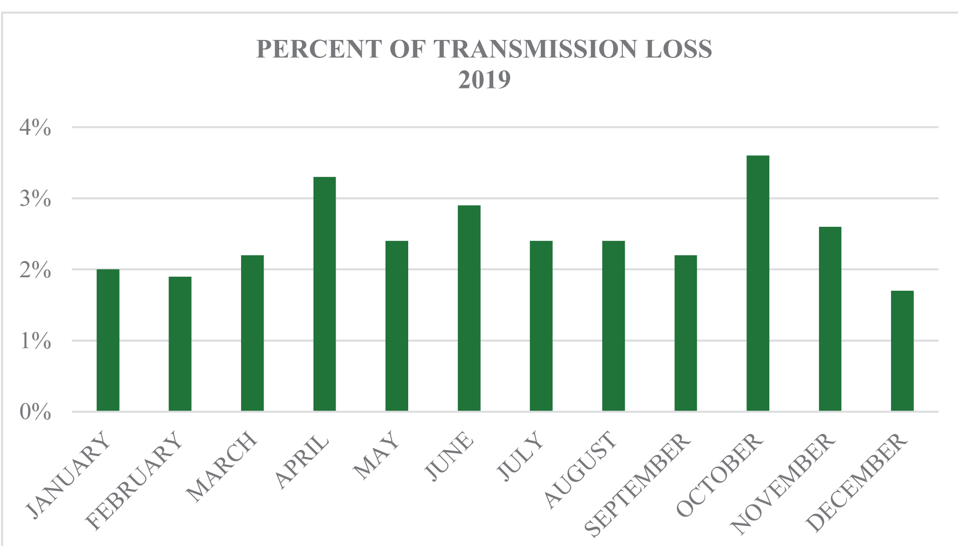
No. de S/E	SUBESTACION	No.	CAPACIDAD (MVA)					CAPACIDAD	REDUCTOR	VOLTAJES (KV)			CONEXION	ENTRADA EN OPERACIÓN
			230KV	115KV	34.5KV	13.8KV	4.16KV			ALTA	BAJA	TERCI.		
1	PANAMA 2	1	175	175		30		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	1999
	PANAMA 2	2	175	175		30		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	1999
	PANAMA 2	3	175	175		30		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	2019
2	PANAMA	1	175	175		30		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	1993
	PANAMA	2	175	175		30		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	1974
	PANAMA	3	350	350		75		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	1981
	PANAMA	4	350	350		75		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	2018
3	CHORRERA	1	50	50	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	1995
	CHORRERA	2	50	50	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	1975
	CHORRERA	3	100	100	100			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2013
4	LLANO SANCHEZ	1	70	60	30			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	1975
	LLANO SANCHEZ	2	70	60	30			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	1995
	LLANO SANCHEZ	3	100	100	33			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2012
5	MATA DE NANCE	1	70	60	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	1975
	MATA DE NANCE	2	70	60	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2012
	MATA DE NANCE	3	70	60	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2003
6	PROGRESO	1	50	50	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2003
	PROGRESO	2	50	50	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	1975
7	CHARCO AZUL	1		24			24	OA/FA	REDUCTOR	115	4.16		DEL/EST	1988
8	CHANGUINOLA	1	50	50	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2009
9	CALDERA	1		62.5	62.5			OA/FA/FOA	REDUCTOR	115	34.5		EST/DEL	2010
10	BOQUERON III	1	83.3		83.3			OA/FA/FOA	REDUCTOR	230	34.5		EST/DEL	2010
	BOQUERON III	2	83.3		83.3			OA/FA/FOA	REDUCTOR	230	34.5		EST/DEL	2016
11	SAN BARTOLO	1	100	100	100			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2015
	TOTAL		2,641.6	2,511.5	922.1	300.0	24.0							

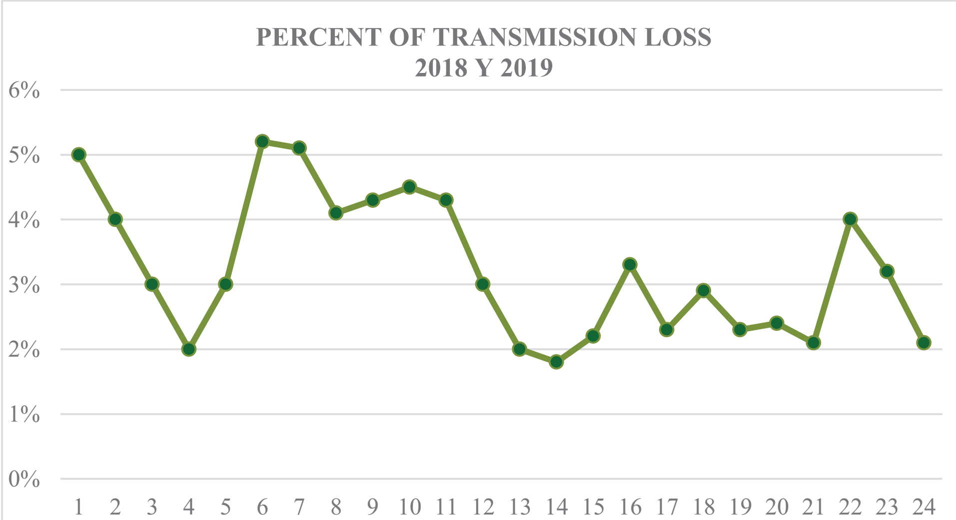
Source: ETESA's 2019 Transmission Expansion Plan

Currently, the system is interconnected with the Regional Electricity System (SER, by its acronym in Spanish) through three (3) transmission lines, two of them are the result of bilateral agreements among the governments of Costa Rica and Panama, the last one is part of the SIEPAC project (Sistema de Interconexión Eléctrica de los Países de América Central), which consist in a 1,800 km of double circuit transmission line from Guatemala to Panama, across the Central Americas Isthmus, with a capacity of 300 MW.

Source: Independent Energy Market Report, Estudios Energéticos Consultores (November 2020), page 61.

The transmission system experiences a certain level of losses in part due to the distances involved between generation producers and consumers. In 2019, these varied from a minimum of 1.66% in December to a maximum of 3.58% in October. This is mostly due to the higher production in October of electricity generated by hydroelectric plants due to the rainy season and the plants being located in the western part of the country, far away from the primary consumption center of Panama City and surrounding areas.





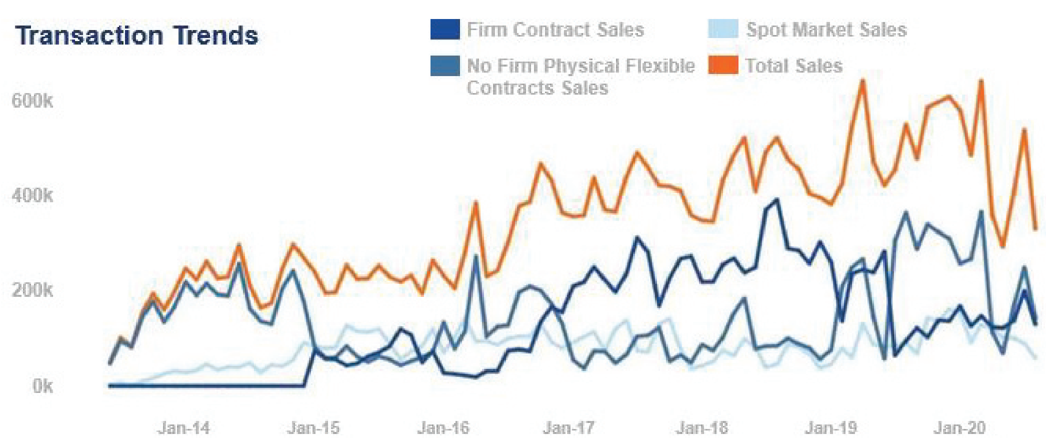
Source: Second Semester, Transmission Report from ASEP.

For the last several years, variation in the annual average of transmission losses has been small, with recorded average losses of 3.50%, 3.82% and 2.46% in 2017, 2018 and 2019, respectively. The greatest losses of the transmission system occur during the months of greatest hydroelectric generation, mainly from the Fortuna, La Estrella, Los Valles Estí, Changuinola, Ideal Panamá, Hydro Caisán and other hydroelectric plants located in the western part of the country.

Energy Exchanges

Since the SIN is interconnected to the Regional Electricity System (SER, for its acronym in Spanish) there are energy exchanges among the Central American countries and Panama. The Regional Electricity Market (MER) is composed by two markets: The contract market (MCR) and the opportunity (Spot) market (MOR).

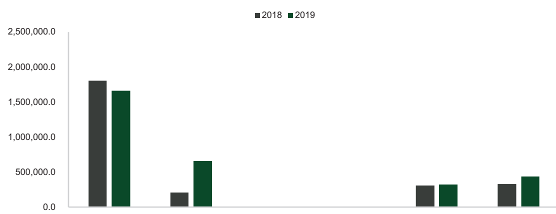
The contract market can be accessed by having a firm right to use the transmission capacity of the transmission lines (maximum for a year period) which are obtained in a bidding process held by the EOR (regional operator). It can also be accessed through flexible contracts, in which case a firm right is not needed, but the transactions will depend on the remaining capacity on the transmission's lines, after filling the transactions with firm rights. Finally, the regional spot market is an offer (bidding) market in which the generators can sell their surplus, subject to the transmission capacity and the differential in markets prices (used to pay the transmission). The chart below shows the evolution of the regional transactions in terms of sales (in USD), in which the increase of the volume of the transactions over the time can be observed:



Source: Comisión Regional de Interconexión Eléctrica (CRIE).

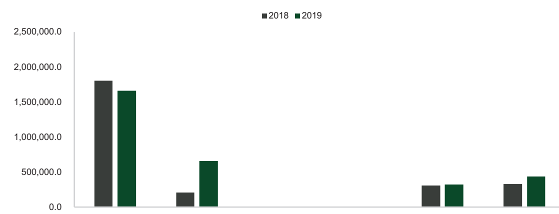
During 2019, Panama reported 96.33 GWh of energy imports from the regional system, this is more than six time the recorded for 2018 (14.662 GWh). This was due the effect in Panama's spot prices driven by the *El Niño* phenomenon, causing an increase, which naturally derived in transactions from Central America to Panama. In terms of exports, during 2019 Panama recorded 431.51 GWh which is 32% higher than 208 (327.20 GWh).

Energy Export to MER



	Guatemala	El Salvador	Honduras	Nicaragua	Costa Rica	Panama
2018	1,798,865.8	209,055.1	8,439.2	227.8	307,484.4	327,201.9
2019	1,657,126.3	656,705.3	5,864.5	150.8	322,563.1	431,511.5

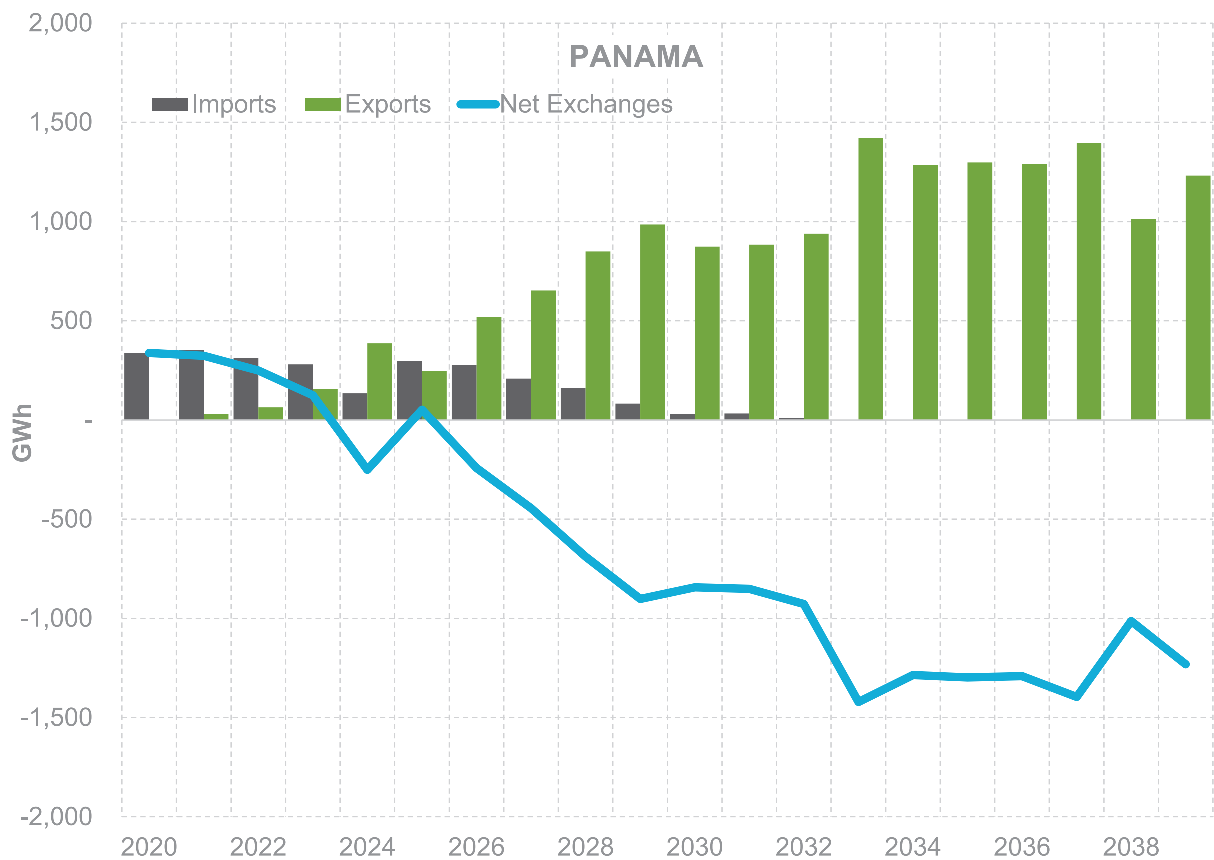
Energy Import to MER



	Guatemala	El Salvador	Honduras	Nicaragua	Costa Rica	Panama
2018	9,683.3	1,968,319.6	381,340.5	201,101.9	65,700.3	14,662.3
2019	9,483.4	1,948,755.0	259,526.9	434,416.7	339,816.4	96,330.8

Source: Transactions Report from December 31st, 2019 — EOR.

According to the Independent Energy Market Report in the mid and long-term, Panama is emerging as a merely exporting country, demonstrating high efficiency in terms of management costs compared to the rest of the Central American countries, having a competitive advantage in this regard.



Source: Independent Energy Market Report, Mercados Energéticos (November 2020)

Distribution and Demand

In Panama there are three companies that hold the concession to be the sole distributors in the electricity sector: ENSA, EDEMET EDECHI.

EDEMET has a concession area comprised of provinces of Veraguas, Coclé, Herrera, Los Santos, the province of Panama west of the Panama Canal, and the western part of the Panama City, including the Metropolitan Natural Park, the Camino de Cruces National Park, the Soberania National Park, and the Cabuya River Agroforestry Farm. EDEMET is 49% owned by the government of Panama and 51% owned by Naturgy Energy Group (rated Baa2 with a stable outlook, BBB with a stable outlook, and BBB with a stable outlook by Moody's, S&P and Fitch, respectively).

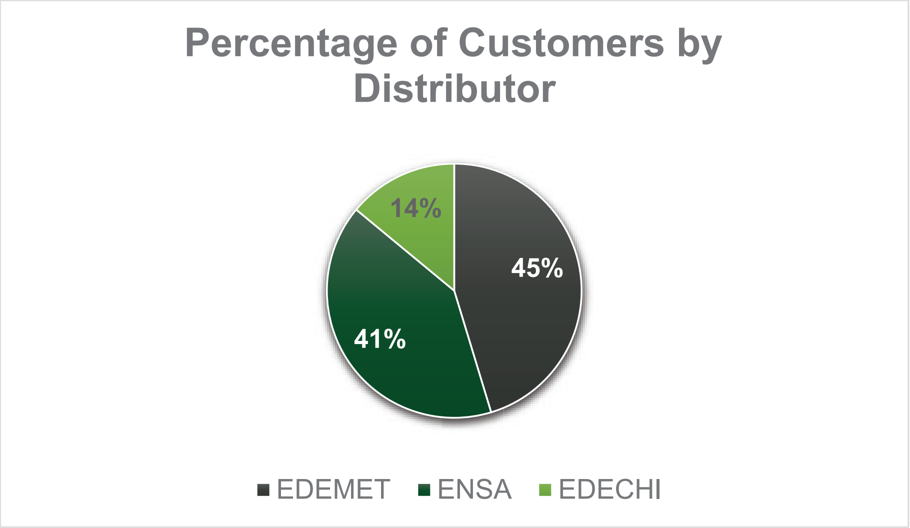
ENSA has a concession area comprised of provinces of Darien, Colon, the part of the province of Panama east of the Panama Canal (except the parts covered by the concession of EDEMET), the San Blas District and the Gulf of Panama Islands. ENSA is 48.25% owned by the government of Panama, 51% owned by Empresas Públicas de Medellin (EPM) (rated Baa3 with a negative outlook and BBB with a negative outlook by Moody's and Fitch, respectively) and 0.7% owned by ENSA's employees.

EDECHI has a concession area comprised of the provinces of Chiriqui and Bocas del Toro. EDECHI is 49% owned by the government of Panama and 51% owned by Naturgy Energy Group (rated Baa2 with a stable outlook, BBB with a stable outlook, and BBB with a stable outlook by Moody's, S&P, and Fitch, respectively).

Distribution Companies service area are shown in the map below.

Source: ETESA.

In 2019, the distribution system serviced 1,155,800 customers. 523,776 customers, or 45% of all customers, were in EDEMET's concession area, 470,429, or 41% of all customers were in ENSA's concession area, and 161,595 customers, or 14% of all customers were in EDECHI's concession area.

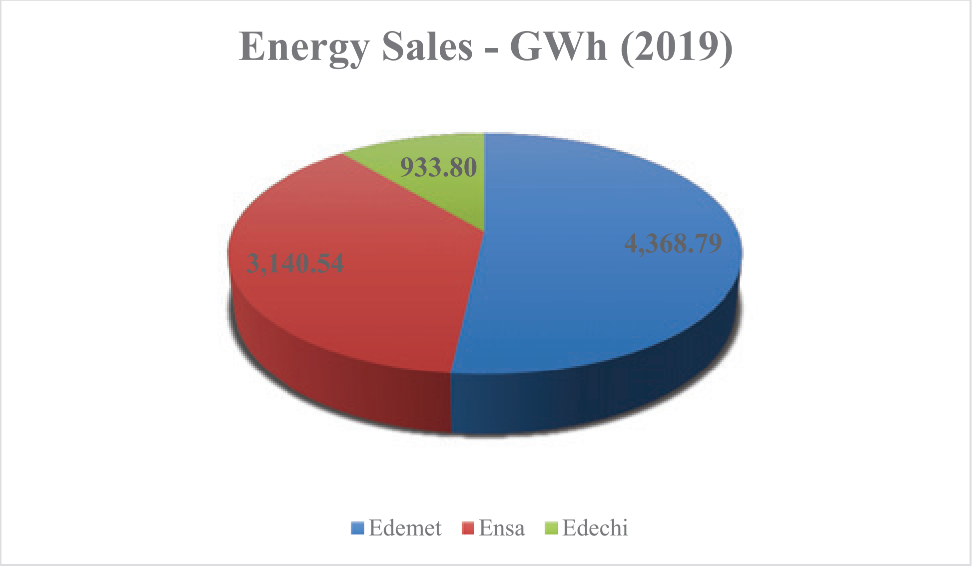


Total Customers (2019)

Customer Type	Edemet	Ensa	Edechi	Total
Residential	458,790	430,576	143,875	1,033,241
Commercial	56409	35853	15089	107351
Government	7234	3798	2046	13078
Industrial	1229	147	533	1909
Others	114	55	52	221
Total	**523,776**	**470,429**	**161,595**	**1,155,800**

Source: ASEP

Distribution companies' sales were 8,443.13 GWh during 2019. Of which 4,368.79 GWh were sales by EDEMET (52%), 3,140.54 GWh were sales by ENSA (37%) and 933.80 GWh were sales by EDECHI (11%).

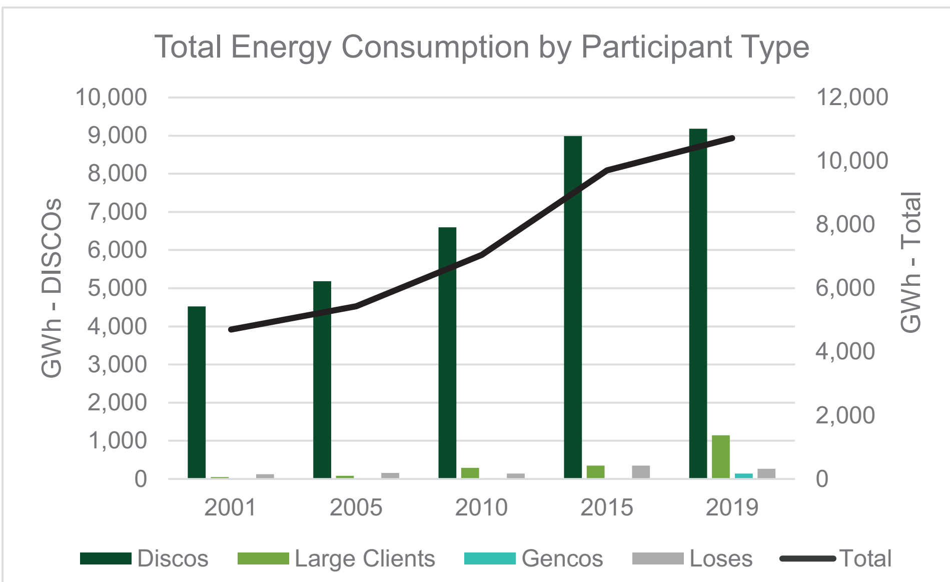


Energy Sales – GWh (2019)

Customer Type	Edemet	Ensa	Edechi	Total
Residential	1,383.43	1,330.83	342.97	3,057.23
Commercial	2,240.53	1,217.24	358.74	3,816.51
Government	506.74	506.10	107.19	1,120.03
Industrial1	18.87	83.74	53.38	255.99
Public lighting	115.07	0.00	70.70	185.77
Others	4.15	2.63	0.82	7.60
Total	**4,368.79**	**3,140.54**	**933.80**	**8,443.13**

Source: ASEP

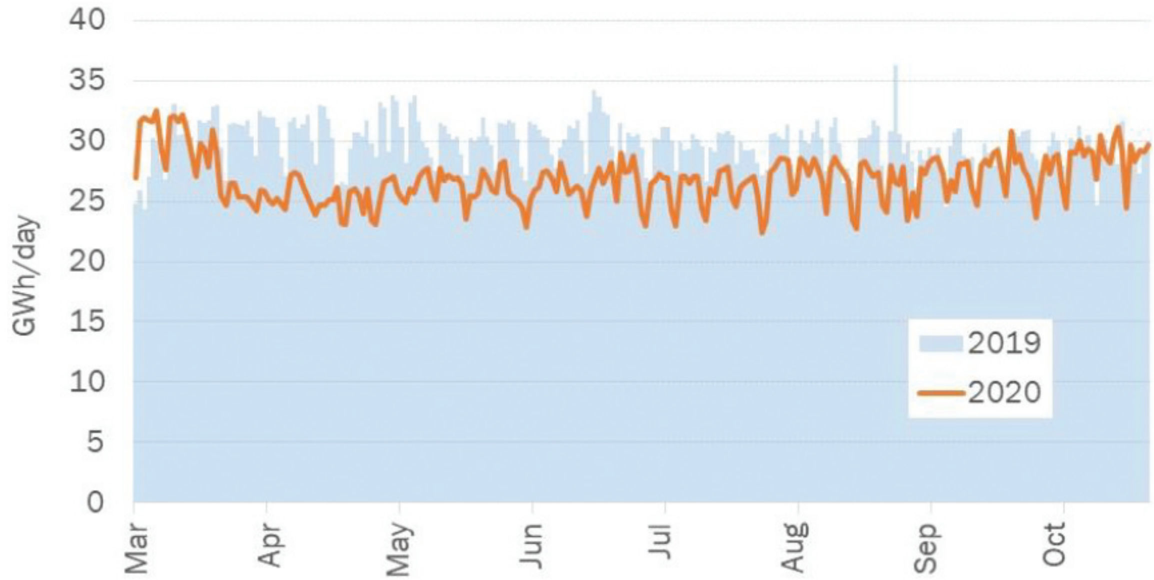
Panama's demand in 2019 was 10,726 GWh, with a gross generation of 11,141 GWh, maximum power of 1,961 MW. Panama has a load factor for the years of 2016, 2017 and 2018 of up to 70% for the years 2016, 2017, and 2018. The average growth in demand in the last 10 years was 5.55% with a slowdown in the last 4 years of 5.26%. The following graph shows the growth of demand, which, like the Panamanian economy, has grown consistently in recent decades.



Source: Own elaboration with CND information.

Maximum peak demand in the Panamanian system for the nine months ended September 30, 2020 was 1,969 MW, which represents 0.41% of growth with respect to the nine months ended September 30, 2019. Electricity demand in Panama during the pandemic decreased when compared to electricity demand in 2019. As observed, between April and August of 2020, the COVID-19 pandemic produced a decrease in demand of -11.93% compared with the same time period in 2019. This decrease reflects the lockdown on the country and the restrictions thereto. Since April, a slow upside trend is observed, and by October 2020, demand has nearly reached 2019 values. Below is a graph and table that shows the comparison between 2020 and 2019 daily and monthly evolution of demand.

Daily evolution of electricity demand in Panama (2020 versus 2019)

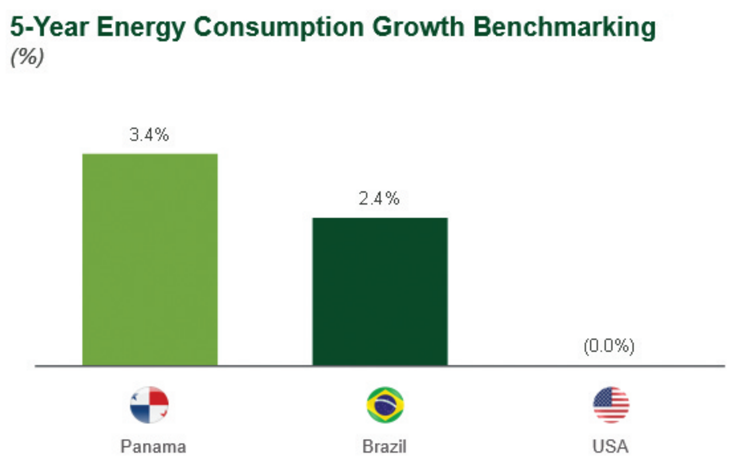


Source: Independent Energy Market Report, Estudios Energéticos Consultores (November 2020)

Year/Month	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
2019	924	915	945	907	913	919	860	892
2020	885	758	808	794	814	823	823	889
Growth rate	-4.2%	-17.2%	-14.5%	-12.4%	-10.9%	-10.4%	-4.3%	-0.3%

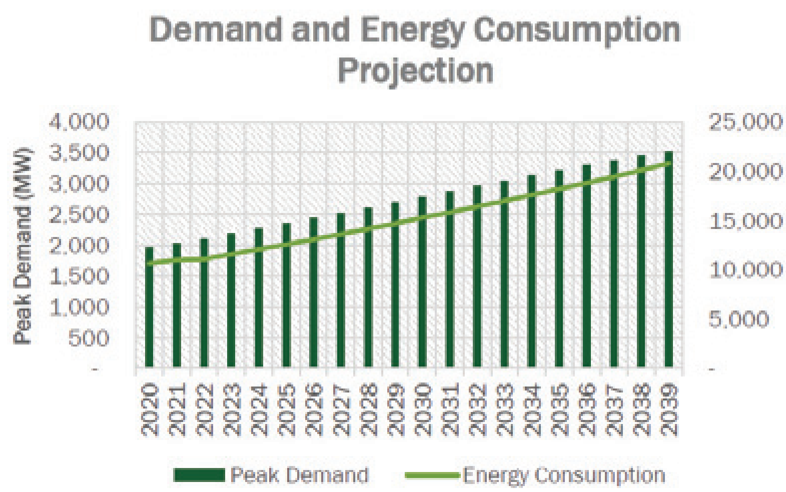
Source: Independent Energy Market Report, Mercados Energéticos (November 2020)

Set forth below is a chart comparing Panama's growth in energy consumption compared to Brazil and the United States. Panama is expected to grow more than both Brazil and the United States, at a percentage of 3.4% compared to 2.4% and 0% respectively.

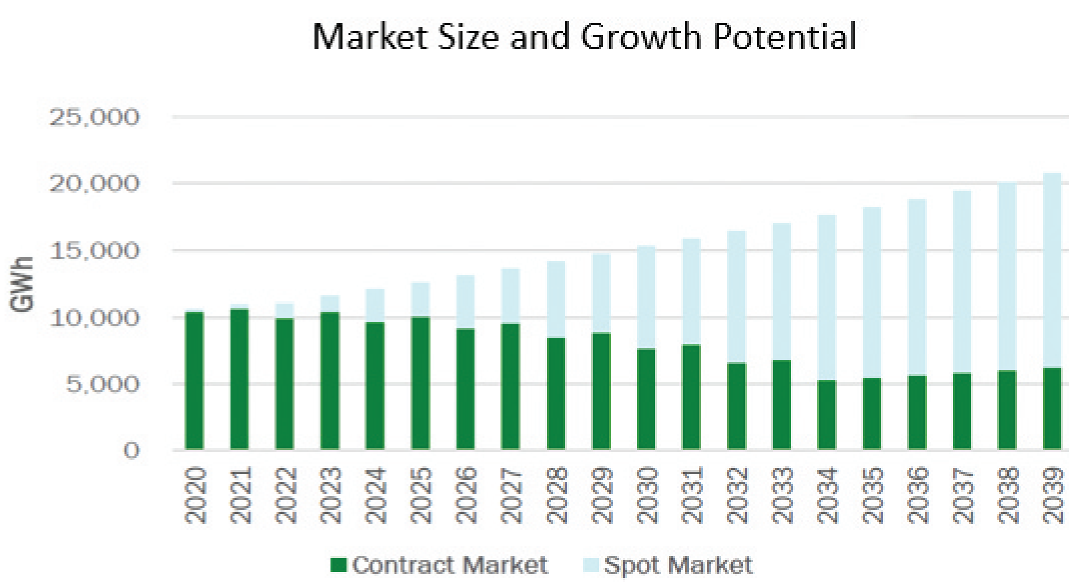


Source: Estudios Energéticos Consultores (November 2020), Ministerio de Minas e Energia (Brazil), Energy Information Administration (USA)

Energy consumption in Panama is expected to increase beyond the five-year mark as well. Set forth below is a table showing the development of annual maximum demand in the system from 2020 to 2025 and from 2020 to 2039.



Source: Independent Energy Market Report, Mercados Energéticos (August 2020)



Source: Own Elaboration using Information Provided by Market Report, Mercados Enérgeticos (November 2020)

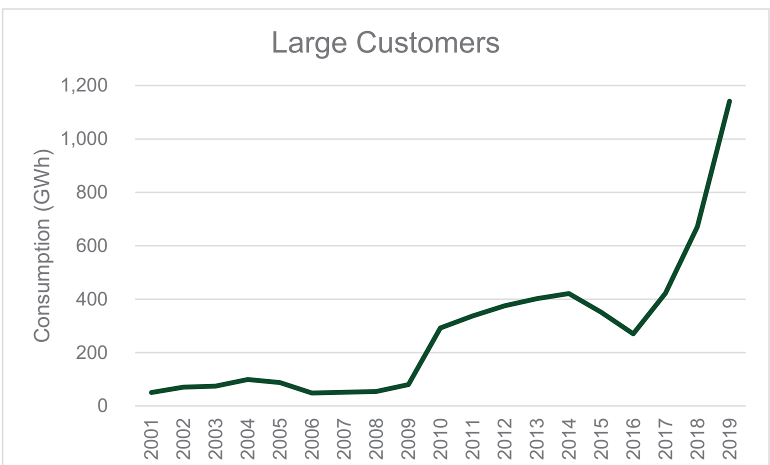
Consumption demand is projected to steadily increase from 2020 through 2039, trending toward significant increases in demand for spot market electricity and away from contract market electricity, which represents further business growth and opportunities. This is because Article 7.4 of Section I of the Purchase Rules establishes that the Distribution Companies shall contract (through PPAs) 100% of their demand projections for the next two (2) years, and for every other subsequent year this requirement decreases 10% until year 15, after which a fixed 30% of demand projections must be contracted. Currently, the Distribution Companies have not contracted for all of their projected needs in the mid and long term. Simultaneously, annual average spot price projections are expected to increase from 2020 through 2039. Currently, however, the PPA market is significantly larger than the spot market.

In recent years, the Large Costumers market has grown significantly. In 2014 there were only 27 Large Costumers, but in 2020 there were 472.

	Participants in the Panamanian Electrical Market						
Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Self-Generators	2	2	2	3	4	4	4
Discos	3	3	3	3	3	3	3
Gencos	32	35	40	47	66	68	68
Large Costumers	27	27	31	72	218	267	472
Total	**64**	**67**	**76**	**125**	**291**	**342**	**547**

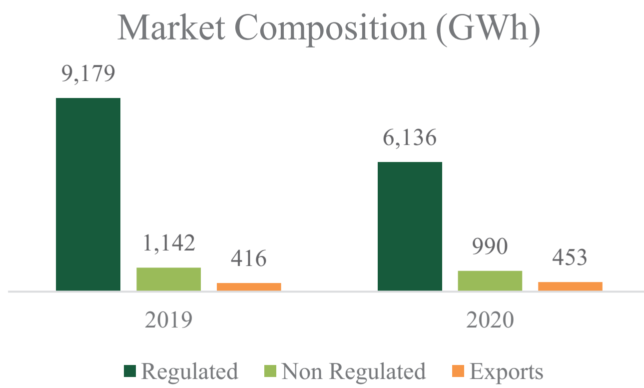
Source: CND.

Consequently, electricity demand of Large Costumers in Panama has continued to increase, reaching a consumption of 1,142 GWh in 2019, with more than 500 frontier points being supplied by more than 25 generation companies.



Source: CND

In 2019, demand by Regulated Consumers, non-regulated Large Costumers and energy exports was 9,179 GWh, 1,142 GWh, and 416 GWh, respectively. For the first nine months of 2020, demand by Regulated Consumers, non-regulated Large Costumers, and energy exports was 6,136 GWh, 990 GWh, and 453 GWh, respectively. The graph below provides the market composition for energy demanded in GWh in 2019 and the nine-month period ended September 30, 2020.

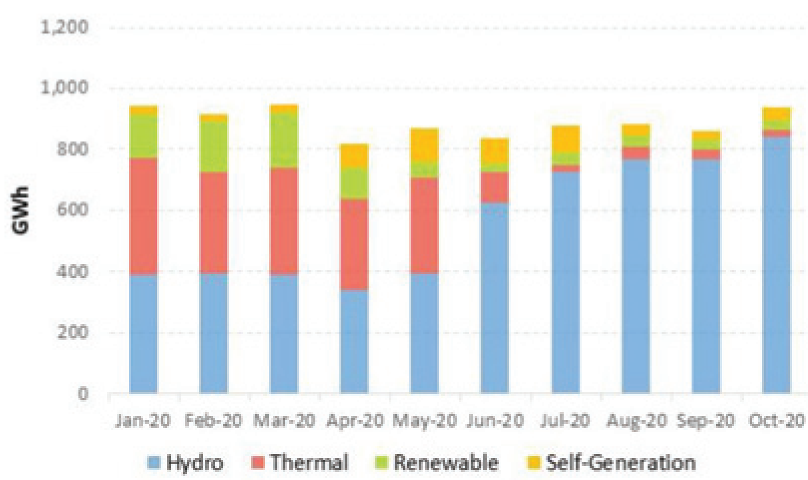


Source: Historic Data from the Market File, CND

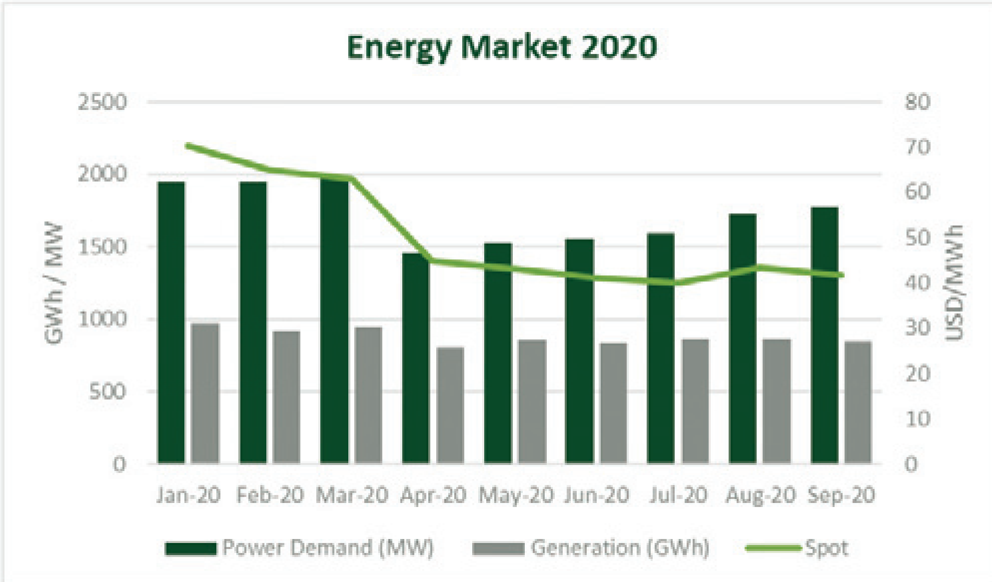
Spot prices in Panama decreased since the onset of the COVID-19 pandemic. The following graph and table show the daily and monthly evolution of energy spot prices during 2020.

Source: Independent Energy Market Report, Mercados Energéticos (November 2020)

During the first months of the COVID-19 pandemic, contraction on the electricity demand reduced energy spot prices. In September, although the demand began to recover, the wet season arrived and with it the increase of hydroelectric plants generation. In correlation with this, the energy spot prices continue to be low, reflecting the additional zero cost offer. This effect can be analyzed in the following figure, that shows generation during this period by type.



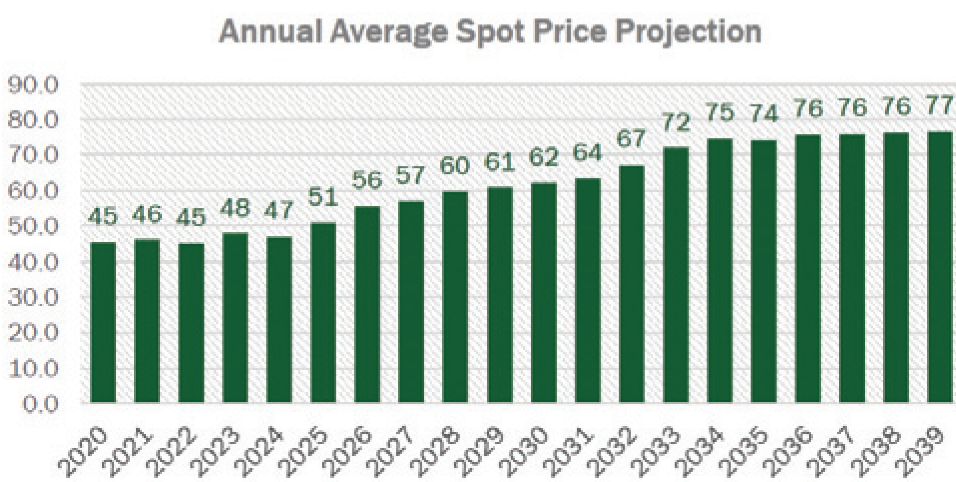
Source: Independent Energy Market Report, Mercados Energéticos (November 2020)



Source: Historic Data from CND — Market File, SMEC information

As time passes and industry appetite shifts, there will be a larger non-regulated Large Customers market, which is expected to, according to forecasts, become increasingly attractive as prices for the same are expected to increase.

The graph below provides annual average spot price projections from 2020 to 2039.



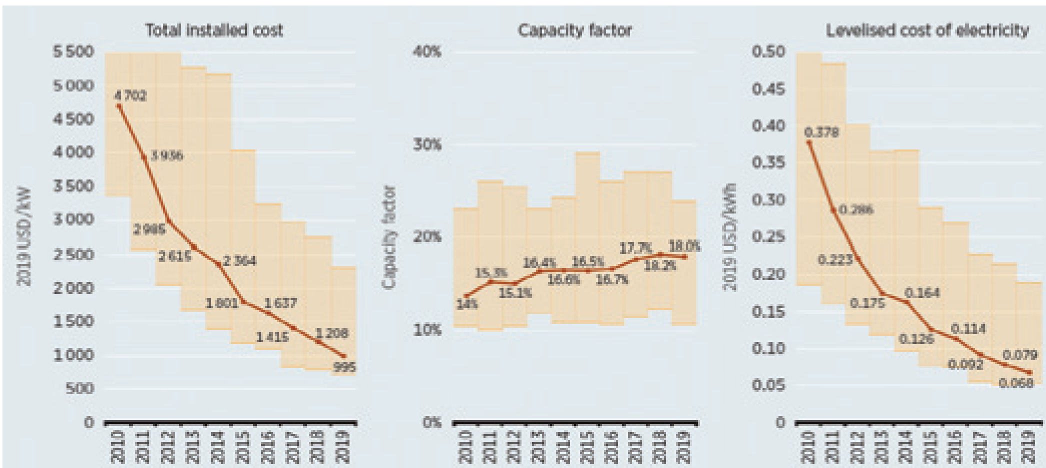
Source: Independent Energy Market Report, Mercados Energéticos (November 2020)

The main driver for projected spot prices in the Panamanian wholesale electricity market is the LNG projected costs. With the entry of LNG into the Panamanian system in 2018, with a terminal in the north side of the country, the Panamanian wholesale electricity market is emerging as a supplier of this fuel in the region and facilitates investments in LNG plants in Panama and Central America. The addition of renewables also plays an important role in the coming years, where the addition of 50 MW of solar per year is outlined on average and 50 MW of wind every six years, based on the recent evolution of the additions to the system's generation park. In the case of Panama, for which the peak demand tends to be at midday (due in part to a large amount of air conditioning), the highest demand tends to be block 2. This is not true for the rest of the countries of the region where peak demand tends to be at the end of the day, during block 1. Blocks 2 also allows us to model the peak in terms of solar generation.

Renewable Energy Costs

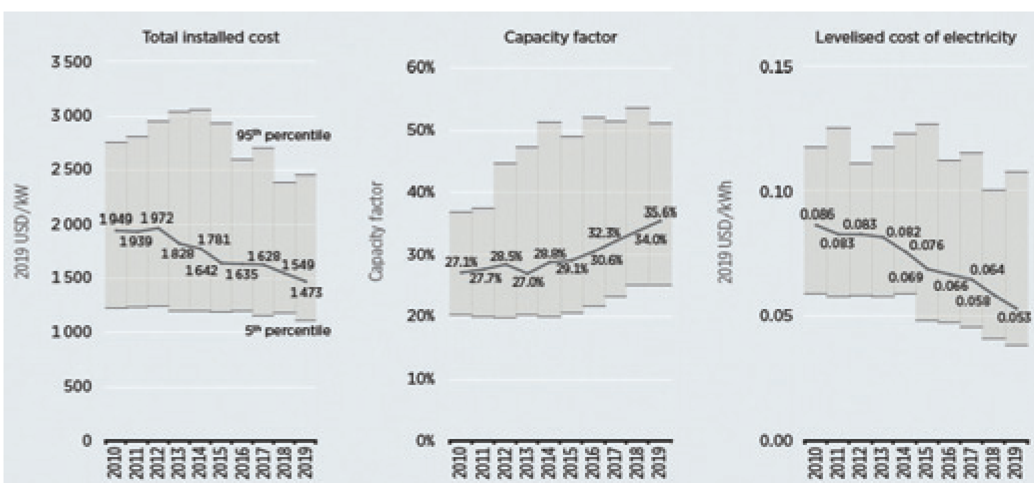
The cost of renewable energy has steadily decreased globally over the past decade, for both wind and solar energy. The CND, through what is known as the merit order, plans the energy dispatch on a weekly basis considering the variable cost of each unit in the system, and requires the entrance from lower to higher cost, until the demand is met. The last unit needed to cover the demand set the spot price. Due to the fact that the variable costs of renewable-based projects are very low, they are dispatched first in the merit order dispatch (dispatch priority vis a vis thermal generation and hydro power plants with reservoirs).

The graph below provides a snapshot of global weighted average total installed costs, capacity factors, and levelized cost of electricity for solar energy.



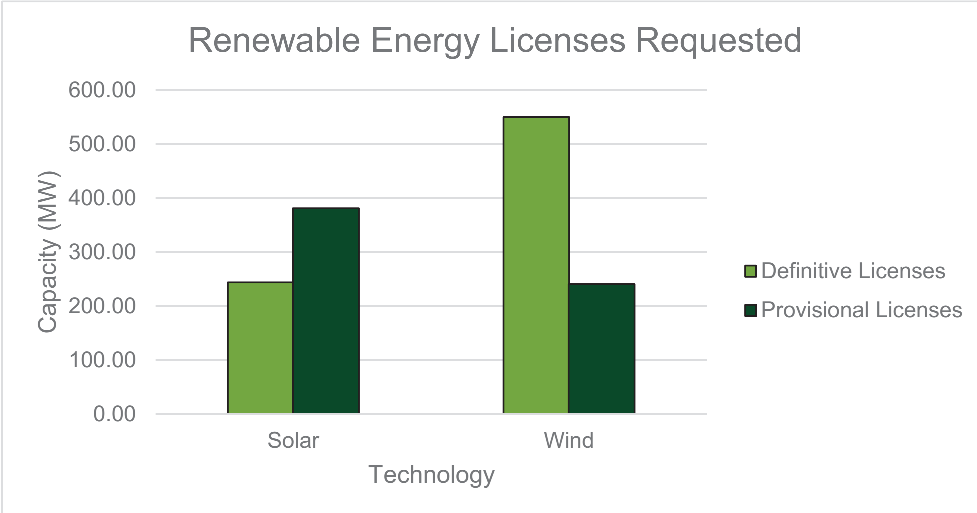
Source: IRENA Renewable Cost Database

The graph below provides a snapshot of global weighted average total installed costs, capacity factors, and levelized costs of electricity for wind energy.



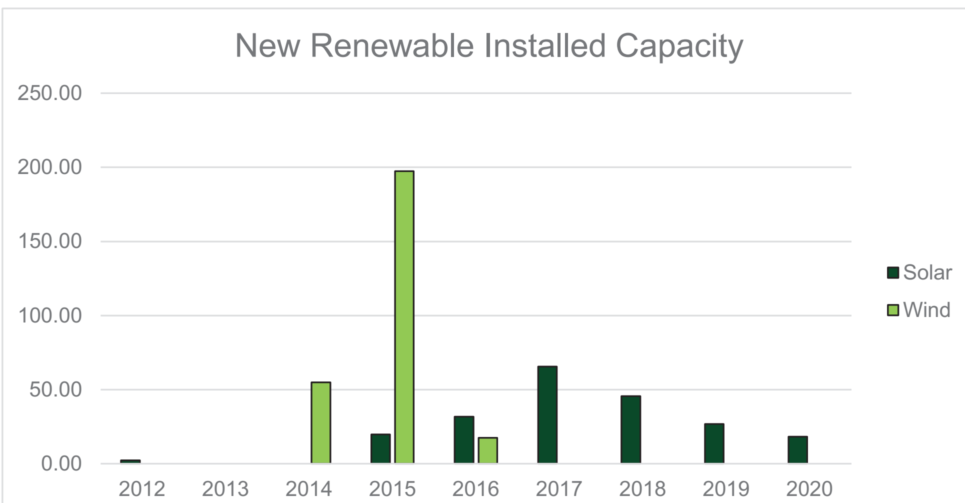
Source: IRENA Renewable Cost Database

This decrease in solar and wind energy installation costs has increased the request for licenses for new projects of these technologies:



Source: Own elaboration with ASEP data.

While in the last 7 years there has been an increase in the wind and solar installed capacity with new solar installed capacity averaging approximately 37 MW per year in the last 5 years:



Source: Own elaboration with data from ASEP

REGULATORY, PERMITS AND ENVIRONMENTAL MATTERS

The Electricity Regulations in Panama

The organizations that participate in the regulation of the electricity sector in Panama are:

- The National Secretariat of Energy (*Secretaría Nacional de Energía* or "SNE"). The SNE has jurisdiction over the energy sector, including electricity. The SNE is responsible for proposing a national energy policy that ensures rational, efficient and sustainable use of resources and energy. More specifically, the SNE has, as part of its duties, the primary responsibility for designing and proposing the national electricity policy, in collaboration with other government agencies such as the ASEP and the ETESA Planning Unit;
- The National Authority of Public Services (*Autoridad Nacional de los Servicios Públicos* or ASEP). The ASEP regulates power generation, transmission, interconnection, and distribution activities in the electric power sector. It approves generation and transmission expansion plans for the SIN. The ASEP also promotes competition within the different areas of the energy sector in order to provide economically efficient and high quality energy services. The ASEP's responsibilities include: (i) regulating the electricity sector, (ii) establishing the criteria, methodologies and formulas to be followed to determine the tariffs applicable to certain public electricity services such as transmission and distribution, (iii) establishing the requirements for access to and use of the grids, (iv) classifying which consumers of electricity are subject to tariff regulation, (v) determining and approving the rules for the planning and coordination of the SIN and (vi) arbitrating discrepancies between participants of the wholesale electricity market;
- ETESA. ETESA is the sole transmission company in the Republic of Panama responsible for preparing the transmission expansion plans for the SIN. It operates through the CND, and maintains the national transmission system. ETESA is also responsible for forecasting the overall energy demand in Panama and determining ways to satisfy such demand. Utility companies are required to provide the information necessary to allow ETESA to prepare the transmission expansion plans;
- The National Dispatch Center (*Centro Nacional de Despacho* or CND). The CND is a unit within ETESA. The CND is the operator of the wholesale electricity market and responsible for planning, supervising, and controlling the integrated operation of the SIN and for ensuring its safe and reliable operation. The CND is also responsible for (i) coordinating the operation of the SIN with regional dispatch centers, (ii) receiving and compiling information necessary for dispatch planning, including the generation costs for each generator, (iii) developing daily demand forecasts and managing dispatch, (iv) determining the hourly energy spot prices in the exchange market and the amounts of electricity sold, (v) managing the transmission network and the auxiliary services required for the proper operation of the SIN, (vi) providing settlement values on a monthly basis with respect to the allocation of energy between suppliers and producers, and (vii) coordinating the commercial transactions between the participants of the wholesale electricity market; and
- On March 28, 2015, pursuant to Law No. 8 of March 25, 2015, the Ministry of the Environment (*Ministerio de Ambiente*) was created to replace the National Environmental Authority, which had previously been responsible for implementing Panama's environmental policy. The Ministry of the Environment is Panama's governing body for matters of protection, conservation, preservation, and restoration of the environment and the sustainable use of natural resources. The Ministry of the Environment is also responsible for the design, approval and implementation of the national environmental policy and for ensuring compliance with and application of the laws and regulations that fall within its purview. The Ministry of the Environment is also in charge of approving the environmental impact assessments required for projects, including those related to the electricity sector.

History

Prior to the 1998 privatization of the Panamanian generation and distribution sectors, the electricity sector in Panama was under the management of the state-owned integrated electric utility, the IRHE. The IRHE was created in 1961, initially to provide service in areas not served by the existing private sector utilities and, in general, to promote the development of electricity services in Panama.

Thereafter, the IRHE gradually took over the assets and operations of the existing private sector utilities. Beginning in the mid-1970s, it significantly expanded the capacity of the system through the commissioning of new hydroelectric plants, particularly in the west of Panama, and introduced a national dispatch center to optimize system operation and allow electricity interchange with the Panama Canal Commission and other Central American countries.

In 1998, as part of the privatization process, the Panamanian government divided the IRHE's assets and operations into four generation companies, three distribution companies and one transmission company. Following a public auction in September 1998, fifty-one percent (51%) of the shares in each distribution company were sold by the Panamanian government. This was followed in November 1998 by the sale of forty-nine percent (49%) of shares in each of the three state-owned hydroelectric generation companies and fifty-one percent (51%) of shares in the main thermoelectric generation company. These sales were completed in 1999. The Panamanian government retained control of ETESA, the state-owned transmission company, which operates and controls the Transmission System of 230Kv and certain 115Kv lines. Under the parameters established by the Panamanian government, a percentage of each bidding consortium had to be held, either directly or through an affiliate, by a company with a minimum required level of generation or distribution experience.

Private capital was reintroduced into the sector following the enactment in 1995 of legislation permitting private electricity generation. This was followed by the Regulatory Entity for Public Services Law in January 1996 and the Electricity Law. Modifications to the Electricity Law were made in February 1998 under Decree Law No. 10 of February 26, 1998, and ancillary regulations were introduced by presidential decree in the form of Executive Decree No. 22 of June 19, 1998. As a result, there are now over 62 independent power producers, the top five of which represent approximately 60% of the nation's generation capacity.

Under the Electricity Law, the Panamanian government can sell its remaining shares by public auction or through the stock exchange, subject in each case, to each purchaser being limited to acquiring no more than five percent (5%) of the company concerned.

The National Authority of Public Services (ASEP)

The 1996 Regulatory Entity for Public Services Law established the *Ente Regulador de los Servicios Públicos*, an autonomous government agency with responsibility for regulating water, telecommunications, radio and TV, electricity and natural gas. Pursuant to Decree Law No. 10 of February 22, 2006, the *Ente Regulador de los Servicios Públicos* was restructured and changed its name to *Autoridad Nacional de los Servicios Públicos* (the National Authority of Public Services or ASEP). ASEP is headed by a general administrator, whose appointment is subject to ratification by the National Assembly.

ASEP's responsibilities include:

- ensuring compliance with sector laws and regulations and applying sanctions;
- issuing concessions and licenses;
- monitoring quality of service standards;
- verifying fulfillment of expansion and system improvement targets as required by law, regulation or under the terms of specific concessions or licenses;
- promoting competition and investigating monopolistic or anti-competitive practices;
- determining efficiency criteria for evaluating the performance of regulated companies;
- establishing the principles and methodologies for tariff regulation;
- arbitrating conflicts between operators, government agencies, municipalities and consumers; and
- authorizing rights of way for the provision of public electricity services.

ASEP is financed from various sources, including fees payable by all providers of electricity services. These fees, which are payable monthly and are not recoverable from consumers, may not exceed one percent (1%) of gross sector revenues in the preceding year on an annual basis. For each individual company, the applicable percentage is applied to revenues from Regulated Consumers and Large Customers less amounts paid by that company to other service providers to cover energy or transmission costs. The fees for the years 2012 to 2019 were set at 0.7268% (Resolution AN No.388-ADM December 15, 2011), 0.7899% (Resolution AN No.497-ADM of December 26, 2012) and 0.8213% (Resolution AN No.598-ADM of December 30, 2013), respectively. In 2015 and 2016, the fee was set at 0.7475% (Resolution AN No.695-ADM of December 22, 2014) and 0.7475% (Resolution AN No.784-ADM of December 22, 2015), 0.8809% (Resolution AN No. 887-ADM of December 16, 2016), 0.8701% (Resolution AN No. 969-ADM of December 11, 2017), 0.8699% (Resolution AN No. 1019-ADM of December 14, 2018) and 0.8591% (Resolution AN No. 1059-ADM of December 13, 2019), respectively.

ASEP may impose sanctions of up to US$20,000,000, depending on the nature and severity of the violations, as detailed in the Electricity Law. Other considerations for determining the amount of the sanctions include aggravating circumstances, any corrective measures taken, the degree of interruption to the electricity industry, and the related damages amount. Additionally, any delays in following ASEP orders for corrective measures, or failure to take action pursuant to such order, may result in fines of up to US$10,000 per day until measures are implemented. Fines are applied as discounts to consumers. Additional sanctions may include terminating a concession agreement or cancellation of licenses.

The Electricity Law

The Electricity Law was introduced to improve operation efficiencies, achieve reliable and good quality service, guarantee good quality of supply through the promotion of competition and private sector participation, and keep the cost of the service at reasonable prices. Key provisions include:

- defining the duties and obligations of electricity service providers including continuity of supply and provision of open access in transmission and distribution;
- dividing the generation, transmission and distribution operations of IRHE into separate companies and establishing requirements for management and accounting separation of generation, transmission and distribution activities;
- restricting participation by Distribution Companies in generation and in transmission and by generation companies in the control of Distribution Companies;
- establishing procedures for privatization of the sector other than ETESA, the company formed to hold IRHE's transmission assets, which was to remain wholly state-owned;
- establishing procedures for granting concessions and licenses subject to limitations on the market shares of individual generators and Distribution Companies;
- defining the role of ETESA and the procedures for management of central dispatch;
- allowing Large Customers with maximum demand of over 500 kW to purchase directly from generators and other suppliers. In 2007, the ASEP reduced this threshold to 100 kW; and
- establishing principles of tariff-setting for price-regulated services.

The SNE has no authority to amend the Electricity Law or to adopt additional laws or regulations relating to the electricity industry. However, the SNE can propose and recommend changes and amendments to existing regulation, or propose new regulation to the Executive Branch, but ultimately the latter dictates Panama's energy sector laws and regulations, which could lead to changes to existing legislation or the adoption of new legislation relating to the energy sector, including the electricity industry.

Generation Licenses and Concessions

Under the Electricity Law, generation licenses are required for the construction and operation of wind and solar power plants, as well as all other power plants that are not geothermal or hydroelectric plants. These licenses are granted by the ASEP for a term of up to 40 years.

Concessions are required for hydroelectric or geothermal plants and for the provision of transmission or distribution services. Concessions are awarded, through contracts, by the ASEP and have the following time limits:

- Hydroelectric or geothermal generation: up to 50 years;
- Transmission: 25 years; and
- Distribution: 15 years.

Under the Electricity Law, generation companies will not be granted additional concessions if such concessions would cause them to account, directly or indirectly, for more than 25% of national electricity consumption. This percentage may be increased by the Panamanian government, where justified by competitive conditions, subject to the approval of ASEP and the Cabinet Council, and it was temporarily increased to forty percent (40%) by Cabinet Resolution No. 76 of 2005 until December 31, 2012. Because the Electricity Law sets forth this restriction regarding "concessions," which include hydroelectric and geothermoelectric generation, this restriction should not apply to generation "licenses" that refer to other types of generation power plants.

In order to reduce Panama's reliance on hydroelectric generation and to increase the security of supply, the Panamanian government has decided to promote alternative sources of energy, including solar and wind energy generators. Law No. 44 of April 25, 2011 and Law No. 37 of June 10, 2013 establish incentives for wind and solar energy generators, respectively, including exemption of taxes, duties, contributions, liens and ITBMS related to the import of equipment and materials for the construction, operation and maintenance of the plant, use an accelerated depreciation of equipment of the plant, and, in the case of solar generators, a 5% tax credit for total direct investment. On August 2012, Law No. 41 of August 2, 2012 was approved, introducing new incentives for natural gas power plants, including an import tax exception, a 20-year income tax holiday for manufacturers of equipment for gas power plants, accelerated depreciation of equipment of the plant and a 5% tax credit for total direct investment. Similarly, Law No. 43 of August 9, 2012 amended the Electricity Law to permit capacity auctions based on the energy technology used (i.e. hydroelectric, wind, coal, natural gas and bunker, among others) and incorporating natural gas as a renewable energy in order to receive the benefit of a 5% preference granted in the bid price for the auction (relative to other types of generators). Currently the generation expansion plan is considering the addition of renewable variable generation and two natural gas combined cycle power plant projects for the next five years.

System Operation

The Electricity Law provides that the operation and administration of the wholesale electricity market shall be managed by the CND, a unit within ETESA, with separate accounting records. The electricity wholesale market comprises all transactions among market participants including generators, self-generators, co-generators, Distribution Companies and Large Customers for the sale of capacity, energy and capacity with associated energy. Transactions are facilitated through contracts with competitive prices, bid processes or spot market sales with hourly prices (*mercado spot*) for settling the transfer of electricity for uncontracted capacity and/or energy.

The regulations under the Electricity Law allow electricity generating companies to compete in sales to Distribution Companies. Distribution Companies, on the other hand, are restricted from carrying out generation activities that exceed fifteen percent (15%) of their annual electricity requirements. Distribution Companies are required to obtain long-term contracts to cover the maximum generation demand, or DMG, capacity requirements of their Regulated Consumers and Large Customers and associated energy of their Regulated Consumer base. The amount of contract cover required is based on a month-by-month analysis submitted to the ASEP by the CND each year using forecasts supplied by the Distribution Companies and the rest of the consumers, including Large Customers (*Informe Indicativo de Demanda*). The amount of contract cover provided by an individual generator may not exceed its own firm capacity and any such capacity acquired from other generators under reserve contracts. For wind and solar plants, firm capacity is calculated by the CND based on the amount of energy a generating unit can create, calculated on the basis of wind speed regime or solar radiation, respectively, with a ninety-five percent (95%) probability of excess and this is reviewed annually based on the availability of the last three years. As such, firm capacity is a more conservative number than installed capacity. For thermal plants, firm capacity is established by the CND based on net capacity and historical availability.

The CND plans the economic dispatch of electricity from the generation units using a model that incorporates stochastic dynamic programming in order to factor into the dispatch process the opportunity cost of the water, the variable cost of thermal plants and the availability of the primary resource for renewable plants, among other factors. This electricity is dispatched from the plants in order of merit. Variables considered in determining merit include variable costs, parameters for system security, operating constraints and the operational regulations (*Reglamento de Operación*) approved by the ASEP. The spot market price is based on the marginal cost of the short-term generation, calculated giving priority to short-term reserve requirements. Transmission losses are valued differently depending on the type of technology and following the methodology established in the Commercial Rules. These losses are charged separately to Distribution Companies based on loss factors applicable to their connection points on the SIN. See "— Dispatch" below.

Variances between a generator's actual dispatch and contracted energy volumes are settled through the spot market. Plants that are dispatched out of merit by the CND to maintain real time system stability (*generación obligada*) receive an additional payment (must-run compensation) to cover the difference between their variable costs and the hourly spot price. The CND is also responsible for the coordination of auxiliary services (*servicios auxiliares*) and their remuneration through additional charges to the system. Details of the average monthly spot price in the wholesale market since January 1999, excluding capacity costs, are set out below under "— The Spot Market."

Dispatch

According to the Electricity Law, the order in which generators dispatch energy depends on the generator's level of efficiency. Coordination of the system dispatch stack is planned by the CND. Generators are dispatched in an order that maximizes consumption of energy while also minimizing the total cost of energy in the Panamanian power system.

Economic Dispatch

The CND generally dispatches generating units in accordance with a merit order based on each generator's variable costs:

- In the case of thermal units, variable costs (in US$/MWh) are calculated based on incremental fuel costs and non-fuel costs, such as a thermal unit's administration, operation and maintenance costs, and its facility heat rate;
- In the case of renewable variation generation, such as run-of-river hydroelectric, wind and solar facilities, variable costs are considered to be zero; and
- In the case of reservoir hydroelectric facilities, variable costs correspond to the opportunity cost of water, which is computed using a dispatch model that incorporates stochastic dynamic programming, or the SDDP model. The CND uses the SDDP model to calculate the expected thermal generation costs saved in the future by the conservation of marginal amounts of water by a hydroelectric generator, considering projected operations of the national interconnected power system over the medium and long term. In determining the marginal amounts of water that must be conserved by a hydroelectric generator, the SDDP model takes into account estimated rainfall in the region and the risks of dam spillage and depletion of reserves by that hydroelectric generator. When calculating the risks of dam spillage and reserve depletion, the SDDP model also considers the size of the reservoir and efficiency of the generator's turbines. Thus, although the value of water is strongly linked to the variable costs of marginal thermal generation, other factors are considered when determining the marginal amounts of water required to save thermal generation costs.

The planned dispatch is revised continuously by the CND in response to any changes affecting the system (e.g., demand, actual generator availability and system restrictions) that may take place throughout the day. Additionally, each week, representatives from the CND and each Panamanian thermal, wind, solar, and hydroelectric generation company meet to discuss the results of the dispatch model. After such meeting and the due consideration of any comment provided by the generation companies, a final determination is made by the CND of the planned dispatch. The hourly spot price is based on the variable cost of the marginal plant dispatched.

Transmission losses are valued as follows:

- In the case of plants with a zero variable cost or reservoir hydroelectric facilities that have PPAs with the Distribution Companies, at the monthly weighted average price of energy in their PPAs;
- In the case of plants with a zero variable cost or reservoir hydroelectric facilities that do not have PPAs with Distribution Companies, at the monthly weighted average price of energy in all the PPAs with Distribution Companies backed by plants using the same technology; or, in case there are no PPAs with Distribution Companies backed by plants using the same technology, at the monthly weighted average price of energy of all the PPAs with Distribution Companies backed by plants having variable costs that never exceeds zero;
- In the case of plants with variable costs greater than zero, except for reservoir hydroelectric facilities that have PPAs with Distribution Companies, at the monthly arithmetical average price of energy in their PPAs indexed fuel price declared in the weekly dispatch; and
- In the case of plants with variable costs greater than zero, except for reservoir hydroelectric facilities that do not have PPAs with Distribution Companies, at the applicable variable cost.

Non-economic Dispatch

The Commercial Rules allow the CND to dispatch energy based on guidelines other than the SDDP model's projections when following the economic dispatch stack would jeopardize the technical security of the system. The resulting altered dispatch stack may cause generators which would have normally been dispatched not to be dispatched, thus forcing them to buy energy on the spot market to satisfy their contractual commitments. The Commercial Rules provide for certain payments to those generators for the non-dispatched energy, or restricted energy, which are based on the difference between the spot price of the energy purchased by the restricted generators to satisfy their contractual commitments and the variable cost assigned to such generators by the CND for the non-economic dispatch period. Under the Commercial Rules, the party causing the condition that triggers the non-economic dispatch is liable for the above payments.

The Spot Market

The Panamanian power sector is structured as a spot market with an overlay of bilateral contracts between the generation companies and the Distribution Companies. The spot market is designed to balance the supply and demand of capacity and associated energy in the wholesale electricity market. The spot market commenced operation on July 1, 1998 under the administration of ETESA and the CND. The principal function of the spot market is to allow market forces to determine the amount, mix and cost characteristics of generation facilities, and the level and shape of demand. The spot market involves transactions of energy and capacity that are not subject to contracts, and consists of the Panamanian Energy Spot Market and the Panamanian Capacity Spot Market (known as daily capacity compensations).

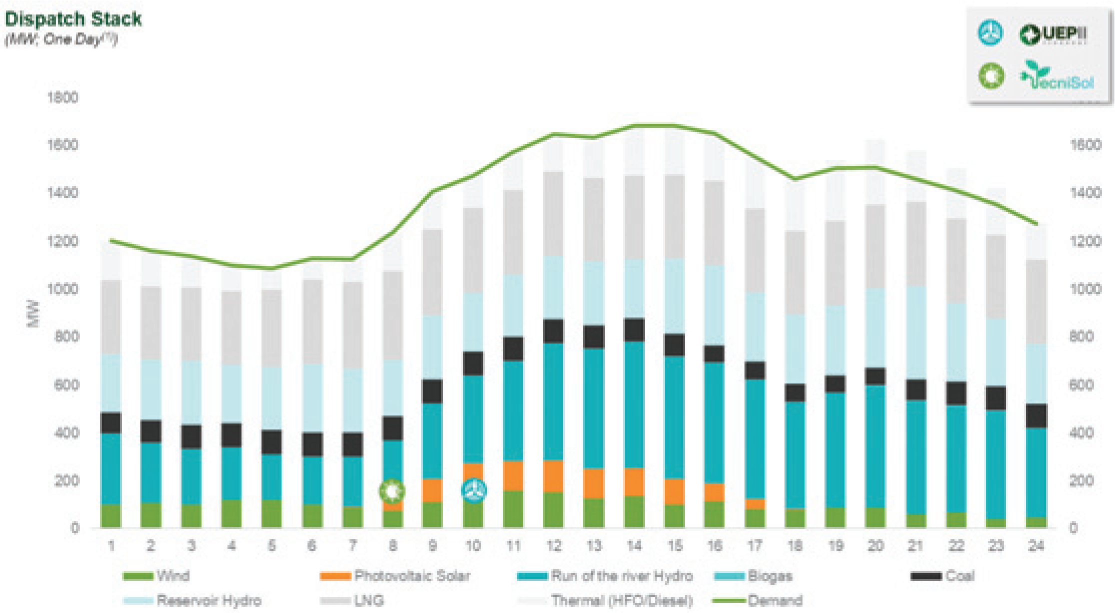
Panamanian Energy Spot Market

In the case of generators, hourly discrepancies between the actual dispatch of energy by each generator and its contractual commitments to supply energy are settled through the Panamanian Energy Spot Market. A generator whose dispatched energy is greater than its contractual commitments to supply energy at any given time is a seller in the Panamanian Energy Spot Market. In an opposite way, a generator whose dispatched energy is less than its contractual commitments to supply energy at any given time is a buyer in the Panamanian Energy Spot Market. Distribution Companies, generators and specific Large Customers can purchase energy in the Panamanian Energy Spot Market and generators and Distribution Companies can sell energy in the Panamanian Energy Spot Market.

The energy spot price is set by the marginal cost of short-term generation, calculated with an economic dispatch that prioritizes short-term reserve requirements. The CND ranks generators according to their variable cost, starting with the lowest cost generator, and establishing on an hourly basis the merit order in which generators will be dispatched the following day to meet expected demand. See "— Dispatch — Economic Dispatch" above. The price in the Panamanian Energy Spot Market for all generators is set by the costliest generator dispatched in each hourly period, which becomes the clearing price for energy. Generally, the CND calculates the price of energy using the variable cost applicable to the dispatch of the generation unit which is required by the price dispatch to cover demand. Such variable cost is equal to the demand plus the current short-term reserve of the system. For more detail on the calculation of the variable cost please see "— Dispatch — Economic Dispatch" above.

If the system is opened in two or more subsystems as a result of failures in the network, the CND will calculate the price for each subsystem with the same procedure and criteria established for the price dispatch; such calculation will use the demand and generation of each subsystem.

Below is a representation of the price ranking system that determines the sport price, referred to as the supply stack curve, as of March 31, 2020.



Source: Own elaboration using CND pre-dispatch data.

Details of the average monthly spot price in the wholesale market since January 2010, excluding capacity costs, are set out below.

Average annual spot prices (US$/MWh)

Year or Month	Marginal Cost US$./MWh
2015	91.13
2016	60.39
2017	58.51
2018	76.70
2019	91.40
Nine months ended September 30, 2020	50.22

Source: CND historical data market

Panamanian Capacity Spot Market

Transactions take place on a daily basis in the Panamanian Capacity Spot Market in order to match the actual available capacity of generators with the actual peak capacity requirements that each generator must meet the under their outstanding supply contracts. Each day, generators must submit their offers to sell their excess capacity for the following day. The CND must accept capacity offers until all capacity requirements are covered. The price for spot capacity transactions is calculated each day based on offers submitted to the CND by the generators during the prior day. Daily prices are expressed as one-thirtieth (1/30) of a monthly price (US$/kW — month). The spot capacity price at which generators sell their actual available capacity is equal to the last offer accepted. As of the date of this offering memorandum, the capacity spot price is capped at a regulated price of US$8.96 per kW a month.

The capacity which the market participant may have available to sell may depend on whether or not it has a shortage or surplus of capacity available. Whether or not the market participant has a shortage or surplus is a determination made by the CND, who calculates the balance between the capacity requirement and availability of each producer participant, discounting the committed capacity for supply from the capacity made available. If the balance is negative, the producing participant has a shortage and may not participate in the market. If on the contrary the balance is positive, the producing participant has a surplus and may access and sell the surplus on the capacity spot market.

Power Purchase Agreements

The dominance of hydroelectric generation and the distinguished seasonal variations of Panama's hydrology result in a high degree of price volatility in the Panamanian Energy Spot Market. In order to mitigate this volatility, generators can enter into long-term PPAs with Distribution Companies or Large Customers for the sale of capacity and/or energy. In addition, generators can enter alternative supply contracts with one another, which are called reserve contracts. The terms and contents of PPAs with Distribution Companies are determined by the conditions set forth by ETESA and the ASEP through a competitive bidding process governed by the Purchase Rules and carried out by ETESA. Those PPAs must include, among other information, the following: (i) identity of the contracting parties; (ii) clear rules or procedures to determine, on an hourly basis, the quantity of energy which may be requested; and (iii) the corresponding prices.

Capacity Charge

The capacity charge is a fee intended to remunerate thermal and hydroelectric generators for the firm capacity made available to the SIN. The capacity charge provides generators with a source of fixed revenue which is dependent primarily on the generator's own availability. The CND can verify a generator's declared availability, and the off-takers in PPAs can impose penalties if the actual availability, and thus the capacity, is lower than the contracted availability. If a generator's actual availability is less than the declared availability, that generator is required to pay an amount equivalent to the capacity charge on the difference between the generator's actual availability and the contracted availability.

Transmission

As of March 31, 2020, the transmission system in Panama, owned and operated by ETESA, comprised approximately 3,185.2 kilometers of single and double circuit 230kV lines linking the main generation facilities to the system load center at Panama City, 307 kilometers of single and double circuit 115kV lines and a total of 24 substations, which are comprised of 2 substations at a 115kV level and the other 22 substations are reducing substations with a total capacity of 2,788.1 MVA at 230/115/13.8kV.

Pursuant to Section 9.6, Mandatory Generation (*Generación Obligada*), of the Commercial Rules, ETESA is required to pay electricity generators for associated cost overrun to the Mandatory Generation, which is caused by a bottleneck in the SIN.

ETESA is responsible for expanding and upgrading the network to meet the requirements of demand growth and system stability. It is currently engaged in an investment program, the main components of which are:

- Panama Second Underground Line — Caceres 115 KV, to be completed in May 2022.
- New Substation Sabanitas 230 kV, to be completed in September 2022.
- Sabanitas — Panama III 230 kV Line and new Substation Panama III 230 kV, to be completed in April 2023.
- Telfers-Sabanitas 230 kV Line, to be completed in January 2023.

Under the Electricity Law, ETESA is responsible for producing an annual expansion plan for the interconnected system in line with quality and reliability standards and development objectives set by the SNE. This plan is based on projections of expected growth in demand and energy consumption over the next fifteen (15) years which market participants are required to submit by September 30 of each year. ETESA is obliged to carry out all projects included in the Transmission Expansion Plan, as approved by ASEP, and all related construction work must be contracted on the basis of competitive bidding. The network expansion must be financed by ETESA; however, ETESA can choose whether or not to finance the connection of generators or distributors to the transmission network in return for a reimbursable contribution. Average losses of energy in transmission over nine months ended September 30, 2020 and for the period from 2015 to 2019 have been as follows:

	Nine months ended September 30,	Years ended December 31,				
	2020	2019	2018	2017	2016	2015
Annual	3.39%	2.40%	3.69%	3.69%	3.41%	3.59%

Source: *CND Historical Market Data.*

As of the date of this offering memorandum, all of the transmission losses are charged to the Distribution Companies and Large Customers.

Tariff Structure

Under the Electricity Law, the ASEP is required to establish tariff methodologies to regulate connection and use of system charges for distribution services, and to approve tariff structures for the sale of energy to Regulated Consumers. In general, the Electricity Law permits ASEP to set maximum and minimum tariff limits and issue methodologies for the determination of tariffs. The tariff formulas are valid for four years and can be modified in exceptional circumstances, either ex officio or at the request of a generation company within a certain timeframe if (i) there are serious and evident errors in their calculation that cause unfair injury to clients or a generation company or (ii) a fortuitous or force majeure event seriously compromises the financial capacity of a generation company to continue providing its services under the established tariff conditions. The Electricity Law provides that tariffs should be set sufficiently high to cover the costs of providing the required level of service on the assumption that anticipated productivity gains are shared between Distribution Companies and their customers.

Under the current tariff structure, all distribution system users and all Regulated Consumers pay a separate consumption-based charge within the tariff to cover the capital, energy and operational costs of public lighting. Panamanians or foreign residents in the territory of Panama that are senior citizens (in the case of women, fifty-five years and older or, in the case of men, sixty years and older), and all retirees (men aged sixty-two years and older and women aged fifty-seven years and older) and pensioners (*pensionados*) receive a 25% discount on charges applied to the first 600 kWh of consumption. For any consumption above the 600 kWh threshold, retirees pay full charges.

Transmission charges

The Electricity Law provides for open access to transmission subject to a regulated tariff for connection and use of system charges. The current tariff, which was approved by Resolution AN No. 12306-Elec of April 20, 2018 issued by ASEP, is due to remain in force until September 30, 2021.

Transmission charges are designed to be set at a level that allows ETESA to achieve sufficient revenues to cover the costs of their efficient investments, operating, maintenance (including metering, billing and customer service), administrative and commercial expenses, transmission losses, and a reasonable return on investment. Each of these costs and return on capital is determined by the ASEP based on the expenses and returns of comparable companies.

The permitted pre-tax rate of return, as determined by the ASEP, must be within a two percent (2%) range above or below the average yield on the 30-year US Treasury Bond in the year preceding the setting of the tariff plus a seven percent (7%) risk premium.

For the current tariff structure, which will remain in force until June 30, 2021 due to the recent resolutions by the ASEP, the pre-tax rate of return (*tasa de rentabilidad*) for ETESA was set at 7.76%.

In addition to the pre-tax rate of return for ETESA, there are three elements of transmission charges:

- Connection charges, which are paid by direct or indirect users of the transmission system or an equipment of the transmission system that belongs to a certain user;
- Use of system charges (wheeling fees), which reflect the costs assigned to each user for the use of the main transmission system and are comprised by a postage stamp and an electric tracking charge (CUSPT). Charges for use of system charges (wheeling fees) do not apply for renewable generators with a capacity below 10MW and partially for those generators with a capacity between 10MW and 20MW according to Law. No. No. 45 of August 4, 2004); and
- Integrated operation service charges, which include costs associated with the CND and hydrometeorology which are currently set at US$0.0993 per kW/month for generators and US$0.2288 per kW/month for distributors and Large Customers.

Value Added of Distribution

The value added of distribution consists of the following costs that an efficient Distribution Company would incur to provide the distribution services within its concession area: (i) administration costs, (ii) operation and maintenance of the distribution system, excluding the costs of measuring, billing and customer service, (iii) the cost of standard losses in networks distribution, (iv) the depreciation cost of the Distribution Company's assets, and (v) the cost corresponding to the opportunity a Distribution Company should have to obtain a reasonable rate of return on its investment.

The ASEP will determine the rate of return that it considers reasonable for the Distribution Company given its efficiency, quality of service, investment program for the period of validity of the tariff rates schedule and any other factor that the ASEP deems relevant. However, the rate of return that the ASEP determines must be within a two percent (2%) range above or below the average yield on the 30-year U.S. Treasury Bond in the year preceding the setting of the tariff plus an eight percent (8%) risk premium.

This rate is applied to the Distribution Company's net fixed assets in operation during the tariff period based on historic accounting values at the start of the tariff period plus the Distribution Company's efficient investment requirements during the tariff period. Once this rate is applied to the assets and efficient investments, the Distribution Company prepares and submits the tariff schedules for each service area and customer category to the ASEP for approval. The ASEP then determines the Distribution Company's maximum allowable rate to charge customers.

For the current tariff structure, which will remain in force until June 30, 2022 due to recent resolutions by the ASEP, the pre-tax rate of return (*tasa de rentabilidad*) for Distribution Companies was set at 7.76%.

Final Customer Tariffs

Tariff options for customers include: (i) a tariff based on energy consumption only, applicable only to residential customers and those other customers that have a monthly electricity demand of 15 kW or less; (ii) a tariff based on energy consumption and maximum monthly demand available to customers that have a monthly electricity demand of more than 15kW; and (iii) a time-of-day based tariff. This last type is supplied to customers at any consumption-supplied tension. The Distribution Companies may offer additional tariff options with the prior approval of the ASEP. Customers are allowed to change their tariff option twice in a twelve-month period without incurring a penalty. From and after the second change in that period, the customer will pay a penalty in the amount of fifty percent (50%) of the connection fee.

The distribution and transmission tariff structure remains in full force and effect for a period of four years. For purposes of the distribution tariff, every six months during the tariff period, the capacity and energy cost-components of the tariff are adjusted to account for variances in actual and expected energy costs, and a portion determined by ASEP of the distribution and commercial charges are eligible to be adjusted for inflation based on the Panama CPI for the prior two semesters. These energy-related component adjustments are applied starting the following semester. Since July 1, 2014, adjustments for variances in actual fuel prices occur monthly, and are applied to the next month's bill. The generation and transmission components of the tariff are adjusted based on the actual energy purchased and the actual cost of transmission.

Purchases by Large Customers

Pursuant to the Electricity Law, generators may sell capacity and energy to Large Customers under PPAs at freely agreed prices. Large Customers are free to purchase energy from any generator, and are not required to enter into PPAs or to comply with any specific procedure when entering into PPAs. A number of regulatory resources are available to help guide Large Customers, including the Procedures and Criteria for the Sale of Energy and Capacity to Large Customers and the Commercial Rules.

Pursuant to the rules applicable to Large Customers in Panama, if a Large Customer demands less than 100Kw for four consecutive months such Large Customer will be declassified and as such will not be supplied energy under any PPA because it will become a Regulated Consumer and will not be classified again as a Large Customer for at least a year.

Regulated Consumer Retail Market

While the wholesale electricity spot prices are based on market forces, transmission and distribution tariffs in the regulated market are set by the ASEP. Regulated Consumer rates are also set by the ASEP and are adjusted every six months based on a formula which combines the Panamanian producer price index and applicable fuel prices projections, except that adjustments for variances in actual fuel prices occur monthly, and are applied to the next month's bill. Regulated consumers may be charged rates according to a tariff formula established by the ASEP. This formula allows the distribution company to pass through generation and certain other costs not within its control and has the effect of rewarding the distribution company for achieving improvements in operating efficiencies greater than those assumed as part of the tariff formula. Regulated consumers are regulated by the Purchase Rules and the Commercial Rules.

Spot Market Sales

Spot market sales are regulated by the Commercial Rules and the Methodology for the Dispatch of Price and Calculation of the Price of Energy in the Second-Hand Market — PMO.

Electric Energy Rationing

The variable costs resulting from energy rationing should be simulated daily during the planning sessions with the SDDP pursuant to the Commercial Rules and the detailed methods (*Metodología para la Programación Diaria y Criterios de Arranque y Parada Diarios)*. Those variable costs are initially simulated on the basis of a curtailment of the demand of five percent (5%) of the total national demand; the second step of those variable costs is simulated as a curtailment of ten percent (10%) of the total national demand; the third step of those variable costs is simulated as a curtailment of thirty percent (30%) of the total national demand; and the fourth step of those variable costs is simulated as a curtailment of one hundred percent (100%) of the total national demand; and each step has a price based on a formula included in the detailed method (*Metodología para Administrar Racionamiento de Suministro de Energía Eléctrica*), which is in function of a price settled by the ASEP, for not supplied energy.

If emergency rationing occurs, the CND will determine the amount of energy to be rationed according to the characteristics and implications of the emergency. The detailed method (*Metodología para administrar el racionamiento de suministro de energía eléctrica*) provides the methodology for calculating the amount of energy to be withheld in case of programmed or emergency rationing and sets forth the parameters for the distribution of the rationed energy to consumers. While the energy rationing is in effect, all generators under firm capacity agreements are obligated to generate the committed energy. In other words, such firm capacity agreements become "physical."

No Traders

Panamanian regulations do not allow traders. The only entities authorized to trade energy are generating companies and distribution companies.

Environmental Regulation

In July of 1998, the Panamanian government enacted Law No. 41, which created the National Environmental Authority, which through Law No. 8 of March 25, 2015 was replaced by the Ministry of the Environment. Law No. 8, which together with Law No. 41 and other supplemental rules also set out the legal framework for the protection of the environment through the sustainable use of natural resources. The Ministry of the Environment is responsible for implementing Panama's environmental policy in collaboration with other government entities under its supervision, such as the Environmental Interinstitutional System (*Sistema Interinstitucional de Ambiente*) and the Environmental Consultative National Commission (*Comisión Consultiva Nacional del Ambiente*). The Ministry of the Environment has the ability to levy all applicable environmental sanctions and fines. Under Law No. 41, as amended by Law No. 8, the Ministry of the Environment may impose fines for any violation of Law No. 41, including the improper use of water concessions or water resources without having the applicable concession.

In addition to administrative liability, Law No. 41, as amended by Law No. 8, also established civil and criminal liability for damages to the environment, and Law No. 5 of 2005 introduced environmental crimes into the Criminal Code, including crimes against wildlife, natural resources, and crimes related to the approval of and compliance with environmental documentation.

Bankruptcy Regime

Law No. 12 of May 19, 2016 (the "Panamanian Bankruptcy Law") replaced the former Panamanian bankruptcy regime that was constructed upon provisions dispersed throughout several codes and laws and which did not provide for the possibility of reorganization, setting out only a framework for liquidation of troubled debtors.

In a more pro-entrepreneur spirit, the new Panamanian Bankruptcy Law, which became effective on January 2, 2017, implemented various rules to avoid the bankruptcy of individuals and companies. The Panamanian Bankruptcy Law resulted from an extensive consultation process with several stakeholders and is inspired by similar regimes enacted in other jurisdictions such as Chile, Argentina, Colombia, Spain and the United States of America. The Panamanian Bankruptcy Law's stated objective is the viability and continuation of enterprises as well as the satisfaction of credits in excess of what would have been possible under the prior regime.

The Panamanian Bankruptcy Law framework provides for both reorganization and liquidation proceedings. In addition, as discussed below, in the case of entities that render public utility services and that are under the purview of the ASEP, as in our case, the ASEP is legally authorized to take administrative control of such entities to guarantee the safety and efficiency of the national energy grid.

Reorganization proceedings

Upon the filing of a petition to commence reorganization proceedings under the Panamanian Bankruptcy Law, the creation or execution of guaranties on the debtor's assets, including by means of a guaranty trust, is not permitted (other than as part of the ordinary course of business of the debtor or with the court's consent). The debtor may not transfer, convey or dispose of assets, or enter into settlement agreements or other arrangements or reworkings with respect to its outstanding obligations or ongoing litigation. Any acts performed in breach of such limitations shall be null and void and the breaching party or parties shall be jointly and severally liable for damages resulting therefrom.

In addition, once the bankruptcy court orders the commencement of reorganization proceedings, bankruptcy protection (*protección financiera concursal*) is activated. Pursuant to such protection, *inter alia*, creditors (including secured parties) may not file any action against the debtor or foreclose on its assets. Moreover, any proceeding seeking the foreclosure of collateral granted by the debtor is suspended. Nevertheless, a debtor may seek to renegotiate certain executory agreements (*contratos de tracto sucesivo*) or, if such agreements cannot be renegotiated and the debtor can demonstrate that the costs to the debtor are onerous (taking into account the cost of replacing such services), request that the court overseeing the reorganization terminate such agreements. All relevant statutes of limitations are also suspended. As an exception, secured creditors may petition the court to commence or continue any such proceeding, as the

Panamanian Bankruptcy Law grants courts the power to authorize such proceedings where the foreclosure of the underlying assets will not affect the operations of the company or the viability of reaching a reorganization agreement.

All contracts entered into by the debtor remain valid during the period of bankruptcy protection, but payment of interest on unsecured debt obligations is suspended.

Liquidation proceedings

Notwithstanding the ASEP's authority to intervene, as discussed below, if creditors holding at least 2/3 of the outstanding claims with the right to vote (i.e., holders of claims that have been recognized by the bankruptcy court) do not approve a reorganization agreement, the debtor would, in all likelihood, be forced into liquidation.

Upon the issuance of the court decision declaring the commencement of liquidation proceedings, the debtor ceases to have the right to manage its assets, as such right and power is conferred upon an appointed liquidator that represents the interests of the creditors. At the same time, such decision suspends all creditors' rights to individually foreclose on the debtors, except for secured creditors who may continue with actions seeking the foreclosure of their collateral with the authorization of the court. Further, interest shall cease to accrue on unsecured credits and secured creditors may only enforce payment of accrued interest up to the value of their collateral. Pursuant to Articles 85 and 178 of the Panamanian Bankruptcy Law, secured credits are not included within the liquidation proceedings unless the secured creditor waives its privilege or, where following the foreclosure of the collateral, the credit is not fully satisfied. As a result, a secured creditor in a liquidation proceeding is generally free to apply the proceeds raised upon the foreclosure of its mortgage, pledge or other security interest up to the amounts owed and secured thereby. In fact, a secured creditor usually does not need to return such proceeds to the estate (unless there is an excess) or wait until the completion of the bankruptcy proceeding to receive them.

In the event of a court order instructing for liquidation, the following would apply to either the Issuer or Guarantors and their assets:

- As of the effectiveness of the liquidation order: (a) the Issuer or Guarantor would not be able to administer or dispose of its assets (except for assets not subject to embargo or attachment) and, as from that moment, such powers would pass on to the creditors, represented by the court-appointed liquidator; (b) all of the Issuer or Guarantor obligations would become due and payable and no further interest shall accrue on such obligations; and (c) the statute of limitations applicable to liabilities payable by it would be suspended.
- Certain executory agreements (*contratos de tracto sucesivo*) such as lease agreements could be terminated subject to the prior delivery of any statutory or agreed upon notice. Any payment or contract entered into by such Issuer or Guarantor following the issuance of the liquidation order would be null and void and any payment it would have to be made directly to the liquidator.
- The following acts could be voidable for the benefit of the liquidation estate if executed after the liquidation order or within the year prior to the date of the liquidation order (*declaratoria de liquidación*): (a) any action or agreement of the Issuer or Guarantor that lacks consideration (*título gratuito*) and those agreements that are entered into for excessive of consideration (*título oneroso*); (b) the constitution of a pledge, mortgage, or any other action entered into to secure obligations previously contracted or to grant a preference over other obligations; (c) payment (either with cash, assignment, transfer) of debts that are not considered past-due or the payment of debts already overdue; and (d) modifications to the articles of incorporation (*pacto social*) or the bylaws (*estatutos*) of the Issuer or Guarantor. Any action or agreement of the Issuer or Guarantor that lacks consideration (*título gratuito*) for the Issuer or Guarantor in favor of a shareholder, administrator, director, manager, officer, legal representative, liquidator or attorney-in-fact could be voidable if executed within the four-year period counted as from the date of insolvency set forth by the court in the liquidation order (*declaratoria de liquidación*).
- Any actions or agreements where there is a simulation of fraud, or a misrepresentation by the parties; and any disposal of assets with or without consideration if made with the intention of

subtracting the asset or its value from reach of the creditors, could be declared null and void by the court irrespective of their date of execution, and without being able to argue statute of limitations.

However, as mentioned above, pursuant to Article 284 of the Panamanian Constitution, the ASEP has the power to intervene electricity market participants in order to guarantee efficiency in the rendering of public services, subject to the restrictions set out in the law. Such power is further defined and regulated by Article 4 of the Panamanian Electricity Law and Executive Decree No. 24 of 2006. Accordingly, in the event that the ASEP deems that, for instance, the failure of an energy generation company poses a substantial risk to the national energy grid, the ASEP may take administrative control of such company with the goal of guaranteeing the continued, efficient and uninterrupted availability of power on the national grid.

Pursuant to Article 5 of the Panamanian Bankruptcy Law, once the ASEP takes administrative control of a company, bankruptcy proceedings may not be commenced against the company and all ongoing proceedings must be suspended. To that end, within 2 days from the date on which the ASEP takes administrative control of such company, the ASEP must serve notice upon bankruptcy courts. Pursuant to Articles 3 and 5 of Executive Decree No. 24 of 2006, the ASEP's administrative control may last for 90 days, which term may be extended if ASEP does not achieve its objective within the 90 day period. Nevertheless, given the relatively recent enactment of the new Panamanian Bankruptcy Law, there are not sufficient precedents available to determine how this process will operate in practice in every case.

Investment Stability Act

The Panamanian government enacted Law No. 54 of July 22, 1998, which is further regulated by Executive Decree No. 9 of February 22, 1999, or the Investment Stability Act. The Investment Stability Act provides for certain legal and tax stability measures in favor of companies registered with the Ministry of Commerce and Industry and engaged in electricity generation, distribution and transmission activities among other activities meeting certain qualifications. The Issuer and the Guarantors have these registries in process.

Foreseeable Political Trends

Panama is part of the 2015 Paris Agreement. Followed by its inclusion, the SNE implemented the Energetic National Plan 2015-2050 in which the SNE gives a leading role to renewable energies in the long-term energy matrix development plan, establishing a goal of greater participation of renewable energies in the mid and long-term.

In addition, this year, the SNE published the strategy for the energy transition 2020-2030 in which the Panamanian state outlined various initiatives in order for the energy transition to occur. Among these strategies are i) the electric mobility strategy, which seeks to promote the implementation of electric vehicles and charging stations in public areas and at a commercial and residential level, and ii) the innovation strategy that seeks to encourage public institutions to purchase energy as Large Customers through a bidding mechanism exclusively available to renewable energy counterparties.

The COVID-19 Pandemic

The COVID-19 Pandemic in Panama

In December 2019, the novel COVID-19 virus was reported in Wuhan, China. The COVID-19 virus has since spread to more than 175 countries, and the World Health Organization declared COVID-19 a global pandemic. The magnitude and duration of the COVID-19 pandemic and its impact on Panama's economy, social and public health situation is uncertain as this continues to evolve domestically and globally. As of November 1st, 2020, Panama reported 134,336 cases and 2,706 fatalities.

- On March 9, 2020, the Panamanian Ministry of Health reported the first confirmed case of COVID-19 in Panama.
- On March 13, 2020, Cabinet Resolution No. 11 declared a national state of emergency and directed government agencies to address this public health emergency.

- On March 16, 2020, the Ministry of Labor issued Resolution No. DM-137-2020, which adopts a protocol to preserve hygiene and health at work to prevent the spread of the COVID-19 virus, pursuant to which, among other things, all companies in Panama must, for the duration of the state of national emergency, create a special health and hygiene committee for the prevention and attention to the COVID-19 pandemic, comprised by an equal number of representatives of the employer and the employees.
- On March 17, 2020, the Panamanian government instituted a curfew throughout Panama for the entire population, from 9:00 p.m. to 5:00 a.m., as a preventive measure against the COVID-19 pandemic. On March 24, 2020, a 24-hour curfew was implemented, starting at 5:01 a.m. on March 25.
- On March 19, 2020, Executive Decree No. 499 declared the provinces of Panama, Panama West and Colón to be epidemic zones subject to sanitary control.
- On March 19, 2020, President Laurentino Cortizo ordered the suspension of all international passenger flights into and out of Panama, beginning on Sunday, March 22, 2020, for a period of 30 days that was later extended until June 23, 2020 and further extended to August 21, 2020.
- On March 24, 2020, President Laurentino Cortizo decreed a total curfew throughout Panama starting on March 25, 2020 at 5:01 A.M., pursuant to which non-essential businesses were closed and citizens are allowed to leave their homes for a maximum of two hours per day to buy food, medicine and basic necessities. Schools and universities were closed nationwide and gatherings of more than 50 people were prohibited. Businesses engaged in the provision of public services, hospitals, pharmacies, gas stations, supermarkets, food delivery services, the energy sector and emergency services, among others, were exempt from the curfew. The curfew also imposed travel and mobility restrictions based on people's gender and ID number. As of the date of this offering memorandum, the curfew has been lifted except for every day of the week between 11p.m. and 5a.m., which as of the date of this offering memorandum continues to be maintained without any official termination or expiration date. Nevertheless, a more limited curfew has been implemented in certain cities and provinces.
- On March 31, 2020, Cabinet Resolution No.19 mandated the Distribution Companies to provide discounts on energy bills to certain consumers and provided for the funding of a tariff stabilization fund (*Fondo de Estabilización Tarifaria*) through which the Panamanian government is expected to compensate the Distribution Companies for discounts provided to consumers.
- On May 1, 2020, a temporary deferment of lease payments beginning on May 1, 2020 until two months after the termination of the state of national emergency, provided that the lessee satisfies certain conditions, including having had a reduction of their income as a result of the COVID-19 pandemic.
- On May 4, 2020, Law 152 mandated a moratorium on payment of certain basic services, including electricity, for a period of four months for people and businesses meeting certain criteria. During this period, service providers are not permitted to disconnect these consumers' service for failure to pay or charge them late fees or interest on late payments.
- On May 11, 2020, a phased reopening was declared, and the second economic block, which includes public construction, non-metal mining, industry, places of worship and social sporting areas were opened on June 1, 2020.
- On May 21, 2020, ASEP issued Resolution No. 16094-Elec prohibiting service providers from disconnecting any end consumer's service, regardless of whether the consumer satisfies the criteria established by Law 152 issuing a moratorium on payments for the period between March and June 2020, and allowing the end customers to cancel the debt in 36 months without surcharges..
- On May 21, 2020, ASEP issued Resolution No. 16095-Elec that provides that payments under any PPA may be reduced in proportion to the deficit in income incurred by the Distribution Companies and imposes a moratorium on electricity generators' right to terminate PPAs for non-payment. Examples of such measures are as follows:

- If (i) a decrease in the income of a Distribution Company reduces its cash flow due to the moratorium granted by Law 152 to final customers and (ii) such decrease is evidenced to the ASEP, a Distribution Company (a) may reduce its payments for transmission service and for electricity purchased in the wholesale electricity market by an amount proportional to such decrease, except for payments under PPAs signed by that Distribution Company; and (b) with respect to the PPAs signed by the Distribution Company, it may inform the seller under the PPA that it will reduce its payments proportionally to the Distribution Company's decrease in monthly income. If the seller does not agree with such payment reductions, the parties may resolve their dispute in an arbitration proceeding with the ASEP. In such case, the seller may not draw on any payment guaranties under the PPA until the ASEP resolves the dispute, and may only draw on a payment guarantee if the dispute is resolved against the Distribution Company and the Distribution Company insists on not paying the amount determined by the ASEP;
- In the case of a partial payment in the spot market by participants affected by the measures established in Law 152, the CND will not draw on any deposit guaranties;
- In the case of lack of payments by users of the transmission system affected by the measures established in Law 152 the CND, ETESA and those agents in the market that apply charges for the use of the network by other agents of the market will not draw on any deposit guaranties for payments of the transmission service;
- Market participants with delayed payments between March 1 until June 30, 2020 will not be charged any default interest related thereto and any accumulated debt for such period will be paid pro rata in equal installments during a period not exceeding 36 months from July 1, 2020;
- Sellers under PPAs are not allowed to terminate the PPA for any lack of payment by the Distribution Companies during the period between March and June 2020; and
- No revisions of the amounts of payment guaranties payments, no default payments and no drawings from payment guaranties are permitted for lack of payment by the Distribution Companies during the period between March and June 2020.

- On June 30, 2020, Law No. 156 granted a moratorium on loan payments until December 31, 2020 to any borrower that may prove that it is affected in its business or personal activities by the COVID-19 pandemic. This moratorium applies to mortgage loans, personal loans, car loans, credit cards, SME loans, commercial loans, loans to the transportation sector, loans to the agriculture and livestock sectors and consumer loans.
- On August 25, 2020, the Panamanian government announced that by October 12, 2020 the following activities or industries were allowed to open: cultural and creative industry, schools of music and art, hotels, other accommodation places and related services, libraries, pools, international aviation, tourism activities, non-essential transport, and the national lottery.
- In response to the COVID-19 pandemic, the Panamanian government has adopted a series of measures which involve:
  - the construction of new hospitals and procurement of medical supplies;
  - the distribution of free food packages and a US$80/month "solidarity payment", which as of April 16, 2020, had reached more than 588,736 families in need; and
  - tax relief through extended payment deadlines.

These measures are funded by the government through facilities including a US$2.5 billion sovereign bond issuance and up to US$1.3 billion available from the Panama Savings Fund (*Fondo de Ahorro de Panamá*). Multilateral organizations have also provided financial support for these measures, including the IMF, through a SDR 376.8 million (about US$515 million) rapid financing instrument loan.

Certain of Panama's neighboring countries and trade partners have imposed similar measures in an attempt to contain the spread of the COVID-19 virus, but others have not taken action. There can be no assurance that the measures taken by Panama and these other countries will successfully contain the spread or mitigate the social, health and economic impact of the COVID-19 pandemic. The COVID-19 pandemic has led to increased volatility and decreased economic activity, which has negatively impacted the financial condition of the Panamanian public and Panamanian businesses, including certain of our customers and has reduced the overall demand for electricity. When comparing the second quarter of 2020 against the first quarter of that same year, the COVID-19 pandemic reduced Panamanian power demand by 21%, 12% in generation and 36.3% in spot prices. Between April and August 2020, electricity demand decreased by 11.93% compared to demand in 2019 within the same months, although since April a slow upside trend is observed, and by October 2020, demand has nearly reached 2019 values. Spot prices in Panama during the COVID-19 pandemic have also decreased 30.94% by August, 2020, since Panama entered total lockdown on March 25, 2020. Electricity demand in September began to increase, but with arrival of the wet season and the corresponding increase in hydroelectric plant generation, prices continue to be low reflecting the increased supply. In addition, as a result of government measures, the Distribution Companies have temporarily reduced tariffs to consumers and suspended shut-offs for non-payment, which has reduced the Distribution Companies' revenue and impacted their ability to make timely payments to generators under their PPAs, including our UEP II PPAs. For example, we have been able to collect 74.51% of the aggregate amount invoiced to the Distribution Companies under the UEP II PPAs between March and June. These government measures have also allowed any outstanding payments due to generators under their PPAs to be paid by Distribution Companies on an interest-free basis. For more information, see "Risk Factors — Risks Relating to our Business — The outbreak of the COVID-19 pandemic has had and may continue to have, and a further severe outbreak or an outbreak of another contagious disease could have, a material adverse impact on our operations and financial condition."

We are currently conducting good faith negotiations with the Distribution Companies and the government of Panama to reach a mutual beneficial solution for the collection of the outstanding 25.49% of the aggregate amount invoiced to the Distribution Companies under the UEP II PPAs between March and June 2020. For additional information regarding the impact of the COVID-19 pandemic on our business, see "Risk Factors — Risks relating to our Business — The outbreak of the COVID-19 pandemic has had and may continue to have, and a further severe outbreak or an outbreak of another contagious disease could have, a material adverse impact on our operations and financial condition" and "Management's Discussion and Analysis of Financial Condition and Results of Operation — Trends and Factors affecting our Results of Operations — Effects of the COVID-19 Pandemic."

Our Response to the COVID-19 Pandemic

We adopted a number of measures to maintain the continuous and uninterrupted operation our businesses and the well-being of their employees, including:

- implementing remote working for corporate and administrative employees;
- issuing and implementing a health and safety protocol in compliance with the legal framework of Panama and the World Health Organization;
- creating a detailed plan to reopen office and workspaces gradually depending on the status of transmission,
- treatment and prevention of COVID-19 infections;
- requiring that employees who work on site use masks and observe social distancing guidelines and limiting
- contractor site visits to those which are essential to the business;
- issuing a temporary ban on business travel;
- issuing a protocol for notifying our management of COVID-19 infections; and
- establishing clear quarantine procedures before allowing employees to return to work.

We will follow the global corporate guidelines as well as guidelines and regulations issued by the Panamanian Government and the World Health Organization before permitting corporate and administrative employees to return to work.

Generation Licenses

Pursuant to Articles 49 and 54 of the Electricity Law, the construction and operation of photovoltaic and wind power plants is subject to a licensing regime. Therefore, photovoltaic and wind power plants must request and obtain a generation license.

The descriptions below summarize the principal aspects of the licenses under which our companies operate:

- Tecnisol I, S.A. is currently operating in accordance with the definitive generation license approved by the ASEP under Resolution AN No. 8545-Elec dated May 6, 2015, as amended by Resolution AN No. 11239-Elec dated May 12, 2017, Resolution AN No. 11303-Elec dated June 6, 2017, and Resolution AN No. 11914-Elec dated December 14, 2017;
- Tecnisol II, S.A. is currently operating in accordance with the definitive generation license approved by the ASEP under Resolution AN No. 8546-Elec dated May 6, 2015, as amended by Resolution AN No. 11240-Elec dated May 12, 2017, and Resolution AN No. 11304-Elec dated June 6, 2017;
- Tecnisol III, S.A. is currently operating in accordance with the definitive generation license approved by the ASEP under Resolution AN No. 8547-Elec dated May 6, 2015, as amended by Resolution AN No. 11241-Elec dated May 12, 2017, and Resolution AN No. 11915-Elec dated December 14, 2017;
- Tecnisol IV, S.A. is currently operating in accordance with the definitive generation license approved by the ASEP under Resolution AN No. 8548-Elec dated May 6, 2015, as amended by Resolution AN No. 11242-Elec dated May 12, 2017, and Resolution AN No. 11293-Elec dated June 2, 2017;
- UEP II-Marañon is currently operating in accordance with the definitive generation license approved by the ASEP under Resolution AN No. 4075-Elec dated December 10, 2010, as amended by Resolution AN No. 5945-Elec dated February 7, 2013, Resolution AN No. 6822-Elec dated November 19, 2013, Resolution AN No. 7145-Elec dated March 6, 2014, Resolution AN No. 7275-Elec dated April 11, 2014, Resolution AN No. 7858-Elec dated September 26, 2014, Resolution AN No. 8770 dated July 6, 2015, Resolution AN No. 10045 dated June 6, 2016, and Resolution AN No. 12257-Elec dated April 6, 2018;
- UEP II-Nuevo Chagres is currently operating in accordance with the definitive generation license approved by the ASEP under Resolution AN No. 4094-Elec dated December 15, 2010, as amended by Resolution AN No. 5946-Elec dated February 7, 2013, Resolution AN No. 6056-Elec dated April 8, 2013, Resolution AN No. 6057-Elec dated April 8, 2013, Resolution AN No. 6088-Elec dated April 17, 2013, Resolution AN No. 6533-Elec dated August 30, 2013, Resolution AN No. 7169-Elec dated March 13, 2014, Resolution AN No. 7326-Elec dated May 2, 2014, Resolution AN No. 7861-Elec dated September 26, 2014, Resolution AN No. 8767-Elec dated July 6, 2015, Resolution AN No. 11774-Elec dated November 15, 2017, Resolution AN No. 11865-Elec dated December 1, 2017, Resolution AN No. 11951-Elec dated December 20, 2017;
- UEP II-Portobelo is currently operating in accordance with the definitive generation license approved by the ASEP under Resolution AN No. 4092-Elec dated December 15, 2010, as amended by Resolution AN No. 5944-Elec February 7, 2013, Resolution AN No. 6056-Elec dated April 8, 2013, Resolution AN No. 6677-Elec dated October 7, 2013, Resolution AN No. 7168-Elec dated March 13, 2014, Resolution AN No. 7278-Elec dated April 14, 2014, Resolution AN No. 7860 dated September 26, 2014, Resolution AN No. 8769-Elec dated July 6, 2015, Resolution AN No. 11864-Elec dated December 1, 2017, Resolution AN No. 12036-Elec dated January 22, 2018 and Resolution AN No. 12308-Elec dated April 23, 2018; and
- UEP II-Rosa de los Vientos I and Rosa de los Vientos II are currently operating in accordance with the definitive generation license approved by the ASEP under Resolution AN No. 5379-Elec dated June 13, 2012, as amended by Resolution AN No. 6674-Elec dated October 3, 2013, Resolution AN No. 7170-Elec dated March 13, 2014, Resolution AN No. 7274-Elec dated April 11, 2014,

Resolution AN No. 7859-Elec dated September 26, 2014, Resolution AN No. 8768-Elec dated July 6, 2015, Resolution AN No. 10056-Elec dated June 9, 2016 and Resolution AN No. 12069-Elec dated January 26, 2018.

Environmental Assessment Study

Environmental matters in Panama are regulated by the following provisions: (i) Law No. 41 dated July 3, 1998, as amended by Law No. 8 dated March 25, 2015, which creates the Ministry of the Environment, and establishes certain other provisions, and (ii) Executive Decree No. 123 dated August 14, 2009, which regulates the environmental assessment studies.

Pursuant to Executive Decree No. 123, construction projects, including our own, may not be carried out in Panama without prior approval of an environmental assessment study. The environmental assessment study is carried out by an environmental expert, who performs specific tests to determine the category of environmental assessment study required for a given construction project. The expert then identifies, evaluates and establishes certain mitigation measures for the construction project to follow, including potential reforestation requirements. This assessment must then be submitted to the Ministry of the Environment for evaluation, at which time the Ministry of the Environment may approve such construction projects by resolution. Additionally, Article 57 of Executive Decree No. 123 establishes that the Sponsor, the Issuer, or the Guarantors in the case of the Projects, must deliver periodic reports with updates on the mitigation measures undertaken. The periodic reports must be submitted to the respective regional office of the Ministry of the Environment in which the construction project is located in accordance with the respective environmental assessment study and the terms set forth in the resolution.

Currently, the Issuer and the Guarantors hold the following environmental permits:

- Resolution ARACH IA-157-2014 dated October 21, 2014, whereby the Ministry of the Environment approved the category I Environmental Assessment Study of "Sistema Solar Fotovoltaico de Generación de Energía Eléctrica Proyecto IKAKO," as amended by Resolution ARACH-IAM-004-16 dated January 6, 2016 and Resolution DRCH-IA CORREC 003-2017 dated March 28, 2017. Tecnisol I has been substantially delivering periodic reports, as well as complying with the mitigation measures prescribed in the applicable environmental assessment study;
- Resolution ARACH IA-046-2016 dated April 8, 2016, whereby the Ministry of the Environment approved the category I Environmental Assessment Study of "Sistema Solar Fotovoltaico de Generación de Energía Eléctrica Proyecto IKAKO I," as amended by Resolution DRCH-IAM 009-17 dated July 14, 2017. Tecnisol II has been substantially delivering periodic reports, as well as complying with the mitigation measures prescribed in the applicable environmental assessment study;
- Resolution ARACH IA-155-2014 dated October 21, 2014, whereby the Ministry of the Environment approved the category I Environmental Assessment Study of "Sistema Solar Fotovoltaico de Generación de Energía Eléctrica Proyecto IKAKO II," as amended by Resolution ARACH-IAM-008-16 dated March 17, 2016 and Resolution DRCH-IA CORREC 005-2017 dated March 30, 2017. Tecnisol III has been substantially delivering periodic reports, as well as complying with the mitigation measures prescribed in the applicable environmental assessment study;
- Resolution ARACH IA-154-2014 dated October 21, 2014, whereby the Ministry of the Environment approved the category I Environmental Assessment Study of "Sistema Solar Fotovoltaico de Generación de Energía Eléctrica Proyecto IKAKO III," as amended by Resolution ARACH-IAM-010-16 dated March 23, 2016 and Resolution DRCH-IA CORREC 004-2017 dated March 28, 2017. Tecnisol IV has been substantially delivering periodic reports, as well as complying with the mitigation measures prescribed in the applicable environmental assessment study;
- Resolution ARACH IA-062-2016 dated May 24, 2016, whereby the Ministry of the Environment approved the category I Environmental Assessment Study of "Construcción y Operación de la Línea de Transmisión de 34.5 kV para la Interconexión de los Proyectos Fotovoltaicos (Solar) IKAKO, IKAKO I, IKAKO II, IKAKO III a la Subestación Mata de Nance." Tecnisol I has been

substantially delivering periodic reports, as well as complying with the mitigation measures prescribed in the applicable environmental assessment study;

- Resolution IA-352-10 dated May 31, 2010 whereby the Ministry of the Environment approved the category III Environmental Assessment Study of "Proyecto Eólico Marañon," as amended by Resolution AG-0599-2010 dated June 28, 2010, Resolution DIEORA IAM-025-2014 dated February 26, 2014 and Resolution DIEORA IAM-038-2017 dated July 20, 2017. UEP II has been substantially delivering periodic reports, as well as complying with the mitigation measures prescribed in the applicable environmental assessment study;
- Resolution IA-353-10 dated May 31, 2010 whereby the Ministry of the Environment approved the category III Environmental Assessment Study of "Proyecto Eólico Nuevo Chagres," as amended by Resolution AG-0600-2010 dated June 28, 2010, Resolution DIEORA IAM-013-2013 dated February 15, 2013, Resolution DIEORA IAM-037-2014 dated April 21, 2014 and Resolution DIEORA IAM-036-2017 dated July 18, 2017. UEP II has been substantially delivering periodic reports, as well as complying with the mitigation measures prescribed in the applicable environmental assessment study;
- Resolution IA-354-10 dated May 31, 2010 whereby the Ministry of the Environment approved the category III Environmental Assessment Study of "Proyecto Eólico Portobelo," as amended by Resolution AG-0601-2010 dated June 28, 2010, Resolution DIEORA IAM-002-2013 dated January 16, 2013, Resolution DIEORA IAM-036-2014 dated April 10, 2014 and Resolution DIEORA IAM-037-2017 dated July 18, 2017. UEP II has been substantially delivering periodic reports, as well as complying with the mitigation measures prescribed in the applicable environmental assessment study;
- Resolution ARAC-IA-068 dated September 10, 2012 whereby the Ministry of the Environment approved the category I Environmental Assessment Study of "Construcción de Caminos del Parque Eólico Penonomé." UEP II has substantially delivered all required periodic reports, as well as complied with the mitigation measures prescribed in the applicable environmental assessment study;
- Resolution ARAC-IA-075-14 dated July 31, 2014 whereby the Ministry of the Environment approved the category I Environmental Assessment Study of "Construcción de Caminos del Parque Eólico Penonomé, Fase III." UEP II has substantially delivered all required periodic reports, as well as complied with the mitigation measures prescribed in the applicable environmental assessment study;
- Resolution ARAC-IA-087-13 dated August 9, 2013 whereby the Ministry of the Environment approved the category I Environmental Assessment Study of "Línea Colectora, Parque Eólico Penonomé." UEP II has substantially delivered all required periodic reports, as well as complied with the mitigation measures prescribed in the applicable environmental assessment study; and
- Resolution IA-355-10 dated May 31, 2010 whereby the Ministry of the Environment approved the category III Environmental Assessment Study of "Proyecto Eólico Rosa de los Vientos," as amended by Resolution AG-0602-2010 dated June 28, 2010, Resolution DIEORA IAM-020-2012 dated March 30, 2012, Resolution DIEORA IAM-012-2014 dated February 10, 2014, and Resolution DIEORA IAM-029-2017 dated June 1, 2017. UEP II has been substantially delivering periodic reports, as well as complying with the mitigation measures prescribed in the applicable environmental assessment study.

Interconnection Agreement

Pursuant to the Electricity Law of the ASEP, transmission services in Panama must be provided by the government through ETESA. Any company that transmits energy in the national grid using the infrastructure of the SIN must enter into an access agreement with ETESA.

The Issuer and the Guarantors hold the following access contracts:

- Access Contract number GG-144-2015, executed by and between ETESA and Tecnisol I on September 28, 2015. Access Contract No. GG-144-2015 is valid for 15 years from the date in which the interconnection grid point reached a commercial operation phase which happened on March 29, 2019, except if a termination occurs;

- Access Contract number GG-143-2015, executed by and between ETESA and Tecnisol II on September 28, 2015. Access Contract No. GG-143-2015 is valid for 15 years from the date in which the interconnection grid point reached a commercial operation phase which happened on March 29, 2019, except if a termination occurs;
- Access Contract number GG-142-2015, executed by and between ETESA and Tecnisol III on September 28, 2015. Access Contract No. GG-142-2015 is valid for 15 years from the date in which the interconnection grid point reached a commercial operation phase which happened on March 29, 2019, except if a termination occurs;
- Access Contract number GG-141-2015, executed by and between ETESA and Tecnisol IV on September 28, 2015. Access Contract No. GG-141-2015 is valid for 15 years from the date in which the interconnection grid point reached a commercial operation phase which happened on May 10, 2019, except if a termination occurs; and
- Access Contract number GG-019-2012, between ETESA and UEP II dated April 16, 2012, assigned to UEP Penonomé I, S.A. on March 7, 2013 and later assigned to the Issuer on July 21, 2014 and amended by Amendment No. 1 dated September 16, 2014. Access Contract No. GG-019-2012 is valid for 15 years from the date of the Agreement, except if a termination occurs.

Occupational Health and Safety Regulation

Companies operating in Panama must have a professional risk plan in place. The Social Security Office may impose penalties if it considers that the health or safety of the employees is threatened. The Issuer and the Guarantors have their respective professional risk plans in place.

MANAGEMENT

Board of Directors

The Issuer is managed by a board of directors (*junta directiva*) (the "Board of Directors" and each a "Board Member"), which, in accordance with the Issuer's articles of incorporation, consists of members appointed by the shareholders. As of the date of this offering memorandum, the Board of Directors consists of four Board Members, who are responsible for the management of strategic, regulatory and business matters. The Board Members are appointed at the Issuer's shareholders meeting for an unlimited term until such Board Member resigns or is removed at any time by a majority decision of the shareholders. The Board of Directors is required to meet at least once a year, but additional meetings can be called as necessary.

The following table sets forth information regarding the members of the Board Members as of the date of this offering memorandum:

Name	Position	Date Appointed	Age	Address
Luis Rolando Gonzalez Bunster	President	April 23, 2014	73	6 Doubling Rd, Greenwich, CT 06830, USA
Flavio da Silveira Pinheiro	Treasurer	February 07, 2018	45	12 Anderson Street London SW3 3NH, UK
Pastor Sanjurjo	Secretary	February 07, 2018	66	335 S. Biscayne Blvd, Miami FL, USA
Rafael Perez-Pire Angulo	Director	January 13, 2013	52	Marina Flamenco, Panamá

Below is a summary of the business experience, activities and areas of expertise of the Board of Directors.

Luis Rolando Gonzalez Bunster. Mr. Gonzalez Bunster founded InterEnergy (formerly Basic Energy, Ltd.) in 1988 and has over 40 years of experience in project management and business development in the energy sector. Mr. Gonzalez Bunster received a Bachelor of Science degree in Economics from the Georgetown College of Arts and Sciences. He has served as a Board Member of the Issuer since 2014 and is also a Director and Trustee of the William Hillary and Chelsea Clinton Foundation. He is also a member of the Energy Committee of the Clinton Global Initiative, focusing on the development of clean and renewable energy.

Flavio da Silveira Pinheiro. Mr. da Silveira Pinheiro leads InterEnergy's corporate finance, investor relations and administrative functions. He has over 23 years of experience in corporate finance and mergers & acquisitions, with a focus on the energy sector since 2007, when Mr. Pinheiro founded Sprimont Capital LLC to advise on and invest in transactions in Latin America. In early 2011, he brought together a group of institutional investors with Basic Energy and played a key role in structuring the transactions that led to the formation of InterEnergy. Mr. Pinheiro received a Bachelor of Science degree in Economics and Finance from Bentley College. He has served as a Board Member of the Issuer since 2014.

Pastor Sanjurjo. Mr. Sanjurjo has over 30 years of experience in the energy sector and leads InterEnergy's thermal business as Head of Thermal Power & Utilities. Mr. Sanjurjo received a Bachelor of Science degree in Engineering from Georgia Tech and a Master of Business Administration degree from Georgia State. In 2002 he joined Globeleq as Director of Acquisitions and in 2003 became CEO of EGE Haina. During his tenure, EGE Haina developed the first wind farm in the Dominican Republic. Mr. Sanjurjo has served as a Board Member of the Issuer since 2015 and currently serves as board member of the Guarantors.

Rafael Pérez-Pire Angulo. Mr. Rafael Pérez-Pire Angulo has over 29 years of experience in the energy sector and over 25 years of experience in the renewables energy sector. Mr. Pérez-Pire received an Industrial Engineering degree from the Superior Technical School of Industrial Engineering of the Polytechnic University in Madrid. Since 1994 has founded and managed several renewable energy companies, developing projects in wind, solar, biomass, biogas, and electrical infrastructure, with an aggregate installed capacity of more than 1,200 MW. In 2009 Mr. Pérez-Pire founded UEP in Panama and developed the 340 MW wind energy project in Penonome, which includes our UEP II Wind Project. Mr. Pérez-Pire is a minor shareholder in Green Field Panamá, S.A and member of the Board of Directors since 2013.

Management

The following table sets forth information regarding our management as of the date of this offering memorandum:

Name	Position	Date Appointed	Age	Address
Eileen Fargis	Managing Director, Head of Investments	November, 2017	51	Greenwich, Connecticut, USA
Andrés Slullitel	Managing Director, Chief Financial Officer	June 01, 2008	43	La Esperilla, Santo Domingo, DR
Mónica Lupianez	Panama Country Manager and Managing Director, Head of Renewables	June 01, 2019	41	Panamá Pacífico, Nativa, Panama
Tomás Esteva	Senior Financial Manager	June 01, 2014	37	Costa del Este, Panama City, Panama
Harold Hernandez	Senior Commercial Manager	January 01, 2015	35	Las Cumbres, Panama City, Panama
Guillem Torrens	Senior Technical Manager	August 1, 2019	39	Explora, Panama Pacifico, Panama
José Barahona	O&M Senior Manager	September 24, 2018	47	Río Hato, Coclé, Panama

Below is a summary of the business experience, activities and areas of expertise of Issuer's management.

Eileen Fargis. Ms. Fargis has over 30 years in the industry and 15 years of experience in the energy sector. She was formerly the Co-Head of the IFC African Latin American and Caribbean (ALAC), leading ALAC's investment into InterEnergy and was formerly a member of the Board. In addition, she was Managing Director of Global Growth for GE Energy Financial Services. Ms. Fargis holds a Bachelors of Arts degree from Hamilton College and a Master of Arts degree in international economics from the Johns Hopkins School of Advanced International Studies.

Andres Slullitel. Mr. Slullitel has over 13 years of experience in the energy sector. He is the Chief Financial Officer of the Sponsor and leads his finance team on all matters related to financing for subsidiaries across the portfolio in four countries. Andres was previously corporate treasury director for CEPM and EGE Haina until he joined the Sponsor in 2011, where he was promoted to CFO. Prior to joining CEPM, he was a private banking relationship manager at Credit Suisse and Banco Galicia. Andres holds a Master of Finance and Capital Markets degree from the Universidad Nacional de Rosario in Argentina as well as a public accountant degree.

Mónica Lupiáñez. Ms. Lupiáñez has over 19 years of experience in the energy sector with more than 12 years of experience in renewables. Ms. Lupiáñez received a Master of Science in Industrial Engineering degree with double major in Thermal and Electrical Engineering from the Polytechnic University of Catalonia in Spain. Since 2019 she serves as Managing Director, Head of Renewables of our Sponsor and recently as our Panama Country Manager. Since 2008 she has founded and managed several renewable companies in Europe. Prior to joining us, she served as CEO and co-founder of Fazilita Holding, a Panama-based renewable energy engineering solutions company, developing projects of more than 1,340MW renewables including 590MW of solar projects. Ms. Lupiáñez serves as board member of the Guarantors.

Tomas Esteva. Mr. Tomas Esteva has over 12 years of experience in the energy sector. Mr. Esteva received an accounting degree from the University Dr. Rafael Belloso Chacin and a Master of Financial Management degree from the University of Zulia. He also holds a Master of Business Administration degree with specialization in management development from ADEN Business. Since 2014 he serves as our Financial Manager. Previously, he obtained 8 years of experience in PwC as a Senior Auditor in the Financial Audit Division.

Harold Hernandez. Mr. Hernandez has over 10 years of experience in the energy sector. He began his professional career at Elektra Noreste S.A. (today ENSA), and thereafter at ETESA in various positions including as a technical planning manager and planning engineer. Mr. Hernandez received an Electromechanical Engineering degree from the Technological University of Panama. He has a Master of Science in Renewable Energies from the Technological University of Panama and a Master of Business Administration degree from the Universidad Latina de Panamá. Since 2015 he serves as our Commercial Manager. Previously, he served as Technical Planning Chief at ETESA, where he was responsible for developing its Transmission Expansion Plan.

Guillem Torrens. Mr. Torrens has over 13 years of experience in the energy sector. He began his professional career at Ibersolar Energia, and thereafter at Fazilita Renewables Holding in various positions including project manager, technical director, and country manager. Mr. Torrens received a Telecommunications Engineering degree from the Technological University of Catalonia, a Bachelor of Science with honors in Communication Networks from the Oxford Brookes University. He has a Master of Energy Efficiency degree and a Master of Renewable Energy degree from the Universidad de Zaragoza in Spain. Since 2019 he serves as our Senior Technical Manager. Previously, he served as Technical Director at Fazilita Holding, where he was responsible for the design of projects in the region of more than 1,340MW renewables including 590MW of solar projects.

José Barahona. Mr. Barahona has over 20 years of experience in the energy sector. He began working in the wind industry in 2010 as an Operation and Maintenance Manager for Enel Costa Rica. He received a Bachelor of Science in Electrical Engineering from the Universidad de Costa Rica and Master of Business Administration degree from Universidad FUNDEPOS in Costa Rica. Since 2018 he serves as our O&M Senior Manager of Wind and Solar.

PRINCIPAL SHAREHOLDERS

The Issuer

As of the date of this offering memorandum, the issued and outstanding share capital was approximately 75,000,000, represented by 1,050 shares without par value and each share is entitled to one vote.

The following table sets forth certain information as of the date of this offering memorandum, concerning the ownership of the Issuer's share capital:

Shareholders	Common shares	Capital Contribution	% of ownership	Total
IEH Penonomé Holdings(1)	1,000	71,428,571	95.24%	71,428,571
Green Field Panamá, S.A.	50	3,571,429	4.76%	3,571,429
Total	1,050	**75,000,000**	**100%**	**75,000,000**

(1) InterEnergy Group Limited owns 87.5% of the outstanding shares of IEH Penonome Holdings and Portland Panama Wind (Cayman) owns the remaining 13% of the IEH Penonome Holdings.

On April 23, 2014, the predecessors of IEH Penonomé Holdings and Green Field Panamá, S.A entered into a shareholders' agreement, for the purpose of regulating the operation and management of the Issuer and the transfer of shares of the Issuer. IEH Penonomé Holdings and Green Field Panamá, S.A., as shareholders of the Issuer, are parties to such shareholders agreement.

The Guarantors

As of the date of this offering memorandum, the aggregate amount of each Guarantors' issued and outstanding share capital is US$10,000 represented by 100 common shares, with a nominal value of US$100 each and each share is entitled to one vote. As of the date of this offering memorandum, all the Guarantors' shares are owned by InterEnergy Renewables, SLU, an affiliate of our Sponsor.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

The following discussion is a brief summary of certain material arrangements, agreements and transactions we have with related parties. We are also engaged in other transactions with related parties that we do not perceive as material. We have engaged, and in the future may engage, in transactions with related parties.

Our related party transactions are detailed in Note 16 to our Issuer Annual Financial Statements, Note 16 to our Issuer Unaudited Interim Financial Statements and note 13 to the Guarantors Unaudited Interim Combined Financial Statements.

Below is a summarized description of our most relevant related party transactions.

The Issuer

UEP II Management Services Agreement

On January 1, 2020 the Issuer and IEH UK entered into the UEP II Management Services Agreement pursuant to which IEH UK provides certain services, including: (i) administration of compliance by us and Goldwind of the Service and Maintenance Agreement, including calculations of availability, bonuses and invoicing, (ii) technical asset management, (iii) operation and maintenance supervision of the assets of the Issuer, (iv) accounting system setup and enhancements and (v) design of our commercial strategy, among others. For such services the Issuer pays to IEH UK a base price of US$322,500 annually and a variable price up to US$967,500 subject to financial performance and distribution ratios under the Notes.

UEP II Shareholders Loan Agreements

On December 9, 2014, IEH Penonomé Holdings (Cayman) granted the Issuer a loan for US$47.6 million pursuant to a global subordinated intercompany note dated December 9, 2014. The loan accrues interest at an 8% annual rate and is payable semi-annually in arrears. The proceeds of the loan were used for the financing of the construction of UEP II Wind Project and related costs. As of September 30, 2020, the principal amount due under this loan was US$47.6 million since no principal payment has been made. We expect to repay this loan with the proceeds from the offering of the Notes.

On December 31, 2014, Green Field Panamá, S.A. granted the Issuer a loan for US$2.4 million pursuant to a global subordinated intercompany note dated December 31, 2014. The loan accrues interest at an 8% annual rate and is payable semi-annually in arrears. The proceeds of the loan were used for the financing of the construction of UEP II Wind Project and related costs. As of September 30, 2020, the principal amount due under this loan was US$2.4 million since no principal payment has been made. We expect to repay this loan with the proceeds from the offering of the Notes.

UEP II Energy Reserve Agreements

The Issuer has entered into two intercompany energy reserve agreements with Tecnisol I, S.A. and Tecnisol III, S.A. whereby the Issuer has agreed to supply energy to Tecnisol I, S.A. and Tecnisol III, S.A. on an as-needed basis (the "UEP II Energy Reserve Agreements"). Pursuant to the terms of the UEP II Energy Reserve Agreements we supply the energy with Rosa de Los Vientos II, which has a total capacity of 50 MW. Under the UEP II Energy Reserve Agreements, the parties are not liable for loss of profit, punitive or consequential damages arising out of such agreements and any controversy or claim arising out of the UEP II Energy Reserve Agreements is required to be settled by binding arbitration. The supply period is until March 2025 under the UEP II Energy Reserve Agreement with Tecnisol I, S.A. and until June 2025 under the UEP II Energy Reserve Agreement with Tecnisol III, S.A. The purchase price is calculated based on US$65.3/MWh and is paid on a monthly basis.

The Guarantors

Tecnisol Management Services Agreements

On February 1, 2020 the Guarantors and IEH UK entered into the Tecnisol Management Services Agreement pursuant to which IEH UK provides certain services, including: (i) business management, (ii) a guaranteed availability of at least 98%, (iii) implementing and enhancing the accounting system, (iv) ensuring regulatory compliance and (v) implementing and supervising commercial strategy, among others. For such services the Guarantors pay to IEH UK a base price of US$60,000 annually and a variable price up to US$140,000 subject to financial performance and distribution ratios under the Notes.

Tecnisol Shareholder Loan Agreement

On December 31, 2018, the Sponsor granted the Guarantors several loans for an aggregate amount of US$47.8 million pursuant to four intercompany notes dated January 1, 2019. Such credits were assigned by the Sponsor to IEH UK on September 11, 2019. The loans accrue interest at a 3% annual rate and are payable on December 20, 2021. The proceeds of the loans were used for the financing of the construction of the Tecnisol Solar Project and related costs. As of September 30, 2020, the principal amount outstanding under these loans was US$40 million. We expect to repay these loans with the proceeds from the offering of the Notes.

Tecnisol Intercompany Energy Reserve Agreements

The Guarantors have entered into four intercompany energy reserve agreements among themselves pursuant to which the supplier under the relevant agreement, as applicable, has agreed to supply all energy generated by such supplier that is not previously sold under other PPAs (the "Tecnisol Intercompany Energy Reserve Agreements"). Under the Tecnisol Intercompany Energy Reserve Agreements, the parties are not liable for loss of profit, punitive or consequential damages arising out of such agreements and any controversy or claim arising out of the Tecnisol Intercompany Energy Reserve Agreements is required to be settled by binding arbitration.

The following chart lists the Tecnisol Intercompany Energy Reserve Agreements that the Guarantors have entered into and their supply period:

Seller	Offtaker	Supply Period
1. Tecnisol II	Tecnisol I	Dec. 2019 – Dec. 2029
2. Tecnisol II	Tecnisol III	Dec. 2019 – Dec. 2029
3. Tecnisol IV	Tecnisol I	Dec. 2019 – Dec. 2029
4. Tecnisol IV	Tecnisol III	Dec. 2019 – Dec. 2029

Tecnisol Intercompany Interconnection Agreements

Tecnisol II, S.A. and Tecnisol IV, S.A. have access to the SIN through the HICACO IV substation, property of Tecnisol I, S.A. August 1, 2018, Tecnisol I, S.A. entered into the Tecnisol Intercompany Interconnection Agreements with Tecnisol II, S.A. and Tecnisol IV, S.A. Under each Tecnisol Intercompany Interconnection Agreements, Tecnisol II, S.A. and Tecnisol IV, S.A. must pay a fee to Tecnisol I, S.A. for the use of the HICACO IV substation. The fee is set by Tecnisol I, S.A., and Tecnisol I, S.A. notifies Tecnisol II, S.A. and Tecnisol IV, S.A. of the fee amount no later than December 31 of the immediately prior year. For a description of the Tecnisol Intercompany Interconnection Agreements, see "Business Overview — Certain Material Agreements — Tecnisol Intercompany Interconnection Agreements".

DESCRIPTION OF PRINCIPAL FINANCIAL DOCUMENTS

Letter of Credit Agreement

The Issuer intends to enter into a Letter of Credit Agreement (the “Letter of Credit Agreement”) for purposes of issuing one or more stand-by letters of credit (each a “Letter of Credit”) to fund, as permitted under the terms of the Notes, the Debt Service Reserve Account or the Trust O&M Reserve Account (as such terms are defined in the “Description of the Notes”). The Issuer may enter into the Letter of Credit Agreement on before or after the Issue Date.

As required under the terms of the Notes, we would enter into the Letter of Credit Facility with an Acceptable Bank (as defined in the “Description of the Notes”), which includes any bank or financial institution with a rating of at least Baa3, in the case of Moody’s or BBB-, in the case of each Standard & Poor’s and Fitch, with respect to its long-term senior unsecured debt. We expect that the maximum exposure of the Letters of Credits issued under the Letter of Credit Facility will be up to US$17,000,000. Any and all proceeds from any drawing under the Letters of Credit will be deposited by the Collateral Trustee in the Debt Service Reserve Account or the Trust O&M Reserve Account, as applicable, and as set forth in greater detail in the Indenture.

The Issuer’ obligations under the Letter of Credit Facility would be secured ratably by the Collateral and jointly and severally guaranteed by the Guarantors. We expect the administrative agent or an authorized representative under the terms of the Letter of Credit Facility to join the Intercreditor Agreement. The payment of the obligations under the Letter of Credit Facility would be made pursuant to the Accounts Waterfall (see “Description of the Notes — Accounts Waterfall”) and, following an enforcement action involving the sale, disposition or other realization, collection or recovery of any amounts or any Collateral, the Issuer’s obligations under the Letter of Credit Agreement would rank *pari passu* with the Notes.

Under the Collateral Trust Agreement, to the extent that Debt Service Reserve Account or the Trust O&M Reserve Account is being funded by Letter of Credit, the Collateral Trustee will draw on the Letter of Credit:

- If, (a) with respect to any Letter of Credit issued to fund the Debt Service Reserve Account, amounts on deposit in the Debt Service Accrual Account are, on the date that is 5 Business Days prior to the next succeeding applicable payment date, insufficient to make payments under the Indenture and any other Additional Debt (including interest expense, principal, fees, premiums or other amounts) for which there is an Additional Debt Service Reserve Requirement, or (b) with respect to any Letter of Credit issue to fund the Trust O&M Reserve Account, if amounts held in the Collections Account, Issuer Working Capital Account or Guarantor Working Capital Account, as applicable, are, on the date that is 5 Business Days prior to the next succeeding applicable payment date, insufficient to pay Operating and Maintenance Expenses, in each case, such Letter of Credit may be drawn to pay such deficiency in accordance with the Panamanian Trust Agreement.
- If (a) at any time after the issuance of a Letter of Credit under the LC Credit Agreement, the issuing bank of the applicable Letter of Credit ceases to be an Acceptable Bank and (b) within 60 days thereof, the Debt Service Reserve Account or the Trust O&M Reserve Account, as applicable, is not funded with cash or a replacement of such Letter of Credit has not been issued by an Acceptable Bank or other Letters of Credit sufficient to cover any reserve required to be maintained under the Panamanian Trust Agreement.
- Within 15 days of maturity of the Letter of Credit if a replacement letter of credit is not obtained and the Debt Service Reserve Account or the Trust O&M Reserve Account, as applicable, is not funded with cash or other Letters of Credit sufficient to cover any reserve required to be maintained under the Panamanian Trust Agreement.

If the aggregate amount of the cash on deposit in the reserve account and the amount available under the Letters of Credit exceeds the “reserve requirement” under the terms of the Panamanian Trust Agreement, the Issuer may, pursuant to the terms of the Panamanian Trust Agreement, direct the Collateral Trustee to transfer excess amounts to the Issuer Collection Account and/or to reduce the amount available under the Letters of Credit. If prior to March 31, 2021, we fund the Debt Service Reserve Account and/or the Trust

O&M Reserve Accounts with one or more Letters of Credit issued under the Letter of Credit Facility, we may instruct the Collateral Trustee to deposit cash in the Issuer Distribution Account an amount equal to any funds deposited in the Debt Service Reserve Account and/or the Trust O&M Reserve Accounts (in cash or covered by such Letters of Credit) in excess of the amounts required to be deposited in such accounts pursuant to the terms of the Panamanian Trust Agreement and the terms of the Notes. For more information, see "Description of the Notes — Accounts Waterfall."

Intercreditor Arrangements

For a description of the Intercreditor Arrangements, see "Description of the Notes — Intercreditor Arrangements."

DESCRIPTION OF COLLATERAL

Capitalized terms used herein but not defined shall have the meaning attributed to them under "Description of the Notes."

Trust Agreement

The Panamanian Trust was established in Panama pursuant to public deed No. 35,284 of November 26, 2014 of the Fifth Notary of the Circuit of Panama registered at Folio No. 30122089 and Entry 1, as modified by public deed No. 20,008 of December 10, 2014 of the Second Notary of the Circuit of Panama, registered at Folio 30122089 and Entry 2 (the "Original Panamanian Trust Agreement") and subsequent amendments, under the technical name of "The Bank of Nova Scotia (Panama), S.A./FID-135" as a contractual arrangement to hold assets that, as amended to date, currently secures certain outstanding indebtedness of the Issuer and that will secure the Issuer and the Guarantors' obligations under the Notes as well as the Additional Debt; *provided* that, only with respect to Additional Debt that will not repay all the indebtedness under the Notes, the Authorized Representative of the holders of such other Additional Debt will have executed a joinder to the Intercreditor Agreement. As of the date of issuance of the Notes, the Noteholders will be secondary beneficiaries of the Panamanian Trust, and will become primary beneficiaries thereof when such outstanding indebtedness is paid in full with the proceeds of the Notes. Not later than fifteen (15) Business Days after the Issue Date, the Original Panamanian Trust Agreement will be further amended (as amended the "Panamanian Trust Agreement") to include a description of the additional Trust accounts to be created in connection with the Notes and provide for the transfers to and/or withdrawals from each Panamanian Trust account in accordance with the priority order described in "Description of the Notes — Intercreditor Arrangements."

Trusts are regulated in Panama by Law No. 1 of January 5, 1984, as amended by Law No. 21 of May 10, 2017. The Superintendency of Banks is the official entity responsible for supervising and safeguarding the adequate functioning of the trust business in the Republic of Panama.

The Panamanian Trust Agreement provides for the establishment and maintenance by the Collateral Trustee of the Issuer Collection Account and such other accounts as the Collateral Trustee will from time to time require and establish and maintain for the Panamanian Trust's operations. Under the Panamanian Trust Agreement, the Collateral Trustee is authorized to open and maintain each Panamanian Trust account with an approved account bank. The Collateral Trustee will be the only signatory under the Panamanian Trust accounts.

The Collateral Trustee will transfer available funds on deposit in the Panamanian Trust Accounts in accordance with the Accounts Waterfall set forth in the Panamanian Trust Agreement, as instructed by the Issuer, unless the following have occurred (collectively a "Change of Control Event") (i) an Event of Default has occurred and is continuing, (ii) the Intercreditor Agent has received a Notice of Default from a Secured Party pursuant to the Intercreditor Agreement, (iii) the Intercreditor Agent has provided the Notice of Default to the Collateral Trustee, and (iv) the Intercreditor Agent gives notice to the Collateral Trustee that the Intercreditor Agent has received a Blocking Remedies Notice (as defined under the Intercreditor Agreement) requesting the Issuer's right to instruct the Collateral Trustee to make such fund transfers with respect to the Panamanian Trust Accounts be suspended; provided, however, that such suspension shall be revoked and the Issuer's ability to deliver instructions to the Collateral Trustee shall be restored following the delivery by the Intercreditor Agent of a notice to the Collateral Trustee upon the earliest of (a) the delivery to the Intercreditor Agent of a Notice of Cessation of Default (as defined in the Intercreditor Agreement), and (b) the rejection by the Required Secured Debtholders, through the applicable Intercreditor Vote, of such suspension requested in the applicable Blocking Remedies Notice (as defined in the Intercreditor Agreement).

Interest and other revenues generated by each Panamanian Trust account will be credited into the same Panamanian Trust account.

The obligations secured by the Panamanian Trust Agreement include, among others:

- The timely and complete payment when due (whether on the original due date or the early date) of each and every amount owed, including but not limited to the payment of principal, current interest, delinquent interest, commissions, expenses, fees and any other amounts owed to the Secured Parties under any of the Secured Debt Documents, according to the terms of the relevant documents, as well as those deriving from any modifications, reforms, supplements, extensions, renewals or replacements thereof;

- The timely and complete payment by the Issuer and the Guarantors of all expenses and obligations incurred by the Collateral Trustee or the beneficiaries under the Panamanian Trust Agreement, by virtue of the Panamanian Trust Agreement and the corresponding Secured Debt Documents to preserve, protect, manage, custody, replace, substitute and add additional Collateral;
- The timely and complete payment by the Issuer and the Guarantors of all expenses and obligations incurred or which may be incurred in the future by the Collateral Trustee or the beneficiaries under the Panamanian Trust Agreement, to collect, either judicially or extra-judicially, the amounts owed under any Secured Debt Document, to ensure fulfillment of the relevant obligations and commitments or to defend the rights of the Collateral Trustee or the beneficiaries under the Panamanian Trust Agreement conferred under the Secured Debt Documents, including but not limited to attorney expenses, costs and other judicial expenses; and
- The timely and complete payment of any other sums the Issuer and/or the Guarantors must pay to the Collateral Trustee or the beneficiaries under the Panamanian Trust Agreement pursuant to the relevant documents, as applicable.

The Panamanian Trust is irrevocable, pure and simple, and it will be extinguished when one of the following events occur: (i) the date on which all obligations secured by the Panamanian Trust Agreement are paid, or (ii) if a Remedies Direction is issued in light of an Event of Default by the Issuer of any of the obligations contracted for in any of the debt related documents, without the Event of Default having been remedied within the term established in the respective debt document that gave rise to the Event of Default, once (1) the Collateral Trustee has paid all obligations secured by the Panamanian Trust Agreement, pursuant to the certification of the Intercreditor Agent; and (2) any judicial action of any other kind filed by the Collateral Trustee as a result of the Remedies Direction has been terminated; or (iii) any of the causes set forth in Article 33 of Law No. 1 of January 5, 1984 takes place.

Collateral

The collateral will consist of a security interest in and to (the "Collateral"):

- All of the Issuer's rights in each of the Intercompany Loans, as assigned to the Collateral Trustee by way of the Panamanian Trust Agreement;
- The Panamanian Trust Accounts and any amounts deposited therein;
- Any other Panamanian Trust Accounts the Collateral Trustee may establish from time to time in fulfillment of its fiduciary duty;
- The rights and moneys derived from each of the Panamanian Mortgages (as such term is defined below) including any rights to the Mortgaged Real Property and personal property mortgaged and to be mortgaged under the Panamanian Chattel Mortgage;
- The agreements and rights assigned under the UEP II Assignment Agreement;
- The agreements and rights assigned under the Tecnisol Assignment Agreement;
- The rights and moneys derived from the UEP II Pledge Agreement, by virtue of which the shares of the Issuer have been delivered or will be delivered to the Collateral Trustee or a custodian, and the due blank endorsement of the share certificates in accordance with the UEP II Pledge Agreement;
- The rights and moneys derived from the Tecnisol Pledge Agreement, by virtue of which the shares of each of the Guarantors have been delivered or will be delivered to the Collateral Trustee or a custodian, and the due blank endorsement of the share certificates in accordance with the Tecnisol Pledge Agreement;

- Moneys, assets and rights the Collateral that forms part of the Panamanian Trust assets may produce in the form of earnings on principal, interest, credits, indemnifications or other amounts; or that derive from such assets by reason of disposals, exchanges, transfers or for any other reason;
- The rights from any insurance policies or guarantees and those policies that secure certain assets of the Issuer and the Guarantors, including over the Mortgaged Real Property if applicable, and the indemnifications that any insurance company may pay in connection therewith and over personal property mortgaged and to be mortgaged under the Panamanian Chattel Mortgage;
- Any payments received by the Trustee from a Letter of Credit;
- The Mortgaged Real Property and personal property mortgaged and to be mortgaged under the Panamanian Chattel Mortgage; and
- Any other moneys, assets or rights that may be transferred from time to time to the Collateral Trustee in order to form part of, or become incorporated into, the Collateral that forms part of the Panamanian Trust assets.

Collateral Secured Debt Certificates

After incurring, contracting, guaranteeing or issuing any Additional Debt permitted under the Financing Documents, and prior to including the holders of any Additional Debt as secured parties under the Panamanian Trust Agreement, the Issuer must notify the Collateral Trustee and the Intercreditor Agent, through the delivery of a certificate, of the incurrence, guarantee, contract or issuance of the Additional Debt and of the Issuer's intention to include the holders of such debt as Secured Parties under the Panamanian Trust Agreement. Such holders will be deemed to be Secured Parties effective upon the date of acceptance of such certificate by the Collateral Trustee (acting upon the instruction of the Intercreditor Agent).

Transfer Certificates

Except as otherwise provided below, the Issuer will deliver to the Collateral Trustee, with a copy to the Intercreditor Agent, a certificate (the "Transfer Certificate") setting forth instructions for the transfer of specific funds to be made by the Collateral Trustee from the Panamanian Trust accounts in the order of priority set forth in "Description of the Notes — Intercreditor Arrangements — Accounts Waterfall." Each Transfer Certificate will include: (i) the flows of funds to be transferred by the Collateral Trustee to the accounts indicated in such Transfer Certificate, together with reasonably detailed calculations of the amounts of such flows and the dates when such transfers are to be made from the Panamanian Trust accounts to the accounts of the respective agents and creditors, other Panamanian Trust accounts and Issuer's or Guarantors accounts as permitted under the Secured Debt Documents; and (ii) all other information as necessary for the Collateral Trustee to fulfill and comply with the instructions given in such Transfer Certificate. The Intercreditor Agent or any other agent may present a notice of objection to the Transfer Certificates delivered by the Issuer pursuant to the Panamanian Trust Agreement.

The Issuer shall be entitled to deliver the Transfer Certificate to the Collateral Trustee, unless such right is suspended according to a Change of Control Event. During such suspension, the Intercreditor Agent shall deliver the Transfer Certificate to the Collateral Trustee; provided, however, that such suspension shall be revoked and the Issuer's ability to deliver instructions to the Collateral Trustee shall be restored following the delivery by the Intercreditor Agent of a notice to the Collateral Trustee upon the earliest of (a) the delivery to the Intercreditor Agent of a Notice of Cessation of Default, and (b) the rejection by the Required Secured Debtholders, through the applicable Intercreditor Vote, of such suspension requested in the applicable Blocking Remedies Notice.

Certificate for the Release of Reserve Amounts

To the extent that, at any time, there are outstanding Letter of Credit and/or cash deposited in the Debt Service Reserve Account and/or the Trust O&M Reserve Account in excess of the Debt Service Reserve Requirement or the Trust O&M Reserve Requirement, as applicable, the Issuer may instruct the Collateral Trustee to (1) transfer funds on deposit in the Debt Service Reserve Accounts or the Trust O&M

Reserve Account, as applicable, to the Issuer Collection Account, (2) reduce the face amount or amounts available under one or more Letters of Credit as permitted by the applicable Letter of Credit Agreement, or (3) a combination of (1) and (2), in each case, up to an aggregate amount not to exceed such excess. Such instructions must be delivered in a certificate signed by a Responsible Officer of the Issuer, which shall certify as to the amount of such excess, provide detailed calculations therefor, and include (if a reduction of the Letter of Credit is required by the Issuer) the form that the Collateral Trustee should execute in favor of the issuer of the Letter(s) of Credit Agreement for such reduction. For further information on the Issuer's right to transfer excess funds in the Debt Service Reserve Accounts and/or the Trust O&M Reserve Account or reduce the face amount of one or more Letter(s) of Credit, see "Description of the Notes — Accounts Waterfall".

The Collateral Trustee, The Bank of Nova Scotia (Panama) S.A., is a corporation organized under the laws of Panama, duly recorded with the Mercantile Section of the Public Registry at Folio No. 566776. The Collateral Trustee holds a trustee license granted by the Superintendence of Banks of Panama through Resolution FID No. 010-2010 issued on September 14, 2010. The Panamanian Trust is domiciled in the offices of the Collateral Trustee. The Collateral Trustee's contact information is:

THE BANK OF NOVA SCOTIA (PANAMA) S.A.
Address: Edificio Torres de las Américas
Tower A, 6th Floor,
Panama, Republic of Panama
Phone: (+507 282-7927)
P.O. Box: 0832-02231, Panama, Republic of Panama
Attention: Christy López
Email address: christy.lopez@pa.scotiabank.com

The Collateral Trustee provides trustee-related services and has never been subject to any sanctions by its supervising entity. The person in charge of the Panamanian Trust Agreement on behalf of the Collateral Trustee is Ms. Christy López.

The Issuer is the settlor under the Panamanian Trust Agreement, and the Collateral that is subject to the Panamanian Trust Agreement is the Issuer's property, except for (i) the shares of each of the Guarantors, which are the property of InterEnergy Renewables SLU ("InterEnergy Renewables"), as pledgor under the Tecnisol Pledge Agreement, (ii) the shares of the Issuer, which are the property of IEH Penonomé Holdings and Green Field Panamá, S.A., as pledgors under the UEP II Pledge Agreement, (iii) the assets mortgaged under the Tecnisol Chattel Mortgage, which are the property of the Guarantors and (iv) the agreements and rights assigned under the Tecnisol Assignment Agreement which are the property of the Guarantors. The Issuer has no subsidiaries, and neither the Issuer nor its affiliates have pending obligations with the Collateral Trustee. The Issuer's contact information is:

UEP PENONOMÉ II, S.A.
P.H. Plaza 58, 9th Floor
Calle Ricardo Arango & Calle 58 Este
Panama, Republic of Panama
Contact Person: Mónica Lupiáñez
Email: Monica@Interenergy.com

The Panamanian Trust Agreement is onerous and the Collateral Trustee will collect an annual remuneration that will be paid by the Issuer and/or the Guarantors. The Panamanian Trust Agreement sets forth that the Collateral Trustee may debit the annual remuneration amount directly from the Panamanian Trust accounts.

Under the Panamanian Trust Agreement, the Collateral will constitute a separate patrimony from the personal assets of the Collateral Trustee and of the Issuer for all the legal effects, and, as a result, the assets that compose it may neither be seized nor attached, except for obligations incurred in or damages caused with the execution of the Panamanian Trust Agreement, or by third parties whenever such Collateral were transferred to the Panamanian Trust Agreement or fraudulently retained in fraud and in prejudice of its rights.

The Collateral Trustee may not dispose of the Collateral in a form contrary or different to what is set forth in the Panamanian Trust Agreement. The Collateral Trustee is not required to grant a security interest of any kind for good administration in favor of the Issuer of any of the Secured Parties. The Collateral Trustee has no power to authorize the substitution of Collateral.

The Collateral Trustee must comply with the obligations set forth in the Panamanian Trust Agreement in respect of the accumulation, distribution or disposition of the assets, rents and products of the Collateral.

There is no expense related to the Panamanian Trust Agreement that must be paid by the Secured Parties.

Duties and Responsibilities of the Collateral Trustee

Under the Panamanian Trust Agreement, which is governed by Panamanian law, the Collateral Trustee will have the following main duties and responsibilities:

- Maintain and manage the Panamanian Trust accounts, until such time as all secured obligations have been paid in their entirety;
- Execute periodic transfers according to the instructions contained in the corresponding Transfer Certificates;
- Undertake the execution, administration and/or completion or partial disposition of the Collateral, in accordance with the instructions received from the Issuer or from the Intercreditor Agent, in order to safeguard the interests of the Secured Parties;
- Undertake transfers from the Panamanian Trust accounts to, among others, the payment account for the Notes, with the periodicity and for the amounts indicated by the Issuer in each Transfer Certificate or by the Intercreditor Agent, as applicable;
- Send to the Issuer and to the Intercreditor Agent, a report including the Panamanian Trust's balance sheet and income statement, as well as the final report on its administrative management, both annually and upon termination of the Panamanian Trust Agreement;
- Deliver to the Issuer and the Intercreditor Agent, at the Issuer's expense, the information, data and reports the Issuer requests, notwithstanding the other obligations provided for in the Panamanian Trust Agreement and the Law;
- Enter into the Intercreditor Agreement according to the written instructions sent thereto jointly by the Issuer and the Intercreditor Agent;
- Enter into any Additional Intercreditor Agreement that may be necessary as required by the Issuer in accordance with our written instructions;
- Deliver to the Intercreditor Agent, at our expense or, in the event the Issuer does not cover such expenses, at the expense of and charged to the Collateral, the information, data and reports it may request, notwithstanding the other obligations provided for in the Panamanian Trust Agreement and the Law;
- Remit, at any time, any information required of it regarding its management as Collateral Trustee, or any other information required by Law, to the proper authorities;
- Retain the documents evidencing fulfillment of its duties as Collateral Trustee during the term of the Panamanian Trust Agreement and until the final rendering of accounts has been approved;
- Act through legal representative(s) or attorney(s) in fact where necessary or appropriate, at its complete judgment and discretion, to execute its authority and responsibility as Collateral Trustee and as such, establish legal representatives to file and pursue to their conclusion any necessary legal actions against us, in the event of breach of our obligations in the Panamanian Trust Agreement, or any other action or judicial or extrajudicial measure that might correspond to a creditor, or otherwise initiate and pursue to their conclusion any and all actions that might correspond to the owner or holder of any of the Panamanian Trust assets;

- Request from the Intercreditor Agent any reports, instructions and notifications it deems necessary to confirm the satisfaction of any Secured Obligation;
- Deduct from the Panamanian Trust assets those funds necessary to cover the expenses necessary for the execution (judicial or extrajudicial), administration, retention and/or disposal of the Panamanian Trust assets;
- Fulfill the obligations imposed by the Panamanian Trust Agreement and applicable law; and
- Such other duties as are set forth in the Panamanian Trust Agreement and the Law or as may be required pursuant to the Intercreditor Agreement.

Duties and Responsibilities of the Issuer

Under the terms of the Panamanian Trust Agreement, our main duties and responsibilities are to:

- Contribute to any measures in order for the Collateral Trustee to be able to open the Panamanian Trust accounts that require opening, and make the initial contributions for the opening of these accounts, if necessary;
- Prepare and deliver to the Collateral Trustee any Collateral Secured Debt Certificates as set forth in the Panamanian Trust Agreement;
- Prepare and deliver to the Collateral Trustee any Transfer Certificate as set forth in the Panamanian Trust Agreement and the Secured Debt Documents;
- Provide to the Collateral Trustee, at the time and on the occasion required, the funds needed to address the obligations the Collateral Trustee incurs on behalf of the trust for its fulfillment, development, execution and settlement;
- Assume responsibility for the payment of all duties, taxes and/or special contributions, national or municipal, domestic or foreign, to be paid with respect to the Panamanian Trust assets, for which the Collateral Trustee may discount said payments from the funds deposited to the Panamanian Trust accounts; and
- Fulfill in its entirety any other obligation specified in the terms and conditions of the Panamanian Trust Agreement, the Secured Debt Documents, the Law and other applicable provisions.

Instructions

The Collateral Trustee will not be required to follow instructions from the Issuer or the Intercreditor Agent (acting at the written direction of the Required Secured Debtholders) if, in its reasonable opinion, compliance with such instructions (i) would result in the violation of any laws, regulations, judicial order or orders from any authorities; (ii) would result in a violation of the terms and conditions of the Panamanian Trust Agreement; (iii) would expose the Collateral Trustee to personal liability or could cause him any damage; or (iv) would require the Collateral Trustee to incur any expenses not covered by the Panamanian Trust assets at the time.

At any time, the Collateral Trustee may seek further clarification from the Intercreditor Agent regarding any instruction given to it by the Issuer or the Intercreditor Agent (acting at the written direction of the Required Secured Debtholders).

If, at any time, a Change of Control Event occurs only the Intercreditor Agent (acting at the written direction of the Required Secured Debtholders) will be allowed to give transfer instructions to the Collateral Trustee, and the Issuer's right to give transfer instructions will be suspended, provided that, such suspension of rights shall be revoked and the Issuer's ability to deliver instructions to the Collateral Trustee shall be restored following the delivery by the Intercreditor Agent of a notice to the Collateral Trustee upon the earliest of (a) the delivery to the Intercreditor Agent of a Notice of Cessation of Default, and (b) the rejection by the Required Secured Debtholders, through the applicable Intercreditor Vote, of such suspension requested in the applicable Blocking Remedies Notice.

If, at any time, the Collateral Trustee receives a notification of the occurrence of a Remedies Direction from the Intercreditor Agent (in the case of a Remedies Direction, acting at the written direction of the

Required Secured Debtholders), only the Intercreditor Agent (acting at the written direction of the Required Secured Debtholders) will be allowed to give instructions to the Collateral Trustee, and the Issuer would not be permitted to give instructions.

In the event that either or both of the Debt Service Reserve Account or the Trust O&M Reserve Account is being funded by a Letter(s) of Credit, the Collateral Trustee may be required to draw upon such Letter(s) of Credit and deposit the proceeds in the corresponding account Debt Service Reserve Account or Trust O&M Reserve Account, as the case may be. For further information on the conditions under which the Collateral Trustee would draw on any Letter of Credit, see "*Description of Principal Financial Documents — Letter of Credit Agreement.*"

Resignation and Removal of the Collateral Trustee

The Collateral Trustee may resign at any time, with or without cause, by providing 90 calendar days' advance notice to the Issuer and the Intercreditor Agent. The Issuer will (with the consent of the Intercreditor Agent who shall act at the written direction of the Required Secured Debtholders) have up to 90 calendar days from the date of the Collateral Trustee's notice of resignation to appoint an Eligible Trustee as a replacement collateral trustee, and if the Issuer (with the consent of the Intercreditor Agent who shall act at the written direction of the Required Secured Debtholders) fails to appoint a replacement collateral trustee in such time, the original Collateral Trustee may appoint a replacement. The Collateral Trustee may be removed by the Intercreditor Agent (acting at the written direction of the Required Secured Debtholders) pursuant to the terms of the Intercreditor Agreement at any time, without cause and without our consent, or by the Issuer with the prior written consent of the Intercreditor and subject to the satisfaction of certain conditions.

Supplement and Modification

The Panamanian Trust Agreement will only be modified by way of a written document signed between the Issuer and the Collateral Trustee, who will follow instructions from the Intercreditor Agent (acting at the written direction of the Required Secured Debtholders). The approved amendments will be valid and binding among all parties to the Panamanian Trust Agreement, and will affect all Secured Parties and holders of any Additional Debt. However, we and the Collateral Trustee (acting at the written direction of the Intercreditor Agent) may, from time to time, establish procedures and rules for the implementation and administration of the Panamanian Trust Agreement, which, as long as such procedures and rules do not contradict or alter the terms of the Panamanian Trust Agreement, will not constitute an amendment thereto. A change of the Intercreditor Agent will not be deemed an amendment to the Panamanian Trust Agreement. See "Description of the Notes — Amendment, Supplement, Waiver."

The resident agent of the Panamanian Trust Agreement will be the law firm ARIAS, FÁBREGA & FÁBREGA. Its domicile is PH ARIFA, 9th and 10th Floor, West Boulevard, Santa Maria Business District Panama City, Republic of Panama. They will countersign the amended and restated Panamanian Trust Agreement.

Governing Law and Jurisdiction

The Panamanian Trust Agreement is governed and interpreted in accordance with the laws of the Republic of Panama. The parties to the Panamanian Trust Agreement agreed that any dispute regarding the agreement's validity, interpretation or execution that cannot be resolved by negotiation, will be submitted to the civil courts of the First Judicial Circuit of the city of Panama, Republic of Panama.

Panamanian Real Property Mortgage

Pursuant to the its obligations under the IFC Loan a first-priority mortgage and antichresis (*primera hipoteca y antichresis sobre bienes inmuebles*) agreement in the form of a public deed was entered into by the Issuer, as mortgagor, and the Collateral Trustee (acting solely in its capacity as trustee of the Panamanian Trust), as mortgagee, on December 10, 2014, and amended by public deed No. 19536 of December 1, 2015 of the First Notary of the Circuit of Panama (the "Original Panamanian Real Property Mortgage"). Not later than 15 Business Days after the Issue Date, the Original Panamanian Mortgage will be amended and restated together with the Original Panamanian Trust Agreement (as amended the "Panamanian Real Property

Mortgage") to conform to the Panamanian Trust Agreement and maintain mortgages created under the Original Panamanian Real Property Mortgage for the benefit of the beneficiaries (including the holders of the Notes) of the Panamanian Trust and for the payment of the secured obligations under the Panamanian Trust Agreement.

The Original Panamanian Real Property Mortgage created a first-priority mortgage and antichresis on the definitive generation licenses for Nuevo Chagres, Portobelo, Rosa de los Vientos and Marañon (the "Mortgaged Real Property") as well as any improvement (whether temporary or permanent), addition or replacement introduced or added to the Mortgaged Real Property.

The Panamanian Real Property Mortgage is governed and interpreted in accordance with the laws of the Republic of Panama. The parties to the Panamanian Real Property Mortgage agreed that any dispute regarding the agreement's validity, interpretation or execution that cannot be resolved by negotiation, will be submitted to the civil courts of the First Judicial Circuit of the city of Panama, Republic of Panama.

UEP II Chattel Mortgage

Pursuant to the its obligations under the IFC Loan, a first-priority chattel mortgage (*primera hipoteca sobre bienes muebles*) agreement in the form of a public deed was entered into by the Issuer, as mortgagor, and the Collateral Trustee (acting solely in its capacity as trustee for the Panamanian Trust), as mortgagee, on December 10, 2014, and amended by public deed 9051 of June 11, 2015 of the First Notary of the Circuit of Panama (the "Original UEP II Chattel Mortgage"). Not later than 15 Business Days after the Issue Date, the Original UEP II Chattel Mortgage will be amended and restated together with the Panamanian Trust Agreement (as amended the "UEP II Chattel Mortgage"), to conform to the Panamanian Trust Agreement and maintain mortgages created under the Original UEP II Chattel Mortgage for the benefit of the beneficiaries (including the holders of the Notes) of the Panamanian Trust and for the payment of the secured obligations under the Panamanian Trust Agreement.

The Original UEP II Chattel Mortgage created a first-priority chattel mortgage (*primera hipoteca sobre bienes muebles*) over certain property necessary for the Issuer's operations (including turbine blades, turbines and vehicles), certain leases over property and certain other contractual arrangements that are necessary for the operation of the Issuer's projects. Following its amendment and restatement, the UEP II Chattel Mortgage will continue the existing first priority chattel mortgage over the following agreements (to the extent such agreements continue to be in effect):

- the Assignment and Transfer agreement dated April 16, 2014 between UEP and UEP II;
- lease agreements listed in the Panamanian Chattel Mortgage;
- vehicles listed in the Panamanian Chattel Mortgage;
- equipment listed in the Panamanian Chattel Mortgage;
- the UEP II Wind Project Interconnection Agreement;
- the Wake Effect Agreement; and
- the rights from any and all insurance policies or guarantees that insure the assets of the Issuer.

For the perfection of the mortgage over certain existing agreements not perfected before the Issue Date, the Issuer shall as promptly as possible, but in any event no later than 180 calendar days following entry into the UEP II Chattel Mortgage, perfect any such mortgage.

The UEP II Chattel Mortgage is governed and interpreted in accordance with the laws of the Republic of Panama. The parties to the UEP II Chattel Mortgage agreed that any dispute regarding the agreement's validity, interpretation or execution that cannot be resolved by negotiation, will be submitted to the civil courts of the First Judicial Circuit of the city of Panama, Republic of Panama.

Tecnisol Chattel Mortgage

On the issue date of the Notes, the Guarantors will, as mortgagors, enter into a first-priority chattel mortgage (*primera hipoteca sobre bienes muebles*) agreement in the form of a public deed and the Collateral

Trustee (acting solely in its capacity as trustee for the Panamanian Trust), as mortgagee (the "Tecnisol Chattel Mortgage" and together with the Panamanian Real Property Mortgage and the UEP II Chattel Mortgage, the "Panamanian Mortgages"), to create and maintain mortgages for the benefit of the beneficiaries (including the holders of the Notes) of the Panamanian Trust and for the payment of the secured obligations under the Panamanian Trust Agreement.

Upon its execution and registration in the Public Registry of Panama, the Tecnisol Chattel Mortgage shall create a first-priority chattel mortgage (*primera hipoteca sobre bienes muebles*) over certain property necessary for the Guarantors' operations (including solar panels, other equipment used for generation activities and vehicles) and certain lease agreements.

For the perfection of the mortgage over certain existing agreements not perfected before the Issue Date, the Guarantors shall have up to 45 business days following entry into the Tecnisol Chattel Mortgage to perfect any such mortgage.

The Tecnisol Chattel Mortgage is governed and interpreted in accordance with the laws of the Republic of Panama. The parties to the Tecnisol Chattel Mortgage agreed that any dispute regarding the agreement's validity, interpretation or execution that cannot be resolved by negotiation, will be submitted to the civil courts of the First Judicial Circuit of the city of Panama, Republic of Panama.

UEP II Pledge Agreement

The Issuer, entered into a pledge agreement dated April 23, 2014 (the "Original UEP II Pledge Agreement") with Unión Eólica Panameña, S.A. ("UEP"), IEH Penonomé Panama, S.A., the Trustee, the shareholders of UEP, the shareholders of IEH Penonomé Panama, S.A. and the shareholder of the Issuer, pursuant to which the shareholders of UEP and the shareholder of the Issuer pledged to the Collateral Trustee, the shares in each of UEP and UEP II, respectively, that they owned in order to secure UEP and UEP II's obligations under certain financing agreements. In connection with the IFC Loan, the Original Pledge Agreement was amended on December 10, 2014 so as to release the shares in UEP and authorize the transfer of shares in IEH Penonomé Panama S.A. by IEH Penonome Holdings to Green Field Panamá, S.A. while maintaining the pledge created by the Original Pledge Agreement over the shares of the Issuer. On April 16, 2015, IEH Penonomé Panama S.A. merged into the Issuer and the Issuer, by operation of merger, issued shares to IEH Penonome Holdings and Green Field Panamá, S.A., which shares were delivered in pledge under the Original Pledge Agreement. On the Issue Date, the Original Pledge Agreement, as subsequently amended, will be further amended and restated (as amended and restated, the "UEP II Pledge Agreement"), to conform to Panamanian Trust Agreement and maintain the pledge over the equity of the Issuer for the benefit of the beneficiaries (including the holders of the Notes) of the Panamanian Trust and for the payment of the secured obligations under the Panamanian Trust Agreement.

At any time during the existence of the UEP II Pledge Agreement, only the Collateral Trustee, as pledgee, will be responsible for: (i) delivering instructions to any named custodian, if appointed, instructions received from the Intercreditor Agent (acting at the written direction of the Required Secured Debtholders) pursuant to the Intercreditor Agreement, or (ii) otherwise carrying out actions pursuant to the UEP II Pledge Agreement, (pursuant to instructions received from the Intercreditor Agent, acting at the written direction of the Required Secured Debtholders), pursuant to the Intercreditor Agreement.

For the duration of the UEP II Pledge Agreement, the assets pledged thereunder will be held by the Collateral Trustee. The assets pledged under the UEP II Pledge Agreement consist of:

- 1,000 shares of the Issuer, property of IEH Penonome Holdings, represented by share certificate No. 4 dated April 20, 2015 (the "IEH Pledged Shares");
- 50 shares of the Issuer, property of Green Field Panamá, S.A., represented by share certificate No. 5 dated April 20, 2015 (the "Green Field Pledged Shares" and together with the IEH Pledged Shares, the "Pledged Issuer Shares");
- Any shares, other securities assets or money that the pledgee may be entitled to receive from the Pledged Issuer Shares as a result of (a) any split or merger of the Pledged Issuer Shares; (b) any shares distributed as dividends of the Pledged Issuer Shares; (c) any merger or consolidation of the Issuer;(d) any spin-off or segregation of the Issuer; (e) any restructuring or reclassification of

capital of the Issuer; (f) any change to the Issuer's Articles of Incorporation; (g) any conversion of the Pledged Issuer Shares; or (h) any other transaction or corporate reorganization of the Issuer;

- Any dividends from the Pledged Issuer Shares; and
- Any product or benefit from the pledged assets including those received from the collection, conversion, exchanger, transformation, investment, sale or other disposition of the Pledged Issuer Shares, without limitation, interest and other credits.

If the Collateral Trustee notifies the Issuer that the Collateral Trustee has received a notice of the occurrence of an Event of Default from the Intercreditor Agent:

- Dividends with respect to the Pledged Issuer Shares will be paid to the Collateral Trustee and the Collateral Trustee will deposit such dividends in the Panamanian Trust accounts, acting upon the instructions of the Intercreditor Agent; and
- Rights to receive notices of, assist to and vote in shareholders meetings will be assigned to the Collateral Trustee.

If the Collateral Trustee receives a Remedies Direction from the Intercreditor Agent, it will take or cause to be taken one or more of the following measures in case of execution of the UEP II Pledge Agreement:

- receive all dividends with respect to the Pledged Issuer Shares;
- reasonably exercise all political rights with respect to the Pledged Issuer Shares;
- sell, assign, transfer or in any other way dispose of all or part of the pledged assets in accordance with the provisions of the UEP II Pledge Agreement; or
- appropriate the pledged assets in accordance with the provisions of the UEP II Pledge Agreement.

The UEP II Pledge Agreement provides authorization for the transfer of the Pledged Shares after the signing of a joinder agreement by each potential transferee of the Pledged Shares to the UEP II Pledge Agreement.

The proceeds from the sale or appropriation of the assets pledged under the UEP II Pledge Agreement will be deposited in the Company Execution Account of the Panamanian Trust.

The UEP II Pledge Agreement is governed and interpreted in accordance with the laws of the Republic of Panama. The parties to the UEP II Pledge Agreement agreed that any dispute regarding the agreement's validity, interpretation or execution that cannot be resolved by negotiation, will be submitted to the civil courts of the First Judicial Circuit of the city of Panama, Republic of Panama.

Tecnisol Pledge Agreement

On the issue date of the Notes, InterEnergy Renewables SLU will enter into a pledge agreement (the "Tecnisol Pledge Agreement") with the Collateral Trustee, whereby it will pledge its equity interest in the Guarantors for the benefit of the beneficiaries (including the holders of the Notes) of the Panamanian Trust and for the payment of the secured obligations under the Panamanian Trust Agreement.

At any time during the existence of the Tecnisol Pledge Agreement, only the Collateral Trustee, as pledgee, will be responsible for: (i) delivering instructions to any named custodian, if appointed, instructions received from the Intercreditor Agent (acting at the written direction of the Required Secured Debtholders) pursuant to the Intercreditor Agreement, or (ii) otherwise carrying out actions pursuant the Tecnisol Pledge Agreement (pursuant to instructions received from the Intercreditor Agent, acting at the written direction of the Required Secured Debtholders), pursuant to the Intercreditor Agreement.

For the duration of the Tecnisol Pledge Agreement, the assets pledged thereunder will be held by the custodian. The assets pledged under the Tecnisol Pledge Agreement consist of:

- 100 shares of Tecnisol I, S.A., property of InterEnergy Renewables SLU, represented by share certificate No. 4 dated December 3, 2019 (the "Tecnisol I Pledged Shares");

- 100 shares of Tecnisol II, S.A., property of InterEnergy Renewables SLU, represented by share certificate No. 4 dated December 3, 2019 (the "Tecnisol II Pledged Shares");
- 100 shares of Tecnisol III, S.A., property of InterEnergy Renewables SLU, represented by share certificate No. 4 dated December 3, 2019 (the "Tecnisol III Pledged Shares");
- 100 shares of Tecnisol IV, S.A., property of InterEnergy Renewables SLU, represented by share certificate No. 4 dated December 3, 2019 (the "Tecnisol IV Pledged Shares" and together with the Tecnisol I Pledged Shares, Tecnisol II Pledged Shares, Tecnisol III Pledged Shares, the "Guarantor Pledged Shares");
- Any shares, other securities assets or money that the pledgee may be entitled to receive from the Guarantor Pledged as a result of (a) any split or merger of the Guarantor Pledged Shares; (b) any shares distributed as dividends of the shares of the Guarantor Pledged Shares; (c) any merger or consolidation of any of the Guarantors;(d) any spin-off or segregation of the Guarantors; (e) any restructuring or reclassification of capital in the Guarantors; (f) any change to the respective Guarantor's Articles of Incorporation; (g) any conversion of the Guarantor Pledged Shares; or (h) any other transaction or corporate reorganization relating to the Guarantor;
- Any dividends from the Guarantor Pledged Shares; and
- Any product or benefit from the pledged assets including those received from the collection, conversion, exchanger, transformation, investment, sale or other disposition of the Guarantor Pledged Shares, without limitation, interest and other credits.

If the Collateral Trustee notifies the Guarantors that the Collateral Trustee has received a notice of the occurrence of an Event of Default from the Intercreditor Agent:

- Dividends with respect to the Guarantor Pledged Shares will be paid to the Collateral Trustee and the Collateral Trustee will deposit such dividends in the Panamanian Trust accounts, acting upon the instructions of the Intercreditor Agent; and
- Rights to receive notices of, assist to and vote in shareholders meetings will be assigned to the Collateral Trustee.

If the Collateral Trustee receives a Remedies Direction from the Intercreditor Agent, it will take or cause to be taken one or more of the following measures in case of execution of the Tecnisol Pledge Agreement:

- receive all dividends with respect to the Guarantor Pledged Shares;
- reasonably exercise all political rights with respect to the Guarantor Pledged Shares;
- sell, assign, transfer or in any other way dispose of all or part of the pledged assets in accordance with the provisions of the Tecnisol Pledge Agreement; or
- appropriate the pledged assets in accordance with the provisions of the Tecnisol Pledge Agreement.

The Tecnisol Pledge Agreement provides authorization for the transfer of the Guarantor Pledged Shares after the signing of a joinder agreement by each potential transferee of the Guarantor Pledged Shares to the Tecnisol Pledge Agreement.

On the date of entry into the Tecnisol Pledge Agreement, the Guarantors will take all necessary actions to perfect the pledge over the Guarantor Pledged Shares.

The proceeds from the sale or appropriation of the assets pledged under the Guarantor Pledged Shares will be deposited in the applicable Guarantor Execution Account of the Panamanian Trust.

The Tecnisol Pledge Agreement is governed and interpreted in accordance with the laws of the Republic of Panama. The parties to the Tecnisol Pledge Agreement agreed that any dispute regarding the agreement's validity, interpretation or execution that cannot be resolved by negotiation, will be submitted to the civil courts of the First Judicial Circuit of the city of Panama, Republic of Panama.

UEP II Assignment Agreement

In connection with its entry into the IFC Loan, the Issuer entered into a master assignment agreement (*contrato de cesión*) dated December 10, 2014 (the "Original Master Assignment Agreement"), with the Collateral Trustee. On the issue date of the Notes, the Issuer and the Collateral Trustee will amend and restate the Original Master Assignment Agreement (the "UEP II Assignment Agreement") in order to conform to the Panamanian Trust Agreement, add certain additional agreements and maintaining the assignment for the benefit of the beneficiaries (including the holders of the Notes) of the Panamanian Trust and for the payment of the secured obligations under the Panamanian Trust Agreement. The UEP II Assignment Agreement will continue the assignment of certain rights of the Issuer and will assign additional rights of the Issuer, as follows (the "UEP II Assigned Agreements"):

- unconditional assignment of all income of the Issuer, including the receivables from the sale of energy through the UEP II PPAs, the spot market, the international market or the regional market and other auxiliary services;
- conditional assignment of the UEP II PPAs;
- conditional assignment of the Shared Assets Access Agreement;
- conditional assignment of the wake effect agreement, dated February 9, 2017 (the "UEP III Wake Effect Agreement") between UEP Penonomé III, S.A. and the Issuer;
- conditional assignment of the Service and Maintenance Agreement;
- conditional assignment of a lease agreement entered by UEP and the *Autoridad Nacional de Administración de Tierras* (ANATI) on September 25, 2014 and assigned to the Issuer on October 15, 2014 (the "ANATI Agreement");
- the conditional assignment of all guarantees and payment bonds created in favor of the Issuer in accordance with any of the UEP II PPAs or the ANATI Agreement; and
- the unconditional assignment of all of the rights to receive any monies derived from the UEP II PPAs, the Shared Assets Access Agreement; the UEP III Wake Effect Agreement and the Service and Maintenance Agreement and any guarantees and payment bonds created in favor of the Issuer in accordance with any of the UEP II Assigned Agreements.

In connection with the assignments under the Original Master Assignment Agreement, the Issuer executed certain direct agreements (the "Direct Agreements") with certain counterparties of the UEP II Assigned Agreements in order to provide the respective counterparties with notice of such assignments.

For the perfection of the conditional assignment of those additional rights and unconditional assignment of all income and payments under certain agreements (in the later case, if not obtained before), assigned under the UEP II Assignment Agreement the Issuer shall have up to 45 business days following entry into the UEP II Assignment Agreement.

For the perfection of the assignment of future agreements (including the conditional assignment of the rights and obligations thereunder and unconditional assignment of all income and payments due under any future assignable agreements) for which government approval is not required, the Issuer shall have up to 45 business days following entry into such agreements to perfect any such assignment. For the perfection of the assignment of future agreements (including the conditional assignment of the rights and obligations thereunder and unconditional assignment of all income and payments due under any future assignable agreements) for which government approval is required, the Issuer shall have up to one year following entry into such agreements (with an additional 120 business days upon the demonstration of reasonable commercial efforts) to perfect such assignment.

The UEP II Assignment Agreement is governed and interpreted in accordance with the laws of the Republic of Panama. The parties to the UEP II Pledge Agreement agreed that any dispute regarding the agreement's validity, interpretation or execution that cannot be resolved by negotiation, will be submitted to the civil courts of the First Judicial Circuit of the city of Panama, Republic of Panama.

Tecnisol Assignment Agreement

On the issue date of the Notes, the Guarantors and the Collateral Trustee will enter into an assignment agreement (the "Tecnisol Assignment Agreement") in order to assign certain credits and payment rights under agreements to which the Guarantors are parties for the benefit of the beneficiaries (including the holders of the Notes) of the Panamanian Trust and for the payment of the secured obligations under the Panamanian Trust Agreement. By way of the Tecnisol Assignment Agreement, the Guarantors will conditionally assign the Tecnisol PPAs and unconditionally assign the following credits and payment rights:

- the receivables from the sale of energy through the Tecnisol PPAs, the spot market the international market or the regional market and other auxiliary services, as well as any credits and payment rights under future PPAs to be entered into by the Guarantors;
- the payment of any insurance proceeds to which the Guarantors are entitled under insurance policies that insure assets of the Guarantors;
- the payment made by the EPC Contractor by virtue of the Warranty Obligations.
- the proceeds from any expropriation payment resulting from the nationalization or expropriation of any of the Guarantor's assets by the Republic of Panama; and
- the payments received from all guarantees and payment bonds in favor of the Guarantors under the Tecnisol PPAs.

Pursuant to the terms of the Tecnisol Assignment Agreement and the Panamanian Trust Agreement, the Guarantors are also assigning any credits and payment rights under future PPA or payment guarantee to be entered into or signed by the Guarantors on a subsequent date.

For the perfection of assignments of certain existing agreements (including the conditional assignment of the rights and obligations thereunder and unconditional assignment of all income and payments due under any future assignable agreements) for which government approval is not required, the Guarantors shall have up to 45 business days following entry into the Tecnisol Assignment Agreement to perfect any such assignment. For the perfection of assignments of certain existing agreements (including the conditional assignment of the rights and obligations thereunder and unconditional assignment of all income and payments due under any future assignable agreements) for which government approval is required, the Guarantors shall have up to one year following entry into the Tecnisol Assignment Agreement (with an additional 120 business days upon the demonstration of reasonable commercial efforts) to perfect such assignment.

For the perfection of the assignment of future agreements (including the conditional assignment of the rights and obligations thereunder and unconditional assignment of all income and payments due under any future assignable agreements) for which government approval is not required, the Guarantors shall have up to 45 business days following entry into such agreements to perfect any such assignment. For the perfection of the assignment of future agreements (including the conditional assignment of the rights and obligations thereunder and unconditional assignment of all income and payments due under any future assignable agreements) for which government approval is required, the Guarantors shall have up to one year following entry into such agreements (with an additional 120 business days upon the demonstration of reasonable commercial efforts) to perfect such assignment.

For the perfection of the assignment of proceeds of the insurance policies and warranty payments under the EPC Contracts, assigned by the Guarantors pursuant to the Tecnisol Assignment Agreement, the Guarantors shall have forty five (45) Business Days following entry into the Tecnisol Assignment Agreement to perfect any such assignment.

The Tecnisol Assignment Agreement is governed and interpreted in accordance with the laws of the Republic of Panama. The parties to the UEP II Pledge Agreement agreed that any dispute regarding the agreement's validity, interpretation or execution that cannot be resolved by negotiation, will be submitted to the civil courts of the First Judicial Circuit of the city of Panama, Republic of Panama.

DESCRIPTION OF THE NOTES

The following summary of certain provisions of the Indenture, the Notes (including the related Note Guarantees) and the Collateral is not complete and is subject to, and qualified in its entirety by reference to, all of the provisions of the Indenture, the Notes and the Financing Documents, as applicable. The holders of the Notes will be entitled to the benefits of, be bound by, and be deemed to have notice of, all of the provisions of the Indenture, the Notes and the Financing Documents, including, without limitation, the immunities and rights of the Indenture Trustee and the Collateral Trustee. Copies of the Indenture and other Financing Documents will be on file at the specified corporate trust office of the Indenture Trustee and may be inspected upon request.

General

In this "Description of the Notes," the word "Issuer" refers only to UEP Penonomé II, S.A., a corporation (*sociedad anónima*) organized under the laws of Panama, and not to any of its Subsidiaries, as defined herein. The definitions of certain other terms used in this description are set forth throughout the text or under "— Certain Definitions."

The Issuer will issue U.S.$262,664,000 in aggregate principal amount of 6.500% Senior Secured Notes due 2038 (the "Notes"). The Notes will be issued under an indenture (the "Indenture") among the Issuer and the Initial Guarantors, and the Guarantors from time to time thereunder, Citibank, N.A., as trustee (the "Indenture Trustee"), registrar, transfer agent and paying agent.

The Notes will constitute senior secured indebtedness of the Issuer.

The Notes will be due and payable on October 1, 2038. The Notes will be, and all of our outstanding indebtedness will be, secured by a security interest in the Collateral, with the ranking described in "— Collateral Arrangements" below.

The Notes will have the benefit of, and shall be subject to, the terms of the Security Documents. The Security Documents set forth the terms of the agreements in respect of the Collateral that will secure the Notes. For a description of the Security Documents, see "Description of the Collateral." We urge each investor to read the Indenture and the Security Documents, because those documents, and not this summary, define your rights as a holder of the Notes.

The Notes will be guaranteed, jointly and severally, by Tecnisol I, S.A., Tecnisol II, S.A., Tecnisol III, S.A. and Tecnisol IV, S.A., each a corporation (*sociedad anónima*) organized under the laws of Panama.

As of the Issue Date, the Issuer has no subsidiaries. Accordingly, as of the Issue Date there will be no "Restricted Subsidiaries," as defined in the Indenture. Under the circumstances described below in the definition of "Unrestricted Subsidiary" under the caption "— Certain Definitions," the Issuer will be permitted to designate additional Subsidiaries as "Unrestricted Subsidiaries." Unrestricted Subsidiaries will not be subject to any of the negative covenants in the Indenture. Further, Unrestricted Subsidiaries will not Guarantee the Notes.

The Indenture will not be qualified under the Trust Indenture Act of 1939, as amended, and holders of the Notes will not be entitled to the protections provided under the Trust Indenture Act to holders of debt securities issued under an indenture that is so qualified.

Status, Ranking and No Recourse

The Notes will constitute the Issuer's direct and unconditional senior secured obligations, secured by the Collateral, and will rank *pari passu* in right of payment without any preference among themselves and with all Additional Notes (as defined herein), if any, and certain other Indebtedness permitted to be ratably secured by the Collateral under the Indenture, if any, the Issuer and the Guarantors may issue in the future. The Issuer's payment obligations under the Notes will, other than in the case of certain of its tax, labor or other obligations, which are granted preferential treatment over the Notes pursuant to law, at all times rank at least *pari passu* in priority of payment with all of its other present and future Indebtedness from time to time outstanding, except that such obligations will be effectively subordinated to any future Indebtedness of the Issuer and the Guarantors that is secured by Liens on assets that do not secure the Notes, to the extent of the value of the assets securing such Indebtedness, and will rank senior in priority of payment to all its present and future unsecured (to the extent of the value of the Collateral) or subordinated obligations from time to time outstanding.

The Note Guarantees will constitute the Guarantors' direct and unconditional senior secured obligations and will rank *pari passu* in right of payment without any preference among themselves and certain other Indebtedness permitted to be ratably secured by the Collateral under the Indenture, if any, that any such Guarantor may issue in the future. Each Guarantor's payment obligations under its Note Guarantee will, other than in the case of certain of its tax, labor or other obligations, which are granted preferential treatment over the Note Guarantee pursuant to law, at all times rank at least *pari passu* in priority of payment with all of its other present and future senior secured obligations from time to time outstanding, except that such obligations will be effectively subordinated to any future Indebtedness of the Guarantors that is secured by Liens on assets that do not secure the Note Guarantees, to the extent of the value of the assets securing such Indebtedness, and will rank senior in priority of payment to all its present and future unsecured (to the extent of the value of the Collateral) or subordinated Indebtedness from time to time outstanding.

All obligations in connection with the Notes are solely obligations of the Issuer and the Guarantors, secured under the Security Documents by the Collateral, with no recourse to any other Person or entity. No Person nor any Permitted Holder or any other Affiliate of the Issuer and the Guarantors, or any of their respective incorporators, stockholders, members, managers, representatives, partners, directors, officers or employees, has guaranteed or will guarantee the payment of the Notes or have any obligation or liability with respect to payment of the Notes or in respect of the Issuer and the Guarantors or any of the Guarantors' obligations under the Notes, the Note Guarantees and/or any of the other Financing Documents. Each holder of Notes by accepting a Note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the Notes. The waiver may not be effective to waive liabilities under the federal securities laws.

As of the Issue Date, and after application of the proceeds of this offering and the Refinancing and Recapitalization Transaction, the Issuer and the Guarantors will have no Indebtedness for borrowed money other than the Notes.

Principal, Maturity and Interest

The Notes will bear interest at 6.500% per annum from December 18, 2020 or from the immediately preceding interest payment date to which interest has been paid, payable semi-annually in arrears on April 1 and October 1 of each year, commencing on April 1, 2021 (each, a "Scheduled Payment Date"), to the holders of record of the Notes at the close of business on March 12 or September 12, respectively, immediately preceding the corresponding interest payment date (each, a "Regular Record Date"). Interest on the Notes will be computed on the basis of a 360-day year of twelve 30-day months.

Installments of principal on the Notes will be payable semi-annually on each Scheduled Payment Date of each year beginning on April 1, 2021, pro rata (subject to the procedures of the depositary for the Notes) to the registered holder thereof on the immediately preceding Regular Record Date in accordance with the following schedule, such payments being the "Amortization Payments":

Principal Payment Date	Principal Amount Payable	Percentage of Original Principal Amount Payable
April 1, 2021	US$3,685,000	1.4%
October 1 , 2021	US$6,318,000	2.4%
April 1, 2022	US$3,492,000	1.3%
October 1, 2022	US$6,657,000	2.5%
April 1, 2023	US$4,129,000	1.6%
October 1, 2023	US$7,127,000	2.7%
April 1, 2024	US$4,900,000	1.9%
October 1, 2024	US$7,949,000	3.0%
April 1, 2025	US$5,358,000	2.1%

Principal Payment Date	Principal Amount Payable	Percentage of Original Principal Amount Payable
October 1, 2025	US$8,638,000	3.3%
April 1, 2026	US$5,711,000	2.2%
October 1, 2026	US$9,331,000	3.6%
April 1, 2027	US$6,043,000	2.3%
October 1, 2027	US$10,058,000	3.8%
April 1, 2028	US$6,104,000	2.3%
October 1 , 2028	US$10,745,000	4.1%
April 1, 2029	US$6,639,000	2.5%
October 1, 2029	US$11,326,000	4.3%
April 1, 2030	US$3,525,000	1.4%
October 1, 2030	US$8,197,000	3.1%
April 1, 2031	US$4,996,000	1.9%
October 1, 2031	US$8,790,000	3.3%
April 1, 2032	US$5,537,000	2.1%
October 1, 2032	US$10,355,000	4.0%
April 1, 2033	US$5,531,000	2.1%
October 1, 2033	US$12,391,000	4.7%
April 1, 2034	US$2,980,000	1.1%
October 1, 2034	US$11,395,000	4.4%
April 1, 2035	US$1,587,000	0.6%
October 1, 2035	US$12,157,000	4.6%
April 1, 2036	US$2,903,000	1.1%
October 1, 2036	US$12,954,000	4.9%
April 1, 2037	US$3,216,000	1.2%
October 1, 2037	US$13,701,000	5.2%
April 1, 2038	US$3,573,000	1.4%
October 1, 2038	US$14,666,000	5.6%

The Notes will not be entitled to the benefit of any sinking fund to retire them.

Note Guarantees

General

Following the Issue Date, the due and punctual payment of all amounts payable under the Notes, including principal, premium, if any, and interest, together with all other payment obligations of the Issuer and the Guarantors under the Indenture and the Notes, will be unconditionally and irrevocably guaranteed on a senior secured basis by the Guarantors and the future Guarantors. See "— Future Guarantors" below. The Guarantors will guarantee the Notes on the Issue Date.

Each Guarantor that makes a payment under its Note Guarantee will be entitled to contribution from any other Guarantor.

The Indenture will limit the obligations of each Guarantor under its Note Guarantee to an amount not to exceed the maximum amount that can be guaranteed by such Guarantor by law or without resulting in its obligations under its Note Guarantee being voidable or unenforceable under applicable laws relating to fraudulent transfer, or under similar laws affecting the rights of creditors generally. By virtue of this limitation, a Guarantor's obligation under its Note Guarantee could be significantly less than amounts payable with respect to the Notes, or a Guarantor may have effectively no obligation under its Note Guarantee. See "Risk Factors — The Issuer and the Guarantors' obligations under the Notes are subordinated to the Issuer and the Guarantors' payment of certain statutory liabilities and may have different treatment from the obligations of unrelated creditors in any Panamanian reorganization proceedings."

Future Guarantors

On or after the Issue Date, any Restricted Subsidiary that is not a Guarantor must become a Guarantor promptly and, in any event, no later than 30 days after the date on which such Restricted Subsidiary becomes a Restricted Subsidiary, and execute a supplemental indenture to provide a Note Guarantee and deliver an Opinion of Counsel to the Indenture Trustee, each in accordance with the provisions of the Indenture. Any such Restricted Subsidiary must also accede to or join, as applicable, the relevant Security Documents as provided in the covenant described under the caption "— Affirmative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries — Covenant to Give Security."

Release of the Note Guarantees and Guarantors

A Note Guarantee of a Guarantor will be automatically and unconditionally released (and thereupon shall terminate and be discharged and be of no further force and effect):

(1) in connection with any sale or other disposition (including by merger or otherwise) of capital stock of the Guarantor after which such Guarantor is no longer a Restricted Subsidiary, if the sale of all such capital stock of that Guarantor complies with the applicable provisions of the Indenture;

(2) upon a defeasance or satisfaction and discharge of the Indenture that complies with the provisions under "— Defeasance" or "— Satisfaction and Discharge";

(3) upon payment in full of the aggregate principal amount of all Notes then outstanding and all other obligations under the Indenture and the Notes then due and owing; or

(4) if the Issuer properly designates such Guarantor as an Unrestricted Subsidiary under the Indenture; or

(5) as otherwise provided in the Intercreditor Agreement;

Upon any release of a Guarantor from its Note Guarantee, if such former Guarantor does not otherwise remain a Restricted Subsidiary, such Guarantor will also be released from its obligations under the Security Documents to the extent permitted under the Security Documents. Upon any occurrence giving rise to a release of a Note Guarantee as specified above, the Indenture Trustee and the Collateral Trustee will execute any documents reasonably required in order to evidence or effect such release, discharge and termination in respect of such Note Guarantee or the release of such Guarantor from its obligations under the Security Document; *provided* that, in each case, the Indenture Trustee and the Collateral Trustee shall be entitled to an Officer's Certificate and Opinions of Counsel stating that all conditions precedent to any such release, discharge and termination or other release in the Indenture and the other Financing Documents have been satisfied. Neither the Issuer nor any Guarantor will be required to make a notation on the Notes to reflect any Note Guarantee or any such release, termination or discharge.

Further Issuances

The Issuer and the Guarantors will initially issue an aggregate of U.S.$262,664,000 of Notes, but may, subject to the limitations set forth under "— Negative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries — Limitation on Indebtedness," issue an unlimited principal amount of the Notes. The Issuer and the Guarantors may, without your consent, issue additional Notes (the "Additional Notes") in one or more transactions, which have substantially identical terms (other than issue price, date of issuance and date from which the interest will accrue) as the Notes issued on the Issue Date. Such Additional Notes may be issued with the same or different CUSIP numbers; *provided*, *however*, that unless such Additional Notes are fungible with the Notes for U.S. federal income tax purposes, such Additional Notes must be issued under a different CUSIP number. Any Additional Notes will be consolidated and form a single class with the other Notes issued on the Issue Date, so that, among other things, holders of any Additional Notes will have the right to vote together with holders of Notes issued on the Issue Date as one class. Unless the context otherwise requires, for all purposes under the Indenture and this "Description of the Notes," references to the Notes includes any Additional Notes actually issued.

Form, Denomination and Registration

The Global Notes (and beneficial interests therein) will be issued in registered form only, without interest coupons, in denominations of U.S.$200,000 and integral multiples of U.S.$1,000 in excess thereof. No Notes will be issued in bearer form. Notes offered and sold in reliance upon Rule 144A under the Securities Act will be issued in the form of one or more Rule 144A Global Notes. Notes offered and sold in reliance on Regulation S under the Securities Act will be issued in the form of one or more Regulation S Global Notes. Each of the Global Notes will be initially registered in the name of The Depositary Trust Company ("DTC") or its nominee and deposited with the Indenture Trustee as custodian for DTC. Beneficial interest in the Global Notes will be shown on, and transfers thereof will be affected only through, the book entry records maintained by DTC and its direct and indirect participants (including Euroclear and Clearstream). Notes traded in Panama will clear through Latinclear as participant in Clearstream.

Payments and Paying Agents

We will make all payments on the Notes exclusively in such coin or legal currency of the United States as at the time of payment will be legal tender for the payment of public and private debts.

The Issuer and the Guarantors will make payments of principal and interest on the Notes to the Indenture Trustee, which will pass such funds to the paying agents or to the holders of the Notes. Initially, the Indenture Trustee will act as registrar, transfer agent and paying agent for the Notes.

The Issuer and the Guarantors will make payments of principal upon surrender of the relevant Notes at the specified corporate trust office of the Indenture Trustee or any of the paying agents. The Issuer and the Guarantors will pay interest on the Notes to the Persons in whose name the Notes are registered on the Regular Record Date. Payments of principal and interest in respect of each global note will be paid by wire transfer of immediately available funds to DTC. Payments of principal and interest in respect of any certificated notes will be made by Dollar check drawn on a bank in the City of New York and mailed to the holder of such Note at its registered address. Upon application by the holder of at least U.S.$1.0 million in aggregate principal amount of Notes to the specified corporate trust office of the Indenture Trustee or any paying agent not less than 15 days before the due date for any payment in respect of a Note, such payment may be made by transfer to a Dollar account maintained by the payee with a bank in The City of New York.

All payments will be subject in all cases to any applicable tax or other laws and regulations, but without prejudice to the provisions of "— Additional Amounts." For the purposes of the preceding sentence, the phrase "applicable tax or other laws and regulations" will include any obligation on the Issuer and the Guarantors to withhold or deduct from a payment pursuant to FATCA (as defined below). No commissions or expenses will be charged to the holders in respect of such payments.

Subject to any applicable abandoned property law, the Indenture Trustee and the paying agents will pay to the Issuer and the Guarantors upon its request any monies held by them for the payment of principal or interest that remains unclaimed for two years, and, thereafter, holders entitled to such monies must look to the Issuer and the Guarantors for payment as its general creditors. After the return of such monies by the Indenture Trustee or the paying agents to the Issuer and the Guarantors, neither the Indenture Trustee nor the paying agents shall be liable to the holders in respect of such monies.

Collateral Arrangements

The Collateral package shall consist of:

- Funds from the Issuer and the Guarantors to be deposited in the Panamanian Trust accounts as described in "Summary of Panamanian Trust Accounts Structure" below;
- A Panama-law governed mortgage over all current and future or additional real property of the Issuer as well as all of the improvements thereon and also a usufructuary right over the proceeds of the mortgaged assets (the "Issuer Real Property Mortgage");

- A Panama-law governed chattel mortgage over certain moveable assets of and agreements entered into by the Issuer, future moveable assets belonging to the Issuer the value of which exceeds individually U.S.$50,000, as well as over the rights of the Issuer to receive payments under the mortgaged agreements for the benefit the Issuer (the "Issuer Chattel Mortgage");
- A Panama-law governed chattel mortgage over certain moveable assets of and agreements entered into by the Guarantors (including land lease agreements), future moveable assets belonging to each Guarantor the value of which exceeds individually U.S.$50,000, (the "Guarantors Chattel Mortgage");
- One Panama-law governed pledge over all the shares of the Issuer (the "Issuer Share Pledge");
- One Panama-law governed pledge over all the shares of the Guarantors (the "Guarantors Share Pledge");
- A Panama-law governed assignment agreement providing for the (i) unconditional assignment of certain accounts receivable and other contractual rights of the Guarantors to receive payments under certain contracts to which the Guarantors are a party and (ii) the conditional assignment of certain contractual rights, including the Guarantor's Power Purchase Agreements, (the "Guarantor Assignment Agreement").
- A Panama-law governed assignment agreement providing for the (i) unconditional assignment of certain accounts receivable and other contractual rights of the Issuer to receive payments under certain contracts to which the Issuer is a party and (ii) conditional assignment of certain contractual rights (the "Company Assignment Agreement").

For a description of the Collateral, see "Description of the Collateral."

Intercreditor Arrangements

The Intercreditor Agreement will govern the rights of the Secured Parties with respect to the Collateral. On or prior to the Issue Date, the Indenture Trustee will accede to the Intercreditor Agreement. The Administrative Agent acting on behalf of the Letter of Credit Secured Parties (or if no Administrative Agent is named, the relevant authorized representative appointed by and acting on behalf of the Letter of Credit Secured Parties) will also accede to the Intercreditor Agreement. If the Issuer and the Guarantors or any of the Guarantors incur any Additional Secured Debt, then the Additional Debt Provider thereof will accede to the Intercreditor Agreement.

Under the Intercreditor Agreement, the holders of the Notes will be represented by the Indenture Trustee and any future holders of other Secured Obligations will be represented by their respective authorized representative. The Intercreditor Agreement will provide for pari passu treatment and voting of the Secured Parties and set forth other relative rights among the holders of the Notes and the holders of any other Secured Obligations.

Pari Passu Benefits

The Secured Obligations will at all times rank at least *pari passu* in right of payment and security with any other present and future senior debt of the Issuer and the Guarantors. The Collateral will secure all Secured Obligations on a *pari passu* basis among themselves.

Priority of Payments

Following an enforcement action involving the sale, disposition or other realization, collection or recovery of any amounts or any Collateral (or any portion thereof) (all proceeds of any sale, collection or other liquidation of any Collateral and all proceeds of any such distribution being collectively referred to as "Proceeds"), the Proceeds will be transferred by the Collateral Trustee, including all such Proceeds attributable to any Debt Service Reserve Account, to the appropriate authorized representative with respect to the Secured Obligations to which such Debt Service Reserve Account relates, to be applied, *first* for the pro rata payment of all accrued and unpaid interest (including default interest, if any) on the relevant Secured Obligations, and *second*, if any unpaid principal or premium (if applicable) of such Secured Obligations has become due (by acceleration or otherwise), to the payment of such unpaid principal and premium. Following the application of the amounts described in the immediately preceding sentence, the Collateral Trustee will apply all other Proceeds toward the payment of the Secured Obligations in the following order of priority:

(i) *first*, (A) *first*, to the payment of the fees, indemnities, costs (including administrative costs owed to the Indenture Trustee or any other Agent, receiver or delegate) and expenses then due and payable to the Indenture Trustee or the other Agents in respect of any Secured Obligations and then (B) *second*, to the payment of the fees (other than fees payable pursuant to clause (ii) below), indemnities, costs and expenses then due and payable to the other Secured Parties in respect of any Secured Obligations;

(ii) *second*, to the payment of any (A) accrued and unpaid interest, premium and breakage costs (including post-petition interest, whether or not an allowed claim in any Insolvency Proceeding) in respect of any Secured Obligations ,(B) accrued and unpaid commitment fees, Letter of Credit fees and participation or other fees in respect of any Secured Obligations (other than (1) administrative costs owed to any Agent, receiver or delegate and (2) fees payable pursuant to expense reimbursement and indemnification provisions set forth in any Secured Debt Document under clause (i) above) and (C) accrued and unpaid Swap Settlement Payments under any Secured Swap Contracts;

(iii) *third*, *pro rata,* to the payment of any outstanding principal amount then due and payable in respect of any Secured Obligations (including reimbursement obligations under any Letter of Credit Document, Letter of Credit Loans and cash collateralization of all outstanding letters of credit (if any) constituting Secured Obligations) and (B) Swap Termination Payments then due and payable under any Secured Swap Contract;

(iv) *fourth*, to the payment of any other outstanding Secured Obligations under any Secured Debt Document; and

(v) *fifth*, the balance, if any, after all Secured Obligations have been paid in full in cash, to the Issuer and the other Guarantors or their successors or permitted assigns, as their interests may appear, or to whosoever may be lawfully entitled to receive the same, or as a court of competent jurisdiction may direct.

Shared Collateral

The Intercreditor Agreement provides that the Secured Parties will share ratably in the Collateral in which the Collateral Trustee holds on behalf of the Secured Parties of two or more Series of Secured Obligations a valid and perfected security interest at such time, except for the Debt Service Reserve Account (the "Shared Collateral"). If more than two Series of Secured Obligations are outstanding at any time and the Collateral Trustee holds on behalf of Secured Parties less than all of the outstanding Series of Secured Obligations a valid and perfected security interest in any Collateral at such time, then such Collateral only constitutes Shared Collateral for those Series of Secured Obligations on whose behalf the Collateral Trustee is acting for such Collateral at such time and does not constitute Shared Collateral for any Series which does not (through the Collateral Trustee) have a valid and perfected security interest in such Collateral at such time. Notwithstanding the foregoing, other than with respect to Debt Service Reserve Account, any assets of the Issuer and the Guarantors which at any time secure any Series of Secured Obligations are deemed to be "Shared Collateral" of the Secured Obligations, regardless of whether all of the Secured Parties then hold a valid and perfected security interest in such assets at such time.

Each Secured Party has agreed that it will not accept any Lien on any Collateral for the benefit of any Secured Obligations other than pursuant to the Security Documents and by executing the Intercreditor Agreement each of the Secured Parties has agreed that it will not question or contest or support any other Person in contesting, in any proceeding, the perfection, priority, validity, attachment or enforceability of a lien held by or on behalf of any of the Secured Parties in all or any part of the Collateral.

Each Secured Party has agreed that if it obtains possession of any Shared Collateral or realizes any proceeds or payment in respect of any such Shared Collateral for any reason, at any time prior to the discharge of each of the Secured Obligations, then it will hold such Shared Collateral, proceeds or payment in trust for the other Secured Parties.

Release of Liens

Each authorized representative of holders of Secured Obligations has authorized the Collateral Trustee, at the direction of the Intercreditor Agent (acting at the written direction of the Required Secured Debtholders), to execute and deliver to the Issuer and the Guarantors any instrument (including a modification to any Security Document) and to perform all acts and provide all instructions and notices reasonably required for such purposes as the Issuer and the Guarantors shall reasonably request to evidence (i) the release of any Lien on any Shared Collateral granted to or held by the Collateral Trustee under any Security Document or (ii) the release of the Issuer and the Guarantors or any of the Guarantors from its obligations under any Secured Debt Document. In each such case, (A) the release of such Lien of the Issuer and the Guarantors or any of the Guarantors should be permitted by the terms of each then-extant Secured Debt Document, and (B) the Collateral Trustee and the Intercreditor Agent should have received an officer's certificate from the Issuer and the Guarantors, at least five (5) Business Days prior to the proposed date of the release, certifying to clause (A) above and specifying the relevant provision(s) in each such Secured Debt Document permitting such release, and attaching the proposed instrument for execution.

Waivers and Amendments

The Collateral Trustee may not enter into any consent, waiver, amendment, modification or supplement to any Security Document other than pursuant to a decision of the Required Secured Debtholders (as defined below), unless such consent, waiver, amendment, modification or supplement (a) is in accordance with the Security Documents pursuant to which such Series of Secured Obligations was incurred and (b) does not adversely affect the Secured Parties of any other Series.

The Intercreditor Agreement may only be terminated, waived, amended or modified in writing by each authorized representative and the Collateral Trustee (acting pursuant to a written decision of the Required Secured Debtholders. The Issuer and the Guarantors do not have any right to consent to or approve any termination, amendment, waiver or other modification to or of the Intercreditor Agreement except to the extent that such termination, amendment, waiver or other modification (i) expressly requires the consent of the Issuer or any Guarantor under the Intercreditor Agreement, (ii) directly affects any obligation or right of the Issuer or any Guarantor or that would impose any additional obligations on the Issuer or any Guarantor or (iii) reduces the rights of the Issuer and the Guarantors to refinance the Secured Obligations.

Voting

Except as otherwise expressly provided in the Intercreditor Agreement, each Secured Debtholder shall be entitled to vote (through its authorized representative) in each Intercreditor Vote conducted under the Intercreditor Agreement. Each decision of the Required Secured Debtholders made in accordance with the terms of the Intercreditor Agreement shall be binding upon each of the Secured Parties.

Each Secured Party that is a party to the Intercreditor Agreement (for itself, each Secured Party on whose behalf it executes the Intercreditor Agreement and any other Person claiming through it) will agree under the Intercreditor Agreement that no Secured Party shall, except in accordance with the provisions of the Intercreditor Agreement, take any enforcement action except in accordance with the provisions of the Intercreditor Agreement (it being agreed that no acceleration in respect of a Secured Obligation event of default or termination or suspension of a commitment under a Secured Debt Documents shall be deemed to be an enforcement action for any purposes of the Intercreditor Agreement).

Each Secured Debtholder (through its authorized representative) will have a number of votes in any Intercreditor Vote equal to the portion (in Dollar amounts in relation to the aggregate Dollar amount of the Combined Exposure) of the Combined Exposure represented by the Secured Obligations owed to it under its respective Secured Debt Documents.

In calculating the Voting Party Percentage consenting to, approving, waiving or otherwise providing direction with respect to any decision, the total number of votes cast by all Secured Debtholders in favor of the proposed Decision (the "Numerator") shall be divided by the total number of votes entitled to be cast with respect to such matter (the "Denominator"). The Voting Party Percentage shall not include any votes excluded.

If, within forty-five (45) Business Days or a longer period prescribed by the Intercreditor Agent (acting at the written direction of the Required Secured Debtholders) not to exceed one hundred and twenty (120) days) (the "Decision Period"), the required Voting Party Percentage is reached then such proposed decision is approved and no Secured Party may object to any of the terms or provisions contained in the Intercreditor Vote. If, within the Decision Period, a Secured Debtholder does not respond approving or disapproving the relevant Intercreditor Vote, then the number of votes of such Secured Debtholder in such Intercreditor Vote is deemed to be cast against the proposed consent, approval, direction or other action for the purpose of calculating the Voting Party Percentage. Except in cases where DTC's Automated Tender Offer Program ("ATOP") procedures are utilized, any outstanding Indebtedness under any Secured Debt Documents constituting a bond or similar security (including the Holders in respect of the Notes) that does not vote affirmatively or negatively in connection with any decision within the prescribed period for such Intercreditor Vote shall be excluded from both the Numerator and Denominator of the calculation. In all cases in which the Indenture Trustee is required to notify Holders of the Notes of any Intercreditor Vote (including any solicitation to such holders to approve or disapprove a relevant Intercreditor Vote) the Indenture Trustee may structure the notice to Holders so that such notice or solicitation is eligible in accordance with the applicable procedures at DTC that the Indenture Trustee determines to facilitate such vote, including causing such notice to be processed through DTC's ATOP, which among other things may only allow Holders to provide an affirmative vote.

The Indenture will address the manner in which holders of Notes may instruct the Indenture Trustee to vote on their behalf in connection with Intercreditor Votes, including in respect of the provision of instructions or votes to the Indenture Trustee through the systems of DTC (including the ATOP procedures described above). The Indenture Trustee will have no responsibility or liability for the terms or requirements of any such systems or procedures offered by DTC, or any unavailability thereof.

Defaults and Remedies

If an Event of Default (as defined in the Intercreditor Agreement) occurs and is continuing, the Required Secured Debtholders may instruct the Intercreditor Agent as provided for in the Intercreditor Agreement to direct the Collateral Trustee to take any or all of the actions listed below (irrespective of their order, each a "Remedies Direction"), instituting judicial or extra-judicial proceedings to protect and enforce the rights vested in any of the Secured Parties by the Secured Debt Documents (including bringing appropriate judicial proceedings or taking any of the actions as shall be provided for in the Security Documents),

(i) either at law, in equity, in bankruptcy or otherwise, whether for the specific enforcement of any covenant or agreement or in aid of the exercise of any power granted thereby, including:

(A) selling or causing to be sold any assets that may at any time form part of the Shared Collateral either in whole or, if permitted by Applicable Law, in part, as provided in the relevant Security Document;

(B) foreclosing on receivables and other rights as provided pursuant to the Security Documents; and

(C) taking any other action required to protect or enforce any Secured Party's rights under any Security Document or any other Secured Debt Document and to collect the proceeds of enforcement of all or part of the Shared Collateral, including instructing the Collateral Trustee or the Intercreditor Agent to take any such action;

(ii) instituting judicial or extra-judicial proceedings to protect and enforce any other legal or equitable right vested in any of the Secured Parties pursuant to the Security Documents or Applicable Law; and

(iii) exercising all rights and remedies of a secured creditor permitted under the UCC or any similar law of Panama or any other applicable jurisdiction with respect to the security interest in the

Shared Collateral and all rights and remedies authorized under the Security Documents and Applicable Law, including to the extent permitted by Applicable Law, the right to take possession of the Shared Collateral.

Unless otherwise consented to in writing by the Collateral Trustee (pursuant to the written instructions of the Intercreditor Agent acting at the written direction of the Required Secured Debtholders), no Secured Party, individually or together with any other Secured Party, has the right, nor will it (x) exercise or enforce any of the rights, powers or remedies that the Collateral Trustee is authorized to exercise or enforce or any other Security Document with respect to the Shared Collateral or (y) take any step for the winding-up, administration of or dissolution of, or any Insolvency Proceeding in relation to, the Issuer and the Guarantors or any of the Guarantors, or for a voluntary arrangement, scheme of arrangement or other analogous step in relation to the Issuer and the Guarantors or any of the Guarantors. However, any Secured Party may:

(i) file a claim or statement of interest with respect to the Secured Obligations owed to such Person so long as a liquidation or Insolvency Proceeding has been commenced by or against the Issuer and the Guarantors or any of the Guarantors;

(ii) file any necessary or appropriate responsive or defensive pleadings in opposition to any motion, claim, adversary proceeding or other pleading made by any person objecting to or otherwise seeking the disallowance of the claims or Liens of the Collateral Trustee or any other Secured Party, including any claims secured by the Shared Collateral; and

(iii) file any pleadings, objections, motions or agreements that assert rights or interests available to unsecured creditors of the Issuer and the Guarantors or any of the Guarantors arising under any liquidation or Insolvency Proceeding of the Issuer and the Guarantors or any of the Guarantors or applicable non-bankruptcy law, or exercise any other rights and remedies that could be exercised by an unsecured creditor against the Issuer and the Guarantors or any of the Guarantors.

Summary of Panamanian Trust Accounts Structure

Pursuant to the Panamanian Trust, the Collateral Trustee has established or will establish, as applicable, the following segregated non-interest-bearing onshore accounts in the name of the Collateral Trustee, all of which will be part of the Collateral (the "Panamanian Trust Accounts"):

(i) *Issuer Collection Account*: The Issuer's collection account (the "Issuer Collection Account") shall be funded with all income of the Issuer, including revenues from the Power Purchase Agreements entered into by the Issuer, payments under the Intercompany Loans, wake effect payments, insurance proceeds, expropriation and termination payments, any other sources of revenue (including any related party payments), construction guaranty payments and liquidated damages payable under the SMA and related agreements, if any, and funds deposited in the Issuer Spot Market Account after netting any spot market payments owing to third parties.

(ii) *Issuer Spot Market Account*: The Issuer's spot market account (the "Issuer Spot Market Account") shall be funded, first, prior to each monthly clearing of the spot market payments, from the Collection Account and, second, after each such monthly clearing, from net proceeds of the monthly clearing of the spot market payments.

(iii) *Guarantor Collection Accounts*: The Guarantors' collection accounts (the "Guarantor Collection Accounts" and, together with the Issuer Collection Account, the "Collection Account") shall be funded with all income of the Guarantors, including revenues from the Power Purchase Agreements entered into by the Guarantors, insurance proceeds, expropriation and termination payments, and from funds deposited in the Guarantor Spot Market Accounts.

(iv) *Guarantor Spot Market Accounts*: The Guarantors' spot market accounts (the "Guarantor Spot Market Accounts") shall be funded, first, prior to each monthly clearing of the spot market payments, from the Guarantor Collection Accounts and, second, after each such monthly clearing, from proceeds of the monthly clearing of the spot market payments.

(v) *Debt Service Accrual Account*: The Debt Service accrual account (the "Debt Service Accrual

Account") shall be funded from the amounts received from the Collection Account pursuant to the accounts' waterfall (the "Accounts Waterfall") established under the Panamanian Trust.

(vi) *Trust Reserve Accounts*: The Panamanian trust's reserve accounts (the "Trust Reserve Accounts") shall be funded from the amounts received from the Collection Account pursuant to the Accounts Waterfall. The Trust Reserve Accounts shall consist of the Debt Service Reserve Account and the Trust O&M Reserve Account:

a. *Debt Service Reserve Account.* The Indenture Debt Service and Additional Debt Service reserve account (the "Debt Service Reserve Account") shall be funded from the amounts received from the Collection Account or Letters of Credit or a combination of the two in an amount at least equal to the then applicable Debt Service Reserve Requirement (other than in respect of amounts of principal or any cash collateralization obligation or reimbursement obligation due under the Letter of Credit Documents); provided that funds held in the Debt Service Reserve Account may be withdrawn to make payments of any amounts (including interest expense, principal, fees, premiums or other amounts other than amounts of principal due under the Letter of Credit Documents (except as provided below)) due on the Notes and any other Secured Debt if and to the extent that the amounts held in the Debt Service Accrual Account are insufficient to make such payments. Amounts on deposit in the Debt Service Reserve Account may be used to reimburse or repay draws upon a related Letter of Credit to the extent such reimbursement or repayment restores dollar for dollar the ability of the Collateral Trustee to draw upon such Letter of Credit for such purposes in the future.

b. *Trust O&M Reserve Account*. The Trust O&M Reserve Account shall be funded from the amounts received from the Collection Account or Letters of Credit, or a combination of the two (the "Trust O&M Reserve Account"). Funds from the Trust O&M Reserve Account may be withdrawn as instructed by the Issuer or the Intercreditor Agent, as applicable, to fund the Issuer Working Capital Account or any of the Guarantor Working Capital Accounts, if and to the extent that (i) the amounts held in the Collection Accounts and the Issuer Working Capital Account or the Guarantor Working Capital Account, as applicable, are insufficient to pay Operating and Maintenance Expenses, or (ii) the amount in the relevant Issuer Distribution Account or the Guarantor Distribution Accounts is insufficient to pay Unscheduled Operating and Maintenance Expenses. The Trust O&M Reserve Account shall be funded up to an amount equal to U.S.$1.00 million (the "O&M Reserve Requirement") or such greater amount as the Issuer at its option may decide.

(vii) *Letter of Credit Account*: The Letter of Credit Account shall be funded from amounts received in the Issuer Collection Account pursuant to the Accounts Waterfall to fund amounts payable under the Letter of Credit Documents, other than commitment and letter of credit fees and accrued and unpaid interest (the "Letter of Credit Account").

(viii) *SWAP Position Account*: The SWAP position account (the "Swap Position Account") shall be funded from amounts received from in the Issuer Collection Account pursuant to the Accounts Waterfall up to an amount sufficient to cover any Swap Settlement Payments or Swap Termination Payments, as applicable, due and payable during the Transfer Period by the Issuer under the Citi Swap; *provided*, that amounts will only be transferred to the Swap Position Account upon satisfaction by the Issuer of the conditions set out under "Limitation on Restricted Payments."

(ix) *Execution Accounts*: The Execution Accounts shall be funded from any proceeds derived from foreclosing on the Collateral in respect of the Issuer and the Guarantors (the "Execution Accounts") in accordance with the Intercreditor Agreement.

Funding of the Trust Reserve Accounts: The Debt Service Reserve Account and the Trust O&M Reserve Account shall be funded in cash in Dollars or, in lieu of such funding in cash, the Issuer shall obtain one or more irrevocable, Letters of Credit from one or more Acceptable Banks in favor of the Collateral Trustee, or a combination of both.

Issuer and Guarantor Account Structure (Outside the Panamanian Trust)

The Issuer and the Guarantors have established or will establish, as applicable, the following onshore accounts, which accounts are outside the Panamanian Trust and not part of the Collateral (the "Panamanian Accounts"):

(i) *Issuer Working Capital Account:* Pursuant to the Panamanian Trust Agreement, the Collateral Trustee will transfer funds on deposit in the Issuer Collection Account to the Issuer's working capital account (the "Issuer Working Capital Account") pursuant to the Issuer's requisition of funds for (a) an amount equal to the excess of the Operating and Maintenance Expenses that would be due and payable by the Issuer within the immediately succeeding three-month period in accordance with the Annual Budget over the amount then on deposit in the Issuer Working Capital Account and (b) Unscheduled Operating and Maintenance Expenses; *provided* that, solely with respect to (b) after giving effect to such transfer, the sum of (i) funds remaining on deposit in the Issuer Collection Account and the Guarantor Collection Accounts after the transfer referred to in (b) above and (ii) funds on deposit in the Debt Service Reserve Account and in the Debt Service Accrual Account, is sufficient to make the next payment in respect of Indenture Debt Service and Additional Debt Service with respect to Additional Secured Debt (other than in respect of principal amounts due under the Letter of Credit Documents). Amounts on deposit in the Issuer Working Capital Account will not be subject to a Lien for the benefit of the Secured Parties.

(ii) *Guarantor Working Capital Account:* Pursuant to the Panamanian Trust Agreement, the Collateral Trustee will transfer funds on deposit in the Guarantor Collection Accounts to one or more working capital accounts of the Guarantors (collectively, the "Guarantor Working Capital Accounts") pursuant to the Guarantors requisition of funds for (a) an amount equal to the excess of the Operating and Maintenance Expenses that would be due and payable by the Guarantors within the immediately succeeding three-month period in accordance with the Annual Budget over the amount then on deposit in the Guarantor Working Capital Account and (b) Unscheduled Operating and Maintenance Expenses; *provided* that, solely with respect to (b) after giving effect to such transfer, the sum of (i) funds remaining on deposit in the Issuer Collection Account and the Guarantor Collection Accounts after the transfer referred to in (b) above and (ii) funds on deposit in the Debt Service Reserve Account and in the Debt Service Accrual Account, is sufficient to make the next payment in respect of Indenture Debt Service and Additional Debt Service with respect to Additional Secured Debt (other than in respect of principal amounts due under the Letter of Credit Documents). Amounts on deposit in the Guarantor Working Capital Accounts will not be subject to a Lien for the benefit of the Secured Parties.

(iii) *Issuer Distribution Account:* Pursuant to the Panamanian Trust Agreement, at the request of the Issuer, the Collateral Trustee will transfer funds on deposit in the Issuer Collection Account pursuant to the Account Waterfall upon satisfaction of the conditions set out under "Limitation on Restricted Payments." To the extent the amount in the Issuer Working Capital Account is insufficient to pay Unscheduled Operating and Maintenance Expenses, the Issuer shall transfer from the Distribution Account to the Issuer Working Capital Account any amounts required to cover any deficit in the funding of such account to pay for any Unscheduled Operating and Maintenance Expenses.

(iv) *Guarantor Distribution Account:* Pursuant to the Panamanian Trust Agreement, at the request of the Guarantors, the Collateral Trustee will transfer funds on deposit in the Guarantor Collection Accounts to one or more distribution accounts of the Guarantors (collectively, the "Guarantor Distribution Accounts") pursuant to the Accounts Waterfall upon satisfaction of the conditions set out under "Limitation on Restricted Payments." To the extent the amount in the Guarantors Working Capital Account is insufficient to pay Unscheduled Operating and Maintenance Expenses, the Guarantors shall transfer from the Guarantor Distribution Account to the Guarantor Working Capital Account any amounts required to cover any deficit in the funding of such account to pay for any Unscheduled Operating and Maintenance Expenses.

Accounts Waterfall

The following is a general summary of the Accounts Waterfall and is not intended to be complete. Reference is made to the Panamanian Trust Agreement for a more complete description of the Accounts Waterfall.

Pursuant to the Panamanian Trust Agreement, the Collateral Trustee will transfer available funds on deposit in the Panamanian Trust Accounts in accordance with the Accounts Waterfall set forth therein, as instructed by the Issuer, unless (i) an Event of Default has occurred and is continuing, (ii) the Intercreditor Agent has received a Notice of Default from a Secured Party pursuant to Section 7.01 of the Intercreditor Agreement, (iii) the Intercreditor Agent has provided the Notice of Default to the Collateral Trustee, and (iv) the Intercreditor Agent gives notice to the Collateral Trustee that the Intercreditor Agent has received a Blocking Remedies Notice (as defined under the Intercreditor Agreement) requesting the Issuer's right to instruct the Collateral Trustee to make such fund transfers with respect to the Panamanian Trust Accounts be suspended; provided, however, that such suspension shall be revoked and the Issuer's ability to deliver instructions to the Collateral Trustee shall be restored following the delivery by the Intercreditor Agent of a notice to the Collateral Trustee upon the earliest of (a) the delivery to the Intercreditor Agent of a Notice of Cessation of Default (as defined under the Intercreditor Agreement), and (b) the rejection by the Required Secured Debtholders, through the applicable Intercreditor Vote, of such suspension requested in the applicable Blocking Remedies Notice (as defined under the Intercreditor Agreement).

<u>The Issuer</u>. In general terms, with respect to the Issuer, the Collateral Trustee will transfer available funds on deposit in the Issuer Collection Account as instructed by the Issuer or the Intercreditor Agent, as applicable, on each Monthly Transfer Date, as follows:

First, to pay on a pro rata basis, any and all fees, costs, indemnities and expenses (including attorneys' fees and expenses) due and payable under the Secured Debt Documents, including, amounts payable to the Collateral Trustee, the Intercreditor Agent, the Indenture Trustee, the Collateral Trustee and the Administrative Agent under the Letter of Credit Documents;

Second, to fund the Issuer Spot Market Account;

Third, to fund the Issuer Working Capital Account and to pay all Issuer's Operating and Maintenance Expenses and any Issuer's Unscheduled Operating and Maintenance Expenses as provided in "*Issuer and Guarantor Account Structure (Outside the Panamanian Trust) — Issuer Working Capital Account*";

Fourth, to fund the Debt Service Accrual Account in an amount equal to:

(i) to the extent the applicable payment date falls within six months after the Monthly Transfer Date (1) the Relevant Fraction of the next immediate semi-annual interest payment due under the Notes, (2) the Relevant Fraction of the next immediate semi-annual principal payment due under the Notes, (3) the Relevant Fraction of any payment in respect to fees payable under the Notes and the Indenture, (4) the Relevant Fraction of the next interest payment due on Additional Secured Debt (other than the Letter of Credit Documents), (5) the Relevant Fraction of the next principal payment due on Additional Secured Debt (other than under the Letter of Credit Documents), (6) the Relevant Fraction of additional amounts due under the Notes and the Indenture and (7) any Swap Settlement Payments and/or any Swap Termination Payments, in each case due and payable during the Transfer Period under any Secured Swap Contract;

(ii) *plus*, to the extent the applicable payment date falls within six months after the Monthly Transfer Date, the Relevant Fraction of (1) any amounts due in respect of commitment fees and Letter of Credit fees under the Letter of Credit Documents, and (2) the next immediate interest payment due under the Letter of Credit Documents;

(iii) plus (but without duplication of clauses (i) to (ii) above), only in the event that, as of any Monthly Transfer Date, both (A) sufficient funds are available to make the interest payment transfer and (B) on any prior Monthly Transfer Date occurring after the most recent interest payment date or semi-annual interest payment date in respect to interest expense related to the Notes, less than the full amount contemplated for the interest payment transfers was transferred to the Debt Service Accrual Account due to insufficient funds on such prior Monthly Transfer Date, such additional amount as necessary (to the extent of available funds) such that the total amount transferred to the Debt Service Accrual Account will be equal to the total amount that would have been transferred to the Debt Service Accrual Account for the interest payment if sufficient funds had been available as of each such prior Monthly Transfer Date;

Fifth, to fund the Debt Service Reserve Account to the extent necessary to cause the balance therein as of the Monthly Transfer Date to be equal to the then-required relevant Debt Service Reserve Requirement, provided that, unless there are amounts of principal due under the Letter of Credit Documents, the Issuer may deposit additional amounts even if there is an outstanding Letter of Credit and/or cash deposited in the Debt Service Reserve Account that would satisfy the Debt Service Reserve Requirement; To the extent that, at any time, there are outstanding Letter of Credit, cash deposited in the Debt Service Reserve Account, or any combination thereof, in excess of the Debt Service Reserve Requirement (such positive amount, the “DSRA Excess Amount”), the Issuer may instruct the Collateral Trustee to (i) transfer funds on deposit in the Debt Service Reserve Account to the Issuer Collection Account, (2) consent to any reduction of the face amount or amounts available under one or more Letters of Credit as permitted by the applicable Letter of Credit Agreement, or (3) any combination of (1) and (2), in each case, up to the DSRA Excess Amount. So long as no Default or Event of Default shall have occurred and be continuing, on or prior to March 31, 2021, the Issuer may instruct the Collateral Trustee to transfer the portion of the DSRA Excess Amount consisting of cash on deposit in the Debt Service Reserve Account to the Issuer Distribution Account;

Sixth, to fund the Trust O&M Reserve Account to the extent necessary to cause the balance therein to equal at least U.S.$1.0 million provided that, unless there are amounts of principal due under the Letter of Credit Documents, the Issuer may deposit additional amounts even if there is an outstanding Letter of Credit and/or cash in the Trust O&M Reserve Account that would satisfy the requirement to fund the Trust O&M Reserve Account pursuant to the Panamanian Trust Agreement; To the extent that, at any time, there are outstanding Letter of Credit, cash deposited in the Trust O&M Reserve Account, or any combination thereof, in excess of the O&M Reserve Requirement (such positive amount, the “O&M Reserve Excess Amount”), the Issuer may instruct the Collateral Trustee to (i) transfer funds on deposit in the Trust O&M Reserve Account to the Issuer Collection Account, (2) consent to any reduction of the face amount or amounts available under one or more Letters of Credit as permitted by the applicable Letter of Credit Agreement, or (3) any combination of (1) and (2), in each case, up to the O&M Reserve Excess Amount. So long as no Default or Event of Default shall have occurred and be continuing, on or prior to March 31, 2021, the Issuer may instruct the Collateral Trustee to transfer the portion of the O&M Reserve Excess Amount consisting of cash on deposit in the Trust O&M Reserve Account to the Issuer Distribution Account;

Seventh, to fund the Letter of Credit Account to make payments of the Relevant Fraction of the next immediate payment of principal due under the Letter of Credit Documents (including in respect of reimbursement obligations, Letter of Credit Loans and cash collateralization of outstanding Letters of Credit (if any));

Eighth, provided satisfaction of the conditions set out under “Limitation on Restricted Payments”, to fund the SWAP Position Account to make payments in the following order of priority to the extent of sufficient funds: (i) in an amount equal to the Swap Settlement Payments due and payable under the Citi Swap, (ii) in an amount equal to the Swap Settlement Payments due and payable under any other unsecured Permitted Swap Contract, (iii) in an amount equal to the Swap Termination Payments due and payable under the Citi Swap, and (iv) in an amount equal to the Swap Termination Payments due and payable under any other unsecured Permitted Swap Contract; and

Ninth, provided satisfaction of the conditions set out under “Limitation on Restricted Payments”, to fund the Issuer Distribution Account.

The Guarantors. In general terms, with respect to the Guarantors, the Collateral Trustee will transfer available funds on deposit in the Guarantor Collection Accounts as instructed by the Issuer or the Intercreditor Agent, as applicable, on each Monthly Transfer Date, as follows:

First, pursuant to the Issuer's instructions, to fund the Guarantor Spot Market Accounts;

Second, pursuant to the Issuer's instructions to fund the Guarantor Working Capital Accounts and to pay all Guarantors Operating and Maintenance Expenses and any Guarantors' Unscheduled Operating and Maintenance Expenses as provided in "*Issuer and Guarantor Account Structure (Outside the Panamanian Trust) — Guarantor Working Capital Account*";

Third, to transfer to the Debt Service Accrual Account any amounts required to be funded into the Debt Service Accrual Account to the extent of any deficit in such funding after making the transfers described under "*Fourth*" above;

Fourth, to transfer to the Debt Service Reserve Account any amounts required to be funded into the Debt Service Reserve Account to the extent of any deficit in such funding after making the transfers described under "*Fifth*" above;

Fifth, to fund the Trust O&M Reserve Account to the extent necessary to cause the balance therein to equal at least U.S.$1.0 million;

Sixth, to pay or optionally prepay to the Issuer any amounts in respect of the Intercompany Loans to the Issuer Collection Account; and

Seventh, provided satisfaction of the conditions set out under "Limitation on Restricted Payments", to the Guarantor Distribution Account.

Debt Service Accrual Account

Pursuant to the Panamanian Trust Agreement, the Collateral Trustee will transfer available funds on deposit in, or credited to, the Debt Service Accrual Account as instructed by the Issuer or the Intercreditor Agent, as applicable, in accordance with the order of priority set forth therein, which, in general terms, can be summarized as follows:

First, for application on a pro rata basis to the payment of interest, fees and additional amounts due under the Notes and the Indenture, interest payments due on Additional Secured Debt, any amounts due in respect of commitment fees, Letter of Credit fees and interest payments under the Letter of Credit Documents and any Swap Settlement Payments under any Secured Swap Contract then due and payable; and

Second, for application *on a pro rata basis* to the payment of any principal under the Notes then due and payable under the Indenture, the principal payment due on Additional Secured Debt (other than the Letter of Credit Documents), and any Swap Termination Payments under any Secured Swap Contract then due and payable.

Open Market Purchases

To the extent permitted under applicable law, the Issuer may at any time and from time to time purchase any Notes or a beneficial interest therein in the open market or otherwise at any price.

Optional Redemption with Make-Whole Premium

We may redeem on one or more occasions some or all of the Notes before they mature.

Prior to October 1, 2038, the Notes will be redeemable, in whole or in part, at the Issuer's option at any time and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of the Notes to be redeemed or (ii) the sum of the present values of the remaining scheduled payments of principal and interest thereon that would have been payable if redemption had not been made (exclusive of any interest accrued and unpaid to the date of redemption) discounted from the dates on which the principal and interest would have been payable if the redemption had not been made, to the date of redemption on a semi-annual basis (assuming a 360-day year consisting of twelve 30 day months) at the applicable Treasury Rate 50 plus basis points, plus, in either case, Additional Amounts, if any, and accrued and unpaid interest, if any, to, but not including, the date of redemption.

The Issuer shall be responsible for determining the redemption price of the Notes in connection with any such redemption, and the Indenture Trustee shall have no duty to verify any such determination.

For purposes of determining the optional redemption price, the following definitions are applicable:

"Comparable Treasury Issue" means the United States Treasury security or securities selected by an Independent Investment Banker as having an actual or interpolated maturity that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of a comparable maturity to the remaining term of the Notes.

"Comparable Treasury Price" means, with respect to any redemption date, (i) the average of five Reference Treasury Dealer Quotations for such redemption date, after excluding the highest and lowest Reference Treasury Dealer Quotations, or (ii) if the Independent Investment Banker is unable to obtain at least five such Reference Treasury Dealer Quotations, the average of all Reference Treasury Dealer Quotations obtained by the Independent Investment Banker.

"Independent Investment Banker" means one of the Reference Treasury Dealers appointed by the Issuer and the Guarantors from time to time to act as the "Independent Investment Banker."

"Reference Treasury Dealer" means Citigroup Global Markets Inc. or its respective affiliates or successors that are primary U.S. Government securities dealers in New York City ("Primary Treasury Dealers"), and two other nationally recognized investment banking firms that are Primary Treasury Dealers selected from time to time by the Issuer and the Guarantors; *provided*, *however*, that if any of the foregoing shall cease to be a Primary Treasury Dealer, the Issuer and the Guarantors shall substitute therefor another nationally recognized investment banking firm that is a Primary Treasury Dealer.

"Reference Treasury Dealer Quotation" means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by the Independent Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Independent Investment Banker by such Reference Treasury Dealer at 3:30 p.m., New York City time, on the third business day preceding that redemption date.

"Treasury Rate" means, with respect to any redemption date, the rate per annum equal to the semi-annual equivalent yield to maturity (computed as of the third business day immediately preceding that redemption date) of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for that redemption date.

Optional Redemption upon Tax Event

The Issuer may at any time redeem the Notes at its option, in whole, but not in part, at a redemption price equal to 100% of the then-outstanding principal amount of the Notes, plus accrued and unpaid interest thereon to, but excluding, the date of redemption and any Additional Amounts payable with respect thereto, if the Issuer and the Guarantors certify to the Indenture Trustee (in the manner prescribed below) that:

(a) the Issuer has or will become obligated to pay Additional Amounts in connection with payments of interest, or amounts deemed interest, on the Notes in respect to withholding taxes as a result of any generally applicable change in or amendment to the laws or regulations of a Relevant Jurisdiction or any political subdivision or governmental authority thereof or therein having power to tax, or any generally applicable change in the application or official interpretation of such laws or regulations, which change or amendment becomes effective (and not publicly announced prior to)or, in the case of a change in official position, is announced on or after the later of the date of issuance of the Notes and the date that a Relevant Jurisdiction becomes a Relevant Jurisdiction; and

(b) such obligation cannot be avoided by taking reasonable measures available to the Issuer; *provided* that reasonable measures will not include any change in the Issuer's or Guarantor's jurisdiction of tax residency;

provided, further, however, that the notice of redemption, which will specify the date of redemption and redemption price, will not be given earlier than 60 days before the earliest date on which the Issuer would be obligated to pay Additional Amounts if a payment in respect of the Notes were then due.

No later than 15 days (unless a shorter period is acceptable to the Indenture Trustee) before giving any notice of redemption as described in the preceding clauses, the Issuer will deliver an Officer's Certificate to the Indenture Trustee stating that the Issuer is entitled to effect such redemption in accordance with the terms of the Indenture and setting forth in reasonable detail a statement of facts relating thereto. The Officer's Certificate will be accompanied by a written opinion of recognized independent counsel experienced in tax and other related matters in the Relevant Jurisdiction to the effect that the Issuer has or will become obligated to pay Additional Amounts as a result of such change or amendment.

Optional Redemption Procedures

The procedures in this "Optional Redemption Procedures" section will apply to any redemption pursuant to "— Optional Redemption with Make-Whole Premium," and "— Optional Redemption upon Tax Event" above. In the event that less than all of the Notes are to be redeemed at any time, selection of Notes for redemption will be made by the Indenture Trustee in compliance with the requirements of the principal securities exchange or market, if any, on which Notes are then listed or, if the Notes are not then listed on a securities exchange or market, on a pro rata basis, by lot or by any other method as the Indenture Trustee shall deem fair and appropriate (or such other basis as required by the applicable depositary for the Notes). No Notes of a principal amount of U.S.$200,000 or less may be redeemed in part, and Notes of a principal amount in excess of U.S.$200,000 may be redeemed in multiples of U.S.$1,000 only.

Notice of any redemption will be given at least 30 but not more than 60 days before the redemption date to the Indenture Trustee and each holder of the Notes in accordance with the provisions described under "— Notices."

If Notes are to be redeemed in part only, the notice of redemption will state the portion of the principal amount thereof to be redeemed. At least U.S.$100.0 million in aggregate principal amount of the Notes issued under the Indenture (not including any Notes held by the Issuer and the Guarantors or any of its Affiliates) must remain outstanding after any redemption of the Notes in part but not in whole. A new Note in a principal amount equal to the unredeemed portion thereof (if any) will be issued in the name of the holder thereof upon cancellation of the original Note (or adjustments to the amount and beneficial interests in a global note will be made, as appropriate). For so long as the Notes are admitted to listing on the SGX-ST, we will cause notices of redemption also to be published as provided under "— Notices."

We will pay the redemption price for any Note together with accrued and unpaid interest and Additional Amounts, if any, thereon up to, but not including, the date of redemption. On and after the redemption date, interest will cease to accrue on Notes or portions thereof called for redemption as long as we have deposited with the paying agent funds in satisfaction of the applicable redemption price pursuant to the Indenture. Upon redemption of any Notes by us, such redeemed Notes will be cancelled.

We will give notice to the applicable depositary for the Notes pursuant to the provisions described under "— Notices" of any optional redemption we propose to make at least 30 days (but not more than 60 days) before the redemption date.

The Indenture will provide that we may not revoke any redemption notice once such notice has been delivered. Notwithstanding the foregoing provisions of this "Optional Redemption Procedures" section, we are not prohibited from acquiring the Notes by means other than a redemption, whether pursuant to a tender offer, open market purchase or otherwise.

Mandatory Redemption Provisions

The Notes will be subject to mandatory redemption prior to their Stated Maturity at a redemption price equal to 100% of the outstanding principal amount of the Notes being redeemed, plus accrued and unpaid interest to the redemption date, plus Additional Amounts, if any (but without payment of any premium), payable in respect of the Notes, as set forth below in "— Redemption in Connection with Events of Loss." For the avoidance of doubt, the proceeds being applied to a mandatory redemption of the Notes will also be applied pro rata to the repayment and/or redemption of principal, accrued and unpaid interest, and Additional Amounts, if any, payable in respect of any Additional Debt that is permitted to be ratably secured by the Collateral and, by its terms, requires such redemption.

Redemption in Connection with Events of Loss

If:

- there occurs an Event of Loss or series of Events of Loss, including any Condemnation Event,
- the Issuer and the Guarantors or any of the Restricted Subsidiaries receive Loss Proceeds constituting Net Available Proceeds in excess of U.S.$5.0 million (or the equivalent in any other currency) as a result of such Event of Loss or series of Events of Loss, and
- the Issuer and the Guarantors make a good faith determination that such Net Available Proceeds from Loss Proceeds, together with any other amounts that are available to the Issuer and the Guarantors, are insufficient to permit the Issuer and the Guarantors to deliver a Feasible Repair Certificate in respect of such Event of Loss or series of Events of Loss without any exceptions or qualifications that are reasonably likely to have a Material Adverse Effect,

the Issuer and the Guarantors will be required to effect a mandatory redemption of the Notes; provided that notwithstanding any other provision of this "Redemption in Connection with Events of Loss" section, any redemption of the Notes pursuant to this "Redemption in Connection with Events of Loss" section shall be conducted in accordance with the Intercreditor Agreement, including any required sharing of proceeds of any Event of Loss with other Secured Obligations.

If Notes of any series are to be redeemed in part only, then the reduction in the principal balance of the Notes will be applied to reduce the remaining scheduled Amortization Payments on a pro rata basis. A new Note of the applicable series in a principal amount equal to the unredeemed portion thereof (if any) will be issued in the name of the holder thereof upon cancellation of the original Note (or adjustments to the amount and beneficial interests in a global note will be made, as appropriate). For so long as the Notes are admitted to listing on the SGX-ST, the Issuer will cause notices of redemption also to be published as provided under "— Notices."

The Issuer and the Guarantors determination as to whether it is required to effect a mandatory redemption of the Notes following receipt of Net Available Proceeds from an Event of Loss or series of Events of Loss shall be evidenced by an Officer's Certificate delivered to the Indenture Trustee not more than 90 days after it or any of the Restricted Subsidiaries receives such Net Available Proceeds. If, with respect to an Event of Loss or series of Events of Loss, the Issuer and the Guarantors have determined that it is not required to effect such mandatory redemption of the Notes, it shall deliver to the Indenture Trustee, within 30 days after the time it delivers the Officer's Certificate referred to above, a Feasible Repair Certificate in respect of such Event of Loss or series of Events of Loss.

If the Issuer and the Guarantors are required to effect the mandatory redemption of Notes in accordance with the foregoing provisions, the Net Available Proceeds from any such Event of Loss or series of Events of Loss shall be applied to redeem all or a portion of the Notes, as applicable, at a redemption price equal to 100% of the principal amount of the Notes being redeemed, plus accrued and unpaid interest and Additional Amounts, if any, on the Notes being redeemed to the date of redemption as described below on a pro rata basis (or such other basis as required by the applicable depositary for the Notes).

Following a determination that the Net Available Proceeds from any Event of Loss or series of Events of Loss are to be applied pursuant to the immediately preceding paragraph, the Issuer and the Guarantors shall, (i) upon written notice to the Indenture Trustee and the Collateral Trustee, set a date for the redemption of Notes, (ii) deliver (or cause to be delivered by the Indenture Trustee at the expense of the Issuer and the Guarantors) notice of redemption in the manner described above to the holders of the Notes (with a copy to the Indenture Trustee) and (iii) once the Net Available Proceeds are received, if received by the Issuer and the Guarantors or any Restricted Subsidiary, transfer the Net Available Proceeds to the Collection Account.

On the date set for redemption, the Issuer and the Guarantors and the Indenture Trustee shall take all actions as are necessary to effect the redemption of the Notes in accordance with the procedures set forth in the first paragraph of "— Optional Redemption Procedures" above and the Intercreditor Agreement, including application of the amounts in the Collection Account to the payment of the principal of the Notes being redeemed, interest accrued but unpaid thereon to the date of redemption and Additional Amounts required to be paid, if any, but excluding, for the avoidance of doubt, application of any such amounts to the payment of any premium.

In the event that the Issuer and the Guarantors are not required to apply the Net Available Proceeds from an Event of Loss to a mandatory redemption and any Net Available Proceeds are left over after payment in full of the cost of rebuilding, repairing or restoring the relevant Project or other asset or property, as contemplated by the applicable Feasible Repair Certificate, such Net Available Proceeds shall be deposited in the Collection Account, for application in accordance with the Security Documents.

Repurchase upon Change of Control Repurchase Event

Except as otherwise described below, by no later than 30 days after the occurrence of a Change of Control Repurchase Event, the Issuer and the Guarantors must give notice thereof to the Indenture Trustee and the holders of the Notes (which notice may be delivered by the Indenture Trustee, upon the written request and at the expense of the Issuer and the Guarantors) a notice (a "Change of Control Notice") offering to purchase all of the Notes then outstanding on a selected date that is no earlier than 30 days and no later than 60 days (or such additional time as may be required by Applicable Laws) after the date of such notice, which selected date must be a Business Day (such offer, a "Change of Control Offer"). In connection with any Change of Control Offer, the Issuer and the Guarantors will hold such offer open for at least twenty (20) (but not more than thirty (30)) Business Days (or such additional time as may be required by Applicable Laws). The Change of Control Notice must advise each holder of the Notes in sufficient detail as to how to tender its Notes should it elect to accept such Change of Control Offer.

The Issuer and the Guarantors will: (a) subject to the next paragraph, accept (except to the extent such would violate Applicable Laws) for purchase all or any part (equal to U.S.$200,000 and multiples of U.S.$1,000 in excess thereof) of the Notes that have been tendered in (but not withdrawn from) such Change of Control Offer, and (b) pay (such payment to be made in Dollars) each applicable holder for its Notes a purchase price equal to 101% of the portion of the outstanding principal balance represented by such Notes plus all accrued and unpaid interest (if any) thereon to but excluding the purchase date plus Additional Amounts, if any, payable in respect of such Notes.

In any such Change of Control Offer, a holder may elect to condition its tender of its Notes subject to the condition that a minimum percentage (selected by such holder) of the outstanding principal balance of the Notes has been tendered in (but not withdrawn from) the offer; *it being understood* that, in determining whether such percentage has been achieved, the Notes of such holder and other holders that have so conditioned their tenders with the same or a higher percentage will not be considered to have been tendered.

If the Issuer and the Guarantors purchase only a portion of an outstanding Note in connection with a Change of Control Offer, the Issuer and the Guarantors will, promptly upon cancellation of the original Note, issue in the name of the holder thereof a new Note in a principal amount equal to the portion thereof not purchased. The unpurchased portion of any Note will not be less than the minimum denomination of a Note specified in "Book-Entry; Settlement and Clearance."

The Issuer and the Guarantors will comply, to the extent applicable, with the requirements of Rule 14e-1 under the Exchange Act and any other Applicable Laws in connection with a Change of Control Offer. To the extent that the provisions of any Applicable Laws conflict with provisions of this covenant, the Issuer and the Guarantors will comply with such Applicable Laws and will not be deemed to have breached its obligations under this covenant by virtue of its compliance with such Applicable Laws.

Each registered holder of the Notes (except as otherwise required by law) will be treated as its absolute owner for all purposes (whether or not it is overdue and regardless of any notice of ownership, trust or any interest in it, writing on, or theft or loss of, the definitive Note issued in respect of it) and no Person will be liable for so treating the holder.

If holders of not less than 90% in aggregate principal amount of the outstanding Notes validly tender and do not withdraw such Notes in a Change of Control Offer and the Issuer and the Guarantors, or any third party making a Change of Control Offer in lieu of the Issuer and the Guarantors as described below, purchases all of the Notes validly tendered and not withdrawn by such holders, the Issuer and the Guarantors will have the right, upon not less than 30 nor more than 60 days' prior notice, given not more than 30 days following such purchase pursuant to the Change of Control Offer described above, to redeem all Notes that remain outstanding following such purchase at a redemption price in cash equal to the applicable payment in the Change of Control Offer plus, to the extent not included in such payment, accrued and unpaid interest, if any, thereon, to, but not including, the date of redemption, plus Additional Amounts, if any, payable in respect of such Notes.

The Issuer and the Guarantors will not be required to make a Change of Control Offer upon a Change of Control Repurchase Event if (1) a third party makes the Change of Control Offer in the manner, at the times and otherwise in compliance with the requirements set forth in the Indenture applicable to a Change of Control Offer made by the Issuer and the Guarantors and purchases all Notes properly tendered and not withdrawn under the Change of Control Offer, or (2) notice of redemption has been given pursuant to the Indenture as described above under the caption "— Optional Redemption with Make-Whole Premium," "Optional Redemption upon Tax Event," "Redemption in Connection with Events of Loss" or "Priority of Payments upon Foreclosure on the Collateral" unless and until there is a default in payment of the applicable redemption price. A Change of Control Offer may be made in advance of a Change of Control Repurchase Event, with the obligation to pay and the timing of payment conditioned upon the occurrence of a Change of Control Repurchase Event, if a definitive agreement to effect a Change of Control is in place at the time the Change of Control Offer is made.

Priority of Payments upon Foreclosure on the Collateral

If the maturity of the Notes has been accelerated and if the Collateral Trustee foreclose on or sell substantially all of the Collateral at any time pursuant to the terms of the Security Documents, all proceeds realized in connection therewith must be applied to pay the holders of the Notes for the Notes and other required amounts in accordance with the priority set forth in the Indenture, irrespective of whether such proceeds are sufficient to pay all amounts then due under the Notes but excluding, for the avoidance of doubt, application of any such proceeds to the payment of any premium.

Additional Amounts

The Issuer and the Guarantors will make payments of, or in respect of, principal, premium (if any) and interest on the Notes free and clear of, and without withholding or deduction for or on account of any present or future tax, levy, impost, duty, assessment or other charge of whatever nature levied by any Governmental Authority, irrespective of the manner in which they are collected or assessed, including any interest, additions to tax or penalties applicable thereto ("Taxes"), unless such withholding or deduction is required by law.

If the Issuer and the Guarantors or any paying agent is required to deduct or withhold any amount in respect of Taxes for the account of Panama (or any political subdivision thereof or any authority therein or thereof having the power to tax) or any other jurisdiction (or any political subdivision or any authority thereof or therein) from or through which such payments are made (each, a "Relevant Jurisdiction"), the Issuer and the Guarantors will pay to a holder of a Note such additional amounts ("Additional Amounts") as may be necessary so that the net amount received by such holder will not be less than the amount such holder would have received if such Taxes had not been withheld or deducted, it being understood that for Panamanian tax purposes the payment of such Additional Amounts will be deemed and construed as additional interest.

The foregoing obligation to pay Additional Amounts to any holder of Notes, however, will not apply to or in respect of:

(a) any Taxes that would not have been so imposed, assessed, levied or collected but for the fact that the holder or beneficial owner of the Note (or a fiduciary, settlor, beneficiary, member or shareholder of, or possessor of a power over, such holder, if such holder is an estate, trust, partnership or corporation) having some present or former connection with a Relevant Jurisdiction, including such holder of the Note (i) being or having been a domiciliary, national or resident of the Relevant Jurisdiction, (ii) engaging or having been engaged in a trade or business in the Relevant Jurisdiction, (iii) maintaining or having maintained an office, a permanent establishment or branch in the Relevant Jurisdiction or (iv) being or having been physically present in the Relevant Jurisdiction, except for a connection solely arising from mere ownership of the Note, receiving payments of any nature on the Note, or enforcing rights under the Note;

(b) any Taxes that would not have been so imposed, assessed, levied or collected but for the fact that, where presentation is required in order to receive payment, the Note was presented more than 30 days after the date on which such payment became due and payable or was provided for, whichever is later, except to the extent that the holder or beneficial owner thereof would have been entitled to Additional Amounts had the Note been presented for payment on the last day of such 30-day period;

(c) any estate, inheritance, gift, sales, use, transfer, excise, or personal property or similar Taxes;

(d) any Taxes that are payable otherwise than by deduction or withholding from payments on or in respect of the applicable Note;

(e) any Taxes that would not have been so imposed, assessed, levied or collected but for the failure by the holder or the beneficial owner of the Note to provide any certification, identification, information, documentation or other evidence or information concerning the nationality, residence or identity of the holder or the beneficial owner or its connection with a Relevant Jurisdiction, if (i) compliance is required by statute, rule, regulation or administrative practice of a Relevant Jurisdiction as a condition to relief, reduction or exemption from all or part of such Taxes and (ii) the Issuer has given the holders at least 30 days' written notice prior to the first payment date with respect to which such certification, identification, information, documentation or other evidence is required to the effect that holders will be required to provide such information and identification;

(f) any payment on the Note to a holder that is a fiduciary, a partnership or any person other than the sole beneficial owner of any such payment to the extent that a beneficiary or settlor with respect to such fiduciary, a partner of such partnership or the beneficial owner of the payment would not have been entitled to the Additional Amounts had the beneficiary, settlor, partner or beneficial owner been the holder of the Note; or

(g) any combination of the Taxes and/or withholdings or deductions described in (a) through (f) above.

The limitations on the Issuer's and the Guarantors' obligations to pay Additional Amounts set forth in clause (e) above will not apply if the provision of information, documentation or other evidence described in such clause (e) would be materially more onerous, in form, in procedure or in the substance of information disclosed, to a holder or beneficial owner of a Note, than comparable information or other reporting requirements imposed under U.S. tax law, regulations (including temporary or proposed regulations) and administrative practice.

In addition, clause (e) above does not require, and will not be construed to require, that any holder, including any non-Panamanian pension fund, retirement fund, tax-exempt organization or financial institution, register, to the extent applicable, with the Panamanian Ministry of Economy and Finance (*Ministerio de Economía y Finanzas*) or the *Dirección General de Ingresos* to establish eligibility for an exemption from, or a reduction of, Panamanian withholding taxes.

As provided in "— Payments and Paying Agents," all payments in respect of the Notes will be made subject to any withholding or deduction required pursuant to Section 1471(b) of the Internal Revenue Code of 1986, as amended (the "Code"), or otherwise imposed pursuant to Sections 1471 through 1474 of the Code, as amended, as of the date of this Agreement (or any amended or successor version that is substantively comparable and not materially more onerous to comply with), any current or future regulations interpretations thereof, any agreement entered into pursuant to Section 1471(b) of the Code, any intergovernmental agreement entered into in connection with the implementation of such Sections of the Code, as amended, and any fiscal or regulation legislation, rules or practices adopted pursuant to such intergovernmental agreement (collectively, "FATCA"), and the Issuer and the Guarantors will not be required to pay any Additional Amounts on account of any such deduction or withholding required pursuant to FATCA.

Unless otherwise stated, references in any context to the payment of principal of, and premium, if any, or interest on, any Note, will be deemed to include payment of Additional Amounts to the extent that, in such context, Additional Amounts are, were or would be payable in respect thereof.

The Issuer and the Guarantors will also pay any present or future stamp, court or documentary taxes or other excise or property taxes, charges or similar levies which arise in any jurisdiction from the execution, delivery, registration or enforcement in respect of the Notes, and the Issuer and the Guarantors agree to indemnify and/or provide security to each of the Indenture Trustee, the paying agents, the Collateral Trustee and the holders of the Notes for any such amounts paid or incurred by any such party.

If the Issuer and the Guarantors will be obligated to pay Additional Amounts with respect to any payment under or with respect to the Notes, the Issuer will deliver to the Indenture Trustee, at least three (3) Business Days prior to the relevant payment date, an Officer's Certificate stating the fact that such Additional Amounts will be payable, the amounts so payable and will set forth such other information necessary to enable the Indenture Trustee to pay such Additional Amounts to holders of Notes on the payment date. Each such Officer's Certificate will be relied upon by the Indenture Trustee without further enquiry until receipt of a further Officer's Certificate addressing such matters.

Affirmative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries

Set forth below are summaries of certain affirmative covenants contained in the Indenture.

Compliance with Laws, etc.

The Issuer and the Guarantors will, and will cause each of their respective Restricted Subsidiaries to, comply with all Applicable Laws and all orders, writs, injunctions and decrees applicable to it or to its business or property (including any Environmental Law), except where any failure to so comply could not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect; *provided* that the Issuer and the Guarantors or any of the Restricted Subsidiaries may, at its expense, contest by appropriate proceedings conducted in good faith the validity or application of any such requirement of Applicable Law, so long as (1) none of the Secured Parties would be subject to any liability for failure to comply therewith and (2) the institution of such proceedings would not reasonably be expected to result in a Material Adverse Effect.

Payment of Obligations

Each of the Issuer and the Guarantors will pay, discharge or otherwise satisfy in full, at or before maturity or before they become delinquent, all of its respective obligations and liabilities arising pursuant to the Notes or the Note Guarantees, as applicable, including all payments of principal, interest, any premium and any Additional Amounts.

The Issuer and the Guarantors will, and will cause each Restricted Subsidiary to, pay and discharge as the same become due and payable all of its obligations and liabilities, including (i) all tax liabilities, assessments and governmental charges or levies upon it or its properties or assets, unless the same are subject to contest in good faith and for which reasonable reserves have been provided for; (ii) all premiums owed under any insurance policies; and (iii) all lawful claims that, if unpaid, would by law become a Lien upon its properties, except in the case of clauses (i), (ii) and (iii) where the failure to do so could not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect.

Preservation of Existence, Etc.

The Issuer and the Guarantors will, and will cause each Restricted Subsidiary to, (i) except as permitted under "— Merger, Consolidation, Liquidation, Dissolution," preserve and maintain its corporate existence under the laws of Panama, as applicable, and (ii) take all reasonable action to obtain and maintain in full force and effect all Governmental Authorizations and all other rights, privileges, permits, licenses, including applicable generation and interconnection licenses, and franchises necessary or desirable in the normal conduct of its business, except where the failure to maintain such Governmental Authorizations could not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect.

Books and Records

The Issuer and the Guarantors will, and will cause each Restricted Subsidiary to, (i) maintain books of record and accounts in conformity with Applicable Accounting Principles consistently applied and in conformity with applicable requirements of any Governmental Authority having regulatory jurisdiction over the Issuer and the Guarantors or any of the Restricted Subsidiaries, as applicable, and (ii) maintain internal accounting, management information and cost control systems adequate to ensure compliance with Applicable Laws in Panama, except, in the case of (i) and (ii), where the failure to do so could not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect.

Inspection Rights

The Issuer and the Guarantors will permit representatives of the holders of the Notes, the Indenture Trustee, and the Collateral Trustee under guidance of officers of the Issuer and the Guarantors, to visit and inspect any of the properties of the Issuer and the Guarantors or the Restricted Subsidiaries and to examine the Issuer and the Guarantors or such Restricted Subsidiary's corporate, financial, operating and other records, no more than one time per year at the expense of the holders of the Notes and at such reasonable times during normal business hours, upon reasonable advance written notice to the Issuer and the Guarantors and with the Issuer and the Guarantors consent (such consent not to be unreasonably withheld); *provided* that when an Event of Default exists, representatives of the holders of the Notes, the Indenture Trustee and the Collateral Trustee may do any of the foregoing as often as may be reasonably desired at the expense of the Issuer and the Guarantors at any time during normal business hours and without advance notice. The Issuer and the Guarantors and the Restricted Subsidiaries will not be required to disclose information to the holders of the Notes, the Indenture Trustee or the Collateral Trustee that is prohibited by Applicable Law or contract (*provided* that such prohibition is not entered into in contemplation of this covenant) or is subject to attorney-client or similar privilege or constitutes attorney work product.

Further Assurances

The Issuer and the Guarantors will, and will cause each Restricted Subsidiary to, promptly upon the written request of the Indenture Trustee or the Collateral Trustee (none of which will be under an obligation to make such request), and at the cost and expense of the Issuer and the Guarantors or any of the Restricted Subsidiaries, as applicable, (i) correct any material defect or error that may be discovered in the Indenture and any Security Document or in the execution, acknowledgment, filing or recordation thereof; and (ii) do, execute, acknowledge, deliver, record, re-record, file, re-file, register and re-register any and all such further acts, deeds, conveyances, pledge agreements, mortgages, deeds of trust, trust deeds, assignments, financing statements and continuations thereof, termination statements, notices of assignment, transfers, certificates, assurances and other instruments necessary (or as the Indenture Trustee or the Collateral Trustee may reasonably request from time to time) in order to (A) enable each of the Issuer and the Guarantors and the Restricted Subsidiaries lawfully to perform and comply with its obligations under the Indenture and the Notes, (B) to the fullest extent permitted by Applicable Law, subject the Issuer and the Guarantors and the Restricted Subsidiaries' properties, assets, rights or interests to the Liens intended to be covered by any of the Security Documents, (C) perfect and maintain the validity, effectiveness and priority of any of the Security Documents and any of the Liens intended to be created thereunder and (D) assure, convey, grant, assign, transfer, preserve and protect and confirm more effectively to the Collateral Trustee for the benefit of the Secured Parties the rights granted or purported to be granted in accordance with the terms of the Security Documents.

Material Project Documents, etc.

The Issuer and the Guarantors will, and will cause each Restricted Subsidiary to, (i) perform and observe all terms and provisions of the Material Project Documents to be performed or observed by it, (ii) maintain the Material Project Documents to which it is a party in full force and effect, and (iii) exercise all its rights, discretion and remedies, if any, under the Material Project Documents to which it is a party in accordance with their terms and in a manner consistent with (and subject to) the Issuer and the Guarantors and the Restricted Subsidiaries' obligations under the Indenture and the Security Documents, in each case of clauses (i) through (iii) above, except to the extent that failure to do any of the foregoing could not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect.

If after the Issue Date the Issuer or the Guarantors or any of its Restricted Subsidiaries enters into a Power Purchase Agreement with any existing or new customer involving annual payments to the Issuer or Restricted Subsidiary in excess of U.S.$1.5 million the Issuer will designate such agreement as a Material Project Document, and in each case, the Issuer will as promptly as practicable (and in any event within twenty (20) Business Days of entrance into any such agreement) notify the Indenture Trustee and the Collateral Trustee in writing if it or any of the Restricted Subsidiaries has entered into any such agreement.

Use of Proceeds

The Issuer and the Guarantors shall use the net proceeds from the offering of the Notes in the manner set forth in this offering memorandum under "Use of Proceeds."

Ranking

The Issuer and the Guarantors will ensure that the Notes and all amounts due under the Indenture will constitute its direct, unconditional and general senior secured obligations and shall at all times rank, in right of payment, upon the bankruptcy or insolvency of the Issuer and the Guarantors, *pari passu* in right of payment with, and share equally and ratably in the Collateral with, all of the Issuer and the Guarantors other present and future Indebtedness secured by the Collateral, other than those obligations or Indebtedness mandatorily preferred by operation of Applicable Law or secured by a Permitted Lien.

Each Guarantor will ensure that its Note Guarantee will constitute its direct, unconditional and general senior secured obligation and shall at all times rank, in right of payment, upon the bankruptcy or insolvency of such Guarantor, *pari passu* in right of payment with, and share equally and ratably in the Collateral with, all of the Guarantor's other present and future Indebtedness secured by the Collateral, other than those obligations or Indebtedness mandatorily preferred by operation of Applicable Law or secured by a Permitted Lien.

Covenant to Give Security

In connection with any property of the Issuer, the Guarantors or any of their Restricted Subsidiaries (including, without limitation, any assets, rights, real estate, contracts, permits, credit instruments, shares and/or equity interests) (i) which is required by the Security Documents to be subject to a perfected first priority security interest in favor of the Collateral Trustee for the benefit of the Secured Parties, (ii) which is not already subject to a perfected first priority security interest in favor of the Collateral Trustee for the benefit of the Secured Parties, (iii) as to which no governmental authority or other third-party consent is required for a first priority Lien to be created upon such property or has been obtained, and (iv) which is not subject to any third-party Lien, the Issuer will, at its own expense, within the terms of the relevant Security Document, (A) duly execute and deliver, in form and substance reasonably satisfactory to the Collateral Trustee, a contribution to the Panamanian Trust or a grant of security interest or pledge to the Collateral Trustee, as applicable, of such property and take whatever action (including the registration with the corresponding public registry of Panama and any other recording, filing of UCC financing statements, the giving of notices and the endorsement of notices on title documents) necessary to vest in the respective Collateral Trustee, as applicable, a valid and subsisting first priority Lien on such property enforceable against all third parties in accordance with its terms; or (B) duly execute and deliver a mortgage, pledge, assignment or other security agreement, in form and substance reasonably satisfactory to the Collateral Trustee, securing payment of all of the Secured Obligations and constituting a Lien on such property and take whatever action (including the registration with the corresponding public registry of Panama or any other recording, the filing of UCC financing statements, the giving of notices and the endorsement of notices on title documents) necessary to vest in the Collateral Trustee, as the case may be, a valid and subsisting first priority Lien on such property purported to be subject to such mortgage, pledge, assignment or other security agreement, enforceable against all third parties in accordance with its terms.

Preservation of Collateral

Subject to the last sentence of the paragraph under "— Perfection and Maintenance of Security Interests" below, the Issuer and the Guarantors will undertake all actions that are necessary to enable the Collateral Trustee, on behalf of the Secured Parties, to exercise and enforce their respective rights, powers, remedies and privileges under the Security Documents, including the making or delivery of all filings and recordations, the payments of fees and other charges, the issuance of supplemental documentation, the discharge of all claims or other Liens (other than Permitted Liens) adversely affecting the rights of the Collateral Trustee, on behalf of the Secured Parties, to and under the Collateral and the publication or other delivery of notice to third parties.

Perfection and Maintenance of Security Interests

Subject to the last sentence of this paragraph, the Issuer and the Guarantors will, at its expense, prepare, give, execute, deliver, file and/or record any notice, financing statement, continuation statement, public deed, instrument or agreement necessary under Applicable Law to maintain, preserve or perfect any Lien granted under the Security Documents. At the written request of the Indenture Trustee, the Issuer shall, at its expense, furnish the Indenture Trustee and the Collateral Trustee, no more than once per year after the first anniversary of the date of the Indenture, with the Opinions of Counsel of U.S. and/or Panamanian counsel specifying the action taken or required to be taken by it and/or the Restricted Subsidiaries to comply with the requirements of this paragraph since the date of the Indenture or the last such Opinions of Counsel, as the case may be, or stating that no such action is necessary. The Issuer and the Guarantors will:

(a) cause the Liens purported to be created and perfected under the Security Documents to be so created and perfected in accordance with the terms thereof and within the time periods prescribed therein;

(b) deliver to the Indenture Trustee promptly after receipt thereof, and in no event later than fifteen (15) Business Days after the Issue Date, evidence that the Guarantors Chattel Mortgage and an amendment and restatement of the Panamanian Trust Agreement, the Issuer Real Property Mortgage and the Issuer Chattel Mortgage, in form and substance satisfactory to the Collateral Trustee have been registered with the Public Registry (*Registro Público*) of Panama;

(c) deliver to the Collateral Trustee evidence of the delivery of the notices of assignment of the receivables arising from the Power Purchase Agreements of the Guarantors assigned under the Guarantor Assignment Agreement to the Guarantor's counterparties under such agreement within (A) forty-five (45) Business Days of the Issue Date if such agreements do not require government approval; and (B) one year of the Issue Date, if such agreements require government approval (with an additional 120-day extension upon delivery by the Issuer to the Collateral Trustee before the expiration of such one-year period certifying that it has not yet obtained such government approval notwithstanding its reasonable commercial efforts to obtain it);

(d) deliver to the Collateral Trustee evidence of the endorsements or delivery of instructions of payment to the Collateral Trustee with respect to any insurance policies whose proceeds were assigned by the Guarantors pursuant to the Guarantor Assignment Agreement within forty-five (45) Business Days of the Issue Date;

(e) deliver to the Collateral Trustee evidence of the delivery of instructions to the Tecnisol EPC Contractors directing that any warranty payments under the EPC Contracts be made to Guarantors pursuant to the Guarantor Assignment Agreement within forty-five (45) Business Days of the Issue Date; and

(f) use commercially reasonable efforts to record the land lease agreements mortgaged under the Guarantor Chattel Mortgage.

Maintenance of Ratings

The Issuer and the Guarantors will at all times use commercially reasonably efforts to maintain a rating of the Notes by at least two Rating Agencies; *provided*, *however*, that, in the event that one or more Rating

Agency (i) ceases to exist, (ii) ceases to issue ratings of the type issued in respect of the Notes as of the Issue Date or (iii) refuses or otherwise declines to provide a rating for the Notes (other than due to the Issuer and the Guarantors failure to (A) provide such Rating Agency with such reports and other information or documents, as such Rating Agency shall reasonably request to monitor and continue to assign ratings to the Notes, (B) pay customary fees to such Rating Agency in connection therewith or (C) take any other action reasonably requested by such Rating Agency in connection therewith) (and, in each of cases (i) through (iii) above, the Issuer and the Guarantors are unable to substitute another Rating Agency in place of such Rating Agency), the failure by the Issuer and the Guarantors to obtain or maintain such rating shall not constitute a Default or Event of Default; *it being understood* that the Issuer and the Guarantors shall not request any Rating Agency to cease rating the Notes and/or the Issuer and the Guarantors. For the avoidance of doubt, the Issuer and the Guarantors shall not have any obligation to maintain any particular minimum rating or level of rating in respect of itself or the Notes.

Maintenance of Permits

The Issuer and the Guarantors will, and will cause each Restricted Subsidiary to, obtain and maintain in full force and effect all consents, approvals or permits of any Governmental Authority required under Applicable Law to be obtained or maintained by it in connection with the construction, operation and maintenance of its respective business and the performance of its obligations under the Material Project Documents and under the Notes, the Indenture and the other Financing Documents to which it is a party, in each case, to the extent failure to so maintain would not reasonably be expected to have a Material Adverse Effect.

Maintenance of Properties

The Issuer and the Guarantors will, and will cause each Restricted Subsidiary to, directly or through its subcontractors, cause all properties used or useful in the Projects and the conduct of its respective business to be maintained and kept in good condition, repair and working order as in its judgment may be necessary so that its respective property and assets may be constructed, acquired, maintained and developed in conformity with the Material Project Documents and the Annual Budget consistent with Prudent Industry Practices and so that its respective business may be properly and advantageously conducted at all times, in each case, except to the extent failure to so comply would not reasonably be expected to have a Material Adverse Effect; *provided* that this paragraph shall not prevent it from discontinuing the use, operation or maintenance of any of such properties or assets or disposing of any of them, if such discontinuance or disposal is, in the Issuer and the Guarantors good faith judgment, desirable in the conduct of the Issuer and the Guarantors and the Restricted Subsidiaries business taken as a whole.

The Issuer and the Guarantors will, and will cause each Restricted Subsidiary to, obtain, and maintain in force, good and valid title and/or rights to the Collateral and such other properties as are necessary for (a) the maintenance and operation of its property and assets and (b) the use of its property, assets and revenues, except, in each case, to the extent failure to so obtain or maintain would not reasonably be expected to have a Material Adverse Effect.

Maintenance of Insurance

The Issuer and the Guarantors will, and will cause each Restricted Subsidiary to, obtain and maintain insurance coverage in such amounts and covering such risks consistent with Prudent Industry Practices, subject to any Applicable Laws. The Issuer and the Guarantors will assign all relevant insurance policies with respect to any assets, rights or properties constituting Collateral under the Security Documents to the Collateral Trustee, and will, therefore cause that all casualty insurance proceeds received under such insurance policies not applied to restore the Collateral or to continue operations during such restoration of the Collateral, to be delivered to the Collateral Trustee under the Panamanian Trust and applied in accordance with the Panamanian Trust Agreement.

Dividends

The Issuer and the Guarantors will, and will cause each Restricted Subsidiary to, deposit any dividends received from any Restricted or Unrestricted Subsidiary to the Collection Account no later than two (2) Business Days after receipt of any such dividend.

Negative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries

Set forth below are summaries of certain negative covenants contained in the Indenture.

Limitation on Indebtedness — The Issuer.

(1) The Issuer will not, and will not permit any of the Restricted Subsidiaries to, create, Incur, assume or suffer to exist any Indebtedness except that the Issuer, or any of the Restricted Subsidiaries may Incur Indebtedness, which may be secured by, and entitled to the ratable benefit of the Collateral if the following conditions are met:

(i) immediately after giving effect to the Incurrence of such Indebtedness, no Default or Event of Default has occurred and shall be continuing or will result from such Incurrence;

(ii) the Issuer delivers an Officer's Certificate to the Indenture Trustee certifying that (a) the Combined Historical Debt Service Coverage Ratio for the applicable Calculation Period is greater than 1.31:1.00 and (b) after giving pro forma effect to the Incurrence thereof and the application of the proceeds therefrom (excluding the aggregate amount of any Debt Service Reserve Requirement), the Issuer reasonably estimates that the Combined Prospective Debt Service Coverage Ratio for each immediately succeeding period of four consecutive Fiscal Quarters ending on the last day of the Fiscal Quarter commencing after the Stated Maturity of the Notes will be greater than 1.31:1.00; and

(iii) the Issuer obtains a Ratings Affirmation in connection with such Incurrence;

provided that, for purposes of calculating the Combined Debt Service Coverage Ratio with respect to the Incurrence of Indebtedness:

(a) the interest rate applicable to any outstanding Indebtedness is equal to the interest rates applicable to such Indebtedness for each of the two (2) Quarterly Periods immediately preceding the date of determination;

(b) the interest rate applicable to any Indebtedness to be Incurred is equal to the fixed interest rate of such Indebtedness under the relevant agreement in effect on the date of determination;

(c) a hypothetical fixed interest rate equal to the Reference Rate shall be applied to all Indebtedness to be Incurred that does not bear interest at a fixed interest rate under the relevant agreement in effect on the date of determination;

(2) Notwithstanding clause (1) above, the Issuer or any of its Restricted Subsidiaries may incur the following Indebtedness:

(a) Indebtedness in respect of the Notes, excluding Additional Notes;

(b) Indebtedness under the Letter of Credit Documents outstanding from time to time; provided that the aggregate stated amount of all Letters of Credit issued thereunder together with the principal amount of all outstanding Letter of Credit Loans (without duplication) shall not exceed U.S.$19.2 million Indebtedness under the Letter of Credit Documents may be secured by and entitled to the benefit of the Collateral;

(c) Indebtedness in existence on the Issue Date, *provided* that in the case of the IFC Loans and IFC Hedge Agreements, such Indebtedness shall be repaid in full within three (3) Business Days after the Issue Date;

(d) Indebtedness under any Permitted Swap Contract outstanding from time to time, *provided* that the such Permitted Swap Contract may be secured by and entitled to the ratable benefit of the Collateral to the extent it is a Secured Swap Contract;

(e) Indebtedness incurred for modifications, additions and improvements to the Projects that are, in either case, (x) necessary to remain in compliance with Applicable Laws and Governmental Approvals or (y) required by the Power Purchase Agreements (without giving effect to any amendment, modification or supplement thereof), in each case, as certified as such by the Issuer and Guarantors and confirmed in writing by the Independent Engineer (which we refer to collectively as "Required Modifications"), so long as immediately after giving effect to the incurrence of such Indebtedness (i) no Default or an Event of Default has occurred and is continuing or will result from such incurrence and (ii) each Ratings Agency then rating the Notes (but in no event less than one Ratings Agency at all times) shall have reaffirmed in writing that the ratings of the Notes immediately following the incurrence of such Indebtedness will be the same as the ratings of the Notes immediately prior to giving effect to such incurrence;

(f) Refinancing Debt with respect to which each of the following conditions has been satisfied:

(i) the Average Life of such Refinancing Debt shall not be shorter than the Average Life of the Indebtedness being refinanced;

(ii) the aggregate principal amount (or initial accreted value, if applicable) of such Refinancing Debt as of the date of such proposed refinancing does not exceed the aggregate principal amount (or accreted value as of such date, if applicable) of the Indebtedness being refinanced (plus the amount of any premium required to be paid under the terms of the instrument governing such Indebtedness and the amount of reasonable expenses incurred by the Issuer and the Guarantors or the applicable Restricted Subsidiary in connection with such refinancing);

(iii) the interest payment dates for such Refinancing Debt shall not fall on dates other than Quarterly Dates and the principal payments for such Refinancing Debt shall not fall on dates other than Quarterly Dates; and

(iv) the holders or lenders in respect of such Refinancing Debt or any agent appointed by them, shall have entered into or acceded to the Intercreditor Agreement on or prior to the Incurrence of such Refinancing Debt;

(g) other Indebtedness in an aggregate principal amount at any time outstanding not to exceed U.S.$10.0 million;

(h) any capital lease obligations or Indebtedness to finance the purchase, lease, construction or improvement of any property, plant or equipment used or to be used in the business of the Issuer or such Restricted Subsidiary through the direct purchase of such property, plant or equipment, and any Indebtedness of the Issuer or Restricted Subsidiary which serves to refund or refinance any Indebtedness Incurred pursuant to this clause (h), in each case incurred in the ordinary course of business; *provided* that such Indebtedness does not at any time exceed U.S.$5.0 million in the aggregate measured on a combined basis when added to any Indebtedness of the Guarantors incurred under (8) in "Limitation on Indebtedness — The Guarantors";

(i) Indebtedness arising from current trade liabilities incurred in the ordinary course of business that are payable in accordance with customary practices that are not overdue by more than 90 days (unless disputed in good faith by the Issuer);

(j) Subordinated Debt, *provided* that the conditions included in the definition thereof are satisfied;

(k) Indebtedness arising from the honoring by a bank or other financial institution of a check, draft or similar instrument drawn against insufficient funds in the ordinary course of business; *provided* that such Indebtedness is extinguished within five (5) Business Days of receipt of notice of insufficient funds;

(l) Indebtedness of the Issuer or any Restricted Subsidiary owing to any Restricted Subsidiary or of any Restricted Subsidiary owing to the Issuer , any other Guarantor or Restricted Subsidiary; *provided* that such Indebtedness is not subordinated to the Notes;

(m) Indebtedness of a Restricted Subsidiary Incurred and outstanding on the date on which such Restricted Subsidiary was acquired by, or merged into, the Issuer and the Guarantors; *provided* that

(A) such Indebtedness is refinanced with Indebtedness incurred by the Issuer or the Guarantors within 30 days of such acquisition or merger;

(B) no Default or Event of Default shall have occurred and be continuing;

(C) the lenders or creditors holding such Indebtedness that is the subject of the refinancing described in subclause (A) above shall have acceded to the Intercreditor Agreement (and, to the extent, required, all applicable Financing Documents);

(D) the Issuer shall have delivered to the Indenture Trustee an Officer's Certificate certifying that the Combined Historical Debt Service Coverage Ratio for the Calculation Period is greater than 1.31:1.00 (in each case taken as one accounting period and pro forma for the Incurrence of such Indebtedness and revenues generated by such Restricted Subsidiary in such period); and

(E) the Issuer shall have obtained a Ratings Affirmation in connection with such Incurrence;

(n) Indebtedness, in respect of severance payments, workers' compensation claims, payment obligations in connection with health or other social security benefits, unemployment insurance or other self-insurance obligations for employees, letters of credit (other than pursuant to the Letter of Credit Documents), bankers' acceptances, payment obligations in connection with insurance premiums or similar obligations, security deposits, completion, surety, appeal, bid, performance, customs or other bonds (including any Power Purchase Agreement performance bond) and reimbursement obligations in respect of the foregoing (or letters of credit or performance bonds in connection with, in lieu of or in respect of each of the foregoing), in each case, Incurred in the ordinary course of business or in order to comply with any requirements of Applicable Law; and

(o) Indebtedness in respect of letters of credit (other than pursuant to the Letter of Credit Documents) or performance, bid or other bonds or reimbursement obligations in respect of such letters of credit or bonds, in each case, entered into in the ordinary course of business (which are not Incurred in connection with the borrowing of money) in order to comply with any requirements under Applicable Law or any Material Project Document; *provided* that, upon the drawing of such letters of credit or the Incurrence of such Indebtedness, such obligations are reimbursed within 30 days following such drawing or Incurrence.

Limitation on Indebtedness — The Guarantors.

The Guarantors will not, and will not permit any of its Restricted Subsidiaries to, create, Incur, assume or suffer to exist any Indebtedness except that the Guarantors and its Restricted Subsidiaries may incur the following Indebtedness:

(1) Indebtedness borrowed from the Issuer;

(2) Subordinated Debt *provided* that the conditions included in the definition thereof are satisfied;

(3) Indebtedness incurred by the Guarantors or their Restricted Subsidiaries for any Required Modifications, so long as immediately after giving effect to the incurrence of such Indebtedness (i) no Default or an Event of Default has occurred and is continuing or will result from such incurrence and (ii) each Ratings Agency then rating the Notes (but in no event less than one Ratings Agency at all times) shall have reaffirmed in writing that the ratings of the Notes immediately following the incurrence of such Indebtedness will be the same as the ratings of the Notes immediately prior to giving effect to such incurrence;

(4) Indebtedness arising from current trade liabilities incurred in the ordinary course of business which are payable in accordance with customary practices that are not overdue by more than 90 days (unless disputed in good faith by the Guarantor);

(5) Indebtedness arising from the honoring by a bank or other financial institution of a check, draft or similar instrument drawn against insufficient funds in the ordinary course of business; provided that such Indebtedness is extinguished within five (5) Business Days of receipt of notice of insufficient funds;

(6) Indebtedness, in respect of severance payments, workers' compensation claims, payment obligations in connection with health or other social security benefits, unemployment insurance or other self-insurance obligations for employees, letters of credit (other than pursuant to the Letter of Credit Documents), bankers' acceptances, payment obligations in connection with insurance premiums or similar obligations, security deposits, completion, surety, appeal, bid, performance, customs or other bonds (including any Power Purchase Agreement performance bond) and reimbursement obligations in respect of the foregoing (or letters of credit or performance bonds in connection with, in lieu of or in respect of each of the foregoing), in each case, Incurred in the ordinary course of business or in order to comply with any requirements of Applicable Law;

(7) Indebtedness in respect of letters of credit (other than pursuant to the Letter of Credit Documents) or performance, bid or other bonds or reimbursement obligations in respect of such letters of credit or bonds, in each case, entered into in the ordinary course of business (which are not Incurred in connection with the borrowing of money) in order to comply with any requirements under Applicable Law or any Material Project Document; provided that, upon the drawing of such letters of credit or the Incurrence of such Indebtedness, such obligations are reimbursed within 30 days following such drawing or Incurrence;

(8) any capital lease obligations or Indebtedness to finance the purchase, lease, construction or improvement of any property, plant or equipment used or to be used in the business of the Guarantors or the applicable Restricted Subsidiary through the direct purchase of such property, plant or equipment, and any Indebtedness of the Guarantors or Restricted Subsidiary which serves to refund or refinance any Indebtedness Incurred pursuant to this clause (i), in each case incurred in the ordinary course of business; provided that such Indebtedness does not at any time exceed U.S.$5.0 million in the aggregate measured on a combined basis when added to any Indebtedness of the Issuer incurred under 2(h) in Limitation on Indebtedness — The Issuer, above; or

(9) Indebtedness under any Permitted Swap Contract outstanding from time to time.

For purposes of determining compliance with this "Limitation on Indebtedness" covenant, in the event that an item of proposed Indebtedness (or any portion thereof) meets the criteria of more than one of the categories described in clauses "Limitation on Indebtedness — The Issuer" or " Limitation on Indebtedness — The Guarantors", or is entitled to be incurred pursuant to clauses "Limitation on Indebtedness — The Issuer" or " Limitation on Indebtedness — The Guarantors", the Issuer and the Guarantors, in their sole discretion, will be permitted to classify such item of Indebtedness (or such portion thereof) on the date of its incurrence, or later reclassify all or a portion of such item of Indebtedness, in any manner that complies with this covenant and will only be required to include the amount and type of such Indebtedness in one of the above clauses.

The accrual of interest, the accretion or amortization of original issue discount and the payment of interest on any Indebtedness permitted under this covenant with the same terms will not be deemed to be an incurrence of Indebtedness for purposes of this covenant. For purposes of determining compliance with any Dollar-denominated restriction on the incurrence of Indebtedness, the Dollar amount of Indebtedness denominated in a currency other than the Dollar shall be calculated based on the relevant currency exchange rate in effect on the date such Indebtedness was incurred; *provided* that, the principal amount of any Refinancing Debt shall be calculated based on the currency exchange rate that is in effect on the date of such refinancing. Notwithstanding any other provision of this covenant, the maximum amount of Indebtedness that the Issuer and the Guarantors or any of the Restricted Subsidiaries may incur pursuant to this covenant shall not be deemed to be exceeded solely as a result of fluctuations in exchange rates or currency values.

Limitation on Restricted Payments

(a) The Issuer and the Guarantors will not, and will not permit any Restricted Subsidiary to, nor will the Issuer, the Guarantor or any Restricted Subsidiary instruct the Collateral Trustee to, make, any Restricted Payment, other than the Issue Date Payments and the Fixed SMA Payments, unless (i) such Restricted Payment is made by any wholly-owned Restricted Subsidiary to another wholly-owned Restricted Subsidiary or to the Issuer or the Guarantors, or by the Issuer or a Guarantor to a Guarantor or the Issuer or (ii) each of the following conditions is satisfied both immediately prior to and after the payment of such Restricted Payment (the conditions set forth in clauses (i) through (iv) below):

(i) (x) in case of the Issuer, any such Restricted Payment is made only with funds available in the Issuer Distribution Account, or (y) in case of the Guarantors, any such Restricted Payment is made only with funds available in the Guarantors Distribution Account;

(ii) at the time of the making of such Restricted Payment, and immediately after giving effect to such Restricted Payment, no Default or Event of Default shall have occurred and be continuing;

(iii) the Issuer delivers an Officer's Certificate to the Indenture Trustee certifying that the Combined Historical Debt Service Coverage Ratio for the applicable Calculation Period is greater than 1.20:1:00, and the Combined Prospective Debt Service Coverage Ratio for each immediately succeeding period of four consecutive Fiscal Quarters ending on the last day of the Fiscal Quarter commencing after the Stated Maturity of the Notes will be greater than 1.20:1.00; and

(iv) the Restricted Payment is made on a Restricted Payment Date.

(b) If the Issuer, the Guarantors or any Restricted Subsidiary is intending to make a Restricted Payment (other than by a Restricted Subsidiary to the Issuer or a Guarantor) it will, not less than five (5) Business Days prior to the date on which the Restricted Payment is intended to be made, give the Indenture Trustee and the Collateral Trustee notice thereof.

(c) If the Issuer enters into a Letter of Credit Agreement and funds the Debt Service Reserve Account and/or Trust O&M Reserve Account with Letters of Credit issued thereunder prior to March 31, 2021, it may, so long as no Default or Event of Default shall have occurred and be continuing, make a Restricted Payment on or before such date up to an amount permitted to be released from the Debt Service Reserve Account and/or the Trust O&M Reserve Account, as applicable, pursuant to the terms of the Panamanian Trust Agreement.

Limitation on Liens

The Issuer and the Guarantors will not, and will cause each Restricted Subsidiary not to, directly or indirectly, grant, create, incur, assume or suffer to exist any Lien (other than Permitted Liens) upon any of their respective properties, assets or revenues, including for the avoidance of doubt any generation or interconnection licenses as Issuer or Guarantors may possess from time to time, whether owned at the Issue Date or thereafter acquired.

Change in Nature of Business

The Issuer and the Guarantors will not, and will cause each Restricted Subsidiary not to, engage in any business other than a Permitted Business.

Merger, Consolidation, Liquidation, Dissolution

The Issuer and the Guarantors will not, and will cause each Restricted Subsidiary not to, consolidate with or merge into any other Person or sell, assign, convey, transfer, lease or otherwise dispose of its properties and assets substantially as an entirety to any Person, in one or more related transactions, (A) except that (i) the Issuer may consolidate or merge into a Guarantor or a Restricted Subsidiary or a Guarantor or a Restricted Subsidiary may consolidate or merge into the Issuer *provided* that the successor person assumes the Issuer's obligations under the Indenture, (ii) a Guarantor or a Restricted Subsidiary may consolidate or merge into a Guarantor; *provided* that the successor person assumes the Guarantor's obligations under the Indenture and (iii) any Restricted Subsidiary may consolidate or merge into another Restricted Subsidiary, or (B) unless (i) the successor Person (if other than the Issuer and the Guarantors or such Restricted

Subsidiary) will be a Person existing under the laws of (a) the United States (or any State thereof or the District of Columbia) or Panama or (b) any country that is a member of the European Union or any political subdivision thereof or that belongs to the Organization for Economic Cooperation and Development, in each case of (a) and (b) whose debt securities are rated investment grade; and will assume, by a supplemental indenture, the due and punctual payment of the principal, premium, if any, and interest (and Additional Amounts, if any) in respect of all the outstanding Notes and the performance of every covenant in the Indenture on the part of the Issuer and the Guarantors or such Restricted Subsidiary (including its Note Guarantee, if any), as applicable, to be performed or observed and shall have assumed by appropriate joinder, supplement and/or other documents all duties and obligations of the Issuer and the Guarantors under the Security Documents; (ii) immediately after giving effect to such transaction, no Event of Default, and no event which, after notice or lapse of time or both, would become an Event of Default, will have happened and be continuing; (iii) immediately after giving effect to such transaction on a pro forma basis, the Issuer and the Guarantors or the Person formed by or surviving any such consolidation or merger (if other than the Issuer and the Guarantors), or to which such sale, assignment, conveyance, transfer, lease or other disposition will have been made, will be permitted to Incur at least $1.00 of additional Indebtedness pursuant to the Combined Historical Debt Service Coverage Ratio tests set forth in clause (a)(ii) of the covenant described above under the caption "— Limitation on Indebtedness" (including delivery of the Officer's Certificate specified in such clause (a)(ii), which may be combined with the Officer's Certificate in clause (iv) below); and (iv) the Issuer and the Guarantors or such Restricted Subsidiary, as applicable, will have delivered to the Indenture Trustee an Officer's Certificate and opinion of counsel stating that such consolidation, merger, sale, assignment, conveyance, transfer, lease or other disposition and such supplemental indenture, joinder, supplement and/or other documents comply with the foregoing provisions relating to such transaction, and such opinion of counsel shall further contain, but need not be limited to, favorable opinions to the effect that any such supplemental indenture, joinder, supplement and/or other documents (a) constitute the legal, valid and binding obligation of such person, enforceable in accordance with their respective terms and (b) create enforceable and perfected security interests with respect to such person as required under the Indenture and the Security Documents. In case of any such consolidation, merger, sale, assignment, conveyance, transfer or other disposition (other than a lease), such successor entity will succeed to and be substituted for the Issuer and the Guarantors as obligor on the Notes or the applicable Restricted Subsidiary, if a Guarantor, under its Note Guarantee, as the case may be, with the same effect as if it had been named in the Indenture as such obligor.

Asset Sales

The Issuer and the Guarantors will not, and will cause each Restricted Subsidiary not to, consummate an Asset Sale unless:

(1) the Issuer, the Guarantors or the Restricted Subsidiary, as the case may be, receives consideration at the time of such Asset Sale at least equal to the Fair Market Value of the assets or Equity Interests issued or sold or otherwise disposed of;

(2) the Issuer and the Guarantors obtain a Ratings Affirmation in connection with such Asset Sale; and

(3) at least 75% of the consideration therefor received by the Issuer, the Guarantors or such Restricted Subsidiary is in the form of:

   (a) Cash or Cash Equivalents (including any Cash Equivalents received from the conversion within 60 days of such Asset Sale of any securities, notes or other obligations received in consideration of such Asset Sale);

   (b) Replacement Assets;

   (c) any liabilities of the Issuer, the Guarantors or any Restricted Subsidiary as shown on the Issuer, the Guarantors or such Restricted Subsidiary's most recent balance sheet (other than contingent liabilities, Indebtedness that is by its terms subordinated in right of payment to the Notes or any Note Guarantee and liabilities to the extent owed to the Issuer, the Guarantors or any Affiliate of the Issuer and the Guarantors) that are assumed by the transferee of any such assets or Equity Interests and for which the Issuer and the Guarantors and all of the Restricted Subsidiaries have been validly released by all creditors in writing;

(d) capital stock in a Person engaged in a Permitted Business that will become a Restricted Subsidiary as a result of such Asset Sale; or

(e) any combination of the consideration specified in clauses (a) to (d).

Within 365 days after the receipt of any Net Available Cash from an Asset Sale, the Issuer and the Guarantors or a Restricted Subsidiary, as the case may be, may apply an amount equal to such Net Available Cash at their option:

(1) to permanently repay Secured Obligations (other than Indebtedness owed to the Issuer and the Guarantors or another Restricted Subsidiary) and, if such Secured Obligation is revolving credit Indebtedness, to correspondingly reduce commitments with respect thereto (including, through optional or mandatory prepayments, redemptions, buy backs and market purchases); or

(2) to purchase Replacement Assets (or enter into a binding agreement to purchase such Replacement Assets; *provided* that (x) such purchase is consummated no later than the later of (i) the 360th day after such Asset Sale or (ii) 180 days after the date of such binding agreement and (y) if such purchase is not consummated within the period set forth in subclause (x), the Net Available Cash not so applied will be deemed to be Excess Proceeds (as defined below)); or

(3) make an Asset Sale Offer as described below.

The amount of such Net Available Cash required to be applied (or to be committed to be applied) during such 365 day period as set forth in the preceding paragraph and not applied (or committed to be applied) as so required by the end of such period shall constitute "Excess Proceeds." If, as of the first day of any calendar month, the aggregate amount of Excess Proceeds totals at least U.S.$5.0 million, the Issuer and the Guarantors must commence, not later than the fifteenth (15th) Business Day of such month, and consummate an offer to purchase (an "Asset Sale Offer"), from the holders of the Notes and all holders of other Secured Obligations containing provisions similar to those set forth in the Indenture with respect to offers to purchase with the proceeds of sales of assets, the maximum principal amount of Notes and such other Secured Obligations that may be purchased out of the Excess Proceeds. The offer price in any such Asset Sale Offer will be equal to 100% of the principal amount (or accredited value, if applicable) of the Notes and such other Secured Obligations plus accrued and unpaid interest, to the date of purchase, subject to the rights of holders of Notes on the relevant record date to receive interest on the relevant interest payment date, and will be payable in cash. To the extent that any Excess Proceeds remain after consummation of an Asset Sale Offer pursuant to this "Asset Sales" covenant, the Issuer and the Guarantors may use those Excess Proceeds for any purpose not otherwise prohibited by the Indenture, and those Excess Proceeds shall no longer constitute "Excess Proceeds." The Issuer and the Guarantors may satisfy its obligations under this covenant with respect to the Excess Proceeds of an Asset Sale by making an Asset Sale Offer prior to the expiration of the relevant 365-day period. The procedures set forth in the first through the fifth paragraph of "Repurchase Upon Change of Control Repurchase Event" above shall apply to any Asset Sale Offer, except to the extent otherwise specified in this "Asset Sales" covenant.

Limitation on Use of Termination Payments

In the event a PPA is terminated pursuant to its terms and the counterparty thereto is required to make a termination payment in respect thereof (a "PPA Termination Payment"), and if during any six-month period after the Issue Date the aggregate amount of PPA Termination Payments received by the Issuer or the Guarantors exceeds U.S.$2.5 million (the "Aggregate PPA Termination Payments"), the Issuer shall make, not later than the fifteenth (15th) Business Day after the receipt of the last PPA Termination Payment, (i) an offer to purchase (an "Termination Payment Offer") from the holders of the Notes a principal amount of Notes that may be purchased by the Issuer with the Aggregate PPA Termination Amount Payments. The offer price in any such Termination Payment Offer will be equal to 100% of the principal amount (or accredited value, if applicable) of the Notes plus accrued and unpaid interest, to the date of purchase, subject to the rights of holders of Notes on the relevant record date to receive interest on the relevant interest payment date, and will be payable in cash, but will not be subject to the payment or make-whole or similar premium or penalty, or (ii) Required Modifications. To the extent that any amounts on account of the Aggregate PPA Termination Payments remain unused or unapplied after consummation of a Termination Payment Offer or making Required Modifications as provided herein, the Issuer and the Guarantors may use such Aggregate PPA Termination Payments for any purpose not otherwise expressly prohibited by the Indenture, including to make restricted payments without being required to comply with any of the conditions set out under the "Limitation on Restricted Payments" covenant. The procedures set forth in the first through the fifth paragraph of "Repurchase Upon Change of Control Repurchase Event" above shall apply *mutandis mutandi* to any Termination Payment Offer, except to the extent otherwise specified in this covenant.

Limitation on Investments

The Issuer and the Guarantors will not, and will cause each Restricted Subsidiary not to, make or hold any Investments in any Person (other than the Issuer and the Guarantors or any of the Restricted Subsidiaries) except for (i) Investments in Cash Equivalents; (ii) Investments in respect of any Permitted Swap Contract; (iii) any Investment acquired from a Person that is merged with or into the Issuer and the Guarantors or any Restricted Subsidiary or any Investment of any Person existing at the time such Person becomes a Restricted Subsidiary, and, in each case, that is not created as a result of or in connection with or in anticipation of any such transaction; (iv) any Investment existing on, or made pursuant to written agreements existing on, the Issue Date and any extension, modification or renewal of such Investments (but not Investments involving additional advances, contributions or other investments of cash or property or other increases thereof (unless a binding commitment therefor has been entered into on or prior to the Issue Date), other than as a result of the accrual or accretion of interest or original issue discount or payment-in-kind pursuant to the terms of such Investment as of the Issue Date); (v) Investments in an Unrestricted Subsidiary, solely to the extent that such Investment is funded exclusively by any shareholder of the Issuer and the Guarantors or an Affiliate of a shareholder of the Issuer and/or the Guarantors (other than the Issuer and the Guarantors or any Restricted Subsidiary) directly or through an Equity Contribution in or subordinated loans made to a Restricted Subsidiary, including in each case with funds deposited in the Distribution Accounts; (vi) Investments constituting pledges and deposits made in the ordinary course of business in compliance with workers' compensation, unemployment insurance and other social security laws or regulations; (vii) Investments by the Issuer in Restricted Subsidiaries and Guarantors or by a Guarantor in another Guarantor, the Issuer or a Restricted Subsidiary of any of the foregoing; and (viii) Investments constituting deposits to secure the performance of bids, trade contracts, leases, statutory obligations, surety and appeal bonds, performance bonds, and other obligations of a like nature, in each case in the ordinary course of business.

Limitation on Transactions with Affiliates

The Issuer and the Guarantors will not, and will cause each Restricted Subsidiary not to, enter into or become a party to any material agreement or arrangement with an Affiliate, unless such agreement or arrangement shall be on terms no more favorable to the Affiliate than those that could be obtained in a comparable arm's-length transaction with a Person that is not an Affiliate; *provided, further that* if any such transaction or series of related transactions involves an aggregate consideration in excess of U.S.$2.5 million, the Issuer and the Guarantors or any such Restricted Subsidiary must deliver to the Indenture Trustee a resolution of its board of directors together with an Officer's Certificate of the Issuer and an Opinion of Counsel and /or the Guarantors stating that such Affiliate transaction complies with the Indenture and that such Affiliate transaction has been approved by not less than a majority of the members of the relevant board of directors. For the avoidance of doubt, these restrictions shall not apply to any material agreement or arrangement with an Affiliate entered into on or prior to the Issue Date but shall apply to any renewal thereof.

The foregoing restriction shall not apply to (i) any transaction solely between or among the Issuer and any Guarantor or between or among the Issuer or any Guarantor and one or more of the Restricted Subsidiaries or solely between or among two or more of the Restricted Subsidiaries; (ii) reasonable and customary payments to or on behalf of the Issuer and the Guarantors or any of the Restricted Subsidiaries' directors, officers or employees (including any payments in connection with any secondment arrangements), or in reimbursement of reasonable and customary payments or reasonable and customary expenditures made or incurred by such Persons as directors, officers or employees; (iii) any transfer to (or, for avoidance of doubt, from) the Distribution Account permitted under "— Limitation on Restricted Payments"; (iv) any loan or advance by the Issuer and the Guarantors or any of Restricted Subsidiaries to its employees in the ordinary course of business; (v) contributions to the common equity capital of the Issuer and the Guarantors or any of the Restricted Subsidiaries; and (vi) any payments required to be made under the existing Sponsor Services Agreements.

Material Project Documents

Except as would not reasonably be expected to have a Material Adverse Effect, the Issuer and the Guarantors will not, and the Issuer and the Guarantors will not permit any Restricted Subsidiaries to, (i) cancel or terminate (other than expiration in accordance with its terms) any Material Project Document or consent to or accept any cancellation or early termination thereof, (ii) amend, modify or change in any manner any term or condition of any Material Project Document, (iii) give any consent, waiver or approval under any Material Project Document, or (iv) consent to any assignment or transfer of rights under any Material Project Document (other than as required by the Security Documents), in each case unless permitted by the Indenture Trustee, acting on the instructions of at least a majority of the holders of the Notes.

Reporting Requirements

The Issuer and the Guarantors will provide the Indenture Trustee and, upon request, the holders of the Notes, with the following reports and notices:

(a) As soon as available, and in any event within one hundred twenty (120) days after the end of each Fiscal Year, an audited consolidated balance sheet of the Issuer as at the end of such Fiscal Year, and the related statements of income or operations and cash flows for such Fiscal Year, in accordance with Applicable Accounting Principles, audited and accompanied by an opinion of the Independent Accountants, which opinion shall state that such financial statements present fairly, in all material respects, our financial position at the end of, and for, such fiscal year, prepared in accordance with Applicable Accounting Principles. The annual financial statements will be accompanied by a "management discussion and analysis of results of operations and financial condition" providing an overview in reasonable detail of the consolidated results of operations and financial condition of the Issuer and will include the related notes in respect thereof. In addition, the Issuer shall provide within 60 days of the end of the first three Fiscal Quarters of each Fiscal Year of the Issuer unaudited consolidated quarterly financial statements of the Issuer (including a balance sheet, statement of comprehensive income and cash flow statement). The quarterly financial statements will be accompanied by a brief narrative overview of the results of operations and financial condition of the Issuer. English translations will be provided of any of the foregoing documents prepared in another language;

(b) As soon as available, and in any event within one hundred twenty (120) days after the end of each Fiscal Year, an audited combined balance sheet of the Guarantors as at the end of such Fiscal Year, and the related consolidated statements of income or operations and cash flows for such Fiscal Year, in accordance with Applicable Accounting Principles, audited and accompanied by an opinion of the Independent Accountants, which opinion shall state that such financial statements present fairly, in all material respects, our financial position at the end of, and for, such fiscal year, prepared in accordance with Applicable Accounting Principles. The annual financial statements will be accompanied by a "management discussion and analysis of results of operations and financial condition" providing an overview in reasonable detail of the combined results of operations and financial condition of the Guarantors and will include the related notes in respect thereof. In addition, the Guarantors shall provide within 60 days of the end of the first three Fiscal Quarters of each Fiscal Year of the Guarantors unaudited combined quarterly financial statements of the Guarantors (including a balance sheet, statement of comprehensive income and cash flow statement). The quarterly financial statements will be accompanied by a brief narrative overview of the results of operations and financial condition of the Guarantors. English translations will be provided of any of the foregoing documents prepared in another language;

(c) without duplication, upon request, English language versions or summaries in electronic format of such other reports or notices as may be filed or submitted by (and within ten (10) days after filing or submission by) the Issuer and the Guarantors with the SGX-ST, or any other stock exchange on which the Notes may be listed, in each case, to the extent that any such report or notice is generally available to the Issuer and the Guarantors debt holders; *provided*, however, that the Issuer and the Guarantors shall not be required to furnish such information to the extent such information is available on the Issuer and the Guarantors website or to the extent that the information contained therein is not materially different than the information provided pursuant to clause (a) and (b) above;

(d) so long as each of the Issuer and the Guarantors is not subject to Section 13 or Section 15(d) of the Exchange Act and exempt from reporting pursuant to Rule 12g3-2(b) of the Exchange Act, upon request, to any holder and any prospective purchaser of the Notes, the information required pursuant to Rule 144A(d)(4) under the Securities Act; and

(d) promptly (but in any event within ten (10) Business Days after a Responsible Officer of the Issuer and the Guarantors obtains Knowledge or is aware thereof), a notice of: (i) the occurrence of any Default or Event of Default under the Notes, (ii) the occurrence of any material default under, or any amendment, waiver, modification, supplement, cancellation, suspension or termination of, under or in respect of any Material Project Document (except for any amendments, modifications, waivers or supplements of a clerical, technical or administrative matter or that would not reasonably be expected to have a Material Adverse Effect) and any request therefor and (iii) a Change of Control.

Simultaneously with the delivery of each set of financial statements referred to in clause (a) and (b) above, the Issuer and the Guarantors will provide the Indenture Trustee with an Officer's Certificate stating (1) that (x) the financial statements referred to in clause (a) fairly and accurately present the consolidated financial condition and results of operations of the Issuer on the dates and for the periods indicated in accordance with the Applicable Accounting Principles, subject to the absence of footnotes and normally recurring year-end adjustments, and (z) the financial statements referred to in clause (b) fairly and accurately present the combined financial condition and results of operations of the Guarantors on the dates and for the periods indicated in accordance with the Applicable Accounting Principles, subject to the absence of footnotes and normally recurring year-end adjustments, and (2) whether a Default or Event of Default exists on the date of such Officer's Certificate and, if a Default or Event of Default exists, setting forth the details thereof and the action which the Issuer and the Guarantors are taking or propose to take with respect thereto. Except where otherwise indicated, all reports, notices, certificates and other documents delivered pursuant to this "Reporting Requirements" covenant shall be in the English language.

Delivery of reports, information and documents to the Indenture Trustee is for informational purposes only and its respective receipt of such reports shall not constitute actual or constructive notice of any information contained therein or determinable from information contained therein, including the Restricted Subsidiaries' or any other Person's compliance with any of its covenants under the Indenture or the Notes (as to which the Indenture Trustee is entitled to rely conclusively on Officer's Certificates).

Annual Budget

The Issuer will deliver to the Indenture Trustee an Annual Budget with respect to the Issuer and the Guarantors not later than 15 days prior to the commencement of each Fiscal Year for the forthcoming fiscal year accompanied by an Officer's Certificate of the Issuer certifying that such Annual Budget constitutes the Issuer and the Guarantors, as applicable, good faith estimate for the period covered; provided, however, that the Annual Budget for the Fiscal Year commencing on January 1, 2021 (and the applicable Officer's Certificate) shall be delivered 5 days prior to the commencement of such Fiscal Year.

Each Annual Budget will (A) contain estimates of the combined revenues and Operating and Maintenance Expenses of the Issuer and the Guarantors and individual line items for each Restricted Subsidiary based on the Issuer and the Guarantors fair and reasonable projections at such time based on facts and circumstances then existing and known to the Issuer and the Guarantors, (B) reflect the Issuer and the Guarantors commercially reasonable estimate of future results and (C) be prepared by the Issuer and the Guarantors in good faith on the basis of written assumptions stated therein that the Issuer and the

Guarantors believes to be reasonable as to all factual and legal matters then known to the Issuer and the Guarantors that are material to such estimates.

Events of Default

Pursuant to the Indenture each of the following events, acts, occurrences or conditions, will constitute an event of default under the Notes (each an "Event of Default"). "Default" means any condition or event that with the lapse of time or the giving of notice, or both, would become an Event of Default.

(a) (i) The Issuer or the Guarantors fail to pay any amount of principal on any Note or Note Guarantee, as applicable, when the same becomes due and payable; *provided* that solely with respect to any such failure to pay that resulted from a cause or causes that are technical or administrative in nature and not from a failure by the Issuer and the Guarantors to make a good faith effort to make such payment, such failure to pay shall not constitute an Event of Default unless such failure to pay continues for a period of three (3) Business Days immediately following the date on which such payment was due and payable, or (ii) the Issuer and the Guarantors fail to pay interest on any Note within thirty (30) days after the same becomes due and payable;

(b) [Reserved]

(c) The Issuer and the Guarantors or any of the Restricted Subsidiaries fail to comply with any of the covenants or agreements in the Notes or the Indenture (other than those referred to in clause (a) above), and such failure continues for sixty (60) days after notice from the Indenture Trustee thereof or notice thereof to the Indenture Trustee and the Issuer and the Guarantors by the holders of at least 25% in aggregate principal amount of the Notes then outstanding;

(d) Any Insolvency Proceeding occurs with respect to the Issuer and the Guarantors or any of the Restricted Subsidiaries;

(e) (i) Any of the Issuer, the Guarantors or any Restricted Subsidiary defaults in the payment of any principal of or interest on any of its Indebtedness, other than the Notes, the Citi Swap or the Note Guarantees (whether at Stated Maturity or otherwise), in an amount in excess of U.S.$5.0 million and such default continues beyond any applicable grace period set forth in the agreements or instruments evidencing or relating to such Indebtedness, or (ii) any of the Issuer and the Guarantors or any Restricted Subsidiary's Indebtedness, other than the Notes, the Citi Swap or the Note Guarantees, in an outstanding principal amount in excess of U.S.$5.0 million becomes due (or required to be prepaid, repurchased, redeemed or defeased) and payable prior to the scheduled maturity thereof;

(f) There is entered against the Issuer and the Guarantors or any of the Restricted Subsidiaries (i) a final non-appealable judgments or orders for the payment of money in an aggregate amount exceeding U.S.$5.0 million (considering the Issuer and the Guarantors and all of the Restricted Subsidiaries together) that such person fails (or such persons fail) to make payment thereof within the period of time mandated by such judgment or order or (ii) any one or more non-monetary judgments that have, or could reasonably be expected to have, individually or in the aggregate, a Material Adverse Effect and, in either case, (A) enforcement proceedings are commenced by any creditor upon such judgment or order, or (B) there is a period of ninety (90) consecutive days during which a stay of enforcement of such judgment, by reason of a pending appeal or otherwise, is not in effect;

(g) Except as could not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect (i) any provision of any Material Project Document, at any time after its execution and delivery and for any reason other than as expressly permitted hereunder or thereunder, ceases to be in full force and effect unless the same is being contested by the Issuer and the Guarantors or any of the Restricted Subsidiaries that is party thereto; or (ii) any of the Issuer, the Guarantors or any of their Restricted Subsidiaries contests in writing the validity or enforceability of any provision of any Material Project Document;

(h) Any Security Document (once executed and delivered and, where appropriate, noticed to counterparties, registered or where other action has been taken in accordance with all Applicable Law and the Indenture) shall for any reason (other than pursuant to the terms thereof) cease to create a valid and perfected first priority lien on and security interest in the Collateral purported to be covered thereby, except when due to clerical error; *provided* that the Issuer, the Guarantors and pledgors thereunder shall be diligently pursuing the perfection of such lien and such clerical error shall be corrected no later than thirty (30) Business Days after the earlier of (i) a Responsible Officer of the Issuer and the Guarantors has Knowledge of such clerical error and (ii) written notice thereof has been given to the Issuer and the Guarantors by the Indenture Trustee, the or the Collateral Trustee or to the Indenture Trustee, the Collateral Trustee and the Issuer and the Guarantors by the holders of at least 25% in aggregate principal amount of the Notes then outstanding;

(i) Except as could not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect (i) any Material Project Document is terminated, rescinded, cancelled or suspended in advance of its expiration unless such termination, rescission, cancellation or suspension is being contested by the Issuer and the Guarantors or any of the Restricted Subsidiaries or (ii) the Issuer and the Guarantors or any of the Restricted Subsidiaries breaches in any respect, or causes the termination, rescission, cancellation or suspension of, any Material Project Document, and such termination described in clauses (i) or (ii) shall remain unremedied for sixty (60) Business Days after the earlier of (A) a Responsible Officer of such Person having knowledge of such termination, termination, rescission, cancellation or suspension and (B) written notice thereof has been given to the Issuer and the Guarantors by the Indenture Trustee, or the Collateral Trustee or to the Indenture Trustee, the Collateral Trustee and the Issuer and the Guarantors by the holders of at least 25% in aggregate principal amount of the Notes then outstanding;

(j) Any Governmental Authority asserting *de jure* or *de facto* governmental or police powers in Panama shall, by moratorium laws or otherwise, cancel, suspend or defer the obligation of the Issuer and the Guarantors or any Guarantor to pay any amount required to be paid under the Indenture or its Note Guarantee, respectively, when the same becomes due and payable thereunder and such cancellation, suspension or deferral shall continue for ten (10) or more consecutive Business Days; and

(k) Except as permitted by the Financing Documents, any Note Guarantee is held in any judicial proceeding to be unenforceable or invalid or ceases for any reason to be in full force and effect, or any Guarantor denies or disaffirms in writing its obligations under its Note Guarantee or, except as permitted by the Financing Documents, the Issuer and the Guarantors denies or disaffirms in writing any obligation of the Issuer and the Guarantors arising under the Indenture or any other Financing Document.

Upon the occurrence and during the continuation of any Event of Default, the Indenture Trustee or the holders of at least 25% in aggregate principal amount of the Notes then outstanding, by notice then given in writing to the Issuer and the Guarantors (and to the Indenture Trustee if given by the holders of the Notes), may declare the aggregate principal balance of all Notes immediately due and payable; *provided* that any Event of Default under clause (d) above will automatically result in the aggregate principal balance of all Notes becoming immediately due and payable.

At any time after a declaration of acceleration with respect to the Notes as described in the preceding paragraph, holders of a majority in principal amount of the outstanding Notes may rescind and cancel such declaration and its consequences:

- if the rescission would not conflict with any judgment or decree;
- if all existing Events of Default have been cured or waived, except nonpayment of principal or interest that has become due solely because of the acceleration;
- to the extent the payment of such interest is lawful, interest on overdue installments of interest and overdue principal, which has become due otherwise than by such declaration of acceleration, has been paid; and

- if the Issuer and the Guarantors have paid the Indenture Trustee its reasonable compensation and reimbursed the Indenture Trustee for its reasonable expenses, disbursements and advances.

No rescission will affect any subsequent Default or impair any rights relating thereto.

Holders of a majority in principal amount of the outstanding Notes may waive any existing Default or Event of Default under the Indenture, and its consequences, except a default under clause (d) above.

The Indenture Trustee will be under no obligation to exercise any of its rights or powers under the Indenture at the request or direction of any of the holders of the Notes, unless such holders will have offered to the Indenture Trustee indemnity and/or security satisfactory to the Indenture Trustee. Subject to such provision for the indemnification and/or security to the Indenture Trustee and such other terms and conditions as are set forth in the Indenture, the holders of a majority in aggregate principal amount of the outstanding Notes will have the right to direct the time, method and place of conducting any proceeding for any remedy available to the Indenture Trustee in respect of the Notes or exercising any trust or power conferred on the Indenture Trustee in respect of the Notes.

Satisfaction and Discharge

The Indenture will be discharged and will cease to be of further effect (except as to surviving rights of registration of transfer or exchange of the Notes and the rights of the Indenture Trustee and agents under the Indenture, as expressly provided for in the Indenture) as to all outstanding Notes when:

(a) either:

(i) all of the Notes previously authenticated and delivered (except lost, stolen or destroyed Notes that have been replaced or paid and Notes for whose payment money has previously been deposited in trust and thereafter repaid to the Issuer and the Guarantors or discharged from such trust) have been delivered to the Indenture Trustee for cancellation; or

(ii) all Notes not previously delivered to the Indenture Trustee for cancellation (i) have become due and payable or will become due and payable at Stated Maturity within one year or (ii) are to be called for redemption within one year under irrevocable arrangements satisfactory to the Indenture Trustee for the giving of notice of redemption by the Indenture Trustee in the name, and at the expense, of the Issuer and the Guarantors and, in each case, the Issuer and the Guarantors have irrevocably deposited or caused to be deposited with the Indenture Trustee cash in Dollars, U.S. Government Securities, or a combination thereof, in such amounts as will be sufficient, in the opinion of an internationally recognized firm of independent public accountants expressed in a written certificate delivered to the Indenture Trustee, without reinvestment to pay and discharge the entire indebtedness on the Notes not previously delivered to the Indenture Trustee for cancellation, for principal of, premium, if any, and interest on the Notes to the date of deposit (in the case of Notes that have become due and payable) or to the maturity or redemption date, as the case may be, and any Additional Amounts payable with respect thereto, together with irrevocable instructions from the Issuer and the Guarantors directing the Indenture Trustee to apply such funds to the payment;

(b) no Default or Event of Default will have occurred and be continuing on the date of such deposit or will occur as a result of such deposit and such deposit will not result in a breach or violation of, or constitute a default under, any other instrument to which the Issuer and the Guarantors or any Restricted Subsidiary is a party or by which the Issuer and the Guarantors or any Restricted Subsidiary is bound;

(c) the Issuer and the Guarantors have paid all other sums payable by it under the Indenture and the Notes; and

(d) the Issuer and the Guarantors have delivered to the Indenture Trustee an Officer's Certificate and Opinion of Counsel stating that all conditions precedent under the Indenture relating to the satisfaction and discharge of the Indenture have been complied with.

Upon satisfaction of the conditions set forth in this "Satisfaction and Discharge" section, the Indenture Trustee, upon the Issuer and the Guarantors' written request and at the Issuer and the Guarantors' expense, shall acknowledge in writing the satisfaction and discharge of the Indenture. Upon satisfaction and discharge of the Indenture, the Liens of the Security Documents shall terminate with respect to the Indenture and the Notes.

Defeasance

The Issuer and the Guarantors may at any time terminate all of its obligations with respect to the Notes and all obligations of the Guarantors with respect to their Note Guarantees ("defeasance"), except for certain obligations, including those to the Indenture Trustee and the agents appointed under the Indenture, those regarding any trust established for a defeasance and obligations to register the transfer or exchange of the Notes, to replace mutilated, destroyed, lost or stolen Notes, to maintain agencies in respect of Notes and those expressly stated to survive any termination or defeasance. The Issuer and the Guarantors may at any time terminate its obligations and any obligations of the Guarantors under certain covenants set forth in the Indenture, and any omission to comply with such obligations will not constitute a Default or an Event of Default with respect to the Notes ("covenant defeasance"). In order to exercise either defeasance or covenant defeasance, the Issuer and the Guarantors must irrevocably deposit in trust, for the benefit of the holders of Notes, with the Indenture Trustee cash in Dollars, U.S. Government Securities, or a combination thereof, in such amounts as will be sufficient, in the opinion of an internationally recognized firm of independent public accountants expressed in a written certificate delivered to the Indenture Trustee, without consideration of any reinvestment, to pay the principal of, premium, if any, on and interest on the Notes to redemption or maturity and comply with certain other conditions, including the delivery of an opinion of legal counsel of nationally recognized standing in the United States to the effect that the holders of the Notes will not recognize income, gain or loss for U.S. federal income tax purposes as a result of the defeasance and will be subject to U.S. federal income tax on the same amount and in the same manner and at the same time as would otherwise have been the case (and in the case of a defeasance that is not a covenant defeasance, such opinion shall be based on a change in applicable U.S. federal income tax law or a published ruling of the U.S. Internal Revenue Service).

Amendment, Supplement, Waiver

Subject to certain exceptions, the Indenture, the Notes and, subject to the terms thereof, the Security Documents, may be amended or supplemented with the consent of the holders of at least a majority in principal amount of the Notes then outstanding, and any past Default or compliance with any provision in the Indenture, the Notes and, subject to the terms of the Security Documents, the Security Documents may be waived with the consent of the holders of at least a majority in principal amount of the Notes then outstanding. However, without the consent of each holder of an outstanding Note affected thereby, no amendment may:

(a) reduce the rate of or extend the time for payment of interest on the Notes;

(b) reduce the principal, or change the Stated Maturity, of the Notes;

(c) reduce the amount payable upon redemption or repurchase of the Notes or change the time at which the Notes may or must be redeemed or repurchased;

(d) make any change in the provisions of the Indenture described under "— Additional Amounts" that adversely affects the rights of any holder of Notes;

(e) change the currency for, or place of payment of, principal, premium or interest on the Notes;

(f) impair the right to institute suit for the enforcement of any payment on or with respect to the Notes or the Note Guarantees;

(g) waive certain Defaults or Events of Default with respect to the Notes;

(h) release any Guarantor from any of its obligations under its Note Guarantee or the Indenture, except in accordance with the terms of the Indenture;

(i) amend, change or modify the obligation of the Issuer and the Guarantors to make and consummate an Change of Control Offer in the event of a Change of Control Repurchase Event in accordance with the covenant described under the caption "— Repurchase upon Change of Control Repurchase Event" after such Change of Control Repurchase Event has occurred, including, in each case, amending, changing or modifying any definition relating thereto;

(j) except as otherwise permitted under the covenants described under the captions "— Negative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries — Merger, Consolidation, Liquidation, Dissolution" and "— Note Guarantees — Future Guarantors," consent to the assignment or transfer by the Issuer and the Guarantors or any Guarantor of any of their rights or obligations under the Indenture;

(k) modify the grant of security interests in the Collateral for the benefit of the Secured Parties in a manner that would adversely impact the Secured Parties or release all or substantially all of the interest in the Collateral, in each case other than pursuant to the terms of the Indenture, the Security Documents and the documents contemplated therein;

(l) make any change in the provisions in the Indenture or the Security Documents dealing with the application of proceeds of Collateral that would adversely affect the holders of the Notes in any material respect;

(m) reduce the principal amount of Notes whose holders must consent to any amendment or waiver; or

(n) make any change in the amendment or waiver provisions which require each holder's consent.

The holders of the Notes will receive prior notice as described under "— Notices" of any proposed amendment to such Notes, the Indenture or the Security Documents described in the immediately preceding paragraph. After an amendment described in the immediately preceding paragraph becomes effective, the Issuer and the Guarantors is required to deliver to the holders of the Notes a notice briefly describing such amendment. However, the failure to give such notice to all holders of the Notes, or any defect therein, will not impair or affect, with respect to such Notes, the validity of the amendment.

The consent of the holders of the Notes is not necessary to approve the particular form of any proposed amendment. It is sufficient if such consent approves the substance of the proposed amendment.

The Issuer and the Guarantors, the Guarantors, the Indenture Trustee, the Collateral Trustee and any other applicable agent under the Indenture or the Security Documents may, without the consent or vote of any holder of the Notes, amend or supplement the Indenture, the Notes and, subject to the terms of the Security Documents, the Security Documents (or, if the Indenture Trustee is not a party to any such Security Document, the Indenture Trustee may consent to the Collateral Trustee, the Collateral Trustee or other relevant agent, as applicable, amending or supplementing such Security Document) for the following purposes:

(a) to cure any ambiguity, omission, defect or inconsistency; *provided* that such amendment or supplement does not materially adversely affect the rights of any holder;

(b) evidence the succession of another Person to the Issuer and the Guarantors and the assumption by such successor of the covenants contained in the Indenture or otherwise established with respect to the Notes, in each case in accordance with the Indenture;

(c) to add guarantees or collateral with respect to the Notes;

(d) to add to the covenants of the Issuer and the Guarantors and/or its Subsidiaries for the benefit of holders of the Notes;

(e) to surrender any right conferred upon the Issuer and the Guarantors or any of its Subsidiaries;

(f) to evidence and provide for the acceptance of an appointment by a successor trustee;

(g) to provide for the issuance of Additional Notes;

(h) to conform the text of the Indenture, the Notes or the Security Documents to any provision of this "Description of the Notes" to the extent that such provision in this "Description of the Notes" was intended to be a verbatim recitation of a provision of the Indenture, the Notes or the Security Documents and the Indenture Trustee has received an Officer's Certificate from the Issuer and the Guarantors to that effect;

(i) to comply with the regulations of any securities exchange on which the Notes may be listed;

(j) to release any Collateral from Liens securing the Notes when permitted or required under the Indenture or the Security Documents or to convey, transfer, assign, mortgage or pledge to the Collateral Trustee as security for the Notes any property;

(k) to release any Note Guarantee in accordance with the Notes and the Indenture;

(l) to make any other change that does not materially adversely affect the rights of any holder of the Notes;

(m) evidence and provide for the acceptance and appointment under the Indenture or any other Financing Document of a successor Indenture Trustee, successor Collateral Trustee or other successor agent thereunder pursuant to the requirements thereof; or

(n) permit or facilitate the issuance of Notes in definitive form.

In executing any amendment, waiver or supplemental indenture to the Indenture, the Notes or the Security Documents, the Indenture Trustee and, if applicable, the Collateral Trustee and any other agent under the Indenture or the Security Documents, will be entitled to receive an Officer's Certificate and an Opinion of Counsel, each stating that such amendment, waiver or supplemental indenture is authorized or permitted by the Indenture and/or the Security Documents, as the case may be, that all covenants and conditions precedent to such amendment, supplement or waiver under the Indenture and the Security Documents have been complied with, and that it shall be valid and binding upon the Issuer and the Guarantors in accordance with its terms.

Pursuant to the Indenture, each holder, by its acceptance of a Note, will authorize and direct the Indenture Trustee and each agent under the Indenture to execute and deliver from time to time, if so requested in writing by the Issuer and the Guarantors, and without the consent of the holders of the Notes, one or more documents or agreements as are expressly contemplated to be executed by the Indenture Trustee or any such agent in accordance with the terms of the Financing Documents (collectively, "Permitted Supplemental Agreements"); *provided* that the entry by any such party into any such Permitted Supplemental Agreement will be subject to the prior receipt of (i) an Officer's Certificate from the Issuer and the Guarantors certifying that (A) each of the conditions precedent specified in the Financing Documents to the entry by the Indenture Trustee or the applicable agent, as the case may be, into such Permitted Supplemental Agreement, and the requirements set forth in the Financing Documents in respect of the relevant transactions contemplated by such Permitted Supplemental Agreement, have been satisfied; and (ii) an Opinion of Counsel stating that, in the opinion of such counsel, the execution, delivery and performance by (A) the Issuer and the Guarantors, the Indenture Trustee, and/or the applicable agent, as applicable, and any other relevant other counterparty(ies) to the Permitted Supplemental Agreement, will not result in any conflict with or breach of any Financing Document.

Listing

The Notes will be registered with the SMV and listed on the Panama Stock Exchange. Promptly after such a listing, the Issuer will notify the Indenture Trustee in writing, which will, in turn, provide notice thereof to each of the holders of the Notes. Upon registration of the Notes with the SMV and the listing of the Notes on the PSE, the Issuer will comply with the reporting and other requirements set forth in the Panamanian securities law applicable to companies who have registered their securities with the SMV, as well as any corresponding requirements of the PSE.

We will apply for the listing and quotation of the Notes on the Official List of the SGX-ST. Each of the Issuer and the Guarantors, the Indenture Trustee, and the Collateral Trustee are (without the need for any approvals, consents or instructions from any holders of the Notes, but in accordance with all other provisions applicable thereto) authorized to join in the execution of any amendment (including amendment and restatement) of any Financing Document(s) to the extent required to provide such a listing. Promptly after such a listing, the Issuer and the Guarantors will so notify the Indenture Trustee, which will provide notice thereof to each of the holders of the Notes.

In the event that the Notes are admitted to listing on the SGX-ST, the Issuer and the Guarantors will use its commercially reasonable efforts to maintain such listing, provided that if, as a result of any legislation the Issuer and the Guarantors could be required to publish financial information either more regularly than it otherwise would be required to or according to accounting principles that are materially different from the Applicable Accounting Principles that it would otherwise use to prepare its published financial information, or if the Issuer and the Guarantors determine that it is unduly burdensome, in its good faith determination, to maintain a listing on the SGX-ST, the Issuer and the Guarantors may delist the Notes from the SGX-ST and, in the event of such delisting, the Issuer and the Guarantors will use its commercially reasonable efforts to seek an alternative admission to listing, trading and/or quotation for the Notes by another listing authority, stock exchange and/or quotation system as it may decide; *provided* that such listing authority, stock exchange or quotation system is used for listing and trading in the international debt capital markets. Although the Issuer and the Guarantors cannot assure you as to the liquidity that may result from a listing on the SGX-ST, delisting the Notes from the SGX-ST may have a material effect on the ability of holders of the Notes to resell the Notes in the secondary market.

The SGX-ST assumes no responsibility for the correctness of any of the statements made or opinions expressed or reports contained in this "Description of the Notes". Listing and quotation of the Notes on the SGX-ST is not to be taken as an indication of the merits of the Issuer or the Notes. For the purposes of the listing and quotation of the Notes on the SGX-ST, the Notes will be traded on the SGX-ST in a minimum board lot size of S$200,000 (or its equivalent in foreign currencies) and a paying agent in Singapore will be appointed upon the issue of the notes in definitive form. In addition, for so long as the Notes are listed on the SGX-ST and the rules of the SGX-ST so require, in the event that the Notes which are issued in global certificated form are exchanged for Notes in definitive registered form or definitive registered Notes, the Issuer shall appoint and maintain a paying agent in Singapore, where the certificates in definitive form in respect of Notes may be presented or surrendered for payment or redemption. In the event that the Notes which are issued in global certificated form are exchanged for Notes in definitive registered form or definitive registered Notes, an announcement of such exchange shall be made by or on behalf of the Issuer through the SGX-ST and such announcement will include all material information with respect to the delivery of the certificates in definitive form, including details of the paying agent in Singapore.

Notices

For so long as Notes in global form are outstanding, notices to holders will be delivered to the depositary, in accordance with its applicable policies as in effect from time to time. If Notes are issued in individual definitive form, notices to holders will be deemed to have been delivered upon the mailing by first class mail, postage prepaid, of such notices to holders of the Notes at their registered addresses as they appear in the registrar's records. Neither the failure to give any notice to a particular holder of the Notes, nor any defect in a notice given to a particular holder of the Notes, will affect the sufficiency of any notice given to another holder of the Notes.

For so long as the Notes are listed on the SGX-ST and in accordance with the rules and regulations of such exchange, the Issuer and the Guarantors will publish notices in a newspaper with general circulation in Singapore, which is expected to be the *Business Times, Singapore Edition*. Notices shall be deemed to have been given on the date of publication as aforesaid or, if published on different dates, on the date of the first such publication.

Governing Law and Submission to Jurisdiction

The Notes, the Indenture, and the Security Documents will be governed by, and construed in accordance with, the laws of the State of New York, except that certain Security Documents will be governed by Panamanian law, as applicable.

Each of the parties to the Indenture will irrevocably submit to the jurisdiction of the U.S. federal and New York State courts located in the Borough of Manhattan, City and State of New York in respect of actions brought against it as a defendant for purposes of all legal actions and proceedings instituted in connection with the Notes, the Indenture, and any Security Document stated to be governed by the laws of the State of New York. Each of the parties to the Indenture will irrevocably waive (and each holder of Notes (by acquiring a Note or a beneficial interest therein or otherwise accepting the benefits of the Indenture and the other applicable Financing Documents) will be deemed to irrevocably waive), to the fullest extent permitted by Applicable Law, any objection that it may now or thereafter have to the laying of the venue of any such proceeding brought in such a court, any claim that any such proceeding brought in such a court has been brought in an inconvenient forum and any objection based on place of residence or domicile.

The Issuer and the Guarantors will appoint on or prior to the Issue Date, and each Guarantor will appoint on or prior to the Issue Date or upon provision of its Note Guarantee, Cogency Global Inc., with an office on the date hereof at 122 East 42nd Street, 18th Floor, New York, NY 10168, United States of America, as its authorized agent upon which process may be served in any such action.

Currency Indemnity

Dollars are the sole currency of account and payment for all sums payable by the Issuer and the Guarantors and each Guarantor under or in connection with the Notes, the Indenture and the Note Guarantees, including damages. To the greatest extent permitted under applicable law, any amount received or recovered in a currency other than Dollars (whether as a result of, or of the enforcement of, a judgment or order of a court of any jurisdiction, in the winding-up or dissolution of the Issuer and the Guarantors or any Guarantor or otherwise) by any holder of a Note in respect of any sum expressed to be due to it from the Issuer and the Guarantors or any Guarantor will only constitute a discharge to the Issuer and the Guarantors or such Guarantor to the extent of the Dollar amount that the recipient is able to purchase with the amount so received or recovered in that other currency on the date of that receipt or recovery (or, if it is not practicable to make that purchase on that date, on the first date on which it is practicable to do so). If that Dollar amount is less than the Dollar amount expressed to be due to the recipient under any Note, the Indenture or any Note Guarantee, the Issuer and the Guarantors and each Guarantor will indemnify such holder against any loss sustained by it as a result; and if the amount of Dollars so purchased is greater than the sum originally due to such holder, such holder will, by accepting a Note, be deemed to have agreed to repay such excess. In any event, the Issuer and the Guarantors and each Guarantor will indemnify the recipient against the cost of making any such purchase.

For the purposes of the preceding paragraph, it will be sufficient for the holder of a Note to certify in a satisfactory manner (indicating the sources of information used) that it would have suffered a loss had an actual purchase of Dollars been made with the amount so received in that other currency on the date of receipt or recovery (or, if a purchase of Dollars on such date had not been practicable, on the first date on which it would have been practicable, it being required that the need for a change of date be certified in the manner mentioned above). These indemnities will constitute a separate and independent obligation from the other obligations of the Issuer and the Guarantors, will give rise to a separate and independent cause of action, will apply irrespective of any indulgence granted by any holder of a Note and will continue in full force and effect despite any other judgment, order, claim or proof for a liquidated amount in respect of any sum due under any Note.

Waiver of Immunity

To the extent that the Issuer and the Guarantors, any of the Restricted Subsidiaries or any of their respective properties, assets or revenues may have or may hereafter become entitled to any right of immunity, on the grounds of sovereignty or otherwise, from any legal action, suit or proceeding, from the giving of any relief in any such legal action, suit or proceeding, from setoff or from counterclaim from the jurisdiction of any Panamanian, New York State or U.S. federal or other applicable court, from service of process, from attachment upon or prior to judgment, from attachment in aid of execution of judgment, or from execution of judgment, or other legal process or proceeding for the giving of any relief or for the enforcement of any judgment, in any such court in which proceedings may at any time be commenced, with respect to the obligations and liabilities of the Issuer and the Guarantors or any of the Restricted Subsidiaries, or any other matter under or arising out of or in connection with, the Notes or the Indenture, the Issuer and the

Guarantors and each Guarantor irrevocably and unconditionally waives or will waive, and will cause each other Restricted Subsidiary to waive, such right, and agrees not to plead or claim any such immunity and consents to such relief and enforcement. To the extent that the Issuer and the Guarantors, any of the Restricted Subsidiaries or any of their respective properties, assets or revenues may hereafter become entitled to any such right of immunity, such waiver may not be effective if it affects the interests of any third parties as they relate to the Issuer and the Guarantors or any such Restricted Subsidiary or if such waiver is expressly forbidden under Panamanian law.

Indenture Trustee

Citibank, N.A. will act as the Indenture Trustee under the Indenture and its corporate office for transfers, exchanges or surrender of the Notes is (i) 480 Washington Boulevard, 30th Floor, Jersey City, New Jersey 07310, Facsimile: 973) 461-7191 or (973) 461-7192, Attention: Agency & Trust — UEP Penonomé II, S.A., and (ii) for all other purposes, 388 Greenwich Street, New York, New York 10013, (973) 461-7191 or (973) 461-7192, Attention: Agency & Trust — UEP Penonomé II, S.A., or such other address as the Indenture Trustee may designate from time to time by notice to the holders of the Notes and the Issuer.

The Indenture contains provisions for the immunities, indemnities, privileges, and the protections and rights of the Indenture Trustee under the Indenture, for which reference is made to the Indenture. The obligations of the Indenture Trustee to the holders of the Notes are subject to such immunities, indemnities, privileges, protections and rights as set forth therein. In addition, the Indenture will contain provision permitting the holders of specified percentages in principal amount of the Notes at the time then outstanding, on behalf of the holders of all Notes, to direct the Indenture Trustee in connection with actions to be taken, or rights to be exercised, under the Indenture and the other Financing Documents, including without limitation in connection with the exercise of rights and remedies following the occurrence and during the continuation of an Event of Default, in each case on and subject to the terms and conditions set forth in the Indenture.

The Indenture Trustee will be responsible for (among other things): (a) maintaining a record of the aggregate holdings of Notes and accepting Notes for exchange and registration of transfer, (b) making payments in respect of the Notes to the holders of the Notes to the extent funds are available therefor and (c) transmitting notices to the holders and from such holders to the Issuer and the Guarantors (in each case, as contemplated by the Indenture). In the event of a transfer of a Note, new Notes will be obtainable at the specified corporate trust office of the Indenture Trustee in connection with such transfer.

Collateral Trustee

The Bank of Nova Scotia (Panamá), S.A. will be appointed to act as Collateral Trustee on behalf of the holders of the Notes and the other Secured Parties pursuant to the Security Documents. The Collateral Trustee will: (a) accept delivery of the Security Documents and execute and deliver each of such Security Documents on behalf of the Secured Parties and (b) hold, for the benefit of the Secured Parties, the Liens intended to be created by such Security Documents over the Collateral located in Panama.

Intercreditor Agent

Citibank, N.A. will act as the Intercreditor Agent under the Intercreditor Agreement. The rights, duties, protections and obligations of the Intercreditor Agent will be set forth in the Intercreditor Agreement.

Certain Definitions

"Acceptable Bank" means any of Citigroup Global Markets Inc., any Affiliate thereof or other bank or financial institution with a rating of at least Baa3, in the case of Moody's or BBB-, in the case of each Standard & Poor's and Fitch, with respect to its long-term senior unsecured debt.

"Additional Amounts" has the meaning set forth in "— Additional Amounts."

"Additional Debt" means any Indebtedness permitted to be incurred by the Issuer pursuant to clause (1) and (2)(a), (b), (f) (in respect only of Debt refinancing Additional Debt), (h) and (m), in each case, of the covenant described under the caption "— Negative Covenant of the Issuer and the Guarantors and the Restricted Subsidiaries — Limitation on Indebtedness — The Issuer".

"Additional Debt Agreements" means each agreement, contract, indenture, instrument or document evidencing, guaranteeing or securing any Additional Debt or securing any Obligations under a Permitted Swap Contract entered into in respect of such Additional Debt.

"Additional Debt Obligations" means all advances to, and debts, liabilities, Obligations, covenants and duties of, the Issuer and the Guarantors or any of its Restricted Subsidiaries under the Additional Debt Agreements, whether direct or indirect (including those acquired by assumption), absolute or contingent, due or to become due, now existing or hereafter arising and including interest and fees that accrue after the commencement by or against the Issuer and the Guarantors or any such Restricted Subsidiary of any Insolvency Proceeding naming the Issuer and the Guarantors or any such Restricted Subsidiary as the debtor in such proceeding, regardless of whether such interest and fees are allowed claims in such proceeding. Without limiting the generality of the foregoing, the Additional Debt Obligations of the Issuer and the Guarantors or any of its Restricted Subsidiaries under the Additional Debt Agreements include the obligation to pay principal, interest, expenses, fees, attorney costs, consultants costs, indemnities and other amounts payable by the Issuer and the Guarantors or any such Restricted Subsidiary under any Additional Debt Agreements.

"Additional Debt Providers" means the holders or providers of Additional Debt.

"Additional Debt Service" means, for any period or date, an amount equal to the sum of all payments due during such period or on such date, as applicable, in respect of principal, fees, and interest any Swap Settlement Payments due and payable (net of any Swap Settlement Payments receivable) by the Issuer and the Guarantors or any of the Restricted Subsidiaries under such Permitted Swap Contracts, and any Swap Termination Payments due and payable (net of any Swap Termination Payments receivable) by the Issuer and the Guarantors or any such Restricted Subsidiary or otherwise under such Permitted Swap Contracts, in each case in respect of Additional Debt,.

"Additional Debt Service Reserve Account" means each segregated Dollar-denominated offshore debt service reserve account, if any, notified from time to time by the Issuer and the Guarantors (and confirmed by the holders of Additional Debt or any agent on their behalf) or any Additional Debt Provider or any agent on their behalf in respect of such Additional Debt to the Collateral Trustee as the reserve account for such Additional Debt.

"Additional Debt Service Reserve Requirement" means the amount notified from time to time (but in any event, no later than ten (10) days prior to each Funds Transfer Date) by the Issuer and the Guarantors or the Additional Debt Providers or any agent on their behalf in respect of Additional Secured Debt to the Collateral Trustee as the amount required to be on deposit in, or credited to, the Additional Debt Service Reserve Account in respect of such Additional Secured Debt on each Funds Transfer Date; *provided* that in no event shall such amount exceed, on any Funds Transfer Date, an aggregate amount equal to the aggregate Additional Debt Service due in respect of such Additional Secured Debt and all related Permitted Swap Contracts during the period of six (6) months thereafter; *provided*, *further*, that the amount under this definition shall never exceed the actual amount required to be held in a reserve account under the terms of the related Indebtedness.

"Additional Material Project Documents" shall mean any contract or agreement (a) pursuant to which such the Issuer of the Guarantors are required to make or receive payments in excess of U.S.$1.5 million Dollars per annum or (b) the termination of which could reasonably be expected to have a Material Adverse Effect.

"Additional Notes" has the meaning set forth in "— Further Issuances."

"Additional Secured Debt" shall have the meaning set forth in the Intercreditor Agreement.

"Additional Secured Debt Obligations" shall mean Obligations with respect to Additional Secured Debt.

"Administrative Agent" means a financial institution, if any, acting in the capacity of administrative agent under any Letter of Credit Documents.

"Affiliate" means, as to any Person, any other Person that, directly or indirectly, controls, is controlled by or is under common control with such Person or is a director or officer of such Person; and for purposes of this definition, the term "control" (including the terms "controlling", "controlled by" and "under common control with") of a Person will mean the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of such Person, whether through the ownership of voting securities, by contract or otherwise.

"Agent" means, the Collateral Trustee, the Indenture Trustee, the Administrative Agent from time to time the Intercreditor Agent, and such other agents party from time to time to the Secured Debt Documents.

"Annual Budget" means an annual budget and operating plan (including a statement of cash flows) prepared by the Issuer and the Guarantors (on a combined basis), together with any updates or revisions thereto made by the Issuer or the Guarantors from time to time.

"Applicable Accounting Principles" means, with respect to (a) any Person (other than the Issuer and the Guarantors), GAAP as in effect from time to time in the jurisdiction in which such Person is incorporated, formed or organized and (b) with respect to the Issuer and the Guarantors, International Financial Reporting Standards, as adopted by the International Accounting Standards Board.

"Applicable Laws" means, with respect to any Person and any Project, all applicable international, foreign, federal, state and local statutes, treaties, rules, guidelines, regulations, ordinances, codes and administrative or judicial precedents or authorities, including the interpretation or administration thereof by any Governmental Authority charged with the enforcement, interpretation or administration thereof, and all applicable administrative orders, directed duties, requests, licenses, authorizations and permits of, and agreements with, any Governmental Authority.

"Asset Sale" means any sale, lease, transfer or other disposition (or series of related sales, leases, transfers or dispositions) by the Issuer, the Guarantors or any Restricted Subsidiary, including any disposition by means of a merger, consolidation or similar transaction (each referred to for the purposes of this definition as a "disposition"), of:

(1) any shares of capital stock (other than or directors' qualifying shares or shares required by applicable law to be held by a Person other than the Issuer, the Guarantors or a Restricted Subsidiary);

(2) all or substantially all the assets of any division or line of business of the Issuer, the Guarantors or any Restricted Subsidiary; or

(3) any other assets of the Issuer, the Guarantors or any Restricted Subsidiary outside of the ordinary course of business of the Issuer, the Guarantors or such Restricted Subsidiary;

provided, however, that Asset Sale will not include any of (a) through (n) below; provided further, that the Net Available Proceeds from any of (a) through (n) must be deposited in the Collection Account.

(a) a disposition between or among the Issuer and the Guarantors and the Restricted Subsidiaries;

(b) for purposes of the provisions described under "— Negative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries — Limitation on Restricted Payments" only, a Restricted Payment that is permitted by such "Limitation on Restricted Payments" covenant;

(c) a disposition of assets with a Fair Market Value of less than U.S.$5.0 million, *provided* that written notice is provided to the Indenture Trustee of any such disposition;

(d) (i) an expenditure of cash or liquidation of Cash Equivalents or other marketable securities disposed of in the open market or (ii) goods held for sale and assets sold in the ordinary course of business;

(e) a disposition of obsolete, worn out, uneconomic, damaged or surplus property, equipment or other assets or property, equipment or other assets that are no longer economically practical to maintain or used or useful in the business of the Issuer and the Guarantors and the Restricted Subsidiaries whether now or hereafter owned or leased or acquired in connection with an acquisition or used or useful in the conduct of the business of the Issuer and the Guarantors and the Restricted Subsidiaries (including by ceasing to enforce, allowing the lapse, abandonment or invalidation of or discontinuing the use or maintenance of or putting into the public domain any intellectual property that is, in the reasonable judgment of the Issuer and the Guarantors or the Restricted Subsidiaries, as applicable, is no longer used or useful, or economically practicable to maintain);

(f) a disposition of assets that are exchanged for or are otherwise replaced by Replacement Assets;

(g) the lease, assignment or sublease of any real or personal property in the ordinary course of business;

(h) dispositions of receivables in connection with the compromise, settlement or collection thereof in the ordinary course of business or consistent with past practice or in bankruptcy or similar proceedings and exclusive of factoring or similar arrangements;

(i) foreclosure, condemnation or any similar action with respect to any property or other assets;

(j) the unwinding of any Swap Contract;

(k) the Incurrence or disposition of any Lien permitted by the covenant described under "— Negative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries — Limitation on Liens";

(l) any disposition governed by the provisions of "— Negative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries — Merger, Consolidation, Liquidation, Dissolution";

(m) the sale of equity interests in any Unrestricted Subsidiary; and

(n) any disposition that would constitute an Investment permitted by the covenant described under the caption "Limitation on Investments."

"Authorized Officer" means: (a) with respect to the Issuer and the Guarantors, any of the Issuer and the Guarantors directors, managers, chief financial officer, secretary, alternate secretary or attorney-in-fact with sufficient authority of the Issuer and the Guarantors from time to time and (b) with respect to any other Person, the general director, the president, any vice president, secretary, chief accountant, treasurer, attorney-in-fact with sufficient authority or any other officer of such Person: (i) to whom a matter is referred because of such officer's responsibility for overseeing the administration of, and reviewing compliance with, the Material Project Documents or (ii) and with respect to any financial matters, the chief financial officer or treasurer of such Person, as the context may require.

"Authorized Representative" has the meaning given to the term "Authorized Representative" in the Intercreditor Agreement.

"Average Life" means, as of any date of determination, with respect to any Indebtedness, the quotient obtained by dividing: (a) the sum of the products of the number of years (rounding to the nearest one twelfth of one year) from the date of determination to the dates of each remaining scheduled principal payment (including the payment at final maturity) of such Indebtedness multiplied by the amount of such payment, by (b) the sum of all such payments.

"Business Day" means any day other than a Saturday, Sunday or other day on which commercial banks are authorized or required to close under the laws of New York, New York, United States of America or Panama City, Panama.

"Calculation Period" means, with respect to any payment or determination date, a period of four consecutive Quarterly Periods immediately preceding such payment or determination date (or as the context otherwise requires) for which financial statements are available.

"Capitalized Leases" means all leases that have been or should be, in accordance with Applicable Accounting Principles, recorded as capitalized leases.

"Cash Equivalents" means Dollar Permitted Investments and any other similar Investments that are used for similar purposes held by the Issuer and the Guarantors or any Restricted Subsidiary on the Issue Date.

"Cash Flow Available for Debt Service" means, for any period, the sum (without duplication) of all cash deposited into any Collection Account (including amounts received from any Unrestricted Subsidiary, solely to the extent that neither the Issuer and the Guarantors nor any Restricted Subsidiary has any obligation to refund or repay any such amounts, except with regard to any advance distribution or dividend, provided that, to the extent that any such advance distribution or dividend is subsequently refunded or repaid in whole or in part, the amount of such advance distribution or dividend that is refunded or repaid will be subtracted from Cash Flow Available for Debt Service in the period in which such repayment or refund occurs and excluding amounts received in the Issuer Collection Account in connection with the repayment of any Indebtedness owed by any Guarantor to the Issuer, to the extent that such amounts were included in the calculation of Cash Flow Available for Debt Service with respect to the Issuer or the Guarantors, as applicable) during the most recently ended Calculation Period completed on or prior to such date of determination, *plus* all cash revenues on a pro forma basis for such Calculation Period of any Person acquired, merged or consolidated with the Issuer and the Guarantors and/or any Restricted Subsidiary during such period, less (b) (i) cost of good and service expenses paid in cash during such Calculation Period, (ii) administrative expenses paid in cash during such Calculation Period, *less* (iii) operating expenses paid in cash during such Calculation Period, and *less* (iv) Taxes (other than withholding taxes) paid in cash during such Calculation Period.

"Change of Control" means the occurrence of the following events:

(a) prior to the first public offering of capital stock of the Issuer and the Guarantors,

  (i) the Permitted Holders ceasing to own, directly or indirectly, more than 50% of the shares (*acciones*) of the Issuer and the Guarantors entitled to vote at meetings of shareholders and the Permitted Holders collectively ceasing to Control the Issuer and the Guarantors; or

  (ii) the direct or indirect sale, transfer, conveyance or other disposition (other than by way of merger or consolidation), in one or a series of related transactions, of all or substantially all of the properties or assets of the Issuer and the Guarantors and the Restricted Subsidiaries, taken as a whole, to any "person" (as that term is used in Section 13(d)(3) of the Exchange Act) other than one or more Permitted Holders; or

  (iii) the adoption of a plan relating to the liquidation or dissolution of the Issuer and the Guarantors; or

(b) after the consummation the first public offering of capital stock of the Issuer and the Guarantors, a Person becomes the beneficial owner, directly or indirectly, of 35% or more of the shares (*acciones*) of the Issuer and the Guarantors entitled to vote at meetings of shareholders if such holding is more than the voting power beneficially owned, directly or indirectly, by Permitted Holders at such time.

"Change of Control Repurchase Event" means the occurrence of both a Change of Control and a Ratings Decline.

"Citi Swap" means, the Interest Rate Swap Contract to be entered into on or about the Issue Date between the Issuer and Citibank, N.A. in connection with the unwinding of the IFC Hedge Agreement.

"Collateral" has the meaning set forth in "— Collateral Arrangements — General."

"Collateral Trustee" means The Bank of Nova Scotia (Panama), S.A., acting not in its individual capacity but in its capacity as trustee (*fiduciario*) under the Panamanian Trust Agreement, or any successor trustee appointed.

"Collection Expenses" means, with respect to any proceeds, all reasonable and documented out-of-pocket costs or expenses (if any), taxes and, if applicable, reasonable and documented transaction costs, including indemnities of the Indenture Trustee or the applicable agents, incurred by the Issuer and the Guarantors, any of the Restricted Subsidiaries, the Collateral Trustee, the Indenture Trustee or any agent in connection with the collection, enforcement, negotiation, consummation, settlement, proceedings, administration or other activity related to the receipt or collection of such proceeds.

"Combined Basis" means, when used with respect to the determination of any amount, that such amount is to be determined by combining, without duplication, the relevant amount with respect to each of the Issuer and each Guarantor, in each case, on a stand-alone basis, all in accordance with Applicable Accounting Principles.

"Combined Debt Service Coverage Ratios" means, collectively, the Combined Historical Debt Service Coverage Ratio and Combined Prospective Debt Service Coverage Ratio.

"Combined Exposure" has the meaning given to it in the Intercreditor Agreement.

"Combined Historical Debt Service Coverage Ratio" means, for any Calculation Period, Cash Flow Available for Debt Service for such period divided by all of the Issuer, the Guarantors and the Restricted Subsidiaries' payment obligations in relation to Indebtedness for borrowed money payable during such Calculation Period, calculated on a Combined Basis.

"Combined Prospective Debt Service Coverage Ratio" means, as of any date of determination, the Projected Cash Flow Available for Debt Service for the applicable period divided by all of the Issuer, the Guarantors and the Restricted Subsidiaries' scheduled payment obligations in relation to Indebtedness for borrowed money payable during such applicable periods, in each case, calculated on a Combined Basis.

"Condemnation Event" means any taking, seizure, confiscation, requisition, exercise of rights of eminent domain, public improvement, inverse condemnation, condemnation, *expropriación*, *ocupación temporal* or similar action or threat of any such action of or proceeding by any Governmental Authority or other Person relating to all or a material part of any of the Projects.

"Control" means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of a Person, whether through the ability to exercise voting power, by contract or otherwise. "Controlling" and "Controlled" have meanings correlative thereto.

"Current Assets" means, with respect to any Person, all assets of such Person that, in accordance with Applicable Accounting Principles, would be classified as current assets on the balance sheet of an Issuer conducting a business the same as or similar to that of such Person, after deducting appropriate and adequate reserves therefrom in each case in which a reserve is proper in accordance with Applicable Accounting Principles.

"Debt Service Reserve Requirement" means, as applicable, the Indenture Debt Service Reserve Requirement, any Additional Debt Service Reserve Requirement and/or any other minimum balance required to be maintained in any debt service reserve account in accordance with the Secured Debt Documents and/or Security Documents.

"Debtor Relief Laws" means the Bankruptcy Code of the United States, Law No. 12 of May 19, 2016 of Panama and all other liquidation, conservatorship, bankruptcy, assignment for the benefit of creditors, moratorium, rearrangement, receivership, insolvency, reorganization or similar debtor relief laws of the United States, Panama or other applicable jurisdictions from time to time in effect and affecting the rights of creditors generally.

"Dollar" or "U.S.$" means the lawful currency of the United States.

"Dollar Permitted Investments" means any of the following types of Investments, free and clear of all Liens (other than Liens created under the Security Documents):

(a) readily marketable obligations issued or directly and fully guaranteed or insured by the United

States or any agency or instrumentality thereof having maturities of not more than 90 days from the date of acquisition thereof; *provided* that the full faith and credit of the United States is pledged in support thereof;

(b) time deposits with, or insured certificates of deposit or bankers' acceptances of, any commercial bank that (i) is organized under the laws of the United States, any state thereof or the District of Columbia or is the principal banking subsidiary of a bank holding company organized under the laws of the United States, any state thereof or the District of Columbia, and is a member of the Federal Reserve System of the United States, (ii) issues (or the parent of which issues) commercial paper rated as described in clause (e) of this definition and (iii) has combined capital and surplus of at least U.S.$500.0 million, in each case with maturities of not more than ninety (90) days from the date of acquisition thereof;

(c) readily marketable Dollar-denominated obligations issued or directly and fully guaranteed or insured by Panama or any federal agency or instrumentality thereof having maturities of not more than one hundred eighty (180) days from the date of acquisition thereof; *provided* that the full faith and credit of Panama is pledged in support thereof;

(d) Dollar-denominated time deposits with, or insured certificates of deposit or bankers' acceptances of, any commercial bank that (i) is organized under the laws of Panama or is the principal banking subsidiary of a bank holding company organized under the laws of Panama, and is supervised by, and is not under intervention or controlled by, the SBP, (ii) issues (or the parent of which issues) commercial paper at least "Prime-1" (or the then-equivalent grade) by Moody's or at least "A-1" (or the then-equivalent grade) by S&P and (iii) has combined capital and surplus of at least U.S.$500.0 billion, in each case with maturities of not more than ninety (90) days from the date of acquisition thereof;

(e) commercial paper issued by any Person organized under the laws of any state of the United States and rated at least "Prime-1" (or the then-equivalent grade) by Moody's or at least "A-1" (or the then-equivalent grade) by S&P, in each case with maturities of not more than ninety (90) days from the date of acquisition thereof;

(f) Investments, classified in accordance with IFRS as Current Assets of the Issuer and the Guarantors, in money market investment programs registered under the United States Investment Company Act of 1940, which are administered by financial institutions that have the highest rating obtainable from either Moody's or S&P, and the portfolios of which are limited solely to Investments of the character, quality and maturity described in clauses (a), (b), (c), (d) and (e) of this definition; and

(g) money market funds having a rating in the highest investment category granted thereby by a recognized credit rating agency at the time of acquisition, or such other similar fund as the Intercreditor Agent (acting at the direction of the Required Secured Debtholders) may designate pursuant to the Intercreditor Agreement.

"DSRA Excess Amount" has the meaning set forth in "— Intercreditor Arrangements — Accounts Waterfall."

"Environmental Laws" means any and all Applicable Laws, in each case as now or hereafter in effect and applicable to the Issuer and the Guarantors, the Restricted Subsidiaries and/or the Projects, relating to Environmental or Social Matters.

"Environmental or Social Matter" means any of: (a) the protection of human health, safety or the environment or to emissions, discharges, releases or threatened releases of pollutants, contaminants, chemicals or toxic or hazardous substances or wastes into the environment, including, without limitation, ambient air, soil, surface water, ground water, wetlands, land or subsurface strata, or otherwise relating to the manufacture, processing, distribution, use, treatment, storage, disposal, transport or handling of pollutants, contaminants, chemicals or toxic or hazardous substances or wastes, (b) nuisance, noise, defective premises, health and safety at work, industrial illness, industrial injury due to environmental factors, environmental health problems (including asbestosis or any other illness or injury caused by exposure to asbestos), (c) conservation, preservation or protection of the natural or man-made environment or any living organisms supported by the natural or man-made environment, (d) conservation of archaeological and historical sites, rights-of-way, resettlement, expropriation and indemnification, indigenous groups, traffic, or any other matters whatsoever affecting social conditions and (e) labor, worker rights or human rights.

"Equity Contribution" means any contribution of funds by a direct or indirect parent of the Issuer and the Guarantors to an account of the Issuer and the Guarantors or any Restricted Subsidiary, including via an equity investment, subordinated loans, or another similar type of contribution.

"Equity Interests" means, with respect to any Person, all of the shares of capital stock of (or other ownership or profit interests in) such Person, all of the warrants, options or other rights for the purchase or acquisition from such Person of shares of capital stock of (or other ownership or profit interests in) such Person, all of the securities convertible into or exchangeable for shares of capital stock of (or other ownership or profit interests in) such Person or warrants, rights or options for the purchase or acquisition from such Person of such shares (or such other interests), and all of the other ownership or profit interests in such Person (including partnership, member or trust interests therein), whether voting or nonvoting, and whether or not such shares, warrants, options, rights or other interests are outstanding on any date of determination.

"Event of Loss" means, with respect to any Project or the property, assets, business or operations of the Issuer and the Guarantors or any of the Restricted Subsidiaries, any of the following events:

(a) destruction, damage, impairment or loss of use of any such Project or any such property or assets in their entirety or such a material portion thereof that the then- remaining portion of such Project or such property or assets cannot practically be used in accordance with Applicable Laws and Prudent Industry Practices and for its intended purpose in accordance with the Material Project Documents; and

(b) any Condemnation Event.

The date of occurrence of any Event of Loss specified above will be the date of the casualty or other occurrence specified above giving rise to such Event of Loss.

"Exchange Act" means the U.S. Securities Exchange Act of 1934, as amended.

"Fair Market Value" of any property, asset, share of capital stock, other security, Investment or other item means, on any date, the fair market value of such property, asset, share of capital stock, other security, Investment or other item on that date as determined in good faith by the senior management of the Issuer, the Guarantors or any Restricted Subsidiary, as applicable.

"Feasible Repair Certificate" means, with respect to any property or assets, or applicable portion thereof, of the Issuer and the Guarantors or any of the Restricted Subsidiaries, an Officer's Certificate (a) describing in reasonable detail the nature of the rebuilding, repair or restoration of such property or assets or portion thereof as a result of the Event of Loss, (b) stating the expected cost of such rebuilding, repair or restoration (including a reasonable contingency), (c) certifying that such property or assets or portion thereof is reasonably expected to be rebuilt, repaired or restored to permit operation thereof on a commercially feasible basis in accordance in all material respects with all Material Project Documents and relevant Governmental Approvals, (d) certifying that the funds available to the Issuer and the Guarantors or any such Restricted Subsidiary for such rebuilding, repair or restoration (other than proceeds of business interruption insurance) are reasonably expected to be sufficient to permit such rebuilding, repair or restoration and (e) certifying that the Issuer and the Guarantors or any such Restricted Subsidiary shall use its commercially best efforts to cause any repairs or restoration to be commenced and completed promptly and diligently at its own cost and expense.

"Financial Model" means the financial model prepared by the Issuer and the Guarantors and delivered to the Trustee and Collateral Trustee on or around the Issue Date, as such financial model may be updated from time to the time after the Issue Date to account for any change in any assumption or estimate that does not hold true anymore, as determined by the Issuer and the Guarantor in good faith.

"Financing Documents" means the Notes, the Indenture, the Letter of Credit Documents, the Security Documents, the Secured Debt Documents and any other documentation providing for Additional Debt or otherwise specified as a Financing Document in the Indenture.

"Fiscal Quarters" means, with respect to the Issuer and the Guarantors and any of the Restricted Subsidiaries, the periods commencing on (a) January 1 in any calendar year and ending on the next succeeding March 31, (b) April 1 in any calendar year and ending on the next succeeding June 30, (c) July 1 in any calendar year and ending on the next succeeding September 30, and (d) October 1 in any calendar year and ending on the next succeeding December 31, each of (a) – (d) a "Fiscal Quarter".

"Fiscal Year" means, with respect to each of the Issuer and the Guarantors and any of the Restricted Subsidiaries, the period commencing on January 1 in any Year and ending on the next succeeding December 31.

"Fitch" means Fitch Ratings, Inc. and any successor to its rating agency business.

"Fixed SMA Payments" means the annual fixed payments owed to the Sponsor under the Sponsor Services Agreements.

"Funds Transfer Date" means the last day of each calendar month or, if such day is not a Business Day, the immediately preceding day that is a Business Day.

"FX Swap Contract" means a Swap Contract, entered into between the Issuer and the Guarantors or one or more of the Restricted Subsidiaries, as applicable, and Swap Counterparty, to protect against the risk of foreign exchange fluctuations in respect of any Indebtedness.

"GAAP" means, with respect to any jurisdiction, generally accepted accounting principles as may be adopted or endorsed by a significant segment of the accounting profession in such jurisdiction, that are applicable to the circumstances as of any date of determination, consistently applied.

"Global Note" has the meaning set forth in "Book-Entry; Settlement and Clearance" in this Offering Memorandum.

"Governmental Approvals" means any Permit, authorization, registration, consent, approval, waiver, exception, variance, claim, license, exemption, publication, filing, notice to and declaration of or with any Governmental Authority, including any approvals relating to anything that is required for:

(a) the ownership, construction, finance, use, operation and maintenance of the property and assets of the Issuer and the Guarantors and the Restricted Subsidiaries and all such other matters as may be necessary in connection with the business and operations of the Issuer and the Guarantors and the Restricted Subsidiaries and (b)(i) the Issuer and the Guarantors and the Restricted Subsidiaries' respective formations and (ii) the compliance by the Issuer and the Guarantors and the Restricted Subsidiaries with, and the enforceability of, any of the Financing Documents and the making of any payments at the times and in the currencies contemplated under the Financing Documents.

"Governmental Authority" means the government of Panama, the United States, or any other nation, or of any political subdivision thereof, whether state or local, and any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government (including any supra-national bodies such as the European Union or the European Central Bank).

"Governmental Authorization" means any authorization, approval, consent, franchise, license, covenant, order, ruling, Permit, certification, exemption, notice, declaration or similar right, undertaking or other action of, to or by, or any filing, qualification or registration with, any Governmental Authority.

"Guarantee" means, as to any Person, (a) any obligation, contingent or otherwise, of such Person guaranteeing or having the economic effect of guaranteeing any Indebtedness or other obligation payable or performable by another Person (the "primary obligor") in any manner, whether directly or indirectly, and including any obligation of such Person, direct or indirect, (i) to purchase or pay (or advance or supply funds for the purchase or payment of) such Indebtedness or other obligation, (ii) to purchase or lease property, securities or services for the purpose of assuring the obligee in respect of such Indebtedness or other obligation of the payment or performance of such Indebtedness or other obligation, (iii) to maintain working capital, equity capital or any other financial statement condition or liquidity or level of income or cash flow of the primary obligor so as to enable the primary obligor to pay such Indebtedness or other obligation, or (iv) entered into for the purpose of assuring in any other manner the obligee in respect of such Indebtedness or other obligation of the payment or performance thereof or to protect such obligee against loss in respect thereof (in whole or in part), or (b) any Lien on any assets of such Person securing any Indebtedness or other obligation of any other Person, whether or not such Indebtedness or other obligation is assumed by such Person (or any right, contingent or otherwise, of any holder of such Indebtedness to obtain any such Lien). The amount of any Guarantee shall be deemed to be an amount equal to the stated or determinable amount of the related primary obligation, or portion thereof, in respect of which such Guarantee is made or, if not stated or determinable, the maximum reasonably anticipated liability in respect thereof as determined by the guaranteeing Person in good faith. The term "Guarantee" as a verb has a corresponding meaning.

"Guarantors" means:

(1) the Initial Guarantors; and

(2) any other Restricted Subsidiary that executes a Note Guarantee in accordance with the provisions of the Indenture;

And their respective successors and assigns until released from their obligations under their Note Guarantees and the Indenture in accordance with the terms of the Indenture.

"Guarantors Shareholders Loans" means, collectively, the subordinated loans granted by the Sponsor to the Guarantors pursuant to the intercompany note issued by Tecnisol I, S.A. dated December 31, 2018, the intercompany note issued by Tecnisol II, S.A. dated December 31, 2018, the intercompany note issued by Tecnisol III, S.A. dated December 31, 2018 and the intercompany note issued by Tecnisol IV, S.A. dated December 31, 2018.

"IFC Hedge Agreement" means the floating interest rate swap by and among the Issuer and the International Finance Corporation pursuant to the terms of the Confirmation dated March 10, 2015 and the ISDA Master Agreement dated December 9, 2014 by and among the Issuer and the International Finance Corporation.

"IFC Loans" means the loans granted to the Issuer by the International Finance Corporation, The Netherlandse Financierings-Maatschappij Voor, Ontowikkelingslanden N.V., Societe de Promotion et de Participation pour la Cooperation Economique S.A., Oesterrichische Entwicklungsbank A.G., Central American Bank for Economic Integration; Banco Nacional de Panama and Banco General, as lenders pursuant to the terms of (a) that certain Common Terms Agreement dated as of December 9, 2014, the Issuer, as borrower and as successor in interest of IEH Penonomé Panamá S.A. which merged into UEP Penonomé II, S.A., the entities described as lenders party thereto and the International Finance Corporation, as the Administrative Agent for the Lenders, and (b) the Loan Agreements dated as of December 9, 2014 entered into with each of the lenders party to the Common Terms Agreement and the Issuer, as borrower, secured by a pledge over substantially all the assets of the Issuer, the assignment in trust of certain assets to a Panamanian Trust and a pledge over the shares of the Issuer.

"IFRS" shall mean International Financial Reporting Standards, as adopted by the International Accounting Standards Board as in effect as of the date of determination thereof.

"Incur" means, with respect to any Indebtedness, to incur, create, issue, assume, guarantee or otherwise, contingently or otherwise, become liable, directly or indirectly, for or with respect to, or to extend the maturity of, or become responsible for, the payment of such Indebtedness; *provided*, *however*, that neither (a) the accrual of interest, (b) the accretion of original issue discount nor (c) an increase in the outstanding amount of Indebtedness caused solely by fluctuations in the exchange rates of currencies shall be considered an Incurrence of Indebtedness. The terms "Incurrence" and "Incurring" have corresponding meanings.

"Indebtedness" means, as to any Person at a particular time, without duplication, all of the following, whether or not included as indebtedness or liabilities in accordance with Applicable Accounting Principles:

(a) all obligations of such Person for borrowed money and all obligations of such Person evidenced by bonds, debentures, notes, indentures, loan agreements or other similar instruments;

(b) all obligations of all direct or contingent obligations of such Person arising under letters of credit (including standby and commercial), bankers' acceptances, bank guaranties, surety bonds and similar instruments;

(c) net obligations of such Person under any Swap Contract;

(d) all obligations of such Person to pay the deferred purchase price of property or services (other than trade accounts payable in the ordinary course of business and not past due for more than 180 days after the date on which each such trade payable or account payable was created);

(e) indebtedness (excluding prepaid interest thereon) secured by a Lien on property owned or being purchased by such Person (including indebtedness arising under conditional sales or other title retention agreements), whether or not such indebtedness shall have been assumed by such Person or is limited in recourse;

(f) all Obligations of such Person under Capitalized Leases;

(g) all obligations of such Person to purchase, redeem, retire, defease or otherwise make any payment in respect of any Equity Interests in such Person or any other Person or any warrants, rights or options to acquire such Equity Interests, valued, in the case of redeemable preferred interests, at the greater of its voluntary or involuntary liquidation preference plus accrued and unpaid dividends; and

(h) all Guarantees of such Person in respect of any of the foregoing.

For all purposes hereof, the Indebtedness of any Person shall include the Indebtedness of any partnership or joint venture (other than a joint venture that is itself a corporation or limited liability company) in which such Person is a general partner or a joint venturer, unless such Indebtedness is expressly made non-recourse to such Person. The amount of any net obligation under any Swap Contract on any date shall be deemed to be the Swap Termination Value thereof as of such date.

"Indenture Debt Service" means, for any period or date, an amount equal to (a) the sum of all payments of principal and fees due during such period or on such date in respect of the Secured Indenture Obligations, *plus* (b) the sum of all interest accrued during such period in respect of the Secured Indenture Obligations.

"Indenture Debt Service Reserve Requirement" means, as of the date of determination, an amount equal to (a) from the Issue Date and until the Monthly Transfer Date occurring in March 2034 the next six (6) months' Indenture Debt Service with respect to the Notes, and from the Monthly Transfer Date occurring in April 2034 until the Stated Maturity of the Notes, twelve (12) months of Indenture Debt Service with respect to the Notes.

"Indenture Trustee" means Citibank, N.A., as trustee under the Indenture.

"Independent Accountants" means PricewaterhouseCoopers, S.R.L. or such other independent auditor of recognized international standing having no affiliation with the Issuer and the Guarantors, the Permitted Holders or any of their Affiliates.

"Independent Engineer" means an engineering firm or technical consultant of international standing with customary experience in the renewable energy industry that is independent in connection with the relevant transaction, including not being affiliated with the Issuer or any of the parties to the applicable transaction(s).

"Initial Guarantors" means Tecnisol I, S.A., Tecnisol II, S.A., Tecnisol III, S.A. and Tecnisol IV, S.A., each a corporation (*sociedad anónima*) organized under the laws of Panama.

"Insolvency Proceeding", with respect to any Person, means (a) entry by any competent Governmental Authority of any jurisdiction or a court having jurisdiction in the premises of (i) a decree or order for relief in respect of such Person in an involuntary case or proceeding under any applicable Debtor Relief Law or (ii) an involuntary or contested decree or order adjudging such Person as bankrupt or insolvent, or approving as properly filed a petition seeking suspension of payment, reorganization, arrangement, adjustment or composition of or in respect of such Person under any applicable Debtor Relief Law, or appointing a custodian, receiver, liquidator, assignee, trustee, sequestrator or other similar official of such Person or of any substantial part of the property of such Person, or ordering the dissolution, winding up or liquidation of the affairs of such Person and the continuance of any such decree or order referred to in clauses (i) and (ii) above remains undismissed or unstayed and in effect for a period of ninety (90) consecutive days, (b) commencement by such Person of a voluntary case or proceeding under any applicable Debtor Relief Law or of any other case or proceeding to be adjudicated as bankrupt or insolvent, or the consent by such Person to the entry of a decree or order for relief in respect of such Person in an involuntary case or proceeding under any applicable Debtor Relief Law or to the commencement of any bankruptcy or insolvency case or proceeding against such Person, or the filing by such Person of a petition or answer or consent seeking reorganization or relief under any applicable Debtor Relief Law; or consent by such Person to the filing of such petition or to the appointment of or taking possession by a custodian, receiver, liquidator, assignee, trustee, sequestrator or other similar official of such Person or of any substantial part of the property of such Person, or the making by such Person of an assignment for the benefit of creditors or (c) the admission by such Person in writing of its inability to pay its debts generally as they become due, or the taking of corporate action by such Person in furtherance of any such action.

"Intercompany Loans" means, the loans granted by the Issuer to each of the Guarantors pursuant to intercompany promissory notes to be issued by the Guarantors to the Issuer on or shortly after the Issue Date.

"Intercreditor Agent" means Citibank, N.A., as the intercreditor agent appointed pursuant to the Intercreditor Agreement.

"Intercreditor Agreement" means the intercreditor agreement, to be entered into on or around December 18, 2020 (as amended, supplemented or otherwise modified from time to time), among the Issuer and the Guarantors, the other credit parties from time to time party thereto, Citibank, N.A., acting as Intercreditor Agent, Citibank, N.A., acting as Indenture Trustee for the Indenture Secured Parties, The Bank of Nova Scotia (Panama), S.A., acting as Collateral Trustee for the Secured Parties, and each other Person that may become party thereto from time to time.

"Intercreditor Vote" has the meaning given to it in the Intercreditor Agreement.

"Interest Rate Swap Contract" means a Swap Contract entered into between the Issuer or the Guarantors and a Swap Counterparty, to protect against the risk of interest rate fluctuations in respect of any Indebtedness of the Issuer or the Guarantors.

"Investment" means, as to any Person, any direct or indirect acquisition or investment by such Person, whether by means of (a) the purchase or other acquisition of Equity Interests or debt of another Person, (b) a loan, advance or capital contribution to, Guarantee or assumption of debt of, or purchase or other acquisition of any other debt or equity participation or interest in, another Person, including any partnership or joint venture interest in such other Person and any arrangement pursuant to which the investor Incurs debt of the type referred to in clause (h) of the definition of "Indebtedness" in respect of such Person, or (c) the purchase or other acquisition (in one transaction or a series of transactions) of assets of another Person that constitute a business unit or all or a substantial part of the business of, such Person.

"Investment Grade Rating" means a rating equal to or higher than BBB- (or the equivalent) by Fitch, Baa3 (or the equivalent) by Moody's or BBB- (or the equivalent) by S&P.

"Issue Date" means the first date of issuance of Notes under the Indenture.

"Issue Date Payment" means the following Restricted Payments to be made by the Issuer or the Guarantors, as applicable, on or promptly after the Issue Date:

(a) Up to U.S.$41.0 million to repay in full by Guarantors Shareholders Loans;

(b) Up to U.S.$51.0 million to repay in full the Issuer Shareholders Loans;

(c) Reduce the Issuer's capital and pay a distribution to the Issuer's shareholders for up to U.S.$14.4 million; and

(d) Pay up to U.S.$4.8 million to our Sponsor for overdue fees under that certain Service and Management Agreement dated October 2, 2014 by and between the Issuer and the Sponsor.

"Issuer Shareholders Loans" means, collectively, (a) the loan granted by IEH Penonomé Holdings (Cayman) to the Issuer pursuant to that certain global subordinated intercompany note dated December 9, 2014, and (b) the loan granted by Green Field Panamá, S.A. to the Issuer pursuant to that certain global subordinated intercompany note dated December 31, 2014.

"Issuing Lender" has the meaning given to it in the Letter of Credit Agreement.

"Knowledge" means, with respect to the Issuer and the Guarantors, the actual knowledge of any of its Authorized Officers, and, with respect to the Indenture Trustee, the actual knowledge of any of its Responsible Officers.

"Lender" shall mean a lender under any Letter of Credit Agreement.

"Letter of Credit" shall mean any letter of credit issued pursuant to a Letter of Credit Agreement, which letters of credit shall be drawable upon delivery of a draw certificate certifying the right of the Collateral Trustee to make a draw at such time, have a tenor of at least one year and meet all the requirement set forth in the Panamanian Trust Agreement.

"Letter of Credit Agreement" shall mean any agreement entered into from time to time among the Issuer, the Administrative Agent therefor, if any, and the other financial institutions from time to time party thereto as Issuing Lenders and Lenders (each of which shall be an Acceptable Bank), pursuant to which Letters of Credit, may be issued to fund (in whole or in part) the Debt Service Reserve Account or the Trust O&M Reserve Account.

"Letter of Credit Documents" means the Letter of Credit Agreement, each Letter of Credit, the Security Documents and each "Financing Document" (as defined in the Letter of Credit Agreement).

"Letter of Credit Loans" has the meaning given to the term "Loans" in the Letter of Credit Agreement.

"Letter of Credit Secured Parties" has the meaning given to it in the Intercreditor Agreement.

"Lien" means any mortgage, pledge, hypothecation, assignment, deposit arrangement, encumbrance, lien (statutory or other), charge or preference, priority, *fideicomiso* or other security interest or preferential arrangement in the nature of a security interest of any kind or nature whatsoever (including any conditional sale or other title retention agreement, any easement, right of way or other encumbrance on title to real property, and any financing lease having substantially the same economic effect as any of the foregoing).

"Material Adverse Effect" means a material adverse effect on:

(a) the operations, business, condition (financial or otherwise), properties or prospects of the Issuer and the Guarantors and the Restricted Subsidiaries, taken as a whole;

(b) the Issuer and the Guarantors or any Guarantor's ability to perform its payment obligations under the Financing Documents to which it is a party;

(c) the Issuer and the Guarantors or any of the Restricted Subsidiaries' (taken as a whole) ability to perform its material obligations under the Material Project Documents to which it is a party;

(d) the legality, validity, effectiveness or enforceability of any Financing Document; or

(e) the validity or priority of any security interest purported to be granted to any agent or any of the Secured Parties under any of the Financing Documents, the rights or remedies available to any agent or any of the Secured Parties under the Financing Documents or the ability of any agent or any of the Secured Parties under the Financing Documents to enforce its rights or remedies under any Financing Document.

"Material Project Documents" shall mean each of the following documents, (i) PPA No.15-12 (Nuevo Chagres) dated March 21, 2012, by and between the Issuer and EDEMET, (ii) PPA No.16-12 (Rosa de los Vientos) dated March 21, 2012, by and between the Issuer and EDEMET, (iii) PPA No.17-12 (Portobelo) dated March 21, 2012, by and between the Issuer and EDEMET, (iv) PPA No. 18 -12 (Marañón) dated March 21, 2012, by and between the Issuer and EDEMET, (v) PPA No.19-12 (Nuevo Chagres) dated March 21, 2012, by and between the Issuer and EDECHI, (vi) PPA No. 20-12 (Rosa de los Vientos) dated March 21, 2012, by and between the Issuer and EDECHI, (vii) PPA No. 21-12 (Portobelo) dated March 21, 2012, by and between the Issuer and EDECHI, (viii) PPA DME-008-12 (Nuevo Chagres), dated March 21, 2012, by and between the Issuer and ENSA, (ix) PPA DME-009-12 (Rosa de los Vientos), dated March 21, 2012, by and between the Issuer and ENSA, (x) PPA DME-010-12 (Portobelo) dated March 21, 2012, by and between the Issuer and ENSA, (xi) PPA No. PA-18-020 dated February 5, 2018, by and between Tecnisol III, S.A. and Riba Smith S.A., and (xii) any document that substitutes or supersedes any of them and each Additional Material Project Document.

"Monthly Transfer Date" shall mean (i) any Business Day from the twentieth (20^{th}) through the last day of each calendar month, as per instructions by the Issuer or the Intercreditor Agent, as applicable, or (ii) if no instruction is received in writing by the Issuer or the Intercreditor Agent, then the last Business Day of each month, *provided* that there shall only be a single Monthly Transfer Date for any calendar month, and *further provided*, that if such day is not a Business Day, then the Monthly Transfer Date shall mean the next succeeding Business Day

"Moody's" means Moody's Investors Service, Inc. and any successor to its rating agency business.

"Net Available Cash" means the aggregate proceeds, including payments in respect of deferred payment obligations (to the extent corresponding to the principal, but not the interest component, thereof), received in Cash Equivalents by the Issuer and the Guarantors or any Restricted Subsidiary in respect of any Asset Sale (including, without limitation, any Cash Equivalents received upon the sale or other disposition of any non-cash consideration received in any Asset Sale), net of (1) the direct costs relating to such Asset Sale, including, without limitation, legal, accounting, investment banking and brokerage fees, and sales commissions, and any relocation expenses incurred as a result thereof, (2) taxes paid or payable as a result thereof, in each case, after taking into account any available tax credits or deductions and any tax sharing arrangements, (3) in the case of any Asset Sale by a Restricted Subsidiary, payments to holders of Equity Interests in such Restricted Subsidiary in such capacity (other than such Equity Interests held by the Issuer and the Guarantors or any Restricted Subsidiary) to the extent that such payment is required to permit the distribution of such proceeds in respect of the Equity Interests in such Restricted Subsidiary held by the Issuer and the Guarantors or any of the Restricted Subsidiaries and (4) appropriate amounts to be provided by the Issuer and the Guarantors or the Restricted Subsidiaries as a reserve against liabilities associated with such Asset Sale, including, without limitation, pension and other post-employment benefit liabilities, liabilities related to environmental matters and liabilities under any indemnification obligations associated with such Asset Sale, all as determined in accordance with Applicable Accounting Principles; *provided* that (a) excess amounts set aside for payment of taxes pursuant to clause (2) above remaining after such taxes have been paid in full or the statute of limitations therefor has expired and (b) amounts initially held in reserve pursuant to clause (4) no longer so held, will, in the case of each of subclause (a) and (b), at that time become Net Available Cash.

"Net Available Proceeds" means, with respect to any proceeds, such proceeds net of the related Collection Expenses.

"Non-Recourse Debt" means Indebtedness as to which (i) neither the Issuer and the Guarantors nor any Restricted Subsidiary provides any Guarantee and as to which the lenders will not have any recourse to the stock or assets of the Issuer and the Guarantors or any Restricted Subsidiary and (ii) no default thereunder would, as such, constitute a default under any other Indebtedness of the Issuer and the Guarantors or any Restricted Subsidiary.

"Note Guarantee" means a Guarantee of the Notes pursuant to the Indenture.

"O&M Reserve Excess Amount" has the meaning set forth in "— Intercreditor Arrangements — Accounts Waterfall."

"O&M Reserve Requirement" means, as of any date of determination, the aggregate amount of Projected Operating Expenses scheduled to be payable under the then-current Annual Budget for the next succeeding one (1) month following such date of determination; *provided* that solely for the purposes of this definition, until the Issuer and the Guarantors have prepared and provided to the Indenture Trustee an Annual Budget for the Fiscal Year beginning January 1, 2019, the O&M Reserve Requirement will be deemed to be U.S.$1.0 million; *provided*, *further*, that, on and after the date on which an Annual Budget for the Fiscal Year beginning January 1, 2019 is provided by the Issuer and the Guarantors to the Indenture Trustee, solely for purposes of this definition, the amount of Projected Operating Expenses scheduled to be payable during any period that is not included in any Annual Budget shall be deemed to be equal to the amount of Projected Operating Expenses payable during the corresponding period as reflected in the most recent Annual Budget.

"Obligations" means, with respect to any Person, any payment, performance or other obligation of such Person of any kind, including any liability of such Person on any claim, whether or not the right of any creditor to payment in respect of such claim is reduced to judgment, liquidated, unliquidated, fixed, contingent, matured, disputed, undisputed, legal, equitable, secured or unsecured, and whether or not such claim is discharged, stayed or otherwise affected by any Insolvency Proceeding.

"Officer's Certificate" means a certificate signed by an Authorized Officer.

"Operating and Maintenance Expenses" shall mean all actual cash maintenance, cost of goods sold and operation costs incurred by the Issuer, the Guarantors or their respective Restricted Subsidiaries in any particular calendar or fiscal year or period to which said term is applicable, including local taxes; ad valorem taxes; real estate taxes; insurance; consumables; payments under any lease, including leases; Fixed SMA Payments, other payments pursuant to the agreements for the management, operation and maintenance of any Project; payments made by the Issuer, the Guarantors or the Restricted Subsidiaries under any project document; legal fees and expenses paid by the Issuer, the Guarantors or the Restricted Subsidiaries in connection with the management, maintenance or operation of any Project; fees paid in connection with obtaining, transferring, maintaining or amending any Permit; fees payable in respect of letters of credit issued for the account of the Issuer, the Guarantors or the Restricted Subsidiaries (including under the Letter of Credit Documents), but exclusive in all cases of (a) noncash charges, including depreciation or obsolescence charges or reserves therefor, amortization of intangibles or other bookkeeping entries of a similar nature.

"Opinion of Counsel" means a written opinion from legal counsel who is reasonably acceptable to the Indenture Trustee that meets the requirements of the Indenture. Except as otherwise specified in the Indenture, the counsel may be counsel to the Issuer and the Guarantors and any Restricted Subsidiaries.

"Panama Stock Exchange" means the *Bolsa de Valores de Panama*.

"Panamanian Trust" means the trust created pursuant to the Panamanian Trust Agreement.

"Panamanian Trust Agreement" means the public deed No. 35,284 of November 26, 2014 of the Fifth Notary of the Circuit of Panama registered at Folio No. 30122089 and Entry 1, as modified by public deed No. 20,008 of December 10, 2014 of the Second Notary of the Circuit of Panama, registered at Folio 30122089 and Entry 2 and public deed No. 8477 of November 25, 2020 of the First Notary of the Circuit of Panama registered at Folio No. 30122089 and Entry 3, under the technical name of "The Bank of Nova Scotia (Panama), S.A./FID-135", as amended from time to time.

"Permit" means any authorization, consent, certification, determination, license, approval, permit, registrations, order, ruling, certification, identification number, exemption, notice, declaration or similar right, undertaking or other action of, to or by, or any filing, qualification or registration with, any Governmental Authority.

"Permitted Business" means the business of constructing, installing, operating and maintaining electricity generation plants based on renewable energy, with their respective connection lines to the transmission grid and transformation equipment, in order to produce and sell electricity in the Panamanian electricity system, and other businesses reasonably related or ancillary thereto.

"Permitted Holder" means any one or more of (a) the Sponsor, (b) any Qualified Investor and (c) any one or more Persons, together with such Persons' Affiliates, whose beneficial ownership constitutes or results in a Change of Control and in respect of which a Change of Control Offer is made if required in accordance with the requirements of the Indenture.

"Permitted Liens" means such of the following as to which no enforcement, collection, execution, levy or foreclosure proceeding shall have been commenced:

(a) Liens for taxes, not yet due or which are subject to contest;

(b) Liens securing judgments for the payment of money not constituting an Event of Default under clause (g) of "— Events of Default" or securing appeal or other surety bonds related to such judgments;

(c) Liens incurred in the ordinary course of business, including carriers', warehousemen's and mechanics' liens and other similar liens arising in the ordinary course of business or incidental to the construction, restoration, repair, replacement, rebuilding or improvement of the Projects with respect to obligations that are not due or that are being contested in good faith;

(d) pledges or deposits made in the ordinary course of business in connection with workers' compensation, unemployment insurance or other similar social security legislation or in connection with deposits or pledges to secure bids, tenders, contracts (other than contracts for the payment of money), leases, statutory obligations, surety and appeal bonds and other obligations of like nature;

(e) defects, easements, rights of way, restrictions, irregularities, encumbrances (other than for borrowed money) and clouds on title and statutory Liens that do not materially impair the value or use of the property affected and that do not individually or in the aggregate materially impair the validity, perfection or priority of the Liens granted under the Security Documents;

(f) any Liens created in favor of any of the Secured Parties under or pursuant to any Financing Document;

(g) with respect to any Restricted Subsidiary acquired by or merged into the Issuer and the Guarantors or any property acquired by the Issuer and the Guarantors or any Restricted Subsidiary or otherwise incorporated into any Project, pre-existing Liens that are extinguished within 60 days of the date of acquisition of the relevant property or incorporation of the same into the Project;

(h) [Reserved]

(i) Liens on any property of the Issuer, the Guarantors or any Restricted Subsidiary that does not constitute Collateral;

(j) Liens to secure Indebtedness permitted to be incurred pursuant to (A) clause (1), (2)(a), (b), (d) (provided such Indebtedness is incurred in respect of Secured Swap Contracts), (f) (*provided*, such Refinancing Debt is secured by Liens that secured the Indebtedness that is being refinanced), (h) (*provided* that such Lien (i) covers only on the assets so acquired or subject to lease and (ii) is created within 180 days of such acquisition or lease), and (m), in each case, of the covenant described under the caption "— Negative Covenants of the Issuer and the Guarantors and the Restricted Subsidiaries — Limitation on Indebtedness — The Issuer" and (B) clause (8), (provided that such Lien (i) covers only on the assets so acquired or subject to lease and (ii) is created within 180 days of such acquisition or lease and of the covenant described under the caption "— Negative Covenants of the Issuer and the Guarantors and the Restricted Subsidiaries — Limitation on Indebtedness — The Guarantors");

(k) Liens created by or resulting from any litigation or legal proceeding as to which the execution thereof has been effectively stayed while the underlying claims are being contested in good faith by appropriate proceedings or means;

(l) any interest or title of a lessor under any lease entered into by us in the ordinary course of business and covering only the assets so leased;

(m) any extension, renewal or replacement (or successive extensions, renewals or replacements), in whole or in part, of any Lien referred to in the foregoing clauses (a) through (l) or of any Indebtedness secured thereby; *provided* that the principal amount of Indebtedness so secured thereby shall not exceed the principal amount of Indebtedness so secured at the time of such extension, renewal or replacement (plus reasonable expenses incurred in connection therewith), and that such extension, renewal or replacement Lien shall be limited to all or part of the property that secured the Lien extended, renewed or replaced (plus improvements on or additions to such property).

"Permitted Swap Contracts" means (i) any Secured Swap Contract, (ii) the Citi Swap and (iii) any other Interest Rate Swap Contract or FX Swap Contract, in the case of (i) and (iii), entered into in the ordinary course of business for bona fide hedging purposes and not for speculative purposes by the Issuer, the Guarantors and the Restricted Subsidiaries, including, without limitation, in respect of financing transactions permitted under the Indenture.

"Person" means any natural person, corporation, limited liability Issuer, trust, joint venture, association, Issuer, partnership, Governmental Authority or other entity.

"Power Purchase Agreement" or "PPA" means each agreement for the supply of capacity and/or energy (*contrato de suministro de energía*), entered into by the Issuer or any Guarantor, as generator.

"Projected" means, with respect to any amount or ratio, such amount or ratio calculated by the Issuer and the Guarantors, in good faith, using assumptions that are consistent in all material respects with those used to calculate such amount or ratio on a historical basis in accordance with the Indenture. The term "project" as a verb has a corresponding meaning.

"Projected Cash Flow Available for Debt Service" means, for any period of four consecutive Fiscal Quarters ending after the relevant determination date, (without duplication) revenues (both operating and non-operating), *minus* sales, general and administrative expenses, *minus* operating expenses, plus/minus any differences in working capital, in each case, projected for the Issuer and the Guarantors for such in accordance with Issuer's Financial Model and calculated on a Combined Basis.

"Projected Operating Expenses" means 100% of the projected Operating and Maintenance Expenses for the Issuer and the Guarantors and the Restricted Subsidiaries included in the then-applicable Annual Budget.

"Projects" has the meaning given to it in the Intercreditor Agreement.

"Prudent Industry Practices" means those practices, methods, techniques and standards that are generally accepted, as they may change from time to time, for use in the international electric energy industry and commonly used in safe and prudent electric energy engineering and operations to design, engineer, construct, test, operate and maintain equipment similar to the Projects.

"Qualified Investor" means any Person (whether directly or indirectly through one or more of its Subsidiaries or, in the case of a fund, one or more funds under management by the same fund manager), that at the time it acquires an interest in the Issuer or the Guarantors:

(1) (A) has a tangible net worth or assets under management of at least U.S.$750.0 million or (B) the ratings (from at least two of S&P, Moody's or Fitch) of the unsecured senior indebtedness of such Person are at least "BBB" from S&P or Fitch and "Baa2" from Moody's; and

(2) either (A) together with its Affiliates, directly or indirectly, owns and manages or operates at least 250 MW of renewable and low-carbon emission power generating assets relating to one or more projects or (B) has contracted with a third party to manage and operate the business and operations of the Issuer and/or Guarantors and/or any of their Restricted Subsidiaries that, together with the Affiliates of such third party, satisfies the requirements set forth in the preceding clause 2(A).

"Quarterly Date" means the first day of January, April, July and October of each year.

"Quarterly Period" means the period commencing on any Quarterly Date through (but excluding) the next succeeding Quarterly Date.

"Rating" means the then-current credit rating of the Notes by a Rating Agency.

"Rating Agency" means Fitch, S&P, Moody's or any other nationally recognized United States rating agency.

"Rating Date" means in connection with a Change of Control Repurchase Event, the date that is 90 days prior to the earlier of (a) the occurrence of a Change of Control or (b) public notice of the occurrence of a Change of Control or of the intention of the Issuer and the Guarantors or any other Person or Persons to effect a Change of Control.

"Ratings Affirmation" means, in the case of any event or proposed event, an affirmation by each Rating Agency then rating the Notes (unless less than all the Rating Agencies then rating the Notes is specified in the applicable condition), that its Rating of the Notes will not be lower immediately after giving effect to the event or proposed event.

"Ratings Decline" means in connection with a Change of Control Repurchase Event, the occurrence, on or within 90 days after the earlier to occur of public notice of (a) the occurrence of a Change of Control and (b) the intention by the Issuer and the Guarantors or any other Person or Persons to effect a Change of Control (which period will be extended for so long as any of the Rating Agencies has publicly announced that it is considering a possible ratings change as a result of a Change of Control), of any of the events listed below:

(i) in the event the Notes have an Investment Grade Rating by each Rating Agency on the Rating Date, the rating of the Notes by any Rating Agency will be changed to below an Investment Grade Rating;

(ii) in the event the Notes have an Investment Grade Rating by any, but not all, of the Rating Agencies on the Rating Date, the rating of the Notes by any Rating Agency that gave the Notes an Investment Grade Rating on the Rating Date will be changed to below an Investment Grade Rating; or

(iii) in the event the Notes are rated below an Investment Grade Rating by each Rating Agencies on the Rating Date, the rating of the Notes by any such Rating Agency will be decreased by one or more gradations (including gradations within rating categories as well as between rating categories),

provided, *however*, that (i) any such Ratings Decline is in whole or in part related to or in connection with a Change of Control and (ii) any such Ratings Decline will not be considered to be attributable to a Change of Control if, before such Ratings Decline, the Issuer and the Guarantors or any Person intending to acquire Control of the Issuer and the Guarantors has obtained a Ratings Affirmation stating that such Change of Control will not cause a Ratings Decline.

"Reference Rate" means a fixed interest rate equal to the weighted average of the fixed interest rates applicable to any existing Indebtedness of the Issuer and the Guarantors (after taking account any fixed rate payable by the Issuer, the Guarantors or a Restricted Subsidiary under any Swap Contract entered into in relation to such Indebtedness) in effect on the date of determination.

"Refinancing Debt" means Indebtedness of the Issuer and the Guarantors or a Restricted Subsidiary, as applicable, incurred in exchange for or to refinance, in whole or in part, existing Indebtedness of the Issuer and the Guarantors or any Restricted Subsidiary, as applicable.

"Regulation S Global Notes" has the meaning set forth in "Book-Entry; Settlement and Clearance" in this Offering Memorandum.

"Relevant Fraction" means, with respect to the applicable calculation date, (a) with respect to interest payments, one divided by the number of months that comprise the then applicable interest period, or (b) with respect to payments of any other amounts other than interest, one divided by the months comprised between the relevant calculation date and the date in which such payment becomes due and payable.

"Replacement Assets" means (1) non-current assets that will be used or useful in a Permitted Business, (2) substantially all the assets of a Permitted Business or (3) a majority of the Voting Interests of any Person engaged in a Permitted Business that will become on the date of acquisition thereof a Restricted Subsidiary.

"Required Secured Debtholders" has the meaning given to it in the Intercreditor Agreement.

"Responsible Officer" means (a) with respect to any agent, any officer within the corporate trust or agency department of such agent including any vice president, assistant vice president, treasurer, assistant treasurer, trust officer or any other officer of such agent who (i) customarily performs functions similar to those performed by the persons who at the time shall be such officers, respectively, or to whom any corporate trust matter is referred because of such person's knowledge of and familiarity with the particular subject and (ii) shall have direct responsibility for the administration of the Financing Documents to which such agent is a party, and (b) with respect to any other Person, the chief executive officer, the president, chief financial officer, general counsel, treasurer or assistant treasurer of a Person. Any document delivered hereunder that is signed by a Responsible Officer of any Person shall be conclusively presumed to have been authorized by all necessary corporate, trust, partnership and/or other action on the part of such Person and such Responsible Officer shall be conclusively presumed to have acted on behalf of such Person.

"Restricted Payment" means:

(a) any dividend or other payment or distribution (whether in cash, securities or other property) with respect to the Equity Interests in the Issuer and the Guarantors or Equity Interests in any Restricted Subsidiaries of the Issuer and the Guarantors other than any such dividend, payment or distribution made to the Issuer and the Guarantors or any of the Restricted Subsidiaries, or any payment (whether in cash, securities or other property), including any sinking fund or similar deposit, on account of the purchase, redemption, retirement, acquisition, cancellation or termination of any Equity Interests in the Issuer and the Guarantors held by any Person other than a Restricted Subsidiary or Equity Interests in any Restricted Subsidiaries held by any Person other than the Issuer and the Guarantors or any other Restricted Subsidiary or any option, warrant or other right to acquire any Equity Interests in the Issuer and the Guarantors or any of the Restricted Subsidiaries;

(b) any payment in respect of or any purchase, retirement, redemption or other acquisition by the Issuer and the Guarantors or any of the Restricted Subsidiaries of any subordinated Indebtedness or any Indebtedness owed to an Affiliate of the Issuer and the Guarantors (other than a Restricted Subsidiary) or any Indebtedness or deposit or similar transaction made to secure any loan or other financial obligation of any Affiliate of the Issuer and the Guarantors (including subordinated Indebtedness) or payment of fees or interest in respect of any of the foregoing;

(c) any loan to any Affiliate of the Issuer and the Guarantors and (ii) to any of the Restricted Subsidiaries if from the Issuer and the Guarantors and to the Issuer and the Guarantors if from any of the Issuer and the Guarantors Subsidiaries; or

(d) any payment (whether in cash, securities or other property) by the Issuer and the Guarantors to any Affiliate of the Issuer and the Guarantors (other than to any of the Restricted Subsidiaries) or by any of the Issuer and the Guarantors Subsidiaries to any Affiliate of any such Restricted Subsidiary (other than to the Issuer and the Guarantors or any of the Issuer and the Guarantors other Restricted Subsidiaries), in each case with respect to the development, management or operation of the business of the Issuer and the Guarantors and the Restricted Subsidiaries (other than fees, costs, expenses or other amounts required to be paid pursuant to the terms of any contract or agreement entered into by the Issuer and the Guarantors or any of the Restricted Subsidiaries with an Affiliate in accordance with the terms and conditions set forth in "— Negative Covenants of the Issuer and the Guarantors and the Restricted Subsidiaries — Limitation on Transactions with Affiliates").

"Restricted Payment Date" means any date on which the Issuer, the Guarantors or any of the Restricted Subsidiaries declares or makes any Restricted Payment during the Restricted Payment Period.

"Restricted Payment Period" means each thirty (30) day period following each Scheduled Payment Date.

"Restricted Subsidiary" mean any Subsidiary of the Issuer or the Guarantors other than an Unrestricted Subsidiary.

"Rule 144A Global Notes" has the meaning set forth in "Book-Entry; Settlement and Clearance" in this Offering Memorandum.

"S&P" means S&P Global Ratings and any successor to its rating agency business.

"SBP" means the *Superintendencia de Bancos de Panamá*.

"Scheduled Payment Date" means April 1 and October 1 of each year, in each case following the Issue Date; *provided* that if any such date is not a Business Day, then such day will not be a payment date and such Scheduled Payment Date will be the first preceding Business Day.

"Secured Debt Documents" has the meaning given to it in the Intercreditor Agreement.

"Secured Debtholders" has the meaning given to it in the Intercreditor Agreement.

"Secured Indenture Obligations" means all advances to, and debts, liabilities, Obligations, covenants and duties of, the Issuer and the Guarantors under the Indenture or otherwise with respect to the Notes, whether direct or indirect (including those acquired by assumption), absolute or contingent, due or to become due, now existing or hereafter arising and including interest and fees that accrue after the commencement by or against the Issuer and the Guarantors thereof of any Insolvency Proceeding naming the Issuer and the Guarantors as the debtor in such proceeding, regardless of whether such interest and fees are allowed claims in such proceeding. Without limiting the generality of the foregoing, the Secured Indenture Obligations of the Issuer and the Guarantors under the Indenture (and, with respect to the Intercreditor Agreement, insofar as they relate to the Indenture) include the obligation to pay principal, interest, expenses, fees, attorney costs, consultants costs, indemnities and other amounts payable by the Issuer and the Guarantors under the Indenture.

"Secured Letter of Credit Obligations" has the meaning given to "Letter of Credit Obligations" in the Intercreditor Agreement.

"Secured Obligations" means (a) the Secured Letter of Credit Obligations, (b) the Secured Indenture Obligations, (c) the Additional Secured Debt Obligations, (d) the Obligations of the Issuer and its Restricted Subsidiaries, as applicable, under any Secured Swap Contracts in respect of any Additional Debt Obligations not otherwise covered in clauses (a) and (c) above, and (e) the obligation of the Issuer and the Guarantors to reimburse any amount in respect of any of the foregoing that any Secured Party, in its sole discretion, may elect to pay or advance on behalf of the Issuer and the Guarantors as well as any costs and expenses incurred by any Secured Party necessary or desirable in order to perfect and protect the first priority liens and security interests created under the Security Documents.

"Secured Parties" has the meaning given to it in the Intercreditor Agreement.

"Secured Swap Contracts" means any Interest Rate Swap Contract or FX Swap Contract that is secured by a Lien over the Collateral and entered into by any the Issuer, the Guarantors or a Restricted Subsidiary and a Secured Swap Counterparty in accordance with the terms of the Indenture or any Additional Secured Debt Documents (as applicable) entered into in connection with Indebtedness that is allowed to be so secured by the Collateral; *provided* the Citi Swap shall not be a Secured Swap Contract.

"Secured Swap Counterparty" means any Person (other than the Borrower or its Affiliate) that is Lender under the Secured Debt Documents or a lender under and as defined in the Additional Secured Debt Documents (as applicable), in each case, at the time it enters into a Secured Swap Contract with the Issuer, the Guarantors or a Restricted Subsidiary in accordance with the Secured Debt Documents or the Additional Secured Debt Documents (as applicable).

"Security Documents" has the meaning given to it in the Intercreditor Agreement.

"Series" has the meaning given to it in the Intercreditor Agreement.

"SGX-ST" means the Singapore Exchange Securities Trading Limited.

"SMV" means the *Superintendencia del Mercado de Valores de Panamá*.

"Sponsor" means, InterEnergy Group Ltd. and any of its respective Affiliates.

"Sponsor Services Agreements" means, collectively, the (a) the Management Services Agreement dated January 1, 2020 by and between the Issuer and IEH UK and (b) Management Services Agreement dated February 1, 2020 by and between the Guarantors and IEH UK.

"Stated Maturity" means, with respect to any security, the date specified in such security as the fixed date on which the principal of such security is due and payable, including pursuant to any mandatory redemption provision (but excluding any provision providing for the repurchase of such security at the option of the holder thereof upon the happening of any contingency unless such contingency has occurred).

"Subordinated Debt" means unsecured Indebtedness of the Issuer, the Guarantors or the Restricted Subsidiaries on terms and conditions that make (i) the payment of principal and interest and any other amounts available only from funds that are available to be distributed as Restricted Payments when the conditions for the making of Restricted Payments have been satisfied, (ii) in the event that any principal, interest, fees, premiums, charges or any other amounts under any such Indebtedness is not paid on the stated maturity or other date set for redemption, then the obligation to make such payment on such maturity date or other redemption date will not be a default under such Indebtedness until after the maturity date of the Notes, and (iii) the terms of which provide that no amount will be payable in bankruptcy, liquidation or any similar proceeding with respect to the debtor until all claims of senior creditors of the debtor, including, without limitation, the holders of the Notes, admitted in such proceeding have been satisfied. No such Indebtedness of the Issuer, the Guarantors and the Restricted Subsidiaries shall constitute Subordinated Debt until such time as the relevant subordinated lender shall have executed and delivered a Subordination Agreement.

"Subordination Agreement" shall mean a subordination agreement, entered into between each provider of Subordinated Debt, the Issuer and the Guarantors, as applicable, and the Collateral Trustee, that includes all terms and conditions reasonably required for any Debt of the Issuer, the Guarantors and/or the Restricted Subsidiaries to constitute "Subordinated Debt".

"Subsidiary" means, with respect to any Person:

(1) a corporation a majority of whose Voting Interests is at the time owned or controlled, directly or indirectly, by such Person, one or more Subsidiaries thereof or such Person and one or more Subsidiaries thereof; and

(2) any other Person (other than a corporation), including, without limitation, a partnership, limited liability company, business trust or joint venture, in which such Person, one or more Subsidiaries thereof or such Person and one or more Subsidiaries thereof, directly or indirectly, at the date of determination thereof, has at least majority ownership interest entitled to vote in the election of directors, managers or trustees thereof (or other Person performing similar functions).

"Swap Contract" means (a) any and all rate swap transactions, basis swaps, credit derivative transactions, forward rate transactions, commodity swaps, commodity options, forward commodity contracts, equity or equity index swaps or options, bond or bond price or bond index swaps or options, forward bond or forward bond price or forward bond index transactions, interest rate options, forward foreign exchange transactions, cap transactions, floor transactions, collar transactions, currency swap transactions, cross-currency rate swap transactions, currency options, spot contracts, or any other similar transactions, or any combination of any of the foregoing (including any options to enter into any of the foregoing), whether or not any such transaction is governed by or subject to any master agreement, and (b) any and all transactions of any kind, and the related confirmations, which are subject to the terms and conditions of, or governed by, any form of master agreement published by the International Swaps and Derivatives Association, Inc., any International Foreign Exchange Master Agreement, or any other master agreement (any such master agreement, together with any related schedules, a "Master Agreement"), including any such obligations or liabilities under any Master Agreement, in each case entered into in compliance with the requirements of the Indenture and the Intercreditor Agreement.

"Swap Settlement Payment" means the amount of any ordinary course or regularly scheduled payment payable in respect of any Swap Contract calculated in accordance with the terms of such Swap Contract, and excluding any Swap Termination Payment.

"Swap Termination Payment" means the amount of any swap breakage or termination payment payable in respect of any Swap Contract upon termination thereof or partial termination thereof, calculated in accordance with the terms of such Swap Contract.

"Swap Counterparty" means (a) with respect to any Interest Rate Swap Contract, any Person that is a Lender or any Affiliate thereof at the time it enters into such Interest Rate Swap Contract and (b) with respect to any FX Swap Contract, any Person that is an Acceptable Bank.

"Swap Termination Value" means, in respect of any Swap Contract, after taking into account the effect of any legally enforceable netting agreement relating to such Swap Contract, (a) for any date on or after the date such Swap Contract have been closed out and termination value determined in accordance therewith, such termination value, and (b) for any date prior to the date referenced in clause (a), the termination value determined in accordance with the terms of such Swap Contract as if such Swap Contract were terminated on such date with both parties as affected parties (under and as defined in such Swap Contract).

"Transfer Period" means any period starting on (and including) a Monthly Transfer Date and ending on (but *excluding*) the immediately succeeding Monthly Transfer Date.

"Trust O&M Reserve Account" has the meaning given to it in the Panamanian Trust Agreement.

"UCC" means the Uniform Commercial Code as in effect from time to time in the State of New York.

"Unrestricted Subsidiary" means any Subsidiary of the Issuer and the Guarantors that shall have been designated an Unrestricted Subsidiary by the board of directors of the Issuer and the Guarantors. The board of directors of the Issuer and the Guarantors may designate any Subsidiary of the Issuer and the Guarantors (including any newly acquired or newly formed Subsidiary or a Person becoming a Subsidiary through merger, consolidation or other business combination transaction, or Investment therein), to be an Unrestricted Subsidiary only if:

(1) such Subsidiary has no Indebtedness other than Non-Recourse Debt;

(2) the aggregate Fair Market Value of all outstanding Investments owned by the Issuer and the Guarantors and the Restricted Subsidiaries in the Subsidiary being so designated (including any Guarantee by the Issuer and the Guarantors or any Restricted Subsidiary of any Indebtedness of such Subsidiary) will be deemed to be an Investment made as of the time of such designation and that such Investment would be permitted under the covenant described above under the caption "— Negative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries — Limitation on Investments";

(3) such Subsidiary does not hold any capital stock or Indebtedness of, or own or hold any Lien on any property or assets of, or have any Investment in, the Issuer and the Guarantors or any Restricted Subsidiary;

(4) the Subsidiary being so designated:

    (a) is not party to any agreement, contract, arrangement or understanding with the Issuer and the Guarantors or any Restricted Subsidiary unless the terms of any such agreement, contract, arrangement will be permitted under the covenant described above under "— Negative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries — Limitation on Transactions with Affiliates";

    (b) is a Person with respect to which neither the Issuer and the Guarantors nor any Restricted Subsidiary has any direct or indirect obligation (i) to subscribe for additional Equity Interests or (ii) to maintain or preserve such Person's financial condition or to cause such Person to achieve any specified levels of operating results; and

(c) has not Guaranteed or otherwise directly or indirectly provided credit support for any Indebtedness of the Issuer and the Guarantors or any Restricted Subsidiary, except to the extent such Guarantee or credit support would be released upon such designation; and

(5) no Default or Event of Default would be in existence following such designation.

The Board of Directors of the Issuer and the Guarantors may at any time designate any Unrestricted Subsidiary to be a Restricted Subsidiary; *provided* that:

(1) such designation will be deemed to be an Incurrence of Indebtedness by a Restricted Subsidiary of any outstanding Indebtedness of such Unrestricted Subsidiary and such designation will only be permitted if such Indebtedness is permitted under the covenant described under the caption "— Negative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries — Limitation on Indebtedness";

(2) all Liens upon property or assets of such Unrestricted Subsidiary existing at the time of such designation would be permitted under the covenant described under the caption "— Negative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries — Limitation on Liens";

(3) all outstanding Investments owned by such Unrestricted Subsidiary will be deemed to be made as of the time of such designation and such designation will only be permitted if such Investments would be permitted under the covenant described above under the caption "— Negative Covenants of the Issuer and the Guarantors and their respective Restricted Subsidiaries — Limitation on Investments"; and

(4) no Default or Event of Default would be in existence following such designation. Any such designation by the board of directors of the Issuer and the Guarantors shall be evidenced to the Indenture Trustee by promptly filing with the Indenture Trustee a copy of the resolution of the board of directors of the Issuer and the Guarantors giving effect to such designation and an Officer's Certificate certifying that such designation complied with the foregoing provisions.

On the Issue Date, there will be no Unrestricted Subsidiaries.

"Unscheduled Operating and Maintenance Expenses" means the amount needed to fund the cost of any reasonably necessary unscheduled repair, replacement, refurbishing or restoration of any property or equipment comprising or relating to any Project or unscheduled Required Modification that was not previously included in the Annual Budget, provided that in the event Unscheduled Operating and Maintenance Expenses exceed the amount in the Trust O&M Reserve Account an Officer's Certificate to the effect that in the opinion of such officer such expenses are reasonably necessary shall be provided.

"US Government Securities" means securities that are direct obligations of the United States of America for the timely payment of which its full faith and credit is pledged.

"Voting Interests" means shares of capital stock issued by a corporation, or equivalent Equity Interests in any other Person, the holders of which are ordinarily, in the absence of contingencies, entitled to vote for the election of directors (or persons performing similar functions) of such Person, even if the right to so vote has been suspended by the happening of such a contingency.

"Voting Party Percentage" has the meaning given to it in the Intercreditor Agreement.

"Year" means, as of any date of determination, the period commencing on such date and ending on the next succeeding December 31 and, thereafter, each period commencing on January 1 in any calendar year and ending on the next succeeding December 31.

BOOK-ENTRY; SETTLEMENT AND CLEARANCE

The Notes are being offered and sold to qualified institutional buyers in reliance on Rule 144A ("Rule 144A Notes"). Notes also may be offered and sold in offshore transactions in reliance on Regulation S ("Regulation S Notes"). Notes will be issued at the closing of this offering only against payment in immediately available funds.

Rule 144A Notes will be represented by one or more Notes in registered, global form without interest coupons (collectively, the "Rule 144A Global Notes"). Regulation S Notes will be represented by one or more Notes in registered, global form without interest coupons (collectively, the "Regulation S Global Notes" and, together with the Rule 144A Global Notes, the "Global Notes").

The Global Notes will be deposited upon issuance with the Trustee as custodian for DTC, in New York, New York, and registered in the name of DTC or its nominee, in each case, for credit to an account of a direct or indirect participant in DTC as described below. Through and including the 40th day after the later of the commencement of this offering and the closing of this offering (such period through and including such 40th day, the "restricted period"), beneficial interests in the Regulation S Global Notes may be transferred to a person that takes delivery through a Rule 144A Global Notes in accordance with the certification requirements described below.

Beneficial interests in the Rule 144A Global Notes may not be exchanged for beneficial interests in the Regulation S Global Notes at any time except in the limited circumstances described below. See "— Exchanges Between Regulation S Notes and Rule 144A Notes."

Except as set forth below, the Global Notes may be transferred, in whole and not in part, only to another nominee of DTC or to a successor of DTC or its nominee. Beneficial interests in the Global Notes may not be exchanged for Notes in certificated form except in the limited circumstances described below. See "— Exchange of Global Notes for Certificated Notes." Except in the limited circumstances described below, owners of beneficial interests in the Global Notes will not be entitled to receive physical delivery of Notes in certificated form.

In addition, transfers of beneficial interests in the Global Notes will be subject to the applicable rules and procedures of DTC and its direct or indirect participants (including, if applicable, those of Euroclear, Clearstream and Latinclear), which may change from time to time. Transfers between participants in Euroclear, Clearstream or LatinClear will be effected in the ordinary way under the rules and operating procedures of those systems.

Depository Procedures

The following description of the operations and procedures of DTC, Euroclear, Clearstream and Latinclear is provided solely as a matter of convenience. These operations and procedures are solely within the control of the respective settlement systems and are subject to changes by them. We take no responsibility for these operations and procedures and urge investors to contact the system or their participants directly to discuss these matters. DTC has advised us that DTC is a limited purpose trust company created to hold securities for its participating organizations (collectively, the "participants") and to facilitate the clearance and settlement of transactions in those securities between participants through electronic book entry changes in accounts of its participants. The participants include securities brokers and dealers (including the Initial Purchaser), banks, trust companies, clearing corporations and certain other organizations. Access to DTC's system is also available to other entities such as banks, brokers, dealers and trust companies that clear through or maintain custodial relationship with a participant, either directly or indirectly (collectively, the "indirect participants"). Persons who are not participants may beneficially own securities held by or on behalf of DTC only through the participants or the indirect participants. The ownership interests in, and transfers of ownership interests in, each security held by or on behalf of DTC are recorded on the records of the participants and indirect participants.

DTC has also advised us that, pursuant to procedures established by it:

1. upon deposit of the Global Notes, DTC will credit the accounts of participants designated by the Initial Purchaser with portions of the principal amount of the Global Notes; and

2. ownership of these interests in the Global Notes will be shown on, and the transfer of ownership of these interests will be effected only through, records maintained by DTC (with respect to the participants) or by the participants and the indirect participants (with respect to other owners of beneficial interests in the Global Notes).

Investors in the Global Notes may hold their interests therein directly through DTC or through organizations (including Euroclear, Clearstream and LatinClear) which are participants in such system. Euroclear, Clearstream and LatinClear will hold interests in the Global Notes on behalf of their participants through customers' securities accounts in their respective names on the books of their respective depositories. All interests in a Global Note, including those held through Euroclear, Clearstream or LatinClear, may be subject to the procedures and requirements of DTC. Those interests held through Euroclear, Clearstream or LatinClear may also be subject to the procedures and requirements of such systems. The laws of some states require that certain persons take physical delivery in definitive form of securities that they own.

Consequently, the ability to transfer beneficial interests in a Global Note to such persons will be limited to that extent. Because DTC can act only on behalf of participants, which in turn act on behalf of indirect participants, the ability of a person having beneficial interests in a Global Note to pledge such interests to persons that do not participate in the DTC system, or otherwise take actions in respect of such interests may be affected by the lack of a physical certificate evidencing such interests.

Except as described below, owners of interests in the Global Notes will not have Notes registered in their names, will not receive physical delivery of Notes in certificated form and will not be considered the registered owners or "holders" thereof under the Indenture for any purpose.

Payments in respect of the principal of, and interest and premium and additional amounts, if any, on a Global Note registered in the name of DTC or its nominee will be payable to DTC in its capacity as the registered holder under the Indenture. Under the terms of the Indenture, the Issuer and the Indenture Trustee will treat the persons in whose names the notes, including the global Notes, are registered as the owners of the Notes for the purpose of receiving payments and for all other purposes.

Consequently, neither the Issuer, the Indenture Trustee, the Transfer Agent, Registrar, the Paying Agent nor any agent of the Issuer, nor the Indenture Trustee has or will have any responsibility or liability for:

1. any aspect of DTC's records or any participant's or indirect participant's records relating to or payments made on account of beneficial ownership interest in the Global Notes or for maintaining, supervising or reviewing any of DTC's records or any participant's or indirect participant's records relating to the beneficial ownership interests in the Global Notes; or

2. any other matter relating to the actions and practices of DTC or any of its participants or indirect participants.

DTC has advised us that its current practice, upon receipt of any payment in respect of securities such as the Notes (including principal and interest) is to credit the accounts of the relevant participants with the payment on the payment date unless DTC has reason to believe it will not receive payment on such payment date. Each relevant participant is credited with an amount proportionate to its beneficial ownership of an interest in the principal amount of the relevant security as shown on the records of DTC. Payments by the participants and the indirect participants to the beneficial owners of Notes will be governed by standing instructions and customary practices and will be the responsibility of the participants or the indirect participants and will not be our responsibility or that of DTC or the Indenture Trustee. Neither the Issuer nor the Indenture Trustee will be liable for any delay by DTC or any of its participants in identifying the beneficial owners of the Notes, and the Issuer and the Indenture Trustee may conclusively rely on and will be protected in relying on instructions from DTC or its nominee for all purposes.

Subject to the transfer restrictions set forth under "Transfer Restrictions," transfers between participants in DTC will be effected in accordance with DTC's procedures, and will be settled in same-day funds, and transfers between participants in Euroclear, Clearstream and LatinClear will be effected in accordance with their respective rules and operating procedures.

Subject to compliance with the transfer restrictions applicable to the Notes described herein, cross-market transfers between the participants in DTC, on the one hand, and Euroclear, Clearstream or LatinClear participants, on the other hand, will be effected through DTC in accordance with DTC's rules on behalf of Euroclear, Clearstream or LatinClear, as the case may be, by its respective depositary; however, such cross market transactions will require delivery of instructions to Euroclear, Clearstream or LatinClear, as the case may be, by the counter-party in such system in accordance with the rules and procedures and within the established deadlines of such system. Euroclear, Clearstream or LatinClear, as the case may be will, if the transaction meets its settlement requirements, deliver instructions to its respective depositary to take action to effect final settlement on its behalf of delivering or receiving interests in the relevant Global Note in DTC, and making or receiving payment in accordance with normal procedures for same-day funds settlement applicable to DTC. Euroclear participants, Clearstream participants and LatinClear participants may not deliver instructions directly to the depositories for Euroclear, Clearstream or LatinClear. DTC has advised us that it will take any action permitted to be taken by a holder of Notes only at the direction of one or more participants to whose account DTC has credited the interests in the Global Notes and only in respect of such portion of the aggregate principal amount of the Notes as to which such participant or participants has or have given such direction. However, if there is an event of default under the Notes, DTC reserves the right to exchange the Global Notes for legended Notes in certificated form, and to distribute such Notes to its participants.

Although DTC, Euroclear, Clearstream and LatinClear have agreed to the foregoing procedures to facilitate transfers of interests in the Rule 144A Global Notes and the Regulation S Global Notes among participants in DTC, Euroclear, Clearstream and LatinClear, they are under no obligation to perform or to continue to perform such procedures, and may discontinue such procedures at any time. Neither the Issuer nor the Trustee nor any of their respective agents will have any responsibility for the performance by DTC, Euroclear, Clearstream or LatinClear or their respective participants or indirect participants of their respective obligations under the rules and procedures governing their operations.

Exchange of Global Notes for Certificated Notes

A Global Note is exchangeable for definitive Notes in registered certificated form ("certificated notes") if:

1. DTC (a) notifies the Issuer that it is unwilling or unable to continue as depositary for the Global Notes and DTC fails to appoint a successor depositary or (b) has ceased to be a clearing agency registered under the Exchange Act;

2. The Issuer, at its option, notifies the Indenture Trustee in writing that it has elected to cause the issuance of the certificated notes; or

3. there has occurred and is continuing a Default or Event of Default with respect to the Notes.

In addition, beneficial interests in a Global Note may be exchanged for certificated Notes upon prior written notice given to the Indenture Trustee by or on behalf of DTC in accordance with the Indenture. In all cases, certificated Notes delivered in exchange for any Global Note or beneficial interests in Global Notes will be registered in the names, and issued in any approved denominations, requested by or on behalf of the depositary (in accordance with its customary procedures) and will bear the applicable restrictive legend referred to in "Transfer Restrictions," unless that legend is not required by applicable law.

Exchanges Between Regulation S Notes and Rule 144A Notes

Beneficial interests in the Regulation S Global Notes may be exchanged for beneficial interests in the Rule 144A Global Notes only if:

1. such exchange occurs in connection with a transfer of the Notes pursuant to Rule 144A; and

2. the transferor first delivers to the Indenture Trustee a written certificate (in the form provided in the Indenture) to the effect that the Notes are being transferred to a person:

    a. who the transferor reasonably believes to be a qualified institutional buyer within the meaning of Rule 144A purchasing for its own account or the account of a qualified institutional buyer in a transaction meeting the requirements of Rule 144A; and

b. in accordance with all applicable securities laws of the states of the United States and other jurisdictions.

Beneficial interests in a Rule 144A Global Notes may be transferred to a person who takes delivery in the form of an interest in the Regulation S Global Notes, whether before or after the expiration of the restricted period, only if the transferor first delivers to the Indenture Trustee a written certificate (in the form provided in the Indenture) to the effect that such transfer is being made in accordance with Rule 903 or 904 of Regulation S.

Transfers involving exchanges of beneficial interests between the Regulation S Global Notes and the Rule 144A Global Notes will be effected in DTC by means of an instruction originated by the DTC participant and approved by the Indenture Trustee through the DTC Deposit/ Withdraw at Custodian system.

Accordingly, in connection with any such transfer, appropriate adjustments will be made to reflect a decrease in the principal amount of the Regulation S Global Note and a corresponding increase in the principal amount of the Rule 144A Global Notes or vice versa, as applicable. Any beneficial interest in one of the Global Notes that is transferred to a person who takes delivery in the form of an interest in the other Global Note will, upon transfer, cease to be an interest in such Global Note and will become an interest in the other Global Note and, accordingly, will thereafter be subject to all transfer restrictions and other procedures applicable to beneficial interest in such other Global Note for so long as it remains such an interest. Transfers between Regulation S and Rule 144A Notes will need to be done on a delivery free of payment basis and separate arrangements will need to be made outside of DTC for payment.

The Depository Trust Company

DTC is a limited-purpose trust company organized under the New York Banking Law; a “banking organization” under the New York Banking Law; a member of the Federal Reserve System; a “clearing corporation” under the New York Uniform Commercial Code; and a “clearing agency” registered under Section 17A of the Exchange Act.

DTC was created to hold securities for its participants and facilitate the clearance and settlement of securities transactions between its participants. It does this through electronic book-entry settlement in the accounts of its direct participants, eliminating the need for physical movement of securities certificates. DTC is owned by a number of its direct participants and by the NYSE Euronext, the American Stock Exchange, Inc. and the Financial Industry Regulatory Authority, Inc. (successor to the National Association of Securities Dealers, Inc.).

DTC can act only on behalf of its direct participants, who in turn act on behalf of indirect participants and certain banks. In addition, unless a global security is exchanged in whole or in part for a definitive security, it may not be physically transferred, except as a whole among DTC, its nominees and their successors. Therefore, your ability to pledge a beneficial interest in the global security to persons that do not participate in the DTC system, and to take other actions, may be limited because you will not possess a physical certificate that represents your interest.

Euroclear

Euroclear was created as a cooperative in 1968 to hold securities for Euroclear Participants, as defined below, and to clear and settle transactions between Euroclear Participants through simultaneous electronic book-entry delivery against payment, thereby eliminating the need for physical movement of securities and any risk from lack of simultaneous transfers of securities and cash. Euroclear provides various other services, including securities lending and borrowing and interfaces with domestic markets in several countries. All operations are conducted by the Euroclear Bank, and all Euroclear securities clearance accounts and Euroclear cash accounts are accounts with the Euroclear Bank, not the cooperative. The cooperative establishes policy for Euroclear on behalf of Euroclear Participants. Euroclear Participants include banks (including central banks), securities brokers and dealers and other professional financial intermediaries and may include the Sole Lead Manager and Structuring Agent (“Euroclear Participants”). Indirect access to

Euroclear is also available to other firms that clear through or maintain a custodial relationship with Euroclear Participants, either directly or indirectly. Euroclear is located at 1 Boulevard du Roi Albert II, B-1210 Brussels, Belgium.

Securities clearance accounts and cash accounts with Euroclear Bank are governed by the Terms and Conditions Governing Use of Euroclear and the related Operating Procedures of the Euroclear System, and applicable Belgian law (collectively, the "Euroclear Terms and Conditions"). The Euroclear Terms and Conditions govern transfers of securities and cash within Euroclear, withdrawals of securities and cash from Euroclear and receipts of payment with respect to securities in Euroclear. All securities in Euroclear are held on a fungible basis without attribution of specific certificates to specific securities clearance accounts. Euroclear Bank acts under the Euroclear Terms and Conditions only on behalf of Euroclear Participants and has no record of or relationship with persons holding through Euroclear Participants.

The ability of an owner of a beneficial interest in the Regulation S Notes to pledge such interest to persons or entities that do not participate in the Euroclear system, or otherwise take actions in respect of such interest, may be limited by the lack of a definitive note for such interest because Euroclear can act only on behalf of Euroclear Participants, who in turn act on behalf of indirect Euroclear Participants and certain banks.

Distributions with respect to the Notes held beneficially through Euroclear will be credited to the cash accounts of Euroclear Participants in accordance with the Euroclear Terms and Conditions, to the extent received by the Euroclear Bank and by Euroclear.

Clearstream

Clearstream is incorporated under the laws of Luxembourg as a professional depository. Clearstream holds securities for Clearstream Participants, as defined below, and facilitates the clearance and settlement of securities transactions between Clearstream Participants through electronic book-entry changes in accounts of Clearstream Participants, thereby eliminating the need for physical movement of securities. Clearstream provides to Clearstream Participants, among other things, services for safekeeping, administration, clearance and settlement of internationally traded securities and securities lending and borrowing. Clearstream interfaces with domestic markets in several countries. As a professional depository, Clearstream is subject to regulation by the Luxembourg Monetary Institute.

Clearstream Participants are recognized financial institutions around the world, including underwriters, securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations and may include the Sole Lead Manager and Structuring Agent ("Clearstream Participants"). Indirect access to Clearstream is also available to others, such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a Clearstream Participant either directly or indirectly. Clearstream is located at 42 Avenue JF Kennedy, L-1855 Luxembourg, Luxembourg.

The ability of an owner of a beneficial interest in the Regulation S Notes to pledge such interest to persons or entities that do not participate in the Clearstream system, or otherwise take actions in respect of such interest, may be limited by the lack of a definitive note for such interest because Clearstream can act only on behalf of Clearstream Participants, who in turn act on behalf of indirect Clearstream Participants and certain banks.

Distributions with respect to the Notes held beneficially through Clearstream will be credited to cash accounts of Clearstream Participants in accordance with its rules and procedures, to the extent received by Clearstream.

LatinClear

LatinClear is incorporated under the laws of Panama as a corporation. LatinClear holds securities deposited with it by its participants and facilitates the settlement of transactions among its participants in such securities through electronic computerized book-entry changes in accounts of the participants, thereby eliminating the need for physical movement of securities certificates. LatinClear's participants include securities brokers-dealers and banks. Access to LatinClear's book-entry system is also available to others, such as banks, brokers, dealers, trust companies and individual investors that clear through or maintain a custodial relationship with a participant, either directly or indirectly. LatinClear's book-entry system is also used by other organizations such as securities brokers and dealers, banks and trust companies that work through a direct participant. The rules that apply to LatinClear and its participants are on file with the SMV. LatinClear is owned by a number of its Panamanian direct participants and by the PSE.

LatinClear is the clearinghouse in Panama for the Notes. LatinClear may be contacted at P.O. Box 0823-0467, Panama, Republic of Panama or by telephone at +(507) 214-6105 or by fax at +(507) 214-8175. LatinClear is a participant in Euroclear and Clearstream.

TAXATION

Certain United States Federal Income Tax Considerations

The following is a general discussion based upon present law of certain United States federal income tax considerations for prospective purchasers of the Notes. The discussion addresses only persons that purchase Notes in the original offering, hold the Notes as capital assets, and, in the case of United States Holders (as defined below), use the U.S. dollar as their functional currency. The discussion does not consider the circumstances of particular purchasers, some of which (such as, financial institutions, insurance companies, regulated investment companies, tax exempt organizations, dealers, traders who elect to mark their investment to market, persons required to accelerate the recognition of any item of gross income as a result of such income being recognized on an "applicable financial statement," and persons holding the Notes as part of a hedge, straddle, conversion, constructive sale or integrated transaction) are subject to special tax regimes. The discussion does not address any state, local or foreign taxes, the Medicare tax on net investment income or the federal alternative minimum tax. This summary is based on the Internal Revenue Code of 1986, as amended to the date hereof (the "Code"), administrative pronouncements, judicial decisions and final, temporary and proposed Treasury regulations, changes to any of which subsequent to the date of this offering memorandum may affect the tax consequences described below, possibly on a retroactive basis. Prospective investors should note that no rulings have been, or are expected to be, sought from the United States Internal Revenue Service (the "IRS") with respect to any of the United States federal income tax consequences discussed below, and we cannot assure you that the IRS or a court will not take contrary positions.

EACH PROSPECTIVE PURCHASER IS URGED TO CONSULT ITS OWN TAX ADVISOR ABOUT THE TAX CONSEQUENCES OF AN INVESTMENT IN THE NOTES UNDER THE STATE AND LOCAL LAWS OF THE UNITED STATES, PANAMA AND THE LAWS OF ANY OTHER JURISDICTION WHERE THE PURCHASER MAY BE SUBJECT TO TAXATION.

For purposes of this discussion, "United States Holder" means a beneficial owner of a Note that for United States federal income tax purposes is

- a citizen or individual resident of the United States;
- a corporation organized in or under the laws of the United States, any state thereof or the District of Columbia;
- a trust subject to the control of one or more U.S. persons and the primary supervision of a United States court or that has validly elected to be treated as a U.S. person; or
- an estate the income of which is subject to United States federal income taxation regardless of its source.

"Non-United States Holder" means a person that is a beneficial owner of a Note that is not a partnership or a United States Holder.

The treatment of partners in a partnership (or entities or arrangements treated as partnerships) that owns Notes may depend on the status of such partners and the status and activities of the partnership and such persons should consult their own tax advisors about the consequences of an investment in the Notes.

Potential Contingent Payment Debt Instrument Treatment

In certain circumstances the Issuer may be required to make payments on a Note that would change the yield of the Note. See "Description of the Notes — Repurchase Upon Change of Control Repurchase Event" and "Description of the Notes — Optional Redemption with Make-Whole Premium."

This obligation may implicate the provisions of Treasury regulations relating to contingent payment debt instruments ("CPDIs"). According to the applicable Treasury regulations, certain contingencies will not cause a debt instrument to be treated as a CPDI if such contingencies, as of the date of issuance, are "remote or incidental" or certain other circumstances apply. The Issuer intends to take the position that the Notes are not CPDIs. This position is binding on a United States Holder under the Code unless such holder discloses its contrary position in a manner required by applicable Treasury regulations. This determination, however, is not binding on the IRS and if the IRS were to challenge this determination, a holder may be required to accrue income on the Notes that such holder owns in excess of stated interest, and to treat as ordinary income rather than capital gain any income realized on the taxable disposition of such Notes before the resolution of the contingency. If the Notes are not CPDIs, but such contingent payments were required to be made, it would affect the amount and timing of the income that a United States Holder recognizes. United States Holders are urged to consult their own tax advisors regarding the potential application to the Notes of the CPDI rules and other rules above and the consequences thereof. The remainder of this discussion assumes that the Notes will not be treated as CPDIs.

Interest

Stated interest paid to a United States Holder, and any Additional Amounts with respect to withholding tax on the Notes (including the amount of tax withheld from payments of interest and Additional Amounts), will be includible in the United States Holder's gross income as ordinary interest income at the time interest and Additional Amounts are received or accrued in accordance with the United States Holder's regular method of tax accounting for United States federal income tax purposes. It is expected, and the remainder of this discussion assumes, that the Notes will not be issued with original issue discount for United States federal income tax purposes.

Interest on the Notes generally will be treated as foreign source income for United States federal income tax purposes and generally will constitute "passive category" income for most United States Holders.

Sale, Exchange or Other Taxable Disposition

Upon the sale, exchange or other taxable disposition (including redemption) of a Note, a United States Holder generally will recognize taxable gain or loss equal to the difference, if any, between the amount realized on the sale, exchange or other taxable disposition (other than accrued but unpaid interest, which will be taxable as ordinary interest income (as described in, "— *Interest*" above)) and the United States Holder's adjusted tax basis in the Note. A United States Holder's adjusted tax basis in a Note generally will be equal to the amount that the United States Holder paid for the Note, less any payments on a Note (other than payments of stated interest). Any such gain or loss generally will be capital gain or loss and generally will be long-term capital gain or loss if the Note has been held for more than one year at the time of its sale, exchange or other taxable disposition. Certain non-corporate United States Holders (including individuals) may be eligible for preferential rates of United States federal income tax in respect of long-term capital gains. The deductibility of capital losses is subject to limitations.

Any gain or loss realized on the sale, exchange or other taxable disposition of a Note generally will be treated as United States source gain or loss, as the case may be. If any gain from the sale, exchange or other taxable disposition of a Note is subject to foreign income tax, United States Holders may not be able to credit such tax against their United States federal income tax liability under the United States foreign tax credit limitations unless such income tax can be credited (subject to applicable limitations) against United States federal income tax due on other income that is treated as derived from foreign sources. The rules governing the foreign tax credit are complex. United States Holders are urged to consult their tax advisors.

Non-United States Holders

Subject to the discussion of backup withholding below, a Non-United States Holder generally will not be subject to United States federal withholding tax on interest and Additional Amounts on or gain with respect to the Notes. A Non-United States Holder also generally will not be subject to United States federal income tax on a net income basis with respect to interest and Additional Amounts received in respect of the Notes or gain realized on the sale, exchange or other taxable disposition (including redemption) of the Notes, unless that interest or gain is effectively connected with the conduct by the Non-United States Holder of a trade or business within the United States or, in the case of gain realized by an individual Non-United States Holder, the Non-United States Holder is present in the United States for 183 days or more in the taxable year of the disposition and certain other conditions are met.

U.S. Backup Withholding and Information Reporting

Information reporting generally will apply to payments of principal of, and interest on, Notes (including Additional Amounts), and to proceeds from the sale, exchange or other taxable disposition (including redemption) of Notes within the United States, or by a United States payor or United States middleman, to a United States Holder (other than an exempt recipient). Backup withholding may be required on reportable payments if the United States Holder fails to furnish its correct taxpayer identification number or otherwise fails to comply with, or establish an exemption from, information reporting and backup withholding requirements. Non-United States Holders generally will be required to comply with applicable certification procedures to establish that they are not United States Holders in order to avoid the application of information reporting and backup withholding. Backup withholding is not an additional tax. A holder of Notes generally will be entitled to credit any amounts withheld under the backup withholding rules against its United States federal income tax liability or to obtain a refund of the amounts withheld provided the required information is furnished to the IRS in a timely manner.

"Specified Foreign Financial Asset" Reporting

Owners of "specified foreign financial assets" with an aggregate value in excess of US$50,000 (and in some circumstances, a higher threshold), may be required to file an information statement with respect to such assets with their United States federal income tax returns, currently on IRS Form 8938. The Notes generally are expected to constitute "specified foreign financial assets" unless they are held in accounts maintained by financial institutions. United States Holders are urged to consult their tax advisors regarding the application of this legislation to their ownership of the Notes.

The above description is not intended to constitute a complete analysis of all tax consequences relating to the ownership of the Notes. Prospective purchasers of Notes should consult their own tax advisors concerning the tax consequences of their particular situations.

Panamanian Tax Considerations

The following is a summary of the principal Panamanian income, stamp and certain other tax consequences in Panama resulting from the beneficial ownership and disposition of the Notes by certain investors. This summary is based on the Panamanian Tax Code of 1956, as amended, and other applicable tax laws, decrees and regulations promulgated thereunder, interpretative rulings issued by tax authorities, and judicial decisions, all as in effect on the date hereof. This summary is subject to changes in these laws, decrees, regulations, rulings, and judicial decisions occurring after the date hereof, possibly with retroactive effect.

This summary is intended as a descriptive summary only and is not a complete analysis or listing of all potential Panamanian income, stamp and other tax consequences to noteholders. In particular, this summary does not address the tax treatment of investors that may be subject to special tax regimes or tax treaties. This summary is not intended as tax advice to any particular investor, nor does it purport to furnish information in the level of detail as, or with attention to, an investor's specific circumstances that would be provided by an investor's own tax advisor. Prospective purchasers of Notes are urged to consult their own tax advisors as to the precise Panamanian and other tax consequences of acquiring, owning, and disposing of the Notes.

Taxation of Interest

Interest payable on the Notes will be exempt from income tax or withholding requirements in Panama, provided that the Notes are registered with the SMV and are placed through a securities exchange or other organized market, whether located in Panama or in any other approved jurisdiction. The Notes have been registered with the SMV and will be initially placed on the PSE. Accordingly, interest payments made on the Notes will be exempt from income tax or withholding requirements in Panama.

Taxation of Dispositions

Under a special tax exemption existing under the Panamanian securities law, because the Notes have been registered with the SMV, any capital gains realized by a holder of the Notes on the sale or other disposition of Notes will be exempt from income tax in Panama, provided that the sale or other disposition of the Notes is made through a securities exchange or other organized market, whether located in Panama or in any other approved jurisdiction.

Sales of Notes not made through a securities exchange or other organized market are subject to the capital gains income tax provisions of article 701(e) of the Panamanian Tax Code of 1956, as amended, and their regulations, regardless of whether such sales are made in Panama or outside of Panama or by a foreign or Panamanian holder. Therefore, such provisions would apply, for example, to sales of Notes by "qualified institutional buyers" outside of Panama, including sales through the facilities of DTC, if such sales are not made through a securities exchange or other organized market. In that situation, pursuant to article 701(e) of the Panamanian Tax Code of 1956, as amended, as regulated through Executive Decree No. 135 of February 6, 2012, (i) the seller will be subject to income tax in Panama on capital gains realized on the sale of the Notes calculated at a fixed rate of ten percent (10%) on the gain realized; (ii) the buyer will be obligated to withhold from the seller an amount equal to five percent (5%) of the aggregate proceeds of the sale, as an advance in respect of the capital gains income tax payable by the seller, and the buyer will be required to send to the fiscal authorities the withheld amount within ten days following the date of withholding; (iii) the seller will have the option of considering the amount withheld by the buyer as definitive payment in full of the seller's obligation to pay income tax on capital gains; and (iv) in the event that the amount withheld by the buyer is greater than the amount of capital gains income tax payable by the seller, that is, exceeding ten percent (10%) of the capital gains actually realized on the sale, the seller may file a sworn affidavit before the Panamanian tax authorities claiming a tax credit or refund in respect of the amounts paid in excess.

Notwithstanding the capital gains income tax provisions of article 701(e) of the Panamanian Tax Code of 1956, as amended, and their regulations, based on certain opinions issued by the *Dirección General de Ingresos*, Panama's Tax Authority, any capital gains realized by a holder of Notes who is not a resident of Panama on the sale or other disposition of Notes executed and effected outside of Panama, and for which payment is made outside of Panama, will not be deemed a Panamanian source of income. The inference from the foregoing is that the income realized from such a sale or disposition would not be subject to capital gains income tax in Panama. Losses incurred on such sale or other disposition of Notes would likewise be disallowed as a deduction for income tax purposes in Panama. We have been advised by our Panamanian counsel that the tax opinions issued by the *Dirección General de Ingresos* are not a legally binding interpretation of the Panamanian tax laws.

Stamp and Other Taxes

As the Notes have been registered with the SMV, the Notes are not subject to stamp taxes.

Foreign Investors

A person domiciled outside of Panama is not required to file a tax return in Panama solely by reason of his or her investment in the Notes, provided that gains realized on the sale and disposition of the Notes are, in effect, exempt from income tax as indicated above.

PLAN OF DISTRIBUTION

Citigroup Global Markets Inc. is acting as global coordinator and sole book-runner for the offering. Subject to the terms and conditions stated in the purchase agreement, the Initial Purchaser named below has agreed to purchase from us, and we have agreed to sell to the Initial Purchaser, the principal amount of the Notes set forth below.

Initial Purchaser	Principal Amount
Citigroup Global Markets Inc.	US$262,664,000
Total	**US$262,664,000**

Subject to the terms and conditions set forth in the purchase agreement dated December 9, 2020, the Initial Purchaser has agreed to purchase all of the Notes sold under the purchase agreement if any of these Notes are purchased. The Initial Purchaser may offer and sell the Notes through any of its affiliates.

The obligations of the Initial Purchaser under the purchase agreement, including its agreement to purchase the Notes from us, are subject to various conditions in the purchase agreement being satisfied or waived on or prior to the settlement date. In addition, the purchase agreement permits the Initial Purchaser to terminate its obligation to purchase the Notes in certain circumstances, including general trading suspensions, bank moratoria in the United States or Panama and acts of war or terrorism.

The Issuer has agreed to indemnify the Initial Purchaser and its controlling persons against certain liabilities in connection with this offering, including liabilities under the Securities Act, or to contribute to payments the Initial Purchaser may be required to make in respect of those liabilities.

The Issuer has been advised that the Initial Purchaser proposes to resell the Notes at the offering price set forth on the cover page of this offering memorandum within the United States to qualified institutional buyers in reliance on Rule 144A and outside the United States to non-U.S. persons in offshore transactions in reliance on Regulation S. The price at which the Notes are offered may be changed at any time without notice. The resale of the Notes by the Initial Purchaser is subject to receipt and acceptance of orders and subject to the Initial Purchaser's right to reject any order in whole or in part.

The Notes have not been and will not be registered under the Securities Act or any applicable United States federal or state securities laws and may not be offered or sold within the United States or to, or for the account or benefit of, any U.S. person (as defined in Regulation S) except in transactions exempt from, or not subject to, the registration requirements of the Securities Act. See "Transfer Restrictions."

In addition, until 40 days after the commencement of this offering, an offer or sale of notes within the United States by a dealer that is not participating in this offering may violate the registration requirements of the Securities Act if that offer or sale is made otherwise than in accordance with Rule 144A.

Each purchaser of the Notes will be deemed to have made acknowledgments, representations and agreements as described under "Transfer Restrictions — Purchasers' Representations and Restrictions on Resale and Transfer."

The Issuer has agreed that, during the period beginning on the date of the purchase agreement and continuing to the date that is 30 days after the closing of the offering, it will not, without the prior written consent of the Initial Purchaser, offer, sell or contract to sell, or otherwise dispose of, except as provided in the purchase agreement, any securities issued or guaranteed by the Issuer that are substantially similar to the Notes.

The Notes will constitute a new class of securities with no established trading market. Application will be made for the listing and quotation of the Notes on the PSE and SGX-ST. However, the Issuer cannot assure you that the prices at which the Notes will sell in the market after the offering will not be lower than the initial offering price or that an active trading market for the Notes will develop and continue after the offering.

Settlement

Panamanian Settlement Process

The Issuer has appointed BG Investment Co., Inc., as the broker-dealer house of the Notes through the PSE and the Initial Purchaser has appointed Citivalores, S.A. as the broker-dealer house of the Initial

Purchaser for the purchase of the Notes through the PSE. BG Investment Co., Inc. has a trading post at the PSE and is a broker-dealer authorized to act as such by the SMV, pursuant to Resolution CNV-322-00 of November 24, 2000, while Citivalores, S.A. has a trading post at the PSE and is broker-dealer authorized to act as such by the SMV, pursuant to Resolution CNV-342-00 of November 22, 2000.

The offices of BG Investment Co., Inc. are located at Calle Aquilino de la Guardia y Avenida 5B Sur, Panama City, Republic of Panama, its telephone number is (507) 303-5001 and its fax number is (507) 215-8160. The offices of Citivalores, S.A. are located at Torres de las Américas, Torre B, Piso 14, Punta Pacífica, Panama, Republic of Panama, its telephone number is (507) 210-5900 and its fax number is (507) 301-6444. BG Investment Co., Inc. will enter into a broker-dealer house agreement with the Issuer to carry out the sale of the Notes through the PSE. Among the services to be rendered in its role as placement agent of the Notes, BG Investment Co., Inc. may:

- carry out the offers of the Notes through the PSE pursuant to the rules of the PSE; and
- deliver at the disposal of the broker-dealer houses, brokers, investments advisors and the public in general, this offering memorandum and any amendments to it.

As set forth in the Primary Market Manual Proceeding of the PSE, as amended, the public auction process described below is applicable to the Notes. The Panamanian public auction procedures applicable to the Notes could be either those applicable to the "first session of the primary market," which is a session solely available on the PSE for certain issuances of securities in respect of which settlement takes place totally or partially in the international markets, including, among others, this offering of the Notes and which takes place between 8:00 a.m. and up to 9:00 a.m. (Panama time) or the regular trading session that takes place between 10:00 a.m. and up to 3:00 p.m. (Panama time).

At the chosen trading session on the date the Issuer offers the Notes through the PSE (the "Local Trading Date"), a trading session in respect of the Notes will be opened, on the one hand, for each person registered as a member of the PSE (each, a "Local Broker") as potential purchasers of the Notes, and, on the other hand, for the Issuer and seller of the Notes (the "Panamanian Public Auction"). During this period, any local broker will be permitted to submit a bid to purchase the Notes and the Issuer will be permitted to present its offer to sell the Notes on the PSE. Any such bids to purchase the Notes are required to be for the full principal amount of the offering as they will be made as a "whole or none" order (AON) under PSE regulation. During the applicable trading session on the same date, the Initial Purchaser will submit their bid to purchase the totality of the Notes through Citivalores S.A.

In the purchase agreement relating to the Notes the Issuer has also agreed that if the representative of the Initial Purchaser shall not have placed and secured the highest (and in case of equality, earliest) bid price for the Notes, the Issuer will withdraw any offer to sell the Notes on the Issue Date on the PSE and any such offer shall immediately be withdrawn and cancelled and be of no further force or effect. See "Risk Factors — Risks relating to the Notes — The public auction at the PSE will allow any investor to submit a bid for the full principal amount of the Notes and the bidder submitting the highest, and in the case of parity the earliest, bid would have the right to purchase the Notes. If a bidder different from the Initial Purchaser submits a higher or an equal but earlier bid, you will not receive the Notes on the Issue Date as we will abstain from selling and the offering will be cancelled in consideration to the liabilities that the Issuer could face under the purchase agreement." If a bidder different from the representatives of the Initial Purchaser submits a higher or an equal but earlier bid, you will not receive the Notes on the Issue Date as the Issuer will abstain from selling and the offering will be cancelled in consideration to the liabilities that it could face under the purchase agreement.

At any time from or after the commencement of the Panamanian Public Auction and or prior to the settlement of the Notes, if the Initial Purchaser determines, in accordance with the terms of the purchase agreement, that any of the conditions has not been satisfied or waived or that a Termination Event (as defined in the purchase agreement) has occurred or if the Issuer and the Initial Purchaser mutually agree, the Initial Purchaser has the right to require the Issuer to repurchase the Notes on the settlement date by delivering a notice to it, and in that event, the Issuer will repurchase on the settlement date the Notes sold to the representative of the Initial Purchaser on the PSE. The repurchase price (and, if redemption of any of the Notes is required, the redemption price) will be equal to the price payable to the Issuer for the Notes (including any premium, discount and/or prepaid interest) and no make-whole premium or any other amounts will be payable in connection therewith. The Issuer's obligation to pay the repurchase price for the Notes acquired by the Initial Purchaser and the Issuer's obligation to pay the repurchase or redemption price for the Notes acquired by other purchasers (in the case of any redemption, to the greatest extent possible) will be set off against the Initial Purchaser's obligation (and the other purchaser's obligation, as applicable) to pay the purchase price for those Notes.

The Notes will be represented by the Global Notes (as defined above). For purposes of listing the Notes with the PSE, prior to the issuance of such Global Notes, the Issuer will issue one or more global temporary notes on the Local Trading Date (the "Temporary Notes") and deposit them with Latinclear. Upon issuance of the Global Notes, the Temporary Notes will, pursuant to their terms and the terms in the purchase agreement, be immediately deemed without effect and will be replaced by the Global Notes.

Repayment of the IFC Loan

We intend to repay the IFC Loan and unwind the IFC Hedge Agreement with the net proceeds from the offering of the Notes substantially simultaneously with, or as soon as practicable after, the International Settlement of the Notes. To that end, immediately after pricing of the issuance of the Notes, we intend to deliver a notice of prepayment to IFC as Administrative Agent under the terms of the IFC Loan notifying that agent that we indent to repay the IFC Loan in full on the issuance date of the Notes or as soon as practicable thereafter. In addition, we intend to enter into pay-off documentation with the lenders under the IFC Loan to confirm the amounts due and payable to the Lenders under the IFC Loan and, pursuant to which all the Collateral securing the IFC Loan shall be released upon confirmation of the receipt by the Lenders of the pay-off amounts. For more information, See "Summary — Recent Developments — The Refinancing and Recapitalization Transaction."

International Settlement

The settlement of the Notes will take place out of the Panamanian trading market and LatinClear system as set out in the purchase agreement. The Issuer expects that delivery of the Notes will be made to investors on or about December 18, 2020 (the "Issue Date"), which will be the seventh business day following the date of this offering memorandum (such settlement being referred to as "T+7"). Under Rule 15c6-1, under the Exchange Act, trades in the secondary market are required to settle in two business days unless the parties to any such trade expressly agree otherwise. Accordingly, purchasers who wish to trade Notes prior to the delivery of the Notes hereunder will be required, by virtue of the fact that the Notes initially settle in T+7, to specify an alternate settlement arrangement at the time of any such trade to prevent a failed settlement. Purchasers of the Notes who wish to trade the Notes prior to their date of delivery hereunder should consult their advisors. The settlement procedures associated with the offering of the Notes on the PSE are complex, must be effected over the course of a short period of time on the Issue Date and depend to a significant degree on the cooperation of various public officials of Panama, who are not within the Issuer's ability to control or direct. Any delays involving these Panamanian settlement procedures may cause correlative delays in respect of the settlement and delivery of the Notes on the system of DTC, with the result that the actual settlement and delivery of the Notes may not be completed on the Issue Date and investors should consider the risks of trading their bonds in the secondary market prior to the Issue Date as settlement is conditioned on the Initial Purchaser having the winning bid on the PSE and even if the Initial Purchaser does have the winning bid, settlement delays may result in delivery to investors of Notes on the business day following the intended settlement date.

New Issue of Securities

The Notes are a new issue of securities with no established trading market. The Issuer intends to list the Notes on the PSE and SGX-ST. The Issuer has been advised by the Initial Purchaser that it currently intend to make a market in the Notes after completion of the offering. However, they are under no obligation to do so and may discontinue any market-making activities at any time without any notice. The Issuer cannot assure the liquidity of the trading market for the Notes. If an active trading market for the Notes does not develop, the market price and liquidity of the Notes may be adversely affected. If the Notes are traded, they may trade at a discount from their initial offering price, depending on prevailing interest rates, the market for similar securities, our operating performance and financial condition, general economic conditions and other factors.

In connection with the offering, the Initial Purchaser may purchase and sell the Notes in the open market. These transactions may include short sales and purchases on the open market to cover positions created by short sales. Short sales involve the sale by the Initial Purchaser of a greater principal amount of Notes than they are required to purchase in the offering. The Initial Purchaser must close out any short position by purchasing Notes in the open market. A short position is more likely to be created if the Initial Purchaser is concerned that there may be downward pressure on the price of the Notes in the open market after pricing that could adversely affect investors who purchase in the offering.

Similar to other purchase transactions, any purchases by the Initial Purchaser to cover the syndicate short sales may have the effect of raising or maintaining the market price of the Notes or preventing or retarding a decline in the market price of the Notes. As a result, the price of the Notes may be higher than the price that might otherwise exist in the open market.

Neither the Issuer nor the Initial Purchaser makes any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the Notes. In addition, neither the Issuer nor the Initial Purchaser makes any representation that the representative will engage in these transactions or that these transactions, once commenced, will not be discontinued without notice.

The Initial Purchaser is a full service financial institution engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. The Initial Purchaser and its affiliates have in the past performed commercial banking, investment banking and advisory services for us from time to time for which they have received customary fees and reimbursement of expenses. In the ordinary course of their various business activities, the Initial Purchaser and its affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (which may include bank loans and/or credit default swaps) for their own account and for the accounts of their customers and may at any time hold long and short positions in such securities and instruments. Such investment and securities activities may involve our securities and instruments.

Sales Outside of the United States

Neither the Issuer nor the Initial Purchaser are making an offer to sell, or seeking offers to buy, the Notes in any jurisdiction where the offer and sale is not permitted. You must comply with all applicable laws and regulations in force in any jurisdiction in which you purchase, offer or sell the Notes or possess or distribute this offering memorandum, and you must obtain any consent, approval or permission required for your purchase, offer or sale of the Notes under the laws and regulations in force in any jurisdiction to which you are subject or in which you make such purchases, offers or sales. Neither the Issuer nor the Initial Purchaser will have any responsibility therefor.

Notice to Prospective Investors in the EEA and the United Kingdom and Prohibition of Sales to EEA and United Kingdom Retail Investors

The Notes are not intended to be offered, sold or otherwise made available to and should not be offered, sold or otherwise made available to any retail investor in the EEA or in the United Kingdom. For these purposes, a retail investor means a person who is one (or more) of: (i) a retail client as defined in point (11) of Article 4(1) of MiFID II; or (ii) a customer within the meaning of Insurance Distribution Directive, where that customer would not qualify as a professional client as defined in point (10) of Article 4(1) of MiFID II. Consequently, no key information document required by PRIIPs Regulation for offering or selling the Notes or otherwise making them available to retail investors in the EEA or in the United Kingdom has been prepared and therefore offering or selling the Notes or otherwise making them available to any retail investor in the EEA may be unlawful under the PRIIPs Regulation.

Any distributor subject to MiFID II subsequently offering, selling or recommending the Notes is responsible for undertaking its own target market assessment in respect of the Notes and determining the appropriate distribution channels for the purposes of the MiFID II product governance rules under Commission Delegated Directive (EU) 2017/593 ("Delegated Directive"). Neither the Issuer nor does the Initial Purchaser make any representations or warranties as to a Distributor's compliance with the Delegated Directive

References to Regulations or Directives include, in relation to the United Kingdom, those Regulations or Directives as they form part of the United Kingdom domestic law by virtue of the European Union (Withdrawal) Act 2018 or have been implemented in United Kingdom domestic law, as appropriate.

Notice to Prospective Investors in the United Kingdom

This document is for distribution only to persons who (i) have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (as amended, the "Financial Promotion Order"), (ii) are persons falling within Article 49(2)(a) to (d) ("high net worth companies, unincorporated associations, etc.") of the Financial Promotion Order, (iii) are outside the United Kingdom, or (iv) are persons to whom an invitation or inducement to engage in investment activity (within the meaning of section 21 of the FSMA) in connection with the issue or sale of any Notes may otherwise lawfully be communicated or caused to be communicated (all such persons together being referred to as "relevant persons"). This document is directed only at relevant persons and must not be acted on or relied on by persons who are not relevant persons. Any investment or investment activity to which this document relates is available only to relevant persons and will be engaged in only with relevant persons.

Notice to Prospective Investors in Peru

The Notes and the information contained in this offering memorandum are not being publicly marketed or offered in Peru and will not be distributed or caused to be distributed to the general public in Peru. Peruvian securities laws and regulations on public offerings will not be applicable to this offering of the Notes and therefore, the disclosure obligations set forth therein will not be applicable to the Issuer or the sellers of the Notes before or after their acquisition by prospective investors. The Notes and the information contained in this offering memorandum have not been and will not be reviewed, confirmed, approved or in any way submitted to the SMV nor have they been registered under the Securities Market Law (*Ley del Mercado de Valores*) or any other Peruvian regulations. Accordingly, the Notes cannot be offered or sold within Peruvian territory except to the extent any such offering or sale qualifies as a private offering under Peruvian regulations and complies with the provisions on private offerings set forth therein.

The Notes may not be offered or sold in Peru except in compliance with the securities law thereof.

Notice to Prospective Investors in France

Neither this offering memorandum nor any other offering material relating to the Notes described in this offering memorandum has been submitted to the clearance procedures of the *Autorité des Marchés Financiers* or of the competent authority of another member state of the European Economic Area and notified to the *Autorité des Marchés Financiers*. The Notes have not been offered or sold and will not be offered or sold, directly or indirectly, to the public in France. Neither this offering memorandum nor any other offering material relating to the Notes has been or will be:

- released, issued, distributed or caused to be released, issued or distributed to the public in France; or
- used in connection with any offer for subscription or sale of the Notes to the public in France.

Such offers, sales and distributions will be made in France only:

- to qualified investors (*investisseurs qualifiés*) and/or to a restricted circle of investors (*cercle restraint d'investisseurs*), in each case investing for their own account, all as defined in, and in accordance with, articles L.411-2, D.411-1, D.411-2, D.734-1, D.744-1, D.754-1 and D.764-1 of the French Code *monétaire et financier*;
- to investment services providers authorized to engage in portfolio management on behalf of third parties; or
- in a transaction that, in accordance with article L.411-2-II-1°-or-2°-or 3° of the French Code *monétaire et financier* and article 211-2 of the General Regulations (*Règlement Général*) of the *Autorité des Marchés Financiers*, does not constitute a public offer (*appel public à l'épargne*).

The Notes may be resold directly or indirectly, only in compliance with articles L.411-1, L.411-2, L.412-1 and L.621-8 through L.621-8-3 of the French Code *monétaire et financier*.

Notice to Prospective Investors in People's Republic of China

The Notes may not be offered or sold directly or indirectly within the People's Republic of China ("PRC"). This offering memorandum or any information contained herein does not constitute an offer to sell or the solicitation of an offer to buy any securities in the PRC. This offering memorandum, any information contained herein or the Notes have not been, and will not be, submitted to, approved by, verified by or registered with any relevant governmental authorities in the PRC and thus may not be supplied to the public in the PRC or used in connection with any offer for the subscription or sale of the Notes in the PRC. The Notes may only be invested in by PRC investors that are authorized to engage in the investment in the Notes of the type being offered or sold. Investors are responsible for obtaining all relevant governmental approvals, verifications, licenses or registrations (if any) from all relevant PRC governmental authorities, including, but not limited to, the State Administration of Foreign Exchange, the China Securities Regulatory Commission, the China Banking Regulatory Commission, the China Insurance Regulatory Commission and/or other relevant regulatory bodies, and complying with all relevant PRC regulations, including, but not limited to, any relevant foreign exchange regulations and/or overseas investment regulations.

Notice to Prospective Investors in Taiwan

The Notes will not be registered with the Financial Supervisory Commission of Taiwan pursuant to relevant securities laws and regulations and the Notes may not be sold, issued or offered within Taiwan through a public offering or in a circumstance which constitutes an offer within the meaning of the Securities and Exchange Act of Taiwan requiring registration or approval of the Financial Supervisory Commission of Taiwan. No person or entity in Taiwan has been authorized to offer, sell, give advice regarding or otherwise intermediate the offering and sale of the Notes in Taiwan.

Notice to Prospective Investors in Hong Kong

The Notes may not be offered or sold in Hong Kong by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap. 32, Laws of Hong Kong), or (ii) to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a "prospectus" within the meaning of the Companies Ordinance (Cap. 32, Laws of Hong Kong) and no advertisement, invitation or document relating to the Notes may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to Notes which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

Notice to Prospective Investors in Japan

The Notes offered in this offering memorandum have not been registered under the Financial Instruments and Exchange Law of Japan. The Notes have not been offered or sold and will not be offered or sold, directly or indirectly, in Japan or to or for the account of any resident of Japan, except (i) pursuant to an exemption from the registration requirements of the Financial Instruments and Exchange Law and (ii) in compliance with any other applicable requirements of Japanese law.

Notice to Prospective Investors in Singapore

This offering memorandum has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, the Notes were not offered or sold or caused to be made the subject of an invitation for subscription or purchase and will not be offered or sold or caused to be made the subject of an invitation for subscription or purchase, and this offering memorandum or any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the Notes, has not been circulated or distributed, nor will it be circulated or distributed, whether directly or indirectly, to any person in Singapore other than (i) to an institutional investor (as defined in Section 4A of the Securities and Futures Act (Chapter 289) of Singapore, as modified or amended from time to time (the "SFA")) pursuant to Section 274 of the SFA, (ii) to a relevant person (as defined in Section 275(2) of the SFA) pursuant to Section 275(1) of the SFA, or any person pursuant to Section 275(1A) of the SFA, and in accordance with the conditions specified in Section 275 of the SFA, or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the Notes are subscribed or purchased under Section 275 of the SFA by a relevant person which is:

- a corporation (which is not an accredited investor (as defined in Section 4A of the SFA)) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or
- a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary of the trust is an individual who is an accredited investor,

securities or securities-based derivatives contracts (each term as defined in Section 2(1) of the SFA) of that corporation or the beneficiaries' rights and interest (howsoever described) in that trust shall not be transferred within six months after that corporation or that trust has acquired the Notes pursuant to an offer made under Section 275 of the SFA except:

- to an institutional investor or to a relevant person, or to any person arising from an offer referred to in Section 275(1A) or Section 276(4)(i)(B) of the SFA;
- where no consideration is or will be given for the transfer;
- where the transfer is by operation of law;
- as specified in Section 276(7) of the SFA; or
- as specified in Regulation 37A of the SFA (Offers of Investments) (Securities and Securities-based Derivatives Contracts) Regulations 2018.

Any reference to any term as defined in the SFA or any provision in the SFA is a reference to that term or provision as modified or amended from time to time including by such of its subsidiary legislation as may be applicable at the relevant time.

Solely for the purposes of its obligations pursuant to Sections 309B(1)(a) and 309B(1)(c) of the SFA, the Issuer has determined, and hereby notifies all relevant persons (as defined in Section 309A of the SFA) that the Notes are "prescribed capital markets products" (as defined in the Securities and Futures (Capital Markets Products) Regulations 2018) and Excluded Investment Products (as defined in MAS Notice SFA 04- N12: Notice on the Sale of Investment Products and MAS Notice FAA-N16: Notice on Recommendations on Investment Products).

Notice to Prospective Investors in Italy

The offering of the Notes has not been cleared by the *Commissione Nazionale per la Società e la Borsa*, or CONSOB, pursuant to Italian securities legislation. Accordingly, the Initial Purchaser has represented and agreed that it has not offered, sold or delivered, directly or indirectly, any Notes to the public in the Republic of Italy.

For the purposes of this provision, the expression "offer of Notes to the public" in Italy means the communication in any form and by any means of sufficient information on the terms of the offer and the Notes to be offered so as to enable an investor to decide to purchase or subscribe the Notes, including the placement through authorized intermediaries.

The Notes will not be offered, sold or delivered, directly or indirectly, to any person and copies of this offering memorandum or of any other document relating to the Notes will not be distributed in the Republic of Italy except:

1. to qualified investors (*investitori qualificati*), as defined under Article 100 of the Legislative Decree No. 58 of February 24, 1998, as amended (the "Italian Financial Act"), as implemented by Article 26, paragraph 1(d) of CONSOB Regulation No. 16190 of October 29, 2007, as amended ("Regulation No. 16190"), pursuant to Article 34-ter, first paragraph, letter b), of CONSOB Regulation No. 11971 of May 14, 1999, as amended ("Regulation No. 11971"); or

2. in other circumstances which are exempted from the rules on public offerings pursuant to Article 100 of the Italian Financial Act and its implementing CONSOB regulations including Regulation No. 11971.

Any such offer, sale or delivery of the Notes or distribution of copies of the offering memorandum or any other document relating to the Notes in the Republic of Italy must be in compliance with the selling restriction under (1) and (2) above and:

(a) made by investment firms, banks or financial intermediaries permitted to conduct such activities in the Republic of Italy in accordance with the relevant provisions of the Italian Financial Act, Regulation No. 16190, Legislative Decree No. 385 of September 1, 1993 as amended (the "Banking Act") and any other applicable laws or regulation;

(b) in compliance with Article 129 of the Banking Act and the implementing guidelines of the Bank of Italy, as amended, pursuant to which the Bank of Italy may request information on the offering or issue of securities in Italy or by Italian persons outside of Italy; and

(c) in compliance with any other applicable laws and regulations or requirement imposed by CONSOB or the Bank of Italy or any other Italian authority.

Any investor purchasing the Notes is solely responsible for ensuring that any offer, sale, delivery or resale of the Notes by such investor occurs in compliance with applicable Italian laws and regulations.

Notice to Prospective Investors in the Netherlands

This offering memorandum has not been and will not be approved by the Netherlands Authority for the Financial Markets (Autoriteit Financiële Markten) in accordance with Article 5:2 of the Dutch Act on Financial Supervision (Wet op het financieel toezicht). The Notes will only be offered in The Netherlands to qualified investors (gekwalificeerde beleggers) as defined in Article 1:1 of the Dutch Act on Financial Supervision.

Notice to Prospective Investors in Switzerland

This offering memorandum is not intended to constitute an offer or solicitation to purchase or invest in the Notes. The Notes may not be publicly offered, directly or indirectly, in Switzerland within the meaning of the Swiss Financial Services Act ("FinSA") and no application has or will be made to admit the Notes to trading on any trading venue (exchange or multilateral trading facility) in Switzerland. Neither this offering memorandum nor any other offering or marketing material relating to the Notes constitutes a prospectus pursuant to FinSA, and neither this offering memorandum nor any other offering or marketing material relating to the Notes may be publicly distributed or otherwise made publicly available in Switzerland.

Notice to Prospective Investors in Chile

Pursuant to the Chilean Securities Market Law and the CMF Rule 336, the Notes may be privately offered in Chile to certain "qualified investors" identified as such by CMF Rule 336 (which in turn are further described in Rule No. 216, dated June 12, 2008, and Rule No. 410, dated July 27, 2016, both of the CMF).

CMF Rule 336 requires the following information to be provided to prospective investors in Chile:

1. Date of commencement of the offer: December 9, 2020. The offer of the Notes is subject to Rule (*Norma de Carácter General*) No. 336, dated June 27, 2012, issued by the Chilean Financial Markets Commission (*Comisión para el Mercado Financiero*, the "CMF").

2. The subject matter of this offer are securities not registered with the Securities Registry (*Registro*

de Valores) of the CMF, nor with the foreign securities registry (*Registro de Valores Extranjeros*) of the CMF, due to the Notes not being subject to the oversight of the CMF.

3. Since the Notes are not registered in Chile there is no obligation by the issuer to make publicly available information about the Notes in Chile.

4. The Notes shall not be subject to public offering in Chile unless registered with the relevant Securities Registry of the CMF.

Información a los Inversionistas Chilenos

De conformidad con la ley N° 18.045, de Mercado de Valores y la Norma de Carácter General N° 336 (la "NCG 336"), de 27 de junio de 2012, de la Comisión para el Mercado Financiero (la "CMF"), los bonos pueden ser ofrecidos privadamente a ciertos "inversionistas calificados," a los que se refiere la NCG 336 y que se definen como tales en la Norma de Carácter General N° 216, de 12 de junio de 2008, y la Norma de Carácter General N° 410 de fecha 27 de julio de 2016, ambas de la CMF.

La siguiente información se proporciona a potenciales inversionistas de conformidad con la NCG 336:

1. *La oferta de los bonos comienza el 9 de diciembre de 2020, y se encuentra acogida a la Norma de Carácter General N° 336, de fecha 27 de junio de 2012, de la CMF.*

2. *La oferta versa sobre valores no inscritos en el Registro de Valores o en el Registro de Valores Extranjeros que lleva la CMF, por lo que tales valores no están sujetos a la fiscalización de esa Superintendencia.*

3. *Por tratarse de valores no inscritos en Chile no existe la obligación por parte del emisor de entregar en Chile información pública sobre los mismos.*

4. *Estos valores no podrán ser objeto de oferta pública en Chile mientras no sean inscritos en el Registro de Valores correspondiente.*

Notice to Prospective Investors in Canada

No prospectus has been filed with any securities commission or similar regulatory authority in Canada in connection with the offer and sale of the Notes described herein. The Notes may be sold only to purchasers purchasing, or deemed to be purchasing, as principal that are accredited investors, as defined in National Instrument 45-106 Prospectus Exemptions or subsection 73.3(1) of the Securities Act (Ontario), and are permitted clients, as defined in National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations, and not be an individual.

Securities legislation in certain provinces or territories of Canada may provide a purchaser with remedies for rescission or damages if this offering memorandum (including any amendment thereto) contains a misrepresentation, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor.

Pursuant to section 3A.3 of National Instrument 33-105 Underwriting Conflicts ("NI 33-105"), this offering is conducted pursuant to an exemption from the requirement that Canadian investors be provided with certain underwriter conflicts of interest disclosure that would otherwise be required pursuant to subsection 2.1(1) of NI 33-105.

No securities commission or similar regulatory authority in Canada has reviewed or in any way passed upon this document or on the merits of the Notes described herein and any representation to the contrary is an offence. Any resale of the Notes acquired by a Canadian investor must be made in accordance with applicable Canadian securities laws, which may require resales to be made in accordance with Canadian prospectus requirements or pursuant to exemptions therefrom. These resale restrictions may under certain circumstances apply to resales of the Notes outside of Canada.

TRANSFER RESTRICTIONS

The Notes have not been registered under the Securities Act or any state securities laws, and the Notes may not be offered or sold except pursuant to an effective registration statement or pursuant to transactions exempt from, or not subject to, registration under the Securities Act. Accordingly, the Notes are being offered and sold only:

- in the United States to qualified institutional buyers (as defined in Rule 144A) pursuant to Rule 144A under the Securities Act; and
- outside of the United States, to certain persons, other than U.S. persons, in offshore transactions meeting the requirements of Rule 903 of Regulation S under the Securities Act.

Purchasers' Representations and Restrictions on Resale and Transfer

Each purchaser of Notes (other than the Initial Purchaser in connection with the initial issuance and sale of Notes) and each owner of any beneficial interest therein will be deemed, by its acceptance or purchase thereof, to have represented and agreed as follows:

- it is purchasing the Notes for its own account or an account with respect to which it exercises sole investment discretion and it and any such account is either (a) a qualified institutional buyer and is aware that the sale to it is being made pursuant to Rule 144A or (b) a non-U.S. person that is outside the United States;
- it acknowledges that the Notes have not been registered under the Securities Act or with any securities regulatory authority of any state and may not be offered or sold within the United States or to, or for the account or benefit of, U.S. persons except as set forth below;
- it understands and agrees that Notes initially offered in the United States to qualified institutional buyers will be represented by one or more global Notes and that Notes offered outside the United States pursuant to Regulation S will also be represented by one or more global Notes;
- it will not offer, pledge, resell or otherwise transfer any of such Notes except (a) to us, (b) within the United States to a qualified institutional buyer in a transaction complying with Rule 144A under the Securities Act, (c) outside the United States in compliance with Rule 903 or 904 of Regulation S under the Securities Act, (d) pursuant to an exemption from registration under the Securities Act (if available) or (e) pursuant to an effective registration statement under the Securities Act and in accordance with all applicable securities laws of the States of the United States and other jurisdictions;
- it agrees that it will give to each person to whom it transfers the Notes notice of any restrictions on transfer of such Notes;
- it acknowledges that prior to any proposed transfer of Notes (other than pursuant to an effective registration statement or in respect of Notes sold or transferred either pursuant to (a) Rule 144A or (b) Regulation S) the holder of such Notes may be required to provide certifications relating to the manner of such transfer as provided in the Indenture;
- it acknowledges that the Indenture Trustee, registrar or transfer agent for the Notes will not be required to accept for registration or transfer of any Notes acquired by it, except upon presentation of evidence satisfactory to us and the Indenture Trustee, registrar or transfer agent that the restrictions set forth herein have been complied with;
- it acknowledges that we, the Initial Purchaser and other persons will rely upon the truth and accuracy of the foregoing acknowledgements, representations and agreements and agrees that if any of the acknowledgements, representations and agreements deemed to have been made by its purchase of the Notes are no longer accurate, it will promptly notify us and the initial Purchaser; and
- if it is acquiring the Notes as a fiduciary or agent for one or more investor accounts, it represents that it has sole investment discretion with respect to each such account and it has full power to make the foregoing acknowledgements, representations and agreements on behalf of each account.

Legends

The following is the form of restrictive legend which will appear on the face of the Rule 144A Global Note, and which will be used to notify transferees of the foregoing restrictions on transfer:

"THIS NOTE HAS NOT BEEN REGISTERED UNDER THE U.S. SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT"), OR ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING THIS NOTE, AGREES FOR THE BENEFIT OF UEP PENONOMÉ II, S.A. (THE "ISSUER") THAT THIS NOTE OR ANY INTEREST OR PARTICIPATION HEREIN MAY BE OFFERED, RESOLD, PLEDGED OR OTHERWISE TRANSFERRED ONLY (1) TO THE ISSUER, (2) SO LONG AS THIS NOTE IS ELIGIBLE FOR RESALE PURSUANT TO RULE 144A UNDER THE SECURITIES ACT ("RULE 144A"), TO A PERSON WHO THE SELLER REASONABLY BELIEVES IS A "QUALIFIED INSTITUTIONAL BUYER" (AS DEFINED IN RULE 144A) IN ACCORDANCE WITH RULE 144A, (3) IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 903 OR RULE 904 OF REGULATION S UNDER THE SECURITIES ACT, (4) PURSUANT TO AN EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT (IF AVAILABLE) OR (5) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE SECURITIES ACT, AND IN EACH OF SUCH CASES IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES OR OTHER APPLICABLE JURISDICTION. THE HOLDER HEREOF, BY PURCHASING THIS NOTE, REPRESENTS AND AGREES THAT IT SHALL NOTIFY ANY PURCHASER OF THIS NOTE FROM IT OF THE RESALE RESTRICTIONS REFERRED TO ABOVE.

THE FOREGOING LEGEND MAY BE REMOVED FROM THIS NOTE ONLY AT THE OPTION OF THE ISSUER."

The following is the form of restrictive legend which will appear on the face of the Regulation S Global Note and which will be used to notify transferees of the foregoing restrictions on transfer:

"THIS NOTE HAS NOT BEEN REGISTERED UNDER THE U.S. SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT"), OR ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING THIS NOTE, AGREES THAT NEITHER THIS NOTE NOR ANY INTEREST OR PARTICIPATION HEREIN MAY BE OFFERED, RESOLD, PLEDGED OR OTHERWISE TRANSFERRED IN THE ABSENCE OF SUCH REGISTRATION UNLESS SUCH TRANSACTION IS EXEMPT FROM, OR NOT SUBJECT TO, SUCH REGISTRATION AND IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY OTHER APPLICABLE JURISDICTION.

THE FOREGOING LEGEND MAY BE REMOVED FROM THIS NOTE AFTER 40 DAYS BEGINNING ON AND INCLUDING THE LATER OF (A) THE DATE ON WHICH THE NOTES ARE OFFERED TO PERSONS OTHER THAN DISTRIBUTORS (AS DEFINED IN REGULATION S UNDER THE SECURITIES ACT) AND (B) THE ORIGINAL ISSUE DATE OF THE NOTES."

Other Jurisdictions

The distribution of this offering memorandum and the offer and sale or resale of the Notes may be restricted by law in certain jurisdictions. Persons into whose possession this offering memorandum comes are required by us and the Initial Purchaser to inform themselves about and to observe any such restrictions.

LISTING AND GENERAL INFORMATION

Clearing Systems

An application has been made to have the Notes accepted for clearance through DTC. The CUSIP and ISIN numbers for the Regulation S Notes are P9434R AA8 and USP9434RAA88, respectively. The CUSIP and ISIN numbers for the Rule 144A Notes are 90363P AA4 and US90363PAA49, respectively.

Listing

Application will be made for the Notes to be listed on the PSE and the SGX-ST. The SGX-ST assumes no responsibility for the correctness of any of the statements made or opinions expressed or reports contained in this offering memorandum. Approval in principle received from the SGX-ST and admission of the Notes to the official list of the SGX-ST is not to be taken as an indication of the merits of the Issuer or the Notes. The Notes will be traded in a minimum board lot size of US$200,000 (or its equivalent in foreign currencies) for so long as any of the Notes are listed on the SGX-ST and the rules of the SGX-ST so require.

We cannot assure you that the Notes will receive final approval or will remain listed. For so long as the Notes are listed on the SGX-ST and are admitted to trading on the SGX-ST and the rules and regulations of the SGX-ST so require, copies of the following documents may be inspected and obtained free of charge at the specified office of each of the Issuer and the Listing Agent during normal business hours on any weekday (Saturdays, Sundays and public holidays excepted):

- copies of the Issuer's by-laws;
- the Indenture, as may be amended or supplemented from time to time; and
- Issuer Annual Financial Statements and the Guarantors Annual Financial Statements.

For so long as the Notes are listed on the SGX-ST and the rules of the SGX-ST so require, in the event that the Notes which are issued in global certificated form are exchanged for Notes in definitive registered form or definitive registered Notes, the Issuer will appoint and maintain a paying agent in Singapore, where the certificates in definitive form in respect of Notes may be presented or surrendered for payment or redemption. In addition, in the event that the Notes which are issued in global certificated form are exchanged for Notes in definitive registered form or definitive registered Notes, an announcement of such exchange shall be made by or on behalf of the Issuer through the SGX-ST and such announcement will include all material information with respect to the delivery of the certificates in definitive form, including details of the paying agent in Singapore.

Authorization

We have obtained all necessary consents, approvals and authorizations in connection with the issuance and performance of each series of Notes.

LEGAL MATTERS

Certain legal matters in connection with the offering will be passed upon for us by Milbank LLP, New York, New York, as to matters of United States federal and New York State law and by SIGMA International and Global Market Attorneys, as to matters of Panamanian law. Certain legal matters will be passed upon for the Initial Purchaser by Shearman & Sterling LLP, as to matters of United States federal and New York State law and by Arias, Fábrega & Fábrega, as to matters of Panamanian law.

INDEPENDENT AUDITORS

The Issuer Annual Financial Statements and the stand-alone financial statements of each of the Guarantors as of and for the year ended December 31, 2019 included in this offering memorandum, have been audited by PwC, independent auditors, as stated in their reports appearing herein.

INDEPENDENT CONSULTANTS

Annex A — Independent Energy Market Report

Mercados Energéticos has prepared the Independent Energy Market Report included in Annex A to this offering memorandum. The Independent Energy Market Report should be read in its entirety for complete information with respect to the subjects and issues discussed therein. As stated in the Independent Energy Market Report, Mercados Energéticos has relied on assumptions regarding circumstances beyond their or our control and not all of these assumptions, which are disclosed in the report, are disclosed in this offering memorandum. Mercados Energéticos believes that the use of such information and assumptions is reasonable for the purposes of the Independent Energy Market Report. The Independent Energy Market Report has been included in this offering memorandum in reliance upon the conclusions therein and upon Mercado Energéticos experience in the review of the design, development, construction and operation of power plants, including those similar to the UEP II Wind Project and the Tecnisol Solar Project.

Annex B — Independent Engineer Report

UL has prepared the Independent Engineer Report with respect to the Projects that is included as Annex B to this offering memorandum. The Independent Engineer Report should be read in its entirety for complete information with respect to the subjects and issues discussed therein. As stated in the Independent Engineer Report, UL has relied on assumptions regarding circumstances beyond their or our control and not all of these assumptions, which are disclosed in the Independent Engineer Report, are disclosed in the main body of this offering memorandum. UL believes that the use of such information and assumptions is reasonable for the purposes of the Independent Engineer Report. The Independent Engineer Report has been included in this offering memorandum in reliance upon the conclusions therein and upon UL's experience in the review of the design, development, construction and operation of electric power plants, including those similar to the UEP II Wind Project and the Tecnisol Solar Project.

INDEX TO FINANCIAL STATEMENTS

UEP Penonome II, S. A.

Report and Interim Financial Statements
September 30, 2020

UEP Penonome II, S. A.

Index to the Interim Financial Statements
September 30,2020

Report on review of interim financial information

To the Board of Directors and Shareholders of
UEP Penonome II, S. A.

Introduction

We have reviewed the accompanying condensed interim balance sheet of UEP Penonome II, S. A. as at September 30, 2020 and the related condensed interim statements of comprehensive income, changes in equity and cash flow for the nine-month period then ended and notes, comprising significant accounting policies and other explanatory notes. Management is responsible for the preparation and presentation of this condensed interim financial information in accordance with IAS 34 - Interim financial reporting. Our responsibility is to express a conclusion on this condensed interim financial information based on our review.

Scope of review

We conducted our review in accordance with International Standard on Review Engagements 2410, "Review of interim financial information performed by the independent auditor of the entity". A review of interim financial information consists of making inquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with International Standards on Auditing and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Conclusion

Based on our review, nothing has come to our attention that causes us to believe that the accompanying condensed interim financial information is not prepared, in all material respects, in accordance with IAS 34 - Interim financial reporting.

PricewaterhouseCoopers

November 21, 2020
Panama, Republic of Panama

UEP Penonome II, S. A.

Condensed Balance Sheet
September 30, 2020
(All amounts in US$ unless otherwise stated)

	Notes	September 2020	December 2019
Assets			
Current assets			
Cash and cash equivalents	2 and 5	17,420,575	25,126,029
Restricted cash	2, 5 and 6	51,165,263	51,165,263
Trade and other receivables	2, 7 and 12	7,185,122	6,988,755
Prepaid expenses		689,756	573,720
Total current assets		76,460,716	83,853,767
Non-current assets			
Plant and equipment, net	2, 8 and 9	233,383,007	243,796,082
Restricted cash	6	17,272,000	17,272,000
Goodwill	2 and 10	20,000,000	20,000,000
Total non-current assets		270,655,007	281,068,082
Total assets		347,115,723	364,921,849
Liabilities and Equity			
Current liabilities			
Current portion of long-term debt	2 and 13	12,296,000	12,803,000
Trade and other payables	2, 11 and 12	26,265,934	34,248,298
Total current liabilities		38,561,934	47,051,298
Non-current liabilities			
Shareholders' loans	12, 14	50,000,000	50,000,000
Lease liabilities long term	9	8,252,995	8,385,098
Deferred income tax	17	2,048,455	2,224,202
Long-term debt	2 and 13	203,844,250	220,002,710
Derivative financial instrument		18,758,977	7,822,058
Total non-current liabilities		282,904,677	288,434,068
Total liabilities		321,466,611	335,485,366
Equity			
Common shares with US$1.00 par value each; authorized and issued: 1,050 shares	2 and 14	1,050	1,050
Capital contribution	2 and 14	74,998,950	74,998,950
Accumulated deficit		(49,331,735)	(45,563,517)
Prepaid dividend tax		(19,153)	-
Total equity		25,649,112	29,436,483
Total liabilities and equity		347,115,723	364,921,849

The accompanying notes are an integral part of these condensed financial statements.

UEP Penonome II, S. A.

Condensed Statement of Comprehensive Income
For the three and nine-month period ended September 30, 2020
(All amounts in US$ unless otherwise stated)

	Notes	For the three months ended September 30, 2020	2019	For the nine months ended September 30, 2020	2019
Energy revenue		2,391,753	5,440,598	40,337,052	49,801,619
Costs of goods and services	8, 9 and 15	(3,754,968)	(3,884,851)	(11,811,907)	(12,256,351)
Gross (loss) profit		(1,363,215)	1,555,747	28,525,145	37,545,268
Expenses	15				
Administrative expenses		(1,065,112)	(832,489)	(3,101,052)	(3,236,240)
Operating expenses		(1,509,158)	(1,864,160)	(4,217,826)	(4,452,674)
Total expenses		(2,574,270)	(2,696,649)	(7,318,878)	(7,688,914)
Operating (loss) profit		(3,937,485)	(1,140,902)	21,206,267	29,856,354
Finance cost amortization	13	(199,176)	(199,176)	(597,528)	(597,528)
Finance cost, net	16	(2,377,072)	(8,668,707)	(24,546,477)	(27,034,607)
Total finance cost		(2,576,248)	(8,867,883)	(25,144,005)	(27,632,135)
Other loss		(2,217)	-	(6,227)	(64,251)
(Loss) profit before income tax		(6,515,950)	(10,008,785)	(3,943,965)	2,159,968
Income tax	17	2,344,137	1,001,163	175,747	(2,551,272)
Loss for the period		(4,171,813)	(9,007,622)	(3,768,218)	(391,304)

The accompanying notes are an integral part of these condensed financial statements.

UEP Penonome II, S. A.

Condensed Statement of Changes in Equity
For the nine-month period ended September 30, 2020
(All amounts in US$ unless otherwise stated)

	Common Shares	Capital Contribution	Accumulated Deficit	Prepaid Dividend Tax	Total Equity
Balance at January 1, 2019	1,050	74,998,950	(44,177,907)	-	30,822,093
Loss for the nine-months period ended September 30, 2019	-	-	(391,304)	-	(391,304)
Balance at September 30, 2019	1,050	74,998,950	(44,569,211)	-	30,430,789
Balance at December 31, 2019	1,050	74,998,950	(45,563,517)	-	29,436,483
Prepaid dividend tax	-	-	-	(19,153)	(19,153)
Loss for the nine-months period ended September 30, 2020	-	-	(3,768,218)	-	(3,768,218)
Balance at September 30, 2020	1,050	74,998,950	(49,331,735)	(19,153)	25,649,112

The accompanying notes are an integral part of these condensed financial statements.

UEP Penonome II, S. A.

Condensed Statement of Cash Flow
For the nine-month period ended September 30, 2020
(All amounts in US$ unless otherwise stated)

	Notes	September 2020	2019
Cash flows from operating activities			
(Loss) profit before income tax		(3,943,965)	2,159,968
Adjustments to reconcile profit before income tax to net cash provided by operating activities:			
Depreciation and amortization	8, 9 and 15	10,456,326	10,361,768
Finance cost amortization	13	597,528	597,528
Interest on borrowings and lease liabilities, net	16	13,609,557	15,295,720
Fair value loss on derivative financial instrument	16	10,936,920	11,738,887
Changes in assets and liabilities:			
Trade and other receivables		(196,367)	6,599,665
Trade and other payables		(4,150,676)	1,754,589
Prepaid expenses		(116,035)	587,473
Interest paid		(17,472,140)	(19,502,762)
Net cash provided by operating activities		9,721,148	29,592,836
Cash flows from investing activities			
Additions of plant and equipment	8	(43,251)	(27,829)
Net cash used in investing activities		(43,251)	(27,829)
Cash flows from financing activities			
Repayment of long-term debt		(17,262,988)	(14,451,000)
Prepaid dividend tax		(19,153)	-
Principal lease payments		(101,210)	(61,822)
Net cash used in financing activities		(17,383,351)	(14,512,822)
Net (decrease) increase in cash and cash equivalents		(7,705,454)	15,052,185
Cash and cash equivalents and restricted cash at the beginning of the year		76,291,292	60,837,269
Cash and cash equivalents and restricted cash at end of the period	5	68,585,838	75,889,454

The accompanying notes are an integral part of these condensed financial statements.

1. General Information

UEP Penonome II, S. A. (the "Company") is incorporated on January 18, 2013 under the laws of the Republic of Panama. The Company is engaged in the production of electricity through its five wind parks located in Penonome, Province of Cocle, Republic of Panama.

The ultimate parent company of UEP Penonome II, S. A. is Interenergy Partners, L. P., incorporated in Cayman Island.

The local regulator, Autoridad Nacional de los Servicios Publicos (ASEP, by its acronym in Spanish), approved the Company's electricity generation license to 215 MW capacity (Note 18).

The Company is located in Torre de las Americas, Punta Pacifica, Republic of Panama, and the wind turbines are in Penonome, Republic of Panama.

These interim financial statements have been approved for issue by the Finance Manager on November 20, 2020.

2. Summary of Significant Accounting Policies

The principal accounting policies applied in the preparation of these interim financial statements are set out below.

Basis of Preparation

The interim financial statements of the Company have been prepared in accordance with International Financial Reporting Standards (IFRS) and the related interpretations adopted by the International Accounting Standards Board (IASB). The interim financial statements have been prepared on the historical cost convention.

These interim financial statement for the nine-month period ended September 30, 2020 have been prepared in accordance with IAS 34 Interim Financial Reporting and should be read in conjunction with the Company's last annual financial statements as at and for the year ended December 31, 2019. They do not include all of the information required for a complete set of financial statements prepared in accordance with IFRS Standards. However, selected explanatory notes are included to explain events and transactions that are significant to an understanding of the change in the Company's financial position and performance since the last annual financial statement. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in Note 4.

2. Summary of Significant Accounting Policies (Continued)

Basis of Preparation (continued)

New standards, amendments and interpretations not yet adopted
Certain new accounting standards and interpretations have been published that are not mandatory for September 30, 2020 reporting periods and have not been early adopted by the Company. These standards are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

Monetary Unit and Functional Currency
The interim consolidated financial statements are expressed in U.S. Dollars (US$), monetary unit of the United States of America, which is at par with the Balboa (B/.), monetary unit of the Republic of Panama. The U.S. Dollar (US$) circulates and is freely exchangeable in the Republic of Panama and is the functional currency.

Financial Assets
The Company classifies its financial assets in the category of loans and receivables and assets at fair value through profit or loss, based on the purpose for which the financial assets were acquired. Management determines the classification of its financial assets at initial recognition.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Loans and receivables with maturities not greater than 12 months are included in current assets.

Cash and Cash Equivalents
For purposes of the cash flow statement, cash and cash equivalents include cash in hand and other short-term highly liquid investments with original maturities of three months or less.

Restricted Cash
Cash is classified as restricted when it is not available for the use of the Company. The restricted cash is classified as current when its release is expected to occur within one year, and non-current when its availability is longer than such period.

Trade and Other Receivables
The Company maintains trade and other receivables in order to collect the contractual cash flows and, therefore, subsequently measures them at amortized cost using the effective interest method, less any estimate for impairment.

2. Summary of Significant Accounting Policies (Continued)

Plant and Equipment

Plant and equipment are stated at cost, less accumulated depreciation, amortization and impairment losses. Depreciation and amortization are calculated on the straight-line method over the estimated useful lives of the assets. Costs of maintenance, repairs, minor refurbishments and improvements are charged to expense. Subsequent costs are capitalized only when it is probable that a future economic benefit associated with the item will flow to the Company and the cost of the item can be measured reliably. The Company has a maintenance program that includes inspecting, testing and repairing all operational power equipment based on the equivalent operating hours (EOH).

Expenditure on the construction, installation or completion of infrastructure facilities, such as constructions, generators and electric power plants facilities, is capitalized within property, plant and equipment according to its nature. No depreciation or amortization is charged during the construction phase. The Company begins depreciating an item of property, plant and equipment when it is available for use.

Right-of-use assets are generally depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. If the Company is reasonably certain to exercise a purchase option, the right-of-use asset is depreciated over the underlying asset's useful life.

Depreciation and amortization rates used are described as follows:

Buildings	2.50%
Right of Use Assets	5%
Generators and plant facilities	5% - 10%
Tools and minor equipment	25%
Equipment of transportation	25%
Furniture and office equipment	25%

Impairment of Long-lived Assets

Plant and equipment and other non-current assets which are non-financial assets that are subject to depreciation and amortization, are reviewed for impairment whenever events or changes in the circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognized for the amount by which the asset's carrying amount exceeds its recoverable amount, which is the higher of an asset's fair value less costs to sell and value in use. For the purpose of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (cash-generating units).

2. Summary of Significant Accounting Policies (Continued)

Leases
The Company has initially applied IFRS 16, for the first time for their annual reporting period commencing January 1, 2019.

- IFRS 16 - Leasing. The IASB issued in January 2016, IFRS 16, which replaces IAS 17- Leases. This standard introduces significant changes in accounting by lessee.

- The Company applied the simplified approach, in which the comparative figures are not restate at the date of initial application. The right-of-use assets for property leases will be initially measured on a retrospective basis as if the new standard had always been applied. All other right-of-use assets will be measured at the amount equal to the lease liability at the time of adoption (adjusted for prepaid or accrued lease payments relating to that lease recognized). In addition, the Company has decided not to apply the new standard to leases whose term will end within twelve months of the date of initial application. In such cases, the leases are accounted for as short-term leases and the lease payments associated with them are recognized as an expense from short-term leases. There is not any lease under the low value exemption.

In the context of the transition, the Company recognized as of January 1, 2019 a right of use asset for US$ 8,568,447 and a lease liability of US$8,568,447. (See Note 9).

Lease Liabilities
Lease liabilities include the following lease payments:

- fixed payments, less any lease incentives receivable
- variable lease payment that are based on an index or a rate,
- amounts expected to be payable by the Company under residual value guarantees
- the exercise price of a purchase option if the Company is reasonably certain to exercise that option, and
- payments of penalties for terminating the lease, if the lease term reflects the Company exercising that option.

The lease payments are discounted using the interest rate implicit in the lease, to the extent that this can be determined. Otherwise, the discount is the lessee's incremental borrowing rate.

Right-of-use assets are measured at cost comprising the following:

- The amount of the initial measurement of lease liability.
- No restoration costs, and no payments were made at or before the lease commencement date as well as not initial direct costs.

2. Summary of Significant Accounting Policies (Continued)

Goodwill
Goodwill arises and represents the excess of the consideration transferred, the amount of any non-controlling interest in the acquire and the acquisition-date fair value of any previous equity interest in the acquire over the fair value of the identifiable net assets acquired. If the total of consideration transferred, non-controlling interest recognized and previously held interest measured at fair value is less than the fair value of the net assets of the subsidiary acquired, in the case of a bargain purchase, the difference is recognized directly in the condensed statement of comprehensive income.

For the purpose of impairment testing, goodwill acquired in a business combination is allocated to each of the CGUs, or Company of CGUs, that is expected to benefit from the synergies of the combination. Each unit or Company of units to which the goodwill is allocated represents the lowest level within the entity at which the goodwill is monitored for internal Management purposes. Goodwill is monitored at the operating segment level.

Goodwill impairment reviews are undertaken annually or more frequently if events or changes in circumstances indicate a potential impairment. The carrying value of the CGU containing the goodwill is compared to the recoverable amount, which is the higher of value in use and the fair value less costs of disposal. Any impairment is recognized immediately as an expense and is not subsequently reversed.

Trade and Other Payables
Trade and other payables are obligations to pay for goods or services that have been acquired in the normal course of the business from suppliers. Trade and other payables are classified as current liabilities as payments are due within one year or less.

Trade and other payables are initially recognized at fair value and subsequently measured at amortized cost using the effective interest method.

Borrowings
Borrowings are initially recognized at fair value, net of transaction costs incurred. Borrowings are subsequently carried at amortized cost, using the effective interest method.

Borrowing Costs
General and specific borrowing costs directly attributed to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets until the assets are substantially ready for their intended use or sale. All other borrowing costs are recognized in the condensed statement of comprehensive income in the period in which they are incurred.

2. Summary of Significant Accounting Policies (Continued)

Current and Deferred Income Tax
Income tax expense for the period comprises current and deferred income tax. Income tax is recognized in the condensed statement of comprehensive income.

The current income tax charge is calculated on the basis of the tax laws enacted at the condensed balance sheet date over the taxable income.

Deferred income tax is provided in full, using the liability method, where temporary differences arise between the fiscal bases of assets and liabilities and their carrying amounts in the financial statements. However, the deferred income tax is not accounted for if it arises from initial recognition of an asset or liability, in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit nor loss. Deferred income tax is determined using tax rates that have been enacted or substantially enacted by the condensed balance sheet date and are expected to apply when the related deferred income tax asset is realized, or the deferred income tax liability is settled.

Deferred income tax assets are recognized to the extent that it is probable that future taxable profit will be available, and the temporary differences can be utilized against it.

Deferred income tax is provided for temporary differences originated by loss drag.

Employee Benefits

Seniority Premium and Severance Trust Fund
According to the Labor Code of the Republic of Panama, employees with a permanent contract of employment are entitled to receive, upon termination of employment, a seniority premium, equal to one week's wage for each year of work, determined from the date of commencement of employment.

In addition, employees dismissed under certain circumstances are entitled to receive compensation based on years of service. Law No.44 of 1995 provides that companies must make a contribution to a fund to cover the Layoff seniority premium payments to dismissed workers. This contribution is determined based on the compensation paid to employees. To manage this fund, the Company established a trust with an authorized private entity. The contributions are treated as defined contribution plans, where the Company has no further payment obligations in addition to those contributions. The contribution for the nine-months period amounted to US$10,865 (2019: US$12,296).

2. Summary of Significant Accounting Policies (Continued)

Employee Benefits (continued)

Social Security
According to Law No.51 of December 27, 2005, the companies must realize monthly contributions to the Panama Social Security (i.e., Caja de Seguro Social de Panama), based on a percentage of the total wages paid to their employees. A portion of these contributions is used by the Panamanian State for the payment of the future retirements of the employees. The contribution for the nine-months period amounted to US$105,271 (2019: US$99,745).

Share Capital
Common shares are classified as equity.

Energy Revenue Recognition
The Company recognizes energy revenue in the periods that it delivers electricity. Contracted prices are billed in accordance to provisions of applicable power sales agreements and spot sales are billed in accordance with prevailing market prices. The unit of measurement of the contract prices is megawatts (MW). The following criteria should be met in order to recognize revenue: (1) persuasive evidence of an arrangement exists; (2) delivery has occurred or services have been rendered; (3) the price to the buyer is fixed or determinable; and (4) collection is reasonably assured. Revenues are measured at fair value of the consideration received or receivable for the sale of the energy.

In accordance of IFRS 15, the Company recognized the revenue from contracts with customers based on a five step model detailed below:

- Step 1. Identify contracts with customers: A contract is defined as the agreement between two or more parties, which creates rights and obligations required and establishes criteria that must be met for each contract. The contracts that are handled are written and grouped in the same type of contracts because all of them are categorized in the same concept of energy sales.

- Step 2. Identify the contract obligations: An obligation is a promise in a contract with a client for the transfer of a good or service.

- Step 3. Determine the price of transaction: The transaction price is the amount of the payment that the Company expects to have the right in exchange for the transfer of the promised goods or services to a client.

2. Summary of Significant Accounting Policies (Continued)

Energy Revenue Recognition (continued)

- Step 4. Assignment of the transaction price: The Company recognizes the price of the contract payable as specified in the contract, subject to the stipulated conditions and adjustments or proposed deductions, as applicable.

- Step 5. Recognition of revenue according to the criteria established by IFRS 15, the Company continues recognizing revenues over time instead of during a certain time.

The Company principally satisfies its performance obligations over time, when, or as, a performance obligation is satisfied, the Company recognizes as revenue the amount of the transaction price that is allocated to that performance obligation. The transaction price is the amount of consideration to which the Company expects to be entitled. The transaction price is allocated to the performance obligations in the contract based on standalone selling prices of the goods or services promised.

Finance Cost

Comprise interest expense on borrowings, unwinding of the discount of provision and deferred consideration.

3. Financial Risk Management

Financial Risk Factors

The Company's activities expose it to a variety of financial risks: market risk (including currency risk, fair value interest rate risk and cash flow interest rate risk), credit risk and liquidity risk.

Risk management is carried out by the General Manager and the Director of Financial Department under the supervision of the Board of Directors. They identify and evaluate financial risks in close co-operation with Management of Departments within the Company.

Market Risk

Foreign exchange risk

The Company is not substantially exposed to the foreign exchange risk fluctuation, since its revenues and expenses are mainly expressed in U. S. Dollars.

Interest rate risk

Interest rate risk is mainly originated from long-term debt with variable interest rates that expose the Company to the cash flows risk.

3. Financial Risk Management (Continued)

Financial Risk Factors (continued)

Interest rate sensitivity
As at September 30, 2020, if interest rates on the variable United States dollar denominated borrowings has been 50 basis points higher/lower with all other variables held constant, net income for the year would have been US$10,721,425 (US$12,506,455) higher/lower.

Credit Risk
Credit risk arises mainly from cash and cash equivalents, restricted cash, trade and other receivables. The Company works only with well-known foreign and local financial institutions and energy distribution companies.

The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit rating.

	September 2020	December 2019
Cash at banks and short-term bank deposits international credit rating - Fitch (A and AA-)	68,585,838	76,291,292

The Company has a concentration of its revenues and accounts receivable with the three offtaker companies operating in the Republic of Panama. Sales of energy made to these customers represent approximately 85% (September 2019: 85%) of total revenues and 70% (September 2019: 61%) of total accounts receivable at the end of the nine-months period. This concentration of risk is mitigated by the fact that demand for electricity in Panama continues to grow steadily and that the energy market is very well structured and regulated by government authorities. For each PPA a guarantee is required and the payment term of invoices originating in the electric market of Panama is averaged in a range of 30 days from the date of presentation of the invoice. The guarantee is a performance bond payable to the collection against any event of default for bad debts or bad debt. There were no default events for unpaid bills as of September 30, 2020.

3. Financial Risk Management (Continued)

Financial Risk Factors (continued)

Liquidity Risk

Liquidity risk is the risk that the Company might not be able to comply with all its obligations. The Company minimizes this risk by maintaining adequate levels of cash on hand or in current accounts for fulfilling commitments with recurring suppliers and borrowers. The current liabilities are covered by the cash flow generated by operations.

Cash flows forecasting is performed by the operating entities of the Company in and aggregated by Company finance. The Company finance monitors rolling forecasts of the Company's liquidity requirements to ensure it has sufficient cash to meet operational needs while maintaining sufficient headroom on its undrawn committed borrowing facilities at all times so that the Company does not breach borrowing limits or covenants on any of its borrowing facilities. Such forecasting takes into consideration the Company's debt financing plans, covenant compliance, compliance with internal balance sheet ratio targets and, if applicable external regulatory or legal requirements.

The table below analyses the Company's non-derivative financial liabilities into relevant maturity groupings based on the remaining period at the balance sheet to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows. Balances due within 12 months approximate their carrying balances as the impact of discounting is not significant.

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
September 30, 2020				
Long-term debt	29,601,248	152,121,970	160,062,559	341,785,777
Trade, lease and other payables	26,265,934	1,182,976	7,070,019	34,518,929
Shareholders' loans	3,960,000	15,840,000	75,740,000	95,540,000
	59,827,182	169,144,946	242,872,578	471,844,706

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
December 31, 2019				
Long-term debt	31,149,117	153,565,493	196,408,994	381,123,604
Trade, lease and other payables	34,248,298	997,488	7,387,610	42,633,396
Shareholders' loans	3,960,000	15,840,000	77,720,000	97,520,000
	69,357,415	170,402,981	281,516,604	521,277,000

The contractual maturity of the derivative financial instrument carried at fair value in the condensed balance sheet that is associated with the long-term debt is on 2031.

3. Financial Risk Management (Continued)

Capital Risk Management
The Company's objectives when managing capital are to safeguard the Company's ability to continue as a going concern in order to provide returns for the shareholders and to maintain an optimal capital structure to reduce the cost of capital.

In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to the shareholders, return capital to the shareholders, issue new shares or sell assets to reduce debt. The Company monitors capital on the basis of the "liabilities to tangible net worth ratio", which is one of the ratios that the Company should consider at the time of paying dividends or incurring debt. Capital is defined by Management as the Company's shareholders' equity. This ratio is calculated as liabilities divided by tangible net worth. Liabilities are calculated as total long-term debt, including current portion of long-term debt. Tangible net worth is calculated as "equity" as shown in the condensed balance sheet, including shareholders loan and excluding intangible assets.

This ratio basically measures the leverage of the Company as a percent of the equity invested by the shareholder and provides the percentage of the funding of the Company with borrowing versus shareholders' equity.

The liabilities to tangible net worth ratio were as follows:

	September 2020	December 2019
Liabilities w/o subordinated debt and lease liabilities	88,292,867	85,030,967
Total tangible net worth w/o subordinated debt	230,931,034	251,783,585
Total liabilities to tangible net worth ratio	0.38	0.34

Fair Value Estimation
For disclosure purposes, the International Financial Reporting Standards specify a fair value hierarchy that categorizes into three levels based on the inputs used in valuation techniques to measure fair value: The hierarchy is based on the transparency of variables used in the valuation of an asset at the date of valuation. These three levels are:

- Quoted prices (unadjusted) in active markets for identical assets and liabilities (Level 1).
- Inputs other than quoted prices included within level 1 that are observable for the asset and liability, either directly (that is, as prices) or indirectly (that is, derived from prices) (Level 2).
- Inputs for the asset or liability that are not based on observable market data (that is, unobservable inputs) (Level 3).

3. Financial Risk Management (Continued)

Fair Value Estimation (continued)
The carrying value of cash and cash equivalents, trade and other receivables, trade and other payables approximates its fair value due to the short-term nature.

The fair value of loans payables is disclosed in Note 13.

4. Critical Accounting Estimates and Judgement

Estimates and judgements are continually evaluated by Management and are based on historical experience and on various other assumptions that management believes to be reasonable under the circumstances, the results of which form the basis for making judgements.

Critical Accounting Estimates and Assumptions
The resulting accounting estimates will, by definition, seldom equal the related actual results. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

Depreciation and Amortization of Plant and Equipment
The Company makes judgements in assessing its assets estimated useful lives and in determining estimated residual values, as applicable. Depreciation and amortization are calculated on the straight-line method, based on the estimated useful lives of the assets.

These estimates are based on analysis of the assets' lifecycles and potential value at the end of its useful life. The assets residual values and useful lives are reviewed, and adjusted if appropriate, at each balance sheet date.

Current and Deferred Income Tax Estimation
The Company is subject to income tax. Significant judgment is required in determining the provision for income tax. There are many transactions and calculations for which the ultimate tax determination is uncertain during the ordinary course of business. The Company recognises liabilities for anticipated tax issues based on estimates of whether additional taxes will be due. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the income tax and deferred tax provisions in the period in which such determination is made.

Impairment of Goodwill
The Company tests annually whether goodwill has suffered any impairment, in accordance with the corresponding accounting policy disclosed herein. The recoverable amounts of cash-generating units have been determined based on value-in-use calculations. These calculations require the use of estimates. (See Note 10).

5. Cash and Cash Equivalents for Cash Flows Statement

The cash and cash equivalents for cash flows statement purposes are detailed as follows:

	September 2020	December 2019
Cash in U. S. currency	908,323	1,264,206
Short-term bank deposits at 0.25% (2019: 0.25%) annual interest rate	67,677,515	75,027,086
	68,585,838	76,291,292

The Company reports the restricted cash of US$51,165,263 as cash and cash equivalents for cash flows statement purposes. This amount is presented as part of the short-term bank deposits.

6. Restricted Cash

The current restricted cash represents a committed deposit for the major maintenance plan. The amount arises as a result of the cash compensation as a conclusion of the arbitration process with Goldwind.

The long-term restricted cash represents the balance standing to the credit of the Senior Debt Service Reserve account and the C-Loan Debt Service Reserve accounts, which balance will be used to service the long-term debt described in Note 13.

7. Trade and Other Receivables

Trade and other receivables are detailed as follows:

	September 2020	December 2019
Clients	5,119,638	5,480,249
Related parties (Note 12)	2,009,597	765,248
Insurance claim	-	560,927
Others	55,887	182,331
	7,185,122	6,988,755

Account receivables are less than two months. At September 30, 2020 and December 31, 2019, there were no past due receivables, therefore, the Company has not recorded any provision for impairment.

7. Trade and Other Receivables (Continued)

The Company revenues in PPAs have been paid in the same proportion than the Distribution Companies have been paying since March, April, May and September; the average payments received has been 63%, 89%, 93% and 92%, respectively. Total accounts receivables on hold for the months of March through September is USD4.152 million.

8. Plant and Equipment, Net

Following is the movement of plant and equipment:

	Transportation Equipment	Building	Furniture and Office Equipment	Generators and Plant Facilities	Right of Use Assets	Total
Cost at December 31, 2019	394,461	805,472	639,771	318,834,736	8,568,447	329,242,887
Accumulated depreciation at December 31, 2019	(383,183)	(62,080)	(561,344)	(83,979,048)	(461,150)	(85,446,805)
Net Book Amount	11,278	743,392	78,427	234,855,688	8,107,297	243,796,082
Period ended September 30, 2020						
Opening Net Book Amount	11,278	743,392	78,427	234,855,688	8,107,297	243,796,082
Additions	-	20,135	23,116	-	-	43,251
Depreciation charge	(10,124)	(15,278)	(44,944)	(10,040,118)	(345,862)	(10,456,326)
Closing Net Book Amount	1,154	748,249	56,599	224,815,570	7,761,435	233,383,007
At September 30, 2020						
Cost at September 30, 2020	394,461	825,607	662,887	318,834,735	8,568,447	329,286,137
Accumulated Depreciation	(393,307)	(77,358)	(606,288)	(94,019,165)	(807,012)	(95,903,130)
Net Book Amount	1,154	748,249	56,599	224,815,570	7,761,435	233,383,007

The Company recognized as of January 1, 2019 a right of use asset for US$8,568,447 and a lease liability of US$8,568,447. (See Note 9).

Plant and equipment include interest on borrowings that are directly attributed to the construction of the assets. During the period ended September 30, 2020 and 2019, there were no interest capitalized.

Plant and equipment are included into the onshore Security Agreements which includes the mortgage on movable and immovable assets. (See Note 13).

9. Lease

As of September 30, 2020 plant and equipment include leases which correspond to the operating land lease located in Penonome. Lease terms are between 14-yr and 25-yr contract with 2% interest rate per year until expiration (See Note 8).

The leased properties are presented below:

	September 2020	December 2019
Right-of-use assets		
Cost	8,568,447	8,568,447
Accumulated depreciation	(807,012)	(461,150)
Net balance	7,761,435	8,107,297
Lease liabilities		
Current	135,194	104,301
Non-current	8,252,995	8,385,098
	8,388,189	8,489,399

In applying IFRS 16 for the first time on January 1, 2019, the Company has used the following practical expedients permitted by the standard:

(a) Applying a single discount rate (7.5%) to a portfolio of leases with reasonably similar characteristics, for the nine-months period ended as of September 30, 2020 the Company has recognised US$636,705 (2019: US$619,796) as interest expense related to lease liabilities.
(b) Relying on previous assessments on whether leases are onerous
(c) Accounting for operating leases with a remaining lease term of less than 12 months as at January 1, 2019 as short-term leases
(d) Excluding initial direct costs for the measurement of the right-of-use asset at the date of initial application, and
(e) Using hindsight in determining the lease term where the contract contains options to extend or terminate the lease.

10. Goodwill

In April 2014, IEH Penonome Holdings (former IEH Penonome Panama, S. A., see Note 1) acquired the share capital of UEP Penonome II, S. A. for US$8,518,361. In December 2014, it acquired a further share capital for US$20,000,000 and obtained control of UEP Penonome II, S. A.

The following table summarizes the consideration paid for UEP Penonome II, S. A., the fair value of assets acquired at the acquisition date:

Consideration transferred	
Cash	28,518,361
Recognized amounts of identifiable assets acquired and construction in progress	(8,518,361)
Goodwill	20,000,000

The recoverable amounts of the business unit are calculated based on their value in use. The value in use is determined by discounting the future cash flows expected from the continuous use of each unit. The calculation of value in use is based on the following basic assumptions:

- Business plan for 2019 was used to project future cash flows. Future cash flows were projected using average growth rates based on the long-term assumptions growth rates, projected power generation, power contract price and spot market price. The forecast period is based on the long-term perspective of the Company with respect to the operation of this unit which was determined in 15 years.

- The discount rate of 6.50% was applied in determining the amounts recoverable for the business unit. This rate is calculated on the basis of market experience and the weighted average cost of capital (WACC) allocated for this unit.

The key assumptions described above may change as economic and market conditions change. The Company estimates that reasonably possible changes in these assumptions are not expected to affect the recoverable amount of the business unit or drops below the value of the carrying amount.

11. Trade and Other Payables

Trade and other payables are detailed as follows:

	September 2020	December 2019
Interest payable on shareholder's loans (Notes 12 and 14)	15,385,172	15,385,172
Related parties (Note 12)	5,084,388	4,838,739
Suppliers	4,590,061	7,858,469
Interest payable	686,333	5,349,737
Others	384,786	711,880
Lease liabilities short-term (Note 9)	135,194	104,301
	26,265,934	34,248,298

12. Balances and Transactions with Related Parties

The Company is fully controlled by InterEnergy Partners, L. P., its ultimate parent company. The Company carried out transactions and maintained balances with related companies, as described below:

	Three months ended September 30, 2020	2019
Transactions		
Professional fees expenses (a)	142,916	-
Energy purchases in the spot market (b)	536	4,551
Energy sold in the spot market (b)	1,419	1,964
Energy sold under reserve contracts (c)	172,515	364,097

12. Balances and Transactions with Related Parties (Continued)

	Nine months ended September 30, 2020	2019
Transactions		
Professional fees expenses (a)	372,996	-
Energy purchases in the spot market (b)	872	11,321
Energy sold in the spot market (b)	13,020	89,192
Energy sold under reserve contracts (c)	1,552,546	1,615,679

	September 2020	December 2019
Balances		
Accounts receivable energy spot market (b)	784	1,461
Accounts receivable energy reserve contracts (c)	1,552,546	307,520
Accounts receivable professional fees (d)	456,267	456,267
	2,009,597	765,248
Accounts payable professional fees (a)	5,083,977	4,836,821
Accounts payable energy spot market (b)	411	1,918
	5,084,388	4,838,739
Shareholders' loans (Note 14)	50,000,000	50,000,000
Interest payable - shareholders' loans (Note 14)	15,385,172	15,385,172

(a) Administrative and asset management services rendered by related parties.

(b) Sales and purchases of energy with related parties in the energy spot market.

(c) Energy Reserve Contracts described in Note 18.

(d) Accounts receivable for services rendered to a related party.

12. Balances and Transactions with Related Parties (Continued)

Key Management Compensation

Key management includes directors (executive and non-executive) and some members of the internal executive committee. The Company does not have post-employment benefits, share-based payments nor other long-term benefits. The compensation paid or payable to key management for employee services is shown below:

	Three months ended September 30, 2020	2019
Salaries and other short-term employee benefits	193,995	45,474

	Nine months ended September 30, 2020	2019
Salaries and other short-term employee benefits	283,466	131,888

13. Long-Term Debt

	September 2020	December 2019
International Finance Corporation (IFC)		
US$250 million senior debt, International Finance Corporation (IFC); The Netherlands Development Finance Company (FMO); French Development Institution (Proparco); Development Bank of the (Austrian Republic OeEB); Central American Bank for Economic Integration (Cabei); Banco Nacional as Lenders; Tenor: 17-years door to door. Tailored amortization scheduled stepping up from 2.4% in average for the first 22 semesters (53% of total amount); 3.66% for the following 6 semesters (22% of total amount) and 6.27% for the last 4 semesters (25% of total amount), hedging agreement to fix rate on a minimum of US$180 million of the total Senior	187,790,012	203,025,000
Carry forward…	187,790,012	203,025,000

13. Long-Term Debt (Continued)

	September 2020	December 2019
Brought forward…	187,790,012	203,025,000
Banco General and Corporacion Interamericana para el Financiamiento de Infraestructura, S. A. (CIFI) US$34 million, Tailored amortization scheduled stepping up from 2.91% in average for the first 16 semesters (47% of total amount) and 4.45% for the following 12 semesters (53% of total amount); Priced at LIBOR + 4.50%	24,208,000	25,500,000
IFC Subordinated C-Loan of US$16 million US$16 million 17-years door to door. Tailored amortization scheduled stepping up from 2.17% in average for the first 18 semesters (39% of total amount); 3.50% for the following 10 semesters (35% of total amount) and 6.5% for the last 4 semesters (26% of total amount); Fix rate at 12%. 13% per annum at any time following the occurrence and during the continuance of a C-Loan Deficiency	12,704,000	13,440,000
	224,702,012	241,965,000
Less: Unamortized finance costs	8,561,762	9,159,290
Long-term debt, net	216,140,250	232,805,710
Less: Current portion	12,296,000	12,803,000
	203,844,250	220,002,710

The movement of the unamortized finance costs is as follows:

	September 2020	December 2019
Beginning balance	9,159,290	9,955,994
Amortization	(597,528)	(796,704)
Ending balance	8,561,762	9,159,290

13. Long-Term Debt (Continued)

The fair value of the borrowings is US$213,196,784 (2019: US$274,236,211), based on discounted cash flows using a rate based on the borrowing rate of 6.5% and is within Level 3 of the fair value hierarchy.

The main conditions and terms on the outstanding borrowings are described as follows:

Senior Debt Agreements:

a) Senior Debt of US$250 million:

International Finance Corporation (IFC); The Netherlands Development Finance Company (FMO); French Development Institution (Proparco); Development Bank of the Austrian Republic (OeEB); Central American Bank for Economic Integration (Cabei); Banco Nacional as Lenders:

- Tenor: 17-years door to door. Tailored amortization scheduled stepping up from 2.4% in average for the first 22 semesters (53% of total amount); 3.66% for the following 6 semesters (22% of total amount) and 6.27% for the last 4 semesters (25% of total amount).
- Priced at LIBOR + 4.75%.
- Hedging agreement to fix rate on a minimum of US$180 million of the total Senior with IFC. (On which the Company has not applied hedge accounting).
- On March 9, 2015, the Company contracted a receive-floating interest rate swaps by which the Company agrees to exchange the difference between fixed and floating interest rate amounts calculated on agreed notional principal amounts for US$180,000,000. Such contract enables the Company to mitigate the risk of changing interest rates on the cash flow exposures on the issued variable rate debt.

b) Senior Debt of US$34 million:

- Banco General and Corporacion Interamericana para el Financiamiento de Infraestructura, S. A. (CIFI) as Lenders.
- Tenor: 15-years door to door. Tailored amortization scheduled stepping up from 2.91% in average for the first 16 semesters (47% of total amount) and 4.45% for the following 12 semesters (53% of total amount).
- Priced at LIBOR + 4.50%.

13. Long-term Debt (Continued)

c) Subordinated C-Loan of US$16 million:

- IFC as lender.
- Tenor: 17-years door to door. Tailored amortization scheduled stepping up from 2.17% in average for the first 18 semesters (39% of total amount); 3.50% for the following 10 semesters (35% of total amount) and 6.5% for the last 4 semesters (26% of total amount).
- Fix rate at 12%. 13% per annum at any time following the occurrence and during the continuance of a C-Loan Deficiency.
- Subordination: in the event that on a debt service payment date a C-Loan deficiency occurs, IFC agrees that it shall not exercise any remedies with respect to the relevant outstanding due and payable amount of principal arising from such C Loan Deficiency.

Common Term Agreement (CTA): Whereby the Lender of each of the Senior Debt and the Subordinated C-Loan the Lenders set forth the terms and conditions in common to each loan.

Security Agreements:

- Offshore Security Agreements: Whereby the Borrowers - IEH Penonome Panama, S. A. and UEP Penonome II, S. A. (hereinafter "UEP II") - grant first priority security interest in all of its rights, titles and interest of Major Project Documents (Turbine Supply Agreement, Goldwind Parent Master Agreement, BOP Contract, Transportation Agreement, Interconnection Agreement, Shared Asset Agreement); proceeds from asset disposals, insurance proceeds. Citibank N. A. acting as Offshore Security Agent.

- Onshore Security Agreements: Includes the pledge on the shares of the Borrowers; collateral assignment on generation licenses, power purchase agreements and ANATI lease titles; mortgage on movable and immovable assets. The Bank of Nova Scotia (Panama) acting as Onshore Security Agent and trustee.

- Master Account and Security Agreements: Whereby the Borrowers certify that they have established Offshore Accounts with the Offshore Account Bank (Citibank, NA) and Onshore Account Banks [The Bank of Nova Scotia (Panama)] in accordance with the Trust Agreements. Offshore Accounts includes Senior Debt Service Reserve account and C-Loan Debt Service Reserve accounts representing the following Debt Service amount on each Loan. The agreement states the procedures to transfer from the Revenue account in accordance with the Common Term Agreement; including Restricted Payments.

13. Long-term Debt (Continued)

Security Agreements: (continued)
Covenants: a) maintenance of existence and conduct of business; b) accounting and management operation system in accordance with the Accounting Standard c) Auditors: maintain at all times international recognized independent public accountant firm acceptable to the lenders d) Access: upon lender request, give access to the site, books and records and borrower employees e) maintain at all times in full force and effect authorizations, security in favor of lenders and project documents payment of obligations f) comply with the construction budget and the major maintenance plan g) interest rate hedging with initial amount of no less than hundred and eighty million Dollars h) financial ratios: prospective debt service coverage ratio of at least 1.15:1.00; among others.

Negative Covenants: The following activities are prohibited: a) make any restricted payment (which means declaration or payment of dividends, distribution of capital securities, payment of shareholder loan capital or interest), unless such restricted payment (i) is made from the restricted payment account (ii) such payment will be made within thirty (30) days after an Interest Payment Date (iii) the Prospective Debt Service Coverage Ratio is not less than 1.20:1.0 (iv) the Prospective Total Debt Service Coverage Ratio is not less than 1.10:1.0 (v) after giving effect to any such action the Financial Debt to Tangible Net Worth Ratio is not more than 3.1:1.0 and (vi) debt service reserve account, major maintenance reserve account and the C-Loan reserve account are fully funded. b) Capital expenditures besides those required to carry out operations normally c) additional financial debt d) guarantees or liens e) asset sales f) financial investments other than permitted investments in high grade securities, among others.

14. Shareholders' Equity

	Common Shares	Capital Contribution	Total
Initial and ending balances for the period ended September 30, 2020 and December 31,2019	1,050	74,998,950	75,000,000

The Company reclassified the equity contribution pursuant the subscription of shares into a combination of common stocks and bearing interest shareholders' loans. The combination is as follows:

- IEH Penonome Holdings: 95.24% economic interest in common shares (US$71.4 million).
- IEH Penonome Holdings: US$47.6 million in bearing interest shareholder loan, fixed rate at 8%, maturity 2031.
- Greenfield Panama, S. A.: 4.76% economic interest in common shares (US$3.5 million).

14. Shareholders' Equity (Continued)

- Greenfield Panama, S.A.: US$2.4 million in bearing interest shareholder loan, fixed rate at 8%, maturity 2031.

After the aforementioned contribution took place, the shareholders composition of the Company is the following:

IEH Penonome Holdings	95.24% economic interest
Greenfield Panama, S. A.	4.76% economic interest

15. Costs and Expenses

The Company classifies its costs and expenses by nature, as follows:

	Three months ended September 30,	
	2020	2019
Cost of goods and services		
Depreciation and amortization (Notes 8 and 9)	3,485,749	3,381,025
Fee transmission cost	53,081	18,837
Salaries and other benefits to employees	103,437	132,332
Energy purchase	112,701	352,657
Repairs and maintenance	-	-
	3,754,968	3,884,851
Administrative expenses		
Salaries and other benefits to employees	194,545	175,226
Insurance costs	144,903	151,180
Other expenses	97,247	(266,614)
Regulator fees	120,521	106,209
Connection Fee Substation	119,490	112,223
Wake effect compensation (Note 18)	144,905	83,519
Professional fees	135,297	609,725
Management service agreement	95,594	(202,533)
Communication expenses	3,047	26,912
Maintenance office	4,919	14,957
Fuel	3,750	5,516
Office expenses	894	2,143
Donations	-	13,608
Electricity	-	418
	1,065,112	832,489
Operating expenses		
Repairs and maintenance	1,438,952	1,756,269
Security	70,206	107,891
	1,509,158	1,864,160
	6,329,238	6,581,500

15. Costs and Expenses (Continued)

	Nine months ended September 30, 2020	2019
Cost of goods and services		
Depreciation and amortization (Notes 8 and 9)	10,456,326	10,361,768
Fee transmission cost	809,391	880,282
Salaries and other benefits to employees	359,907	363,487
Energy purchase	185,320	642,540
Repairs and maintenance	963	8,274
	11,811,907	12,256,351
Administrative expenses		
Salaries and other benefits to employees	563,909	499,737
Insurance costs	499,810	453,540
Other expenses	402,758	243,687
Regulator fees	361,564	318,625
Connection Fee Substation	358,469	354,184
Wake effect compensation (Note 18)	324,017	584,719
Professional fees	296,547	609,725
Management service agreement	241,875	-
Communication expenses	30,719	98,564
Maintenance office	12,103	24,759
Fuel	6,695	14,250
Office expenses	2,586	6,464
Donations	-	27,196
Electricity	-	790
	3,101,052	3,236,240
Operating expenses		
Repairs and maintenance	3,994,646	4,093,037
Security	223,180	359,637
	4,217,826	4,452,674
	19,130,785	19,945,265

15. Costs and Expenses (Continued)

Salaries and other benefits to employees are summarized as follows:

	Three months ended September 30, 2020	2019
Salaries and wages	247,667	229,233
Statutory contributions	38,006	33,869
Other	7,649	28,563
Seniority premium and indemnity	4,660	15,893
	297,982	307,558

	Nine months ended September 30, 2020	2019
Salaries and wages	770,889	668,015
Statutory contributions	105,271	99,745
Other	26,614	47,846
Seniority premium and indemnity	21,042	47,618
	923,816	863,224

Salaries and other benefits to employees are included in costs of goods and services, administrative and operating expenses as follows:

	Three months ended September 30, 2020	2019
Cost of goods and services	103,437	132,332
Administrative expenses	194,545	175,226
	297,982	307,558

	Nine months ended September 30, 2020	2019
Cost of goods and services	359,907	363,487
Administrative expenses	563,909	499,737
	923,816	863,224

16. Finance Cost, Net

Finance cost are detailed as follows:

	Three months ended September 30, 2020	2019
Interest on borrowings and lease liabilities, net	(4,235,510)	(5,012,481)
Fair value loss on derivative financial instrument	1,858,438	(3,656,226)
	(2,377,072)	(8,668,707)

	Nine months ended September 30, 2020	2019
Interest on borrowings and lease liabilities, net	(13,609,557)	(15,295,720)
Fair value loss on derivative financial instrument	(10,936,920)	(11,738,887)
	(24,546,477)	(27,034,607)

17. Income Tax

The income tax is presented as follows:

	September 2020	September 2019
Current tax	-	307,602
Deferred tax	(175,747)	2,243,670
	(175,747)	2,551,272

The movement in deferred income tax liabilities during the year is as follows:

	September 2020	September 2019
Deferred income tax liabilities		
At January 1	2,224,202	580,149
Accelerated tax depreciation charged to the condensed statement of comprehensive income	(175,747)	2,243,670
At September 30	2,048,455	2,823,819

17. Income Tax (Continued)

Deferred tax liability is the result of temporary differences from accelerated tax depreciation.

Under current tax legislation in the Republic of Panama, the profits of the Company from local operations are subject to income tax.

Income tax is based on the higher of the following computations:

a. The rate of 25% on taxable income.
b. The net taxable profit resulting from applying 4.67% to the total taxable income times the rate of 25% which represents 1.17% of taxable income (alternative minimum tax).

In certain circumstances, if the application of 1.17% of revenue results in the entity incurring losses for tax reasons, or the effective tax rate is higher than 25%, then the entity may choose to request not to apply minimum tax. In such cases, the Company must file a petition to the Tax Authority, who may authorize the no application for a term of three years.

The income tax resultant by applying the in-force rates to the net profit (loss), is reconciled with the income tax provision presented in the financial statements, as follows:

	2020	2019
(Loss) profit before income tax	(3,943,965)	2,159,968
Fiscal adjustment to recognize accelerated depreciation	(8,193,821)	(11,295,276)
Less: Non-taxable income	(54,403)	(142,760)
Plus: Non-deductible expenses	10,936,919	11,738,887
Taxable (loss) income	(1,255,270)	2,460,819
Loss carried forward	-	(1,230,409)
Net taxable gain	-	1,230,410
Income tax (traditional method)	-	307,602

17. Income Tax (Continued)

According to Tax Legislation of Panama, income tax returns for the last three (3) years are subject to review by fiscal authorities, including year ended December 31, 2019.

Management requested to the Tax Authority the non-application of the CAIR for the 2019 fiscal year. The request was accepted and approved for the fiscal years 2019, 2020 and 2021.

Law No.52 of August 28, 2012, established the transfer pricing regime oriented to regulate tax purposes transactions between related parties, and applicable to the taxpayer to perform operations with related parties that are tax residents of other jurisdictions. The most important aspects of this regulation include:

- Taxpayers must submit annually an information return related operations with related parties, within six (6) months following the close of the relevant fiscal period. This obligation applies to transactions from fiscal year 2012.

- Failure to submit the report shall be punishable by a fine equivalent to 1% of the total amount of transactions with related parties.

- Persons required to submit the report referred to in the preceding paragraph, shall maintain a transfer pricing study, which shall contain the information and analysis to assess and document their transactions with related parties, in accordance by Law. The taxpayer must present study only at the request of the Department of Revenue of the Ministry of Economy and Finance within 45 days of your request.

18. Commitments

- The Company has twelve PPA Contract's assigned by three to Nuevo Chagres, Portobelo, Rosa de los Vientos and Maranon parks. The PPA's were awarded on March 21, 2012, by which energy production is sold to the three distribution companies in Panama: Empresa de Distribucion Electrica Metro-Oeste, S. A. (EDEMET) (controlled by Gas Natural Fenosa), Empresa de Distribucion Electrica Chiriqui, S. A. (EDECHI) (controlled by Gas Natural Fenosa) and Elektra Noreste, S. A. (ENSA) (controlled by Empresas Publicas de Medellin).

  Each PPA states that the energy supply period is for 180 months, beginning on July 1, 2014 and finishing on September 30, 2029. Portobelo and Maranon PPA's were extended until December 2033. Price will be reset annually, keeping 75% of the base price fixed and the remaining 25% will be indexed to Panamanian Consumer Price Index (CPI). In the event that the Company is unable to fulfill its obligations under any of the contracts, the performance bonds that support the obligations may be drawn by the customers. The amounts of the performance bonds outstanding as at September 30, 2020 were US$17,884,164 (2019 US$21,492,232).

  In December 2014, the Company signed the Wake Effect Agreement with UEP Penonome I, S. A., in which UEP II must compensate UEP Penonome I, S. A. (hereinafter "UEP I") for the energy losses caused by the preferred physical position of the wind turbines which impact the wind regime. The Company agrees to pay a monthly payment beginning with the Commercial Operation Date occurred on February 19, 2018, for 25 years term. The wake effect compensation amount is disclosed in Note 15.

18. Commitments (Continued)

- In January 2016, the Company signed the Amendment No.4 of the PPA's with the offtaker to solve some sections that were ambiguous and penalized UEP II, even if the Company supplied the energy generated.

  This amendment clarifies the following subjects:

  1. The PPAs contemplate a penalty if the wind farm does not reach the expected generation committed in the PPAs. The portion that the wind farm has to comply in order to avoid such penalty is 0.6 (60%), "Fraccion de la Generacion Esperada" (FGE, for its acronym in Spanish) that represents the portion of the expected generation on an annual basis.

     Based on the historical data, the probability of such penalty is remote because it depends on the energy compromised in the PPA. Historical data shows that even in the worst-case scenario the wind farm complies with 0.6. Also, the buyer must acquire all the energy produced by the seller, so the committed energy in PPAs is less than the energy produced and sold.

  2. The base Consumer Price Index (CPI) was fixed to 93.05 to match with the CPI base that reports the Contraloria Nacional de Panama each month.

- On March 16, 2016, the Company was awarded four PPA Contract's by ETESA, through Resolution GC-03-2016, for hiring short-term energy supply only for 2017 until 2019, which will address the requirements of the companies EDEMET, EDECHI and ENSA. This energy it will be supply for Rosa de los Vientos (SPOT).

- On November 10, 2017, the Company has signed a reserve contract with its affiliated generator Tecnisol I, by which the excess energy production of Rosa de los Vientos II (50 MW) Wind farm is sold to cover the affiliated company obligations with the market. The Reserve Contract states that the energy supply period is for 12 months (extendable), beginning at the moment the CND (National Dispatch Center) declares the Contract manageable and finishing one year later with the option to extend the supply period if desired by the Contract Parties. Contract Price will be fixed for all the energy supply period.

18. Commitments (Continued)

- Turbine Supply Agreement (TSA) consists in 86 Goldwind G109 2.5 MW wind turbine generators with a hub height of 90 meters to be procured pursuant to an Amended and Restated Turbine Supply Agreement entered on April 23, 2014 (TSA) and further amended on December 10, 2014 with Goldwind International Holdings (HK) Limited, a subsidiary of wind manufacturer Xinjiang Goldwind Science and Technology ("Goldwind") and together Goldwind Company; for the supply of:

  - 66 turbines contracted energy totaling 165 MW; divided in four wind parks:

    - Nuevo Chagres 62.5 MW.
    - Portobelo 32.5MW.
    - Rosa de los Vientos 52.5 MW.
    - Maranon 17.5 MW and.

  - 20 turbines partially contracted and merchant energy totaling 50 MW.

- Under the TSA, Goldwind Company provides a five years warranty on the equipment for defects, power curve, availability and noise. Availability is guaranteed at 95% during the warranty period. In addition, the Company entered into a 5-year service and maintenance agreement (SMA) with Goldwind Company for the operation, maintenance, repair and replacement services on the wind turbines at a fixed price adjusted for inflation, including warranties for availability and noise in line with those during the warranty period. It includes a full warranty for years 3 to 5, and the availability guarantee of 95% for those years. This SMA contract can be extended by UEP II until year ten.

- Balance of plant works are performed pursuant to a turn-key agreement for the civil works, electric and communication infrastructure, interconnection to the medium tension gird (34,5 kV), construction of the control and operations buildings and all other installation required by the Interconnected System (BOP Contract); entered into by the Company and Instalacion y Servicios CODEPA, S. A. is a Panamanian subsidiary of Grupo Cobra, on October 14, 2014, and amended on April 23, 2014.

- Delivery of turbines under the TSA was at China Port. Sea and inland transportation are provided by Tree Logistic pursuant a transportation agreement dated April 23, 2014, ended 2015.

18. Commitments (Continued)

- ASEP (the regulator) granted final license for the construction, operation, maintenance, power generation and sale of wind farms Maranon, Portobelo Ballestillas, Rosa de los Vientos and New Chagres a Panamanian company Union Eolica Panameña, S. A. (UEP) through Resolutions AN No.4075-Elec the December 10, 2010, AN No.4092-Elec the December 15, 2010, AN No.5379-Elec the September 13, 2012 and AN No.4094-Elec the December 15, 2010, respectively. This final license is granted for a term of forty (40) years from September 26, 2014.

- Subsequently, the ASEP issued resolutions AN No.7252-Elec the April 11, 2014, AN No.7274-Elec the April 11, 2014, AN No.7278-Elec the April 14, 2014 and No.7326 AN-Elec of May 2, 2014, in which is authorized yield UEP for Penonome II, S. A., the final licenses originally granted to UEP.

- On September 15, 2018, the Company and UEP Penonome I, S. A., signed the Phase II Shared Assets Access Agreement, pursuant to which the Company agreed to pay to UEP I, who is the owner of and maintains the El Coco Substation to which UEP II's wind park connects, a monthly access fee of US$27,130 and the reimbursement of maintenance costs.

19. Impact of COVID-19

On March 11, 2020, the World Health Organization declared the coronavirus strain (COVID-19) in the category of pandemic.

The COVID-19 pandemic has affected the Wholesale Electricity Market (The Market) in Panama, since March the Government decreed a total quarantine with movement restrictions, this caused many businesses and industries to remain closed or reduce their production capacity, which in turn caused a wave of layoffs and work contract suspensions, this caused an economic crisis in the country and in the electricity sector since many people did not have the resources to pay for their electricity bills.

19. Impact of COVID-19 (Continued)

To minimize the effect of the pandemic the Government approved the Decree 291 of May 13th, 2020 that established a moratorium for the months from March to September to establish a non-obligation of payment for the people affected by the pandemic. With great part of the regulated clients not paying, this decreased the cash flow of the Distribution Companies and these could not keep with their payments to the Generation Companies. The foregoing caused a domino effect in the Market since the lack of liquidity of the Distribution Companies prevented them from fulfilling the full payments of the PPAs with the Generation Companies and ASEP through resolution AN No- 16095-Ele of May 21th 2020 let the Distribution Companies to pay proportionally with their income the commitments with the Market and also allows the Generation Companies affected by the pandemic due to this lack of payment by the Distribution Companies to pay their DTE (Economic Transactions Document) obligations proportionally without their payment guarantee being executed by the CND (National Dispatch Center).

UEP Penonome II, S. A.

Report and Financial Statements
December 31, 2019

UEP Penonome II, S. A.

Index to the Financial Statements
December 31, 2019

PricewaterhouseCoopers, S.R.L.

Independent Auditors' Report

To the Board of Directors and Shareholders of
UEP Penonome II, S. A.

Our opinion

In our opinion, the financial statements of UEP Penonome II, S. A. (the "Company") present fairly, in all material respects, the financial position of the Company as at December 31, 2019, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

What we have audited

The Company's financial statements comprise:

- the balance sheet as at December 31, 2019;
- the statement of comprehensive income for the year then ended;
- the statement of changes in equity for the year then ended;
- the statement of cash flows for the year then ended; and
- the notes to the financial statements, which include a summary of significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Company in accordance with the International Ethics Standards Board for Accountants' Code of Ethics for Professional Accountants (IESBA Code), and the ethical requirements that are relevant to our audit of the financial statements in the Republic of Panama. We have fulfilled our other ethical responsibilities in accordance with the IESBA Code and the ethical requirements of the Republic of Panama.

Emphasis of matter

We draw attention to Note 22 to the financial statements, which describes the restatement and reissuance of the financial statements due to the correction of the accounting treatment applied to derivative financial instrument and cash compensation received. We issued our original auditor's report dated May 29, 2020 on the previously issued financial statements. Due to the restatement described in Note 22, we provide this new auditor's report on the reissued financial statements.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with ISAs, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

PricewaterhouseCoopers

October 8, 2020
Panama, Republic of Panama

UEP Penonome II, S. A.

Balance Sheet
December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019 Restated *	2018 Restated *	2017 Restated *
Assets				
Current assets				
Cash and cash equivalents	2 and 5	25,126,029	60,837,269	2,003,036
Restricted cash	2, 5 and 6	51,165,263	-	11,964,372
Trade and other receivables	2, 7 and 15	6,988,755	9,708,289	5,681,889
Prepaid expenses		573,720	646,397	591,091
Total current assets		83,853,767	71,191,955	20,240,388
Non-current assets				
Plant and equipment, net	2, 8 and 9	243,796,082	249,148,511	317,834,655
Deferred income tax	17	-	-	1,041,458
Restricted cash	6	17,272,000	17,272,000	17,272,000
Goodwill	2 and 10	20,000,000	20,000,000	20,000,000
Derivative financial instrument		-	893,870	-
Total non-current assets		281,068,082	287,314,381	356,148,113
Total assets		364,921,849	358,506,336	376,388,501
Liabilities and Equity				
Current liabilities				
Current portion of long-term debt	2 and 12	12,803,000	14,451,000	15,324,000
Trade and other payables	2, 11 and 15	34,248,298	30,644,088	36,800,709
Total current liabilities		47,051,298	45,095,088	52,124,709
Non-current liabilities				
Shareholders' loans	15	50,000,000	50,000,000	50,000,000
Lease liabilities long term	9	8,385,098	-	-
Deferred income tax	17	2,224,202	580,149	-
Long-term debt	2 and 12	220,002,710	232,009,006	245,663,302
Derivative financial instrument		7,822,058	-	2,962,275
Total non-current liabilities		288,434,068	282,589,155	298,625,577
Total liabilities		335,485,366	327,684,243	350,750,286
Equity				
Common shares with US$1 par value each; authorized and issued: 1,050 shares	2 and 13	1,050	1,050	1,050
Capital contribution	2 and 13	74,998,950	74,998,950	74,998,950
Accumulated deficit		(45,563,517)	(44,177,907)	(49,361,785)
Total equity		29,436,483	30,822,093	25,638,215
Total liabilities and equity		364,921,849	358,506,336	376,388,501

* See Note 22 for details regarding the restatement.

The accompanying notes are an integral part of these financial statements.

UEP Penonome II, S. A.

Statement of Comprehensive Income
For the year ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019 Restated *	2018 Restated *	2017 Restated *
Energy revenue		56,069,859	50,310,461	42,404,370
Costs of goods and services	8, 9 and 14	(16,289,094)	(19,572,202)	(29,149,561)
Gross profit		39,780,765	30,738,259	13,254,809
Expenses	14			
Administrative expenses		(4,278,136)	(5,773,244)	(10,869,785)
Operating expenses		(6,377,825)	(5,455,031)	(4,129,058)
Total expenses		(10,655,961)	(11,228,275)	(14,998,843)
Operating profit		29,124,804	19,509,984	(1,744,034)
Finance cost amortization	12	(796,704)	(796,704)	(796,704)
Finance cost, net	16	(28,630,584)	(20,095,926)	(24,116,638)
Total finance cost		(29,427,288)	(20,892,630)	(24,913,342)
Other income		560,927	8,879,417	-
Profit (loss) before income tax		258,443	7,496,771	(26,657,376)
Income tax	17	(1,644,053)	(2,312,893)	1,697,970
Total comprehensive (loss) income for the year		(1,385,610)	5,183,878	(24,959,406)

* See Note 22 for details regarding the restatement.

The accompanying notes are an integral part of these financial statements.

UEP Penonome II, S. A.

Statement of Changes in Equity
For the year ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Common Shares	Capital Contribution	Accumulated Deficit	Total Equity
Balance at December 31, 2016 as originally presented	1,050	74,998,950	(20,940,631)	54,059,369
Effect of restatement (Note 22)	-	-	(3,461,748)	(3,461,748)
Restated total equity as at December 31, 2016	1,050	74,998,950	(24,402,379)	50,597,621
Comprehensive loss:				
Net loss	-	-	(24,959,406)	(24,959,406)
Balance at December 31, 2017 *	1,050	74,998,950	(49,361,785)	25,638,215
Comprehensive income:				
Net income	-	-	5,183,878	5,183,878
Balance at December 31, 2018 *	1,050	74,998,950	(44,177,907)	30,822,093
Comprehensive loss:				
Net loss	-	-	(1,385,610)	(1,385,610)
Balance at December 31, 2019 *	1,050	74,998,950	(45,563,517)	29,436,483

* See Note 22 for details regarding the restatement.

The accompanying notes are an integral part of these financial statements.

UEP Penonome II, S. A.

Statement of Cash Flows
For the year ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019 Restated *	2018 Restated *	2017 Restated *
Cash flows from operating activities				
Profit (loss) before income tax		258,443	7,496,771	(26,657,376)
Adjustments to reconcile profit (loss) before income tax to net cash provided by operating activities:				
Depreciation and amortization	8, 9 and 14	13,969,487	17,535,133	25,643,520
Finance cost amortization	12	796,704	796,704	796,704
Interest on borrowings, net	16	19,914,656	23,952,071	24,616,111
Fair value loss (gain) on derivative financial instrument	16	8,715,928	(3,856,145)	(499,473)
Net changes in assets and liabilities:				
Trade and other receivables		2,719,534	(4,026,400)	(206,903)
Trade and other payables		4,480,065	(10,705,136)	3,431,247
Prepaid expenses		72,676	(55,305)	1,675,355
Interest paid		(20,894,811)	(20,094,843)	(20,865,105)
Net cash provided by operating activities		30,032,682	11,042,850	7,934,080
Cash flows from investing activities				
Additions of plant and equipment	8	(48,611)	(14,252)	(146,724)
Cash compensation	19	-	51,165,263	-
Restricted cash	6	-	11,964,372	-
Net cash (used in) provided by investing activities		(48,611)	63,115,383	(146,724)
Cash flows from financing activities				
Repayment of long-term debt	12	(14,451,000)	(15,324,000)	(14,377,000)
Principal lease payments	9	(79,048)	-	-
Net cash used in financing activities		(14,530,048)	(15,324,000)	(14,377,000)
Net increase (decrease) in cash and cash equivalents		15,454,023	58,834,233	(6,589,644)
Cash and cash equivalents at the beginning of year		60,837,269	2,003,036	8,592,680
Cash and cash equivalents and restricted cash at the end of year	5	76,291,292	60,837,269	2,003,036

* See Note 22 for details regarding the restatement.

The accompanying notes are an integral part of these financial statements.

1. General Information

UEP Penonome II, S. A. (the "Company") is incorporated on January 18, 2013 under the laws of the Republic of Panama. The Company is engaged in the production of electricity through its five wind parks located in Penonome, Province of Cocle, Republic of Panama.

The ultimate parent company of UEP Penonome II, S. A. is Interenergy Partners, L. P., incorporated in Cayman Island.

The local regulator, Autoridad Nacional de los Servicios Publicos (ASEP, by its acronym in Spanish), approved the Company's electricity generation license to 215 MW capacity (Note 18).

The Company is located in Torre de las Americas, Punta Pacifica, Republic of Panama, and the wind turbines are in Penonome, Republic of Panama.

These financial statements have been approved for issue by the Finance Manager on October 8, 2020.

2. Summary of Significant Accounting Policies

The principal accounting policies applied in the preparation of these financial statements are set out below.

Basis of Preparation
The financial statements of the Company have been prepared in accordance with International Financial Reporting Standards (IFRS) and the related interpretations adopted by the International Accounting Standards Board (IASB). The financial statements have been prepared on the historical cost convention, except for derivative financial instruments measured at fair value.

The preparation of financial statements in conformity with IFRS requires the use of certain critical accounting estimates. It also requires Management to exercise its judgement in the process of applying the Company's accounting policies. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in Note 4.

2. Summary of Significant Accounting Policies (Continued)

Basis of Preparation (continued)

New Standards, Amendments and Interpretations Adopted by the Company
The Company has applied the following standard for the first time in its annual reporting period commencing January 1, 2019:

IFRS 16 - Leases

The Company has initially applied IFRS 16, for the first time for their annual reporting period commencing January 1, 2019.

- IFRS 16 - Leasing. The IASB issued in January 2016, IFRS 16, which replaces IAS 17-Leases. This standard introduces significant changes in accounting by lessee.

- The Company applied the simplified approach, in which the comparative figures are not restate at the date of initial application. The right-of-use assets for property leases will be initially measured on a retrospective basis as if the new standard had always been applied. All other right-of-use assets will be measured at the amount equal to the lease liability at the time of adoption (adjusted for prepaid or accrued lease payments relating to that lease recognized). In addition, the Company has decided not to apply the new standard to leases whose term will end within twelve months of the date of initial application. In such cases, the leases are accounted for as short-term leases and the lease payments associated with them are recognized as an expense from short-term leases. There is not any lease under the low value exemption.

In the context of the transition, the Company recognized as of January 1, 2019 a right of use asset for US$8,568,447 and a lease liability of US$8,568,447. (See Note 9).

Accounting policy applied until December 31, 2018

A lease agreement in which the lessor transfers to the lessee, in exchange for a payment or a series of payments, the right to use an asset for an agreed period is classified as a finance lease.

A lease agreement was defined as an agreement in which the lessor conveys to the lessee the right to use an asset for a specified period in return for a payment or several payments. In accordance with IAS 17, beneficial ownership of the leased assets was attributed to the lessee if the lessee substantially bore all the risks and rewards inherent to ownership of the leased asset.

2. Summary of Significant Accounting Policies (Continued)

Basis of Preparation (continued)

New Standards, Amendments and Interpretations Adopted by the Company (continued)

IFRS 16 - Leases (continued)

Accounting policy applied until December 31, 2018 (continued)

Leases were recognized to the extent that beneficial ownership was attributable to the Company as a lessee. Financial leases were capitalized at the beginning of the lease, either at fair value of the leased property or, if less, at the present value of the minimum lease payments. A lease liability in the same amount was recognized as a non-current liability. The lease was subsequently measured at amortized cost using the effective interest method. The depreciation methods and estimated useful lives corresponded to those comparable purchased assets.

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to the statement of comprehensive income on a straight-line basis over the period of the lease

Accounting policy applied as of January 1, 2019

Lease liabilities include the following lease payments:

- fixed payments, less any lease incentives receivable,
- variable lease payment that are based on an index or a rate,
- amounts expected to be payable by the Company under residual value guarantees,
- the exercise price of a purchase option if the Company is reasonably certain to exercise that option, and
- payments of penalties for terminating the lease, if the lease term reflects the group exercising that option.

The lease payments are discounted using the interest rate implicit in the lease, to the extent that this can be determined. Otherwise, the discount is the lessee's incremental borrowing rate.

Right-of-use assets are measured at cost comprising the following:

- The amount of the initial measurement of lease liability.

2. Summary of Significant Accounting Policies (Continued)

Basis of Preparation (continued)

New standards, amendments and interpretations not yet adopted
Certain new accounting standards and interpretations have been published that are not mandatory for December 31, 2019 reporting periods and have not been early adopted by the Company. These standards are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

Monetary Unit and Functional Currency
The financial statements are expressed in U.S. Dollars (US$), monetary unit of the United States of America, which is at par with the Balboa (B/.), monetary unit of the Republic of Panama. The U.S. Dollar (US$) circulates and is freely exchangeable in the Republic of Panama and is the functional currency.

Financial Assets
The Company classifies its financial assets in the category of loans and receivables and assets at fair value through profit or loss, based on the purpose for which the financial assets were acquired. Management determines the classification of its financial assets at initial recognition.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Loans and receivables with maturities not greater than 12 months are included in current assets.

Derivatives
Derivatives are initially recognized at fair value on the date a derivative contract is entered into, and they are subsequently remeasured to their fair value at the end of each reporting period. Derivative instruments that were not defined since its inception for hedge accounting, are accounted at fair value and changes in fair value are presented in finance costs in the statement of comprehensive income. The derivative financial instrument is classified as non-current asset or liability in the balance sheet as the instrument is associated with the long-term debt. The hedging agreement referred in Note 12 was not designated for hedge accounting at the inception of the contract.

Cash and Cash Equivalents
For purposes of the cash flow statement, cash and cash equivalents include cash in hand and other short-term highly liquid investments with original maturities of three months or less. For purposes of cash flows statement, the restricted cash in 2019 is presented as part of cash and cash equivalents as it is expected that the funds will be used in the maintenance and or purchases of equipment of the Company.

2. Summary of Significant Accounting Policies (Continued)

Restricted Cash

Cash is classified as restricted when it is not available for the use of the Company. The restricted cash is classified as current when its release is expected to occur within one year, and non-current when its availability is longer than such period.

Trade and Other Receivables

The Company maintains trade and other receivables in order to collect the contractual cash flows and, therefore, subsequently measures them at amortized cost using the effective interest method, less any estimate for impairment.

Plant and Equipment

Plant and equipment are stated at cost, less accumulated depreciation, amortization and impairment losses. Depreciation and amortization are calculated on the straight-line method over the estimated useful lives of the assets. Costs of maintenance, repairs, minor refurbishments and improvements are charged to expense. Subsequent costs are capitalized only when it is probable that a future economic benefit associated with the item will flow to the Company and the cost of the item can be measured reliably. The Company has a maintenance program that includes inspecting, testing and repairing all operational power equipment based on the equivalent operating hours (EOH).

Expenditure on the construction, installation or completion of infrastructure facilities, such as constructions, generators and electric power plants facilities, is capitalized within plant and equipment according to its nature. No depreciation or amortization is charged during the construction phase. The Company begins depreciating an item of plant and equipment when it is available for use.

Right-of-use assets are recognized as leasehold and generally depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. If the Company is reasonably certain to exercise a purchase option, the right-of-use asset is depreciated over the underlying asset’s useful life.

Depreciation and amortization rates used are described as follows:

Buildings	2.50%
Leasehold	5%
Generators and plant facilities	5% - 10%
Tools and minor equipment	25%
Equipment of transportation	25%
Furniture and office equipment	25%

2. Summary of Significant Accounting Policies (Continued)

Impairment of Long-lived Assets

Plant and equipment and other non-current assets which are non-financial assets that are subject to depreciation and amortization, are reviewed for impairment whenever events or changes in the circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognized for the amount by which the asset's carrying amount exceeds its recoverable amount, which is the higher of an asset's fair value less costs to sell and value in use. For the purpose of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (cash-generating units).

Goodwill

Goodwill arises and represents the excess of the consideration transferred, the amount of any non-controlling interest in the acquire and the acquisition-date fair value of any previous equity interest in the acquire over the fair value of the identifiable net assets acquired. If the total of consideration transferred, non-controlling interest recognized and previously held interest measured at fair value is less than the fair value of the net assets of the subsidiary acquired, in the case of a bargain purchase, the difference is recognized directly in the statement of comprehensive income.

For the purpose of impairment testing, goodwill acquired in a business combination is allocated to each of the CGUs, or Company of CGUs, that is expected to benefit from the synergies of the combination. Each unit or Company of units to which the goodwill is allocated represents the lowest level within the entity at which the goodwill is monitored for internal Management purposes. Goodwill is monitored at the operating segment level.

Goodwill impairment reviews are undertaken annually or more frequently if events or changes in circumstances indicate a potential impairment. The carrying value of the CGU containing the goodwill is compared to the recoverable amount, which is the higher of value in use and the fair value less costs of disposal. Any impairment is recognized immediately as an expense and is not subsequently reversed.

Trade and Other Payables

Trade and other payables are obligations to pay for goods or services that have been acquired in the normal course of the business from suppliers. Trade and other payables are classified as current liabilities as payments are due within one year or less.

Trade and other payables are initially recognized at fair value and subsequently measured at amortized cost using the effective interest method.

2. Summary of Significant Accounting Policies (Continued)

Borrowings
Borrowings are initially recognized at fair value, net of transaction costs incurred. Borrowings are subsequently carried at amortized cost, using the effective interest method.

Borrowing Costs
General and specific borrowing costs directly attributed to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets until the assets are substantially ready for their intended use or sale. All other borrowing costs are recognized in the statement of comprehensive income in the period in which they are incurred.

Current and Deferred Income Tax
Income tax expense for the period comprises current and deferred income tax. Income tax is recognized in the statement of comprehensive income. The current income tax charge is calculated on the basis of the tax laws enacted at the balance sheet date over the taxable income.

Deferred income tax is provided in full, using the liability method, where temporary differences arise between the fiscal bases of assets and liabilities and their carrying amounts in the financial statements. However, the deferred income tax is not accounted for if it arises from initial recognition of an asset or liability, in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit nor loss.

Deferred income tax is determined using tax rates that have been enacted or substantially enacted by the balance sheet date and are expected to apply when the related deferred income tax asset is realized, or the deferred income tax liability is settled.

Deferred income tax assets are recognized to the extent that it is probable that future taxable profit will be available, and the temporary differences can be utilized against it. Deferred income tax is provided for temporary differences originated by loss drag.

2. Summary of Significant Accounting Policies (Continued)

Employee Benefits

Seniority Premium and Severance Trust Fund
According to the Labor Code of the Republic of Panama, employees with a permanent contract of employment are entitled to receive, upon termination of employment, a seniority premium, equal to one week's wage for each year of work, determined from the date of commencement of employment.

In addition, employees dismissed under certain circumstances are entitled to receive compensation based on years of service. Law No.44 of 1995 provides that companies must make a contribution to a fund to cover the Layoff seniority premium payments to dismissed workers. This contribution is determined based on the compensation paid to employees. To manage this fund, the Company established a trust with an authorized private entity. The contributions are treated as defined contribution plans, where the Company has no further payment obligations in addition to those contributions. The contribution for the year amounted to US$16,305 (2018: US$18,656 and 2017: US$22,453).

Social Security
According to Law No.51 of December 27, 2005, the companies must realize monthly contributions to the Panama Social Security (i.e., Caja de Seguro Social de Panama), based on a percentage of the total wages paid to their employees. A portion of these contributions is used by the Panamanian State for the payment of the future retirements of the employees. The contribution for the year amounted to US$350,036 (2018: US$385,569 and 2017: US$509,615).

Share Capital
Common shares are classified as equity.

Energy Revenue Recognition
The Company recognizes energy revenue in the periods that it delivers electricity. Contracted prices are billed in accordance to provisions of applicable power sales agreements and spot sales are billed in accordance with prevailing market prices. The unit of measurement of the contract prices is megawatts (MW). The following criteria should be met in order to recognize revenue: (1) persuasive evidence of an arrangement exists; (2) delivery has occurred or services have been rendered; (3) the price to the buyer is fixed or determinable; and (4) collection is reasonably assured. Revenues are measured at fair value of the consideration received or receivable for the sale of the energy.

2. Summary of Significant Accounting Policies (Continued)

Energy Revenue Recognition (continued)

In accordance of IFRS 15, the Company recognized the revenue from contracts with customers based on a five-step model detailed below:

- Step 1: Identify contracts with customers: A contract is defined as the agreement between two or more parties, which creates rights and obligations required and establishes criteria that must be met for each contract. The contracts that are handled are written and grouped in the same type of contracts because all of them are categorized in the same concept of energy sales.

- Step 2: Identify the contract obligations: An obligation is a promise in a contract with a client for the transfer of a good or service.

- Step 3. Determine the price of transaction: The transaction price is the amount of the payment that the Company expects to have the right in exchange for the transfer of the promised goods or services to a client.

- Step 4. Assignment of the transaction price: The Company recognizes the price of the contract payable as specified in the contract, subject to the stipulated conditions and adjustments or proposed deductions, as applicable.

- Step 5. Recognition of revenue according to the criteria established by IFRS 15, the Company continues recognizing revenues over time instead of during a certain time.

The Company principally satisfies its performance obligations over time, when, or as, a performance obligation is satisfied, the Company recognizes as revenue the amount of the transaction price that is allocated to that performance obligation. The transaction price is the amount of consideration to which the Group expects to be entitled. The transaction price is allocated to the performance obligations in the contract based on standalone selling prices of the goods or services promised.

Finance Cost
Comprise interest expense on borrowings, unwinding of the discount of provision and deferred consideration.

3. Financial Risk Management

Financial Risk Factors

The Company's activities expose it to a variety of financial risks: market risk (including currency risk, fair value interest rate risk and cash flow interest rate risk), credit risk and liquidity risk.

Risk management is carried out by the General Manager and the Director of Financial Department under the supervision of the Board of Directors. They identify and evaluate financial risks in close co-operation with Management of Departments within the Company.

Market Risk

Foreign exchange risk

The Company is not substantially exposed to the foreign exchange risk fluctuation, since its revenues and expenses are mainly expressed in U. S. Dollars.

Interest rate risk

Interest rate risk is mainly originated from long-term debt with variable interest rates that expose the Company to the cash flows risk.

Interest rate sensitivity

As at December 31, 2019, if interest rates on the variable United States dollar denominated borrowings has been 50 basis points higher/lower with all other variables held constant, net income for the year would have been US$12,506,455 (2018: US$13,986,127 and 2017: US$15,511,377) higher/lower.

Credit Risk

Credit risk arises mainly from cash and cash equivalents, restricted cash, trade and other receivables. The Company works only with well-known foreign and local financial institutions and energy distribution companies.

The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit rating.

	2019	**2018**	**2017**
Cash at banks and short-term bank deposits international credit rating - Fitch (A and AA-)	76,291,292	60,837,269	2,003,036

3. Financial Risk Management (Continued)

Financial Risk Factors (continued)

Credit Risk (continued)

The Company has a concentration of its revenues and accounts receivable with the three off takers companies operating in the Republic of Panama. Sales of energy made to these customers represent approximately 85% (2018: 87% and 2017: 86%) of total revenues and 90% (2018: 89% and 2017: 87%) of total accounts receivable at the end of the period. This concentration of risk is mitigated by the fact that demand for electricity in Panama continues to grow steadily and that the energy market is very well structured and regulated by government authorities. For each PPA a guarantee is required and the payment term of invoices originating in the electric market of Panama is averaged in a range of 30 days from the date of presentation of the invoice. The guarantee is a performance bond payable to the collection against any event of default for bad debts or bad debt. There were no default events for unpaid bills as of December 31, 2019, 2018 and 2017.

The credit risk for derivative financial instruments is associated and concentrated with the risk of the counterpart that is the International Finance Corporation (IFC), as disclosed in Note 12.

Liquidity Risk

Liquidity risk is the risk that the Company might not be able to comply with all its obligations. The Company minimizes this risk by maintaining adequate levels of cash on hand or in current accounts for fulfilling commitments with recurring suppliers and borrowers. The current liabilities are covered by the cash flow generated by operations.

Cash flow forecasting is performed by the operating entities of the Company in and aggregated by Company finance. The Company finance monitors rolling forecasts of the Company's liquidity requirements to ensure it has sufficient cash to meet operational needs while maintaining sufficient headroom on its undrawn committed borrowing facilities at all times so that the Company does not breach borrowing limits or covenants on any of its borrowing facilities. Such forecasting takes into consideration the Company's debt financing plans, covenant compliance, compliance with internal balance sheet ratio targets and, if applicable external regulatory or legal requirements.

3. Financial Risk Management (Continued)

Financial Risk Factors (continued)

Liquidity Risk (continued)

The table below analyses the Company's non-derivative financial liabilities into relevant maturity groupings based on the remaining period at the balance sheet to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows. Balances due within 12 months approximate their carrying balances as the impact of discounting is not significant.

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
December 31, 2019				
Long-term debt	31,149,117	153,565,493	196,408,994	381,123,604
Trade, lease and other payables	34,248,298	997,488	7,387,610	42,633,396
Shareholders' loans	3,960,000	15,840,000	77,720,000	97,520,000
	69,357,415	170,402,981	281,516,604	521,277,000

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
December 31, 2018				
Long-term debt	33,851,928	152,569,148	223,359,265	409,780,341
Trade and other payables	30,644,088	-	-	30,644,088
Shareholders' loans	3,960,000	15,840,000	81,680,000	101,480,000
	68,456,016	168,409,148	305,039,265	541,904,429

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
December 31, 2017				
Long-term debt	34,952,458	151,294,317	255,045,324	441,292,099
Trade and other payables	36,800,709	-	-	36,800,709
Shareholders' loans	3,960,000	15,840,000	85,640,000	105,440,000
	75,713,167	167,134,317	340,685,324	583,532,808

The contractual maturity of the derivative financial instrument carried at fair value in the balance sheet that is associated with the long-term debt is on 2031.

3. Financial Risk Management (Continued)

Cash Flows Information – Net Debt Reconciliation

The combined analysis of net debt and the movements in the net debt for each of the periods presented is detailed below:

	2019	2018	2017
Cash and cash equivalents	76,291,292	60,837,269	2,003,036
Long-term debt	(241,965,000)	(256,416,000)	(271,740,000)
Shareholders' loan	(50,000,000)	(50,000,000)	(50,000,000)
Lease liabilities	(8,385,098)	-	-
Net debt	(224,058,806)	(245,578,731)	(319,736,964)

	Liabilities from Financing Activities				Other Assets	
	Long-term Debt	Shareholders Loan	Leases Liabilities	Sub-total	Cash and Equivalents	Total
Net debt as at January 1, 2017	(286,117,000)	(50,000,000)	-	(336,117,000)	8,592,680	(327,524,320)
Cash flows	14,377,000	-	-	14,377,000	(6,589,644)	7,787,356
Net debt as December 31 2017	(271,740,000)	(50,000,000)	-	(321,740,000)	2,003,036	(319,736,964)
Cash flows	15,324,000	-	-	15,324,000	58,834,233	74,158,233
Net debt as December 31 2018	(256,416,000)	(50,000,000)	-	(306,416,000)	60,837,269	(245,578,731)
Leases	-	-	(8,568,447)	(8,568,447)	-	(8,568,447)
Cash flows	14,451,000	-	183,349	14,634,349	15,454,023	30,088,372
Net debt as December 31 2019	(241,965,000)	(50,000,000)	(8,385,098)	(300,350,098)	76,291,292	(224,058,806)

3. Financial Risk Management (Continued)

Capital Risk Management

The Company's objectives when managing capital are to safeguard the Company's ability to continue as a going concern in order to provide returns for the shareholders and to maintain an optimal capital structure to reduce the cost of capital.

In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to the shareholders, return capital to the shareholders, issue new shares or sell assets to reduce debt. The Company monitors capital on the basis of the "liabilities to tangible net worth ratio", which is one of the ratios that the Company should consider at the time of paying dividends or incurring debt. Capital is defined by Management as the Company's shareholders' equity. This ratio is calculated as liabilities divided by tangible net worth. Liabilities are calculated as total long-term debt, including current portion of long-term debt. Tangible net worth is calculated as "equity" as shown in the balance sheet, including shareholders loan and excluding intangible assets.

This ratio basically measures the leverage of the Company as a percent of the equity invested by the shareholder and provides the percentage of the funding of the Company with borrowing versus shareholders' equity.

The liabilities to tangible net worth ratio were as follows:

	2019	2018	2017
Liabilities w/o subordinated debt and lease liabilities	85,030,967	71,268,243	79,010,286
Total tangible net worth w/o subordinated debt	251,783,585	267,238,093	277,378,215
Total liabilities to tangible net worth ratio	0.34	0.27	0.28

Fair Value Estimation

For disclosure purposes, the International Financial Reporting Standards specify a fair value hierarchy that categorizes into three levels based on the inputs used in valuation techniques to measure fair value: The hierarchy is based on the transparency of variables used in the valuation of an asset at the date of valuation. These three levels are:

- Quoted prices (unadjusted) in active markets for identical assets and liabilities (Level 1).
- Inputs other than quoted prices included within level 1 that are observable for the asset and liability, either directly (that is, as prices) or indirectly (that is, derived from prices) (Level 2).
- Inputs for the asset or liability that are not based on observable market data (that is, unobservable inputs) (Level 3).

3. Financial Risk Management (Continued)

Fair Value Estimation (continued)
The carrying value of cash and cash equivalents, trade and other receivables, trade and other payables approximates its fair value due to the short-term nature.

The fair value of loans payables is disclosed in Note 12 and derivative financial instruments carried in the balance sheet are included in Level 2 of the fair value hierarchy.

4. Critical Accounting Estimates and Judgement

Estimates and judgements are continually evaluated by Management and are based on historical experience and on various other assumptions that Management believes to be reasonable under the circumstances, the results of which form the basis for making judgements.

Critical Accounting Estimates and Assumptions
The resulting accounting estimates will, by definition, seldom equal the related actual results. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

Depreciation and Amortization of Plant and Equipment
The Company makes judgements in assessing its assets estimated useful lives and in determining estimated residual values, as applicable. Depreciation and amortization are calculated on the straight-line method, based on the estimated useful lives of the assets. These estimates are based on analysis of the assets' lifecycles and potential value at the end of its useful life. The assets residual values and useful lives are reviewed, and adjusted if appropriate, at each balance sheet date.

During the year ended December 31, 2017, Management reassessed the useful life of certain assets, resulting in an increase of the depreciation expense in US$6,912,049. Assuming these assets are held until the end of their estimated useful lives, depreciation in future years will be increased from US$2,758,405 to US$5,516,809 per year since 2018.

Current and Deferred Income Tax Estimation
The Company is subject to income tax. Significant judgment is required in determining the provision for income tax. There are many transactions and calculations for which the ultimate tax determination is uncertain during the ordinary course of business. The Company recognizes liabilities for anticipated tax issues based on estimates of whether additional taxes will be due. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the income tax and deferred tax provisions in the period in which such determination is made.

4. Critical Accounting Estimates and Judgement (Continued)

Critical Accounting Estimates and Assumptions (continued)

Impairment of Goodwill
The Company tests annually whether goodwill has suffered any impairment, in accordance with the corresponding accounting policy disclosed herein. The recoverable amounts of cash-generating units have been determined based on value-in-use calculations. These calculations require the use of estimates (Note 10).

5. Cash and Cash Equivalents for Statement of Cash Flows

The cash and cash equivalents for statement of cash flows purposes are detailed as follows:

	2019	2018	2017
Cash in U. S. currency	1,264,206	429,838	578,736
Short-term bank deposits at 0.25% (2018 and 2017: 0.25%) annual interest rate	75,027,086	60,407,431	1,424,300
	76,291,292	60,837,269	2,003,036

In 2019, the Company reports the restricted cash of US$51,165,263 as cash and cash equivalents for cash flows statement purposes. This amount is presented as part of the short-term bank deposits.

6. Restricted Cash

The current restricted cash represents a committed deposit for the major maintenance plan. The amount arises as a result of the cash compensation as a conclusion of the arbitration process (Note 19) and the instructions for the transfer to the major maintenance reserve account was performed during 2019. This amount is classified as cash and cash equivalents for cash flows statement purposes.

The long-term restricted cash represents the balance standing to the credit of the Senior Debt Service Reserve account and the C-Loan Debt Service Reserve accounts, which balance will be used to service the long-term debt described in Note 12.

7. Trade and Other Receivables

Trade and other receivables are detailed as follows:

	2019	2018	2017
Clients	5,480,249	8,676,922	4,994,237
Related parties (Note 15)	765,248	833,938	458,571
Insurance claim	560,927	-	-
Others	182,331	197,429	229,081
	6,988,755	9,708,289	5,681,889

Account receivables are less than two months. At December 31, 2019, 2018 and 2017, there were no past due receivables, therefore, the Company has not recorded any provision for impairment.

8. Plant and Equipment, Net

Following is the movement of plant and equipment:

	Transportation Equipment	Building	Furniture and Office Equipment	Generators and Plant Facilities	Right of Use Assets	Total
Cost at January 1, 2019 (Restated)	394,461	805,472	591,160	318,834,736	-	320,625,829
Additions	-	-	48,611	-	-	48,611
Adjustment for change in accounting policy (Note 9)	-	-	-	-	8,568,447	8,568,447
Cost at December 31, 2019 (Restated)	394,461	805,472	639,771	318,834,736	8,568,447	329,242,887
Accumulated depreciation at January 1, 2019 (Restated)	(362,808)	(41,943)	(480,346)	(70,592,221)	-	(71,477,318)
Depreciation charge (Restated)	(20,375)	(20,137)	(80,998)	(13,386,827)	(461,150)	(13,969,487)
Accumulated depreciation at December 31, 2019 (Restated)	(383,183)	(62,080)	(561,344)	(83,979,048)	(461,150)	(85,446,805)
Net balance at December 31, 2019 (Restated)	11,278	743,392	78,427	234,855,688	8,107,297	243,796,082
Cost at January 1, 2018 as originally presented	394,461	805,472	576,908	369,999,999	-	371,776,840
Effect of restatement (Note 22)	-	-	-	(51,165,263)	-	(51,165,263)
Cost at January 1, 2018 (Restated)	394,461	805,472	576,908	318,834,736	-	320,611,577
Additions	-	-	14,252	-	-	14,252
Cost at December 31, 2018 (Restated)	394,461	805,472	591,160	318,834,736	-	320,625,829
Accumulated depreciation at January 1, 2018	(268,957)	(21,806)	(382,595)	(53,268,827)	-	(53,942,185)
Depreciation charge (Restated)	(93,851)	(20,137)	(97,751)	(17,323,394)	-	(17,535,133)
Accumulated depreciation at December 31, 2018 (Restated)	(362,808)	(41,943)	(480,346)	(70,592,221)	-	(71,477,318)
Net balance at December 31, 2018 (Restated)	31,653	763,529	110,814	248,242,515	-	249,148,511

8. Plant and Equipment, Net (Continued)

	Transportation Equipment	Building	Furniture and Office Equipment	Generators and Plant Facilities	Right of Use Assets	Total
Cost at January 1, 2017	394,461	805,472	430,184	369,999,999	-	371,630,116
Additions	-	-	146,724	-	-	146,724
Cost at December 31, 2017	394,461	805,472	576,908	369,999,999	-	371,776,840
Accumulated depreciation at January 1, 2017	(170,452)	(1,678)	(268,978)	(27,857,557)	-	(28,298,665)
Depreciation charge	(98,505)	(20,128)	(113,617)	(25,411,270)	-	(25,643,520)
Accumulated depreciation at December 31, 2017	(268,957)	(21,806)	(382,595)	(53,268,827)	-	(53,942,185)
Net balance at December 31, 2017	125,504	783,666	194,313	316,731,172	-	317,834,655

The Company recognized as of January 1, 2019 a right of use asset for US$8,568,447 and a lease liability of US$8,568,447. (See Note 9).

Plant and equipment include interest on borrowings that are directly attributed to the construction of the assets. During the years ended December 31, 2019, 2018 and 2017, there were no interest capitalized.

Plant and equipment are included into the onshore Security Agreements which includes the mortgage on movable and immovable assets. (See Note 12).

9. Lease

As of December 31, 2019, plant and equipment include leases which correspond to the operating land lease located in Penonome. Lease terms are between 14-yr and 25-yr contract with 2% interest rate per year until expiration (See Note 8).

The leased properties are presented below:

	2019
Right-of-use assets	
Cost	8,568,447
Accumulated depreciation	(461,150)
Net balance	8,107,297
Lease liabilities	
Current	104,301
Non-current	8,385,098
	8,489,399

9. Lease (Continued)

In applying IFRS 16 for the first time on January 1, 2019, the Company has used the following practical expedients permitted by the standard:

(a) Applying a single discount rate (7.5%) to a portfolio of leases with reasonably similar characteristics, for the 2019 year-end the Company has recognised US$642,634 as interest expense related to lease liabilities.
(b) Relying on previous assessments on whether leases are onerous.
(c) Accounting for operating leases with a remaining lease term of less than 12 months as at January 1, 2019 as short-term leases.
(d) Excluding initial direct costs for the measurement of the right-of-use asset at the date of initial application.
(e) Using hindsight in determining the lease term where the contract contains options to extend or terminate the lease.

10. Goodwill

In April 2014, IEH Penonome Holdings (former IEH Penonome Panama, S. A., see Note 1) acquired the share capital of UEP Penonome II, S. A. for US$8,518,361. In December 2014, it acquired a further share capital for US$20,000,000 and obtained control of UEP Penonome II, S. A.

The following table summarizes the consideration paid for UEP Penonome II, S. A., the fair value of assets acquired at the acquisition date:

Consideration transferred	
Cash	28,518,361
Recognized amounts of identifiable assets acquired and construction in progress	(8,518,361)
Goodwill	20,000,000

The recoverable amounts of the business unit are calculated based on their value in use. The value in use is determined by discounting the future cash flows expected from the continuous use of each unit. The calculation of value in use is based on the following basic assumptions:

- Business plan for 2019 was used to project future cash flows. Future cash flows were projected using average growth rates based on the long-term assumptions growth rates, projected power generation, power contract price and spot market price. The forecast period is based on the long-term perspective of the Company with respect to the operation of this unit which was determined in 15 years.

10. Goodwill (Continued)

- The discount rate of 6.50% was applied in determining the amounts recoverable for the business unit. This rate is calculated on the basis of market experience and the weighted average cost of capital (WACC) allocated for this unit.

The key assumptions described above may change as economic and market conditions change. The Company estimates that reasonably possible changes in these assumptions are not expected to affect the recoverable amount of the business unit or drops below the value of the carrying amount.

11. Trade and Other Payables

Trade and other payables are detailed as follows:

	2019	2018	2017
Interest payable on shareholder's loans (Notes 13 and 15)	15,385,172	15,385,172	11,385,176
Suppliers	7,858,469	3,656,472	14,622,294
Interest payable	5,349,737	5,687,258	5,830,026
Related parties (Note 15)	4,838,739	4,800,184	3,630,477
Others	711,880	403,585	813,774
Lease liabilities short-term (Note 9)	104,301	-	-
Income tax payable	-	691,286	-
Insurance payable	-	20,131	518,962
	34,248,298	30,644,088	36,800,709

12. Long-Term Debt

	2019	2018	2017
International Finance Corporation (IFC)			
US$250 million senior debt, International Finance Corporation (IFC); The Netherlands Development Finance Company (FMO); French Development Institution (Proparco); Development Bank of the (Austrian Republic OeEB); Central American Bank for Economic Integration (Cabei); Banco Nacional as Lenders; Tenor: 17-years door to door. Tailored amortization scheduled stepping up from 2.4% in average for the first 22 semesters (53% of total amount); 3.66% for the following 6 semesters (22% of total amount) and 6.27% for the last 4 semesters (25% of total amount), hedging agreement to fix rate on a minimum of US$180 million of the total Senior	203,025,000	215,000,000	227,100,000
Carry forward…	203,025,000	215,000,000	227,100,000

12. Long-Term Debt (Continued)

	2019	2018	2017
Brought forward…	203,025,000	215,000,000	227,100,000
Banco General and Corporacion Interamericana para el Financiamiento de Infraestructura, S. A. (CIFI) US$34 million, Tailored amortization scheduled stepping up from 2.91% in average for the first 16 semesters (47% of total amount) and 4.45% for the following 12 semesters (53% of total amount); Priced at LIBOR + 4.50%	25,500,000	27,336,000	29,920,000
IFC Subordinated C-Loan of US$16 million US$16 million 17-years door to door. Tailored amortization scheduled stepping up from 2.17% in average for the first 18 semesters (39% of total amount); 3.50% for the following 10 semesters (35% of total amount) and 6.5% for the last 4 semesters (26% of total amount); Fix rate at 12%. 13% per annum at any time following the occurrence and during the continuance of a C-Loan Deficiency	13,440,000	14,080,000	14,720,000
	241,965,000	256,416,000	271,740,000
Less: Unamortized finance costs	9,159,290	9,955,994	10,752,698
Long-term debt, net	232,805,710	246,460,006	260,987,302
Less: Current portion	12,803,000	14,451,000	15,324,000
	220,002,710	232,009,006	245,663,302

Due dates of the long-term debt and the total exposure of the Company's borrowings to interest rate changes and the contractual reprising date at December 31, are as follows:

	2019	2018	2017
1 - 5 years	89,149,000	68,339,000	68,800,000
Over 5 years	152,816,000	188,077,000	202,940,000
	241,965,000	256,416,000	271,740,000

The movement of the unamortized finance costs is as follows:

	2019	2018	2017
Beginning balance	9,955,994	10,752,698	11,549,402
Amortization	(796,704)	(796,704)	(796,704)
Ending balance	9,159,290	9,955,994	10,752,698

12. Long-Term Debt (Continued)

The fair value of the borrowings is US$274,236,211 (2018: US$306,645,819 and 2017: US$293,256,634), based on discounted cash flows using a rate based on the borrowing rate of 6.5% and is within Level 3 of the fair value hierarchy.

The main conditions and terms on the outstanding borrowings are described as follows:

Senior Debt Agreements:

a) Senior Debt of US$250 million:

International Finance Corporation (IFC); The Netherlands Development Finance Company (FMO); French Development Institution (Proparco); Development Bank of the Austrian Republic (OeEB); Central American Bank for Economic Integration (Cabei); Banco Nacional as Lenders:

- Tenor: 17-years door to door. Tailored amortization scheduled stepping up from 2.4% in average for the first 22 semesters (53% of total amount); 3.66% for the following 6 semesters (22% of total amount) and 6.27% for the last 4 semesters (25% of total amount).
- Priced at LIBOR + 4.75%.
- Hedging agreement to fix rate on a minimum of US$180 million of the total Senior with IFC. (On which the Company has not applied hedge accounting).
- On February 27, 2015, the Company contracted a receive-floating interest rate swaps by which the Company agrees to exchange the difference between fixed and floating interest rate amounts calculated on agreed notional principal amounts for US$180,000,000. Such contract enables the Company to mitigate the risk of changing interest rates on the cash flow exposures on the issued variable rate debt.

b) Senior Debt of US$34 million:

- Banco General and Corporacion Interamericana para el Financiamiento de Infraestructura, S. A. (CIFI) as Lenders.
- Tenor: 15-years door to door. Tailored amortization scheduled stepping up from 2.91% in average for the first 16 semesters (47% of total amount) and 4.45% for the following 12 semesters (53% of total amount).
- Priced at LIBOR + 4.50%.

12. Long-term Debt (Continued)

Senior Debt Agreements: (continued)

c) Subordinated C-Loan of US$16 million:

- IFC as lender.
- Tenor: 17-years door to door. Tailored amortization scheduled stepping up from 2.17% in average for the first 18 semesters (39% of total amount); 3.50% for the following 10 semesters (35% of total amount) and 6.5% for the last 4 semesters (26% of total amount).
- Fix rate at 12%. 13% per annum at any time following the occurrence and during the continuance of a C-Loan Deficiency.
- Subordination: in the event that on a debt service payment date a C-Loan deficiency occurs, IFC agrees that it shall not exercise any remedies with respect to the relevant outstanding due and payable amount of principal arising from such C Loan Deficiency.

Common Term Agreement (CTA): Whereby the Lender of each of the Senior Debt and the Subordinated C-Loan the Lenders set forth the terms and conditions in common to each loan.

Security Agreements:

- Offshore Security Agreements: Whereby the Borrowers - IEH Penonome Panama, S. A. and UEP Penonome II, S. A. (hereinafter "UEP II") - grant first priority security interest in all of its rights, titles and interest of Major Project Documents (Turbine Supply Agreement, Goldwind Parent Master Agreement, BOP Contract, Transportation Agreement, Interconnection Agreement, Shared Asset Agreement); proceeds from asset disposals, insurance proceeds. Citibank N. A. acting as Offshore Security Agent.

- Onshore Security Agreements: Includes the pledge on the shares of the Borrowers; collateral assignment on generation licenses, power purchase agreements and ANATI lease titles; mortgage on movable and immovable assets. The Bank of Nova Scotia (Panama) acting as Onshore Security Agent and trustee.

12. Long-term Debt (Continued)

Security Agreements (continued)

- Master Account and Security Agreements: Whereby the Borrowers certify that they have established Offshore Accounts with the Offshore Account Bank (Citibank, NA) and Onshore Account Banks [The Bank of Nova Scotia (Panama)] in accordance with the Trust Agreements. Offshore Accounts includes Senior Debt Service Reserve account and C-Loan Debt Service Reserve accounts representing the following Debt Service amount on each Loan. The agreement states the procedures to transfer from the Revenue account in accordance with the Common Term Agreement; including Restricted Payments.

Covenants: a) maintenance of existence and conduct of business; b) accounting and management operation system in accordance with the Accounting Standard c) Auditors: maintain at all times international recognized independent public accountant firm acceptable to the lenders d) Access: upon lender request, give access to the site, books and records and borrower employees e) maintain at all times in full force and effect authorizations, security in favor of lenders and project documents payment of obligations f) comply with the construction budget and the major maintenance plan g) interest rate hedging with initial amount of no less than hundred and eighty million Dollars h) financial ratios: prospective debt service coverage ratio of at least 1.15:1.00; among others.

Negative Covenants: The following activities are prohibited: a) make any restricted payment (which means declaration or payment of dividends, distribution of capital securities, payment of shareholder loan capital or interest), unless such restricted payment (i) is made from the restricted payment account (ii) such payment will be made within thirty (30) days after an Interest Payment Date (iii) the Prospective Debt Service Coverage Ratio is not less than 1.20:1.0 (iv) the Prospective Total Debt Service Coverage Ratio is not less than 1.10:1.0 (v) after giving effect to any such action the Financial Debt to Tangible Net Worth Ratio is not more than 3.1:1.0 and (vi) debt service reserve account, major maintenance reserve account and the C-Loan reserve account are fully funded. b) Capital expenditures besides those required to carry out operations normally c) additional financial debt d) guarantees or liens e) asset sales f) financial investments other than permitted investments in high grade securities, among others.

13. Shareholders' Equity

The shareholders' equity is as follows:

	Common Shares	Capital Contribution	Total
Initial and ending balances for the years ended December 31, 2019 and 2018	1,050	74,998,950	75,000,000

The Company reclassified the equity contribution pursuant the subscription of shares into a combination of common stocks and bearing interest shareholders' loans. The combination is as follows:

- IEH Penonome Holdings: 95.24% economic interest in common shares (US$71.4 million).
- IEH Penonome Holdings: US$47.6 million in bearing interest shareholder loan, fixed rate at 8%, maturity 2031.
- Green Field Panama, S.A.: 4.76% economic interest in common shares (US$3.5 million).
- Green Field Panama, S.A.: US$2.4 million in bearing interest shareholder loan, fixed rate at 8%, maturity 2031.

After the aforementioned contribution took place, the shareholders composition of the Company is the following:

IEH Penonome Holdings	95.24% economic interest
Green Field Panama, S.A.	4.76% economic interest

14. Costs and Expenses

The Company classifies its costs and expenses by nature, as follows:

	2019	2018	2017
Cost of goods and services			
Depreciation and amortization (Notes 8 and 9)	13,969,487	17,535,133	25,643,520
Fee transmission cost	1,114,554	909,009	1,130,391
Salaries and other benefits to employees	564,763	547,645	250,057
Energy purchase	612,016	446,225	1,939,470
Repairs and maintenance	28,274	134,190	186,123
	16,289,094	19,572,202	29,149,561
Administrative expenses			
Salaries and other benefits to employees	807,845	825,434	1,332,085
Professional fees	768,833	497,672	5,821,700
Wake effect	682,321	431,375	-
Insurance costs	662,402	651,395	717,720
Substation rent	478,150	607,955	-
Regulator fees	424,833	339,372	384,941
Other expenses	221,269	296,678	381,289
Communication expenses	128,434	121,954	139,755
Maintenance office	43,798	24,038	90,868
Donations	31,503	7,778	12,754
Fuel	18,765	19,311	20,005
Office expenses	8,548	14,778	25,700
Electricity	1,435	1,529	31,076
Management fee (Note 15)	-	1,200,000	1,200,000
Land rent	-	733,975	711,892
	4,278,136	5,773,244	10,869,785
Operating expenses			
Repairs and maintenance	5,683,256	4,856,706	3,454,173
Security	467,528	364,617	367,422
Internal consumption	227,041	233,708	307,463
	6,377,825	5,455,031	4,129,058
	26,945,055	30,800,477	44,148,404

14. Costs and Expenses (Continued)

Salaries and other benefits to employees are summarized as follows:

	2019	2018	2017
Salaries and wages	1,115,733	1,081,892	1,210,859
Statutory contributions	134,086	147,501	156,320
Other	59,202	77,540	130,803
Seniority premium and indemnity	63,587	66,146	84,160
	1,372,608	1,373,079	1,582,142

Salaries and other benefits to employees are included in costs of goods and services, administrative and operating expenses as follows:

	2019	2018	2017
Cost of goods and services	564,763	547,645	250,057
Administrative expenses	807,845	825,434	1,332,085
	1,372,608	1,373,079	1,582,142

15. Balances and Transactions with Related Parties

The Company is fully controlled by InterEnergy Partners, L. P., its ultimate parent company. The Company carried out transactions and maintained balances with related companies, as described below:

	2019	2018	2017
Transactions			
Professional fees expenses (a)	-	1,200,000	1,401,825
Interest - shareholders' loans (Note 13)	-	4,000,000	4,000,000
Energy sold in the spot market (b)	90,814	25,961	100,762
Energy sold under reserve contracts (c)	1,953,564	1,020,797	-
Energy purchases and associated costs (b)	12,342	1,152	33,518
Balances			
Accounts receivables professional fees (d)	456,267	456,267	456,267
Accounts receivables energy spot market (b)	1,461	3,162	2,304
Accounts receivables energy reserve contracts (c)	307,520	374,509	-
	765,248	833,938	458,571

15. Balances and Transactions with Related Parties (Continued)

	2019	2018	2017
Balances (continued)			
Accounts payable professional fees (a)	4,800,000	4,800,000	3,626,354
Accounts payable energy spot market (b)	38,739	184	4,123
	4,838,739	4,800,184	3,630,477
Shareholders' loans (Note 13)	50,000,000	50,000,000	50,000,000
Interest payable - shareholders' loans (Note 13)	15,385,172	15,385,172	11,385,176

(a) Administrative and asset management services rendered by related parties.

(b) Sales and purchases of energy with related parties in the energy spot market.

(c) Energy Reserve Contracts described in Note 18.

(d) Accounts receivable for services rendered to a related party.

Key Management Compensation

Key management includes directors (executive and non-executive) and some members of the internal executive committee. The Company does not have post-employment benefits, share-based payments nor other long-term benefits. The compensation paid or payable to key management for employee services is shown below:

	2019	2018	2017
Salaries and other short-term employee benefits	225,950	254,487	345,999

16. Finance Cost, Net

Finance cost are detailed as follows:

	2019	2018	2017
Interest on borrowings, net	19,914,656	23,952,071	24,616,111
Fair value loss (gain) on derivative financial instrument	8,715,928	(3,856,145)	(499,473)
	28,630,584	20,095,926	24,116,638

17. Income Tax

The income tax is presented as follows:

	2019	2018	2017
Current tax	-	(691,286)	-
Deferred tax	(1,644,053)	(1,621,607)	1,697,970
	(1,644,053)	(2,312,893)	1,697,970

The movement in deferred income tax assets and liabilities during the year is as follows:

	2019	2018	2017
Deferred income tax assets			
At January 1	-	1,041,458	-
Accelerated tax depreciation charged to statement of comprehensive income	-	(1,041,458)	1,041,458
At December 31	-	-	1,041,458
Deferred income tax liabilities			
At January 1	580,149	-	656,512
Accelerated tax depreciation charged to statement of comprehensive income	1,644,053	580,149	(656,512)
At December 31	2,224,202	580,149	-

Deferred tax liability is the result of temporary differences from accelerated tax depreciation and tax bases of and other depreciation tax treatment of the cash compensation received.

Under current tax legislation in the Republic of Panama, the profits of the Company from local operations are subject to income tax.

Income tax is based on the higher of the following computations:

a. The rate of 25% on taxable income.

b. The net taxable profit resulting from applying 4.67% to the total taxable income times the rate of 25% which represents 1.17% of taxable income (alternative minimum tax).

In certain circumstances, if the application of 1.17% of revenue results in the entity incurring losses for tax reasons, or the effective tax rate is higher than 25%, then the entity may choose to request not to apply minimum tax. In such cases, the Company must file a petition to the Tax Authority, who may authorize the no application for a term of three years.

17. Income Tax (Continued)

The income tax resultant by applying the in-force rates to the net profit (loss), is reconciled with the income tax provision presented in the financial statements, as follows:

	2019	**2018**	**2017**
Profit (loss) profit before income tax	258,443	7,496,771	(26,657,376)
Fiscal adjustment to recognize accelerated depreciation	(10,175,902)	(4,120,414)	8,319,478
Less: Non-taxable income	(166,069)	(4,130,186)	(524,677)
Plus: Non-deductible expenses	10,237,840	5,316,943	5,205,405
Taxable income	154,312	4,563,114	(13,657,170)
Loss carried forward	(77,156)	(2,281,557)	-
Other adjustments	(77,156)	-	-
Net taxable gain	-	2,281,557	-
Income tax (traditional method)	-	570,389	-
Calculation of Alternative Method			
Taxable Income	56,625,012	59,210,750	-
Presumed net taxable income (4,67% of taxable income)	2,644,388	2,765,143	-
Income tax (alternative method)	661,097	691,286	-

According to Tax Legislation of Panama, income tax returns for the last three (3) years are subject to review by fiscal authorities, including year ended December 31, 2019.

Management will request to the Tax Authority the non-application of the CAIR for the 2019 fiscal year and they expect to obtain a positive outcome on the request.

17. Income Tax (Continued)

Law No.52 of August 28, 2012, established the transfer pricing regime oriented to regulate tax purposes transactions between related parties, and applicable to the taxpayer to perform operations with related parties that are tax residents of other jurisdictions. The most important aspects of this regulation include:

- Taxpayers must submit annually an information return related operations with related parties, within six (6) months following the close of the relevant fiscal period. This obligation applies to transactions from fiscal year 2012.

- Failure to submit the report shall be punishable by a fine equivalent to 1% of the total amount of transactions with related parties.

- Persons required to submit the report referred to in the preceding paragraph, shall maintain a transfer pricing study, which shall contain the information and analysis to assess and document their transactions with related parties, in accordance by Law. The taxpayer must present study only at the request of the Department of Revenue of the Ministry of Economy and Finance within 45 days of your request.

18. Commitments

- The Company has twelve PPA Contract's assigned by three to Nuevo Chagres, Portobelo, Rosa de los Vientos and Maranon parks. The PPA's were awarded on March 21, 2012, by which energy production is sold to the three distribution companies in Panama: Empresa de Distribucion Electrica Metro-Oeste, S. A. (EDEMET) (controlled by Gas Natural Fenosa), Empresa de Distribucion Electrica Chiriqui, S. A. (EDECHI) (controlled by Gas Natural Fenosa) and Elektra Noreste, S. A. (ENSA) (controlled by Empresas Publicas de Medellin).

  Each PPA states that the energy supply period is for 180 months, beginning on July 1, 2014 and finishing on June 30, 2029. Portobelo and Maranon PPA's were extended until December 2033. Price will be reset annually, keeping 75% of the base price fixed and the remaining 25% will be indexed to Panamanian Consumer Price Index (CPI).

  In December 2014, the Company signed the Wake Effect Agreement with UEP Penonome I, S. A., in which UEP II must compensate UEP Penonome I, S. A. (hereinafter "UEP I") for the energy losses caused by the preferred physical position of the wind turbines which impact the wind regime. The Company agrees to pay a monthly payment beginning with the Commercial Operation Date occurred on February 19, 2018, for 25 years term. The wake effect compensation amount is disclosed in Note 14.

18. Commitments (Continued)

- In January 2016, the Company signed the Amendment No.4 of the PPA's with the offtakers to solve some sections that were ambiguous and penalized UEP II, even if the Company supplied the energy generated.

  This amendment clarifies the following subjects:

  1. The PPAs contemplate a penalty if the wind farm does not reach the expected generation committed in the PPAs. The portion that the wind farm has to comply in order to avoid such penalty is 0.6 (60%), "Fraccion de la Generacion Esperada" (FGE, for its acronym in Spanish) that represents the portion of the expected generation on an annual basis.

     Based on the historical data, the probability of such penalty is remote because it depends on the energy compromised in the PPA. Historical data shows that even in the worst-case scenario, the wind farm complies with 0.6. Also, the buyer must acquire all the energy produced by the seller, so the committed energy in PPAs is less than the energy produced and sold.

  2. The base Consumer Price Index (CPI) was fixed to 93.05 to match with the CPI base that reports the Contraloria Nacional de Panama each month.

- On March 16, 2016, the Company was awarded four PPA Contract's by ETESA, through Resolution GC-03-2016, for hiring short-term energy supply only for 2017 until 2019, which will address the requirements of the companies EDEMET, EDECHI and ENSA. This energy it will be supply for Rosa de los Vientos (SPOT). In the event that the Company is unable to fulfill its obligations under any of the contracts, the performance bonds that support the obligations may be drawn by the customers. The amounts of the performance bonds outstanding as at December 31, 2019, 2018 and 2017 were US$21,492,232.

- On November 10, 2017, the Company has signed a reserve contract with its affiliated generator Tecnisol I, by which the excess energy production of Rosa de los Vientos II (50 MW) Wind farm is sold to cover the affiliated company obligations with the market. The Reserve Contract states that the energy supply period is for 12 months (extendable), beginning at the moment the CND (National Dispatch Center) declares the Contract manageable and finishing one year later with the option to extend the supply period if desired by the Contract Parties. Contract Price will be fixed for all the energy supply period.

18. Commitments (Continued)

- Turbine Supply Agreement (TSA) consists in 86 Goldwind G109 2.5 MW wind turbine generators with a hub height of 90 meters to be procured pursuant to an Amended and Restated Turbine Supply Agreement entered on April 23, 2014 (TSA) and further amended on December 10, 2014 with Goldwind International Holdings (HK) Limited, a subsidiary of wind manufacturer Xinjiang Goldwind Science and Technology ("Goldwind") and together Goldwind Company; for the supply of:

  - 66 turbines contracted energy totaling 165 MW; divided in four wind parks:

    - Nuevo Chagres 62.5 MW.
    - Portobelo 32.5MW.
    - Rosa de los Vientos 52.5 MW. and
    - Maranon 17.5 MW.

  - 20 turbines partially contracted and merchant energy totaling 50 MW.

- Under the TSA, Goldwind Company provides a five years warranty on the equipment for defects, power curve, availability and noise. Availability is guaranteed at 95% during the warranty period. In addition, the Company entered into a 5-year service and maintenance agreement (SMA) with Goldwind Company for the operation, maintenance, repair and replacement services on the wind turbines at a fixed price adjusted for inflation, including warranties for availability and noise in line with those during the warranty period. It includes a full warranty for years 3 to 5, and the availability guarantee of 95% for those years. This SMA contract can be extended by UEP II until year ten.

- Balance of plant works are performed pursuant to a turn-key agreement for the civil works, electric and communication infrastructure, interconnection to the medium tension gird (34,5 kV), construction of the control and operations buildings and all other installation required by the Interconnected System (BOP Contract); entered into by the Company and Instalacion y Servicios CODEPA, S. A. is a Panamanian subsidiary of Grupo Cobra, on October 14, 2014, and amended on April 23, 2014.

- Delivery of turbines under the TSA was at China Port. Sea and inland transportation are provided by Tree Logistic pursuant a transportation agreement dated April 23, 2014, ended 2015.

18. Commitments (Continued)

- ASEP (the regulator) granted final license for the construction, operation, maintenance, power generation and sale of wind farms Maranon, Portobelo Ballestillas, Rosa de los Vientos and New Chagres a Panamanian company Union Eolica Panameña, S. A. (UEP) through Resolutions AN No.4075-Elec the December 10, 2010, AN No.4092-Elec the December 15, 2010, AN No.5379-Elec the June 13, 2012 and AN No.4094-Elec the December 15, 2010, respectively. This final license is granted for a term of forty (40) years from September 26, 2014.

- Subsequently, the ASEP issued resolutions AN No.7252-Elec the April 11, 2014, AN No.7274-Elec the April 11, 2014, AN No.7278-Elec the April 14, 2014 and No.7326 AN-Elec of May 2, 2014, in which is authorized yield UEP for Penonome II, S. A., the final licenses originally granted to UEP.

- On June 15, 2018, the Company and UEP Penonome I, S. A., signed the Phase II Shared Assets Access Agreement, pursuant to which the Company agreed to pay to UEP I, who is the owner of and maintains the El Coco Substation to which UEP II's wind park connects, a monthly access fee of US$27,129.85 and the reimbursement of maintenance costs.

19. Contingency

On May 15, 2018, Goldwind and UEP II entered into a Settlement and Release Agreement that resolved and terminated all disputes, claims and actions against each other. Pursuant to the terms of settlement agreement, the Company was awarded with following:

- Cash compensation of US$51,165,263.
- Refund of US$5,714,293 for incurred expenses during the arbitration.
- A final receipt of US$3,087,027 for accrued and unpaid expenses owed to Goldwind and affiliated.

On the other hand, Goldwind was awarded with:

- Final cancellation of last milestone of the Turbine supply agreement draw under Stand by letter of credit with cash collateral provided by the company of US$11,964,372.

20. Subsequent Event

Impact of COVID-19

On March 11, 2020, the World Health Organization declared the coronavirus strain (COVID-19) in the category of pandemic.

The COVID-19 pandemic has affected the Wholesale Electricity Market (The Market) in Panama, since March the Government decreed a total quarantine with movement restrictions, this caused many businesses and industries to remain closed or reduce their production capacity, which in turn caused a wave of layoffs and work contract suspensions, this caused an economic crisis in the country and in the electricity sector since many people did not have the resources to pay for their electricity bills.

To minimize the effect of the pandemic the Government approved the Decree 291 of May 13, 2020 that established a moratorium for the months from March to June to establish a non-obligation of payment for the people affected by the pandemic. With great part of the regulated clients not paying, this decreased the cash flow of the Distribution Companies and these could not keep with their payments to the Generation Companies. The foregoing caused a domino effect in the Market since the lack of liquidity of the Distribution Companies prevented them from fulfilling the full payments of the PPAs with the Generation Companies and ASEP through Resolution AN No.16095-Ele of May 21, 2020 let the Distribution Companies to pay proportionally with their income the commitments with the Market and also allows the Generation Companies affected by the pandemic due to this lack of payment by the Distribution Companies to pay their DTE (Economic Transactions Document) obligations proportionally without their payment guarantee being executed by the CND (National Dispatch Center).

21. Reclassification

For comparison purposes, certain figures from 2018 and 2017 were reclassified. This reclassification has no effect on the net income of the period, or on the accumulated deficit previously reported or in the statement of cash flows.

21. Reclassification (Continued)

These reclassifications has the purpose to recognize the depreciation expense, salaries and other benefits to O&M employees and other costs as part of the cost of goods and services.

Statement of Comprehensive Income	As Originally Presented in 2018	Reclassification	Reclassified 2018
Costs of goods and services	(1,469,024)	(18,103,178)	(19,572,202)
Depreciation expense	(17,535,133)	17,535,133	-
Salaries and other benefits to O&M employees	(547,645)	547,645	-
Other costs	(20,400)	20,400	-

Statement of Comprehensive Income	As Originally Presented in 2017	Reclassification	Reclassified 2017
Costs of goods and services	(3,106,283)	(26,043,278)	(29,149,561)
Depreciation expense	(25,643,520)	25,643,520	-
Salaries and other benefits to O&M employees	(250,057)	250,057	-
Other costs	(149,701)	149,701	

22. Effects of Restatements

During 2018, the Company received cash compensation by US$51,165,263 (Note 19) that was accounted as a liability (other current liabilities and accrued expenses) to purchase the related assets that were part of the settlement agreement. On further detailed analysis performed by Company's management during the third quarter of 2020, it was determined that the appropriate accounting treatment of the compensation received should be reflected as a reduction of plant and equipment that cause an adjustment to the depreciation expense of the associated assets. The US$51,165,263 was restated in 2018 and 2019 financial statements to present the figures as a reduction of PPE and the reduction of the related depreciation expense and accumulated depreciation for 2018 and 2019 as presented in the table below. The related deferred tax liability was adjusted accordingly to the figures presented in the table below.

22. Effects of Restatements (Continued)

In addition, the Company evaluated and determined at the inception of the long-term debt agreement and the hedging agreement to fix rate disclosed in Note 12, were considered as closely related at the inception as it is established that the borrower would have to repay both simultaneously and is required to have the debt hedged. Although, in subsequent analysis of the contracts during the third quarter of 2020, it was determined that from a legal perspective there are both separate contract that required that the derivative financial instrument from the interest rate swap should be accounted at fair value, since the hedge accounting option was not adopted in the inception of the contracts. The transaction resulted in the restatement for the recognition of the derivative financial instrument separately in the balance sheet and recognizing the corresponding fair value losses (gains) on interest rate swap for the 2019 and prior financial years. The amount of US$3,461,748 was recognized as the initial adjustment to accumulated deficit as of December 31, 2016.

The effects of the restatement derived from the correction of errors in each of the affected financial statement line items for the prior periods are as follows:

Balance Sheet (extract)	**December 31, 2019**	**Adjustments**	**December 31, 2019 (Restated)**	**December 31, 2018**	**Adjustments**	**December 31, 2018 (Restated)**
Plant and equipment, net	283,153,978	(39,357,896)	243,796,082	296,377,985	(47,229,474)	249,148,511
Derivative financial instrument – asset	-	-	-	-	893,870	893,870
Other assets	121,125,767	-	121,125,767	108,463,955	-	108,463,955
Other current liabilities and accrued expense	(51,165,263)	51,165,263	-	(51,165,263)	51,165,263	-
Deferred income tax – liability	(622,244)	(1,601,958)	(2,224,202)	(46,163)	(533,986)	(580,149)
Derivative financial instrument – liability	-	(7,822,058)	(7,822,058)	-	-	-
Other liabilities	(325,439,106)	-	(325,439,106)	(327,104,094)	-	(327,104,094)
Net assets	**27,053,132**	**2,383,351**	**29,436,483**	**26,526,420**	**4,295,673**	**30,822,093**
Accumulated deficit	47,946,868	(2,383,351)	45,563,517	48,473,580	(4,295,673)	44,177,907
Other equity accounts	(75,000,000)	-	(75,000,000)	(75,000,000)	-	(75,000,000)
Total equity	**(27,053,132)**	**(2,383,351)**	**(29,436,483)**	**(26,526,420)**	**(4,295,673)**	**(30,822,093)**

Balance Sheet (extract)	**December 31, 2017**	**Adjustments**	**December 31, 2017 (Restated)**
Plant and equipment, net	317,834,655	-	317,834,655
Derivative financial instrument – asset	-	-	-
Other assets	58,553,846	-	58,553,846
Deferred income tax – liability	-	-	-
Derivative financial instrument – liability	-	(2,962,275)	(2,962,275)
Other liabilities	(347,788,011)	-	(347,788,011)
Net assets	**28,600,490**	**(2,962,275)**	**25,638,215**
Accumulated deficit	46,399,510	2,962,275	49,361,785
Other equity accounts	(75,000,000)	-	(75,000,000)
Total equity	**(28,600,490)**	**2,962,275**	**(25,638,215)**

22. Effects of Restatements (Continued)

Statement of comprehensive income (extract)	December 31, 2019	Adjustments	December 31, 2019 (Restated)	December 31, 2018	Adjustments	December 31, 2018 (Restated)
Energy revenue	56,069,859	-	56,069,859	50,310,461	-	50,310,461
Cost of goods and services	(24,160,672)	7,871,578	(16,289,094)	(23,507,991)	3,935,789	(19,572,202)
Total expenses	(10,655,961)	-	(10,655,961)	(11,228,275)	-	(11,228,275)
Total finance cost	(20,711,360)	(8,715,928)	(29,427,288)	(24,748,775)	3,856,145	(20,892,630)
Other income	560,927	-	560,927	8,879,417	-	8,879,417
Profit (loss) before income tax	**1,102,793**	**(844,350)**	**258,443**	**(295,163)**	**7,791,934**	**7,496,771**
Income tax	(576,081)	(1,067,972)	(1,644,053)	(1,778,907)	(533,986)	(2,312,893)
Total comprehensive income (loss) for the year	**526,712**	**(1,912,322)**	**(1,385,610**	**(2,074,070)**	**7,257,948**	**5,183,878**

Statement of comprehensive income (extract)	December 31, 2017	Adjustments	December 31, 2017 (Restated)
Energy revenue	42,404,370	-	42,404,370
Cost of goods and services	(29,149,561)	-	(29,149,561)
Total expenses	(14,998,843)	-	(14,998,843)
Total finance cost	(25,412,815)	499,473	(24,913,342)
Loss before income tax	**(27,156,849)**	**499,473**	**(26,657,376)**
Income tax	1,697,970	-	1,697,970
Total comprehensive loss for the year	**(25,458,879)**	**499,473**	**(24,959,406)**

Statement of cash flows (extract)	December 31, 2019	Adjustments	December 31, 2019 (Restated)	December 31, 2018	Adjustments	December 31, 2018 (Restated)
Net cash provided by operating activities	30,675,316	(642,634)	30,032,682	62,208,113	(51,165,263)	11,042,850
Net cash (used in) provided by investing activities	(48,611)	-	(48,611)	11,950,120	51,165,263	63,115,383
Net cash used in financing activities	(15,172,682)	642,634	(14,530,048)	(15,324,000)	-	(15,324,000)
Net increase in cash and cash equivalents	15,454,023	-	15,454,023	58,834,233	-	58,834,233
Cash and cash equivalents at the beginning of year	60,837,269	-	60,837,269	2,003,036	-	2,003,036
Cash and cash equivalents and restricted cash at the end of year	**76,291,292**	-	**76,291,292**	**60,837,269**	-	**60,837,269**

Statement of cash flows (extract)	December 31, 2017	Adjustments	December 31, 2017 (Restated)
Net cash provided by operating activities	7,934,080	-	7,934,080
Net cash (used in) provided by investing activities	(146,724)	-	(146,724)
Net cash used in financing activities	(14,377,000)	-	(14,377,000)
Net decrease in cash and cash equivalents	(6,589,644)	-	(6,589,644)
Cash and cash equivalents at the beginning of year	8,592,680	-	8,592,680
Cash and cash equivalents and restricted cash at the end of year	**2,003,036**	-	**2,003,036**

Tecnisol Group

Report and Combined Financial Statements
September 30, 2020 and 2019

Tecnisol Group

Index to the Combined Financial Statements
September 30, 2020 and 2019
(All amounts in US$ unless otherwise stated)

Report on Review of Combined Financial Statements

To the Board of Directors and Shareholders of
Tecnisol Group

Introduction

We have reviewed the accompanying combined balance sheets of the entities set out in Note 1 to the combined financial statements as at September 30, 2020 and 2019 and the related combined statements of comprehensive income, changes in equity and cash flows for the nine month periods then ended, and notes, comprising significant accounting policies and other explanatory information. Management is responsible for the preparation and fair presentation of these combined financial statements in accordance with International Financial Reporting Standards. Our responsibility is to express a conclusion on these combined financial statements based on our review.

Scope of review

We conducted our review in accordance with International Standard on Review Engagements 2410, "Review of interim financial information performed by the independent auditor of the entity". A review of interim financial statements consists of making inquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with International Standards on Auditing and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Conclusion

Based on our review, nothing has come to our attention that causes us to believe that the accompanying combined financial statements do not present fairly, in all material respects, the financial position of the entities set out in Note 1 to the combined financial statements as at September 30, 2020 and 2019, and of its financial performance and its cash flows for the nine month periods then ended in accordance with International Financial Reporting Standards.

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To the Board of Directors and Shareholders of
Tecnisol Group
Page 2

Emphasis of matter - Basis of accounting

We draw attention to the fact that, as described in Note 1 to the combined financial statements, the businesses included in the combined financial statements have not operated as a single entity. These combined financial statements are, therefore, not necessarily indicative of results that would have occurred if the businesses had operated as a single business during the year presented or of future results of the combined businesses.

The combined financial statements are prepared for the board of directors of Tecnisol Group to assist them in presenting the financial position and results of the entities set out in Note 1, in connection with the transaction described in Note 1 to these combined financial statements. As a result, the combined financial statements may not be suitable for another purpose. Our conclusion is not modified in respect of this matter.

PricewaterhouseCoopers

November 21, 2020
Panama, Republic of Panama

Tecnisol Group

Combined Balance Sheets
September 30, 2020 and 2019
(All amounts in US$ unless otherwise stated)

	Notes	September 30, 2020	September 30, 2019
Assets			
Current assets			
Cash and cash equivalents	2, 3 and 5	4,376,260	7,333,061
Trade and other receivables	2, 6 and 13	1,368,258	4,943,395
Prepaid expenses and other assets		781,572	505,877
Total current assets		6,526,090	12,782,333
Non-current assets			
Plant and equipment, net	2, 7 and 8	38,553,842	41,391,045
Intangible assets	2 and 9	240,635	235,182
Total non-current assets		38,794,477	41,626,227
Total assets		45,320,567	54,408,560
Liabilities and Equity			
Liabilities			
Current liabilities			
Lease liabilities short-term debt	2 and 8	32,517	31,343
Shareholder's loans	2 and 13	39,943,927	47,812,496
Trade and other payables	2, 10 and 13	4,305,477	5,523,487
Total current liabilities		44,281,921	53,367,326
Non-current liability			
Lease liabilities long term	2 and 8	962,880	979,726
Total liabilities		45,244,801	54,347,052
Equity			
Parent company investment	2 and 11	40,000	40,000
Retained earnings		94,752	39,219
Prepaid dividend tax		(58,986)	(17,711)
Total equity		75,766	61,508
Total liabilities and equity		45,320,567	54,408,560

The accompanying notes are an integral part of these combined financial statements.

Tecnisol Group

Combined Statements of Comprehensive Income
For the nine-month periods ended September 30, 2020 and 2019
(All amounts in US$ unless otherwise stated)

	Notes	2020	2019
Energy revenue		7,696,347	9,238,506
Other income		46,820	-
Costs of goods and services	2, 7, 12 and 13	(5,638,921)	(6,758,807)
Gross profit		2,104,246	2,479,699
Expenses	12		
Administrative expenses		(596,571)	(643,026)
Operating expenses		(240,696)	(7,756)
Total expenses		(837,267)	(650,782)
Operating profit		1,266,979	1,828,917
Finance costs		(955,007)	(1,166,635)
Income before income tax		311,972	662,282
Income tax	15	(141,138)	(250,797)
Profit for the period		170,834	411,485

The accompanying notes are an integral part of these combined financial statements.

Tecnisol Group

Combined Statements of Changes in Equity
For the nine-month periods ended September 30, 2020 and 2019
(All amounts in US$ unless otherwise stated)

	Parent Company Investment	Retained Earnings (Accumulated Deficit)	Prepaid Dividend Tax	Total Equity
Balance at January 1, 2019	40,000	(372,266)	-	(332,266)
Profit for the period	-	411,485	-	411,485
Prepaid dividend tax	-	-	(17,711)	(17,711)
Balance at September 30, 2019	40,000	39,219	(17,711)	61,508
Balance at December 31, 2019	40,000	(76,082)	(17,711)	(53,793)
Profit for the period	-	170,834	-	170,834
Prepaid dividend tax	-	-	(41,275)	(41,275)
Balance at September 30, 2020	40,000	94,752	(58,986)	75,766

The accompanying notes are an integral part of these combined financial statements.

Combined Statements of Cash Flow
For the nine-month periods ended September 30, 2020 and 2019
(All amounts in US$ unless otherwise stated)

	Notes	2020	2019
Cash flows from operating activities			
Income before income tax		311,972	662,282
Adjustments to reconcile income before income tax to net cash provided by operating activities:			
Depreciation and amortization	7, 9 and 12	2,165,078	2,513,668
Finance costs	8	955,007	1,166,635
Changes in assets and liabilities:			
Trade and other receivables		74,102	(2,637,816)
Trade and other payables		(793,663)	92,966
Prepaid expenses and other assets		(154,754)	(503,877)
Interest paid	13	(304,906)	-
Net cash provided by operating activities		2,252,836	1,293,858
Cash flows from investing activities			
Additions of plant and equipment	7	(77,743)	(215,950)
Net cash used in investing activities		(77,743)	(215,950)
Cash flows from financing activities			
Repayment of shareholder's loans		(710,339)	-
Principal lease payments	8	(15,672)	(29,156)
Prepaid dividend tax		(41,275)	(17,711)
Net cash used in financing activities		(767,286)	(46,867)
Net increase in cash and cash equivalents		1,407,807	1,031,041
Cash and cash equivalents at the beginning of the period		2,968,453	6,302,020
Cash and cash equivalents at end of the period	5	4,376,260	7,333,061

The accompanying notes are an integral part of these combined financial statements.

1. General Information

Tecnisol I, S. A.; Tecnisol II, S. A.; Tecnisol III, S. A. and Tecnisol IV, S. A. (the “Companies” and together as Tecnisol Group the “Group”, for purposes of these special purpose report) were incorporated on February 20, 2014 under the laws of the Republic of Panama. The Companies are engaged in the production of electricity through its photovoltaic panel parks located in David, Province of Chiriqui, Republic of Panama.

The ultimate parent company of the Companies is Interenergy Partners, L. P., incorporated in Cayman Island.

The combined financial statements have been prepared for the purposes of including the combined financial information of the Companies in a prospectus issued in connection with the listing of two or more businesses that are owned by the same individual. The combined business has not operated as a single entity and the combined financial statements are not necessarily indicative of results that would have occurred if the business had been a single entity during the periods presented or of future results of the businesses.

The Companies are located in Torres de las Americas, Punta Pacifica, Republic of Panama, and the photovoltaic panels are in David, Republic of Panama. The local regulator, Autoridad Nacional de los Servicios Publicos (ASEP, by its acronym in Spanish), approved the Companies’ electricity generation license to 40 MW capacity (Note 14).

These combined financial statements have been approved for issue by the Finance Manager on November 20, 2020.

2. Summary of Significant Accounting Policies

The principal accounting policies applied in the preparation of these combined financial statements are set out below.

Basis of Preparation

The combined financial statements of the Companies for the nine-month periods ended September 30, 2020 and 2019 have been prepared in accordance with the International Financial Reporting Standards (IFRS) and the related interpretations adopted by the International Accounting Standards Board (IASB). The combined financial statements have been prepared on the historical cost convention.

The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the combined financial statements are disclosed in Note 4.

2. Summary of Significant Accounting Policies (Continued)

Basis of Preparation (continued)
The combined financial statements include the following companies:

- Tecnisol I, S. A.
- Tecnisol II, S. A.
- Tecnisol III, S. A.
- Tecnisol IV, S. A.

The Companies prepared stand-alone financial statements that were audited for the year ended December 31, 2019. These are the first set of combined financial statements prepared by the Companies. Intercompany transactions and balances between the Companies included in the combined financial statements, which are related parties, are eliminated.

New Standards, Amendments and Interpretations not yet Adopted
Certain new accounting standards and interpretations have been published that are not mandatory for September 30, 2020 reporting periods and have not been early adopted by the Companies. These standards are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

Monetary Unit and Functional Currency
The combined financial statements are expressed in U.S. Dollars (US$), monetary unit of the United States of America, which is at par with the Balboa (B/.), monetary unit of the Republic of Panama. The U.S. Dollar (US$) circulates and is freely exchangeable in the Republic of Panama and is the functional currency.

Financial Assets
The Companies classify their financial assets in the category of loans and receivables and assets at fair value through profit or loss, based on the purpose for which the financial assets were acquired. Management determines the classification of its financial assets at initial recognition.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Loans and receivables with maturities not greater than 12 months are included in current assets.

Cash and Cash Equivalents
For purposes of the cash flows statement, cash and cash equivalents include cash in hand.

Trade and Other Receivables
The Companies maintain trade and other receivables in order to collect the contractual cash flows and, therefore, subsequently measures them at amortized cost using the effective interest method, less any estimate for impairment.

2. Summary of Significant Accounting Policies (Continued)

Plant and Equipment and Depreciation

Plant and equipment are stated at cost, less accumulated depreciation and impairment losses. Depreciation is calculated on the straight-line method over the estimated useful lives of the assets. Costs of maintenance, repairs, minor refurbishments and improvements are charged to expense. Subsequent costs are capitalized only when it is probable that a future economic benefit associated with the item will flow to the Companies and the cost of the item can be measured reliably. The Companies has a maintenance program that includes inspecting, testing and repairing all operational power equipment based on the equivalent operating hours (EOH).

Expenditure on the construction, installation or completion of infrastructure facilities, such as construction, generators and electric power plants facilities, is capitalized within property, plant and equipment according to its nature. No depreciation or amortization is charged during the construction phase. The Companies begin depreciating an item of property, plant and equipment when it is available for use.

Right-of-use assets are generally depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. If the Companies are reasonably certain to exercise a purchase option, the right-of-use asset is depreciated over the underlying asset's useful life.

Depreciation rates used are described as follows:

Buildings	2.50%
Generators and plant facilities	5% - 10%
Right of uses assets	5% - 5.5%
Tools and minor equipment	25%
Equipment of transportation	25%
Furniture and office equipment	25%

Impairment of Long-Lived Assets

Plant and equipment and other non-current assets which are non-financial assets that are subject to depreciation and amortization, are reviewed for impairment whenever events or changes in the circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognized for the amount by which the asset's carrying amount exceeds its recoverable amount, which is the higher of an asset's fair value less costs to sell and value in use. For the purpose of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (cash-generating units).

2. Summary of Significant Accounting Policies (Continued)

Intangible Assets

Right of use
Represent the value attributable to the right of use of a high voltage transmission for a 25 years period, by virtue of a long-term contract with the landowners and the Companies. The intangible assets are recognised at cost and subsequently measured at cost less accumulated amortization, which is calculated using the straight-line method to allocate the cost of the intangible assets over its estimated useful life of 25 years.

Leases
The Companies had initially applied IFRS 16, for the first time for their annual reporting period commencing January 1, 2019.

- IFRS 16 - Leasing. The IASB issued in January 2016, IFRS 16, which replaces IAS 17- Leases. This standard introduces significant changes in accounting by lessee.

- The Companies applied the simplified approach, in which the comparative figures are not restate at the date of initial application. The right-of-use assets for property leases will be initially measured on a retrospective basis as if the new standard had always been applied. All other right-of-use assets will be measured at the amount equal to the lease liability at the time of adoption (adjusted for prepaid or accrued lease payments relating to that lease recognized). In addition, the Companies have decided not to apply the new standard to leases whose term will end within twelve months of the date of initial application. In such cases, the leases are accounted for as short-term leases and the lease payments associated with them are recognized as an expense from short-term leases. There is not any lease under the low value exemptions.

In the context of the transition, the Companies recognized as of January 1, 2019 a right of use asset for US$1,040,227 and a lease liability of US$1,040,227. (See Note 10).

Lease Liabilities
Lease liabilities include the following lease payments:

- Fixed payments, less any lease incentives receivable,
- Variable lease payment that are based on an index or a rate,
- Amounts expected to be payable by the companies under residual value guarantees,
- The exercise price of a purchase option if the companies are reasonably certain to exercise that option, and
- Payments of penalties for terminating the lease, if the lease term reflects the companies exercising that option.

2. Summary of Significant Accounting Policies (Continued)

Leases (continued)

Lease Liabilities (continued)
The lease payments are discounted using the interest rate implicit in the lease, to the extent that this can be determined. Otherwise, the discount is the lessee's incremental borrowing rate.

Right-of-use assets are measured at cost comprising the following:

- The amount of the initial measurement of lease liability.

- No restoration costs, and no payment were made at or before the lease commencement date as well as not initial direct cost.

Shareholder's Loan
Borrowings are initially recognized at fair value, net of transaction costs incurred. Borrowings are subsequently carried at amortized cost, using the effective interest method.

Trade and Other Payables
Trade and other payables are obligations to pay for goods or services that have been acquired in the normal course of the business from suppliers. Trade and other payables are classified as current liabilities as payments are due within one year or less.

Trade and other payables are initially recognized at fair value and subsequently measured at amortized cost using the effective interest method.

Parent Company Investment
Common shares of each of the Companies considered in the combined financial statements are classified as parent company investment. (See Note 11).

Energy Revenue Recognition
The Companies recognize energy revenue in the periods that it delivers electricity. Contracted prices are billed in accordance to provisions of applicable power sales agreements and spot sales are billed in accordance with prevailing market prices. The unit of measurement of the contract prices is megawatts (MW). The following criteria should be met in order to recognize revenue: (1) persuasive evidence of an arrangement exists; (2) delivery has occurred or services have been rendered; (3) the price to the buyer is fixed or determinable; and (4) collection is reasonably assured. Revenues are measured at fair value of the consideration received or receivable for the sale of the energy.

2. Summary of Significant Accounting Policies (Continued)

Energy Revenue Recognition (continued)
In accordance of IFRS 15, the Companies recognized the revenue from contracts with great clients (customers) based on a five-step model detailed below:

Step 1. Identify contracts with large clients: A contract is defined as the agreement between two or more parties, which creates rights and obligations required and establishes criteria that must meet for each contract. The contracts that are handled are written and grouped in the same type of contracts because all of the are categorized in the same concept of energy sales.

Step 2. Identify the contract obligations: An obligation is a promise in a contract with a client for the transfer of a good or service.

Step 3. Determine the price of transaction: The transaction price is the amount of the payment that the Companies expects to have the right in exchange for the transfer of the promised goods or services to a client.

Step 4. Assignment of the transaction price: The Companies recognizes the price of the contract payable as specified in the contract, subject to the stipulated conditions and adjustments or proposed deductions, as applicable.

Step 5. Recognition of revenue according to the criteria established by IFRS 15, the Companies continues recognizing revenues over time instead of during a certain time.

The Companies mainly satisfy their performance obligations at over time, when, or as, a performance obligation is satisfied, the Companies recognize as revenue the amount of the transaction price that is allocated to that performance obligation. The transaction price is the amount of consideration to which the Companies expect to be entitled. The transaction price is allocated to the performance obligations in the contract based on standalone selling prices of the goods or services promised.

Finance Cost
Comprise interest expense on borrowings, interest expense related to lease liabilities and bank fees.

3. Financial Risk Management

Financial Risk Factors
The Companies' activities expose it to a variety of financial risks: market risk (including currency risk, fair value interest rate risk and cash flow interest rate risk), credit risk and liquidity risk.

3. Financial Risk Management (Continued)

Financial Risk Factors (continued)

Risk management is carried out by the General Manager and the Director of Financial Department under the supervision of the Board of Directors. They identify and evaluate financial risks in close co-operation with management of departments within the Companies.

Market Risk

Foreign exchange risk.

The Companies are not substantially exposed to the foreign exchange risk fluctuation, since its revenues and expenses are mainly expressed in U.S. dollars.

Interest Rate Risk

Interest rate risk is mainly originated from long-term debt with variable interest rates that expose the Companies to the cash flows risk.

Credit Risk

Credit risk arises mainly from cash and cash equivalents, restricted cash, trade and other receivables. The Companies work only with well-known foreign and local financial institutions and energy distribution companies.

The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit rating.

	September 30, 2020	September 30, 2019
Cash at banks and short-term bank deposits international credit rating:		
Fitch (B/BB)	4,376,260	7,333,061
	4,376,260	7,333,061

The Companies have a concentration of its revenues and accounts receivable with large clients and customers from the spot market in the Republic of Panama. Sales of energy made to these customers represent approximately 9 months 80% (September 30, 2019: 74%), 19% (September 30, 2019: 26%) of total revenues and 78% (September 30, 2019: 18%) of total accounts receivable at the end of the nine-month period. This concentration of risk is mitigated by the fact that demand for electricity in Panama continues to grow steadily and that the energy market is very well structured and regulated by government authorities. For each PPA a guarantee is required and the payment term of invoices originating in the electric market of Panama is averaged in a range of 30 days from the date of presentation of the invoice. The guarantee is a performance bond payable to the collection against any event of default for bad debts or bad debt. There were no default events for unpaid bills as of September 30, 2020.

3. Financial Risk Management (Continued)

Financial Risk Factors (continued)

Liquidity Risk
Liquidity risk is the risk that the Companies might not be able to comply with all their obligations. The Companies minimize this risk by maintaining adequate levels of cash on hand or in current accounts for fulfilling commitments with recurring suppliers and borrowers. Cash flow forecasting is performed by the Companies and aggregated by Group finance. The Companies finance monitors rolling forecasts of the Companies' liquidity requirements to ensure it has sufficient cash to meet operational needs while maintaining sufficient headroom on its undrawn committed borrowing facilities at all times so that the Companies do not breach borrowing limits or covenants on any of its borrowing facilities. Such forecasting takes into consideration the Companies' debt financing plans, covenant compliance, compliance with internal balance sheet ratio targets and, if applicable external regulatory or legal requirements. Also, if there are any deficiencies on the working capital of the individual Companies such will be supported by the other companies of the Group.

The table below analyses the Companies' financial liabilities into relevant maturity groupings based on the remaining period at the balance sheet to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows. Balances due within 6 months approximate their carrying balances as the impact of discounting is not significant.

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
September 30, 2020				
Shareholder's loan	39,943,927	-	-	39,943,927
Lease liabilities	32,517	210,397	752,483	995,397
Trade and other payables	4,305,477	-	-	4,305,477
	44,281,921	210,397	752,483	45,244,801

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
September 30, 2019				
Shareholder's loan	47,812,496	-	-	47,812,496
Lease liabilities	31,343	195,707	784,019	1,011,069
Trade and other payables	5,523,487	-	-	5,523,487
	53,367,326	195,707	784,019	54,347,052

3. Financial Risk Management (Continued)

Capital Risk Management
The Companies' objectives when managing capital are to safeguard the Companies' ability to continue as a going concern in order to provide returns for the shareholders and to maintain an optimal capital structure to reduce the cost of capital.

In order to maintain or adjust the capital structure, the Companies may adjust the number of dividends paid to the shareholders, return capital to the shareholders, issue new shares or sell assets to reduce debt. The Companies monitor capital on the basis of the "liabilities to tangible net worth ratio", which is one of the ratios that the Companies should consider at the time of paying dividends or incurring debt. Capital is defined by Management as the Companies' shareholders' equity.

This ratio is calculated as liabilities divided by tangible net worth. Liabilities are calculated as total long-term debt, including current portion of long-term debt. Tangible net worth is calculated as "equity" as shown in the balance sheet, including shareholders loan and excluding intangible assets.

This ratio basically measures the leverage of the Companies as a percent of the equity invested by the shareholder and provides the percentage of the funding of the Companies with borrowing versus shareholders' equity.

The liabilities to tangible net worth ratio were as follows:

	September 30, 2020	September 30, 2019
Liabilities w/o subordinated debt and lease liabilities	4,305,477	5,523,487
Total tangible net worth w/o subordinated debt	39,835,361	47,645,652
Total liabilities to tangible net worth ratio	0.11	0.12

Fair Value Estimation
For disclosure purposes, the International Financial Reporting Standards specify a fair value hierarchy that categorizes into three levels based on the inputs used in valuation techniques to measure fair value: The hierarchy is based on the transparency of variables used in the valuation of an asset at the date of valuation. These three levels are:

- Quoted prices (unadjusted) in active markets for identical assets and liabilities (Level 1).

- Inputs other than quoted prices included within level 1 that are observable for the asset and liability, either directly (that is, as prices) or indirectly (that is, derived from prices) (Level 2).

3. Financial Risk Management (Continued)

Fair Value Estimation (continued)

- Inputs for the asset and liability that are not based on observable market data (that is, unobservable inputs) (Level 3).

The carrying value of cash and cash equivalents, trade and other receivables, trade and other payables approximates its fair value due to the short-term nature.

4. Critical Accounting Estimates and Judgement

Estimates and judgements are continually evaluated by Management and are based on historical experience and on various other assumptions that management believes to be reasonable under the circumstances, the results of which form the basis for making judgements.

Critical Accounting Estimates and Assumptions
The resulting accounting estimates will, by definition, seldom equal the related actual results. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

Depreciation of Plant and Equipment
The Companies makes judgements in assessing its assets estimated useful lives and in determining estimated residual values, as applicable. Depreciation is calculated on the straight-line method, based on the estimated useful lives of the assets.

These estimates are based on analysis of the assets' lifecycles and potential value at the end of its useful life. The assets residual values and useful lives are reviewed, and adjusted if appropriate, at each balance sheet date.

During the year 2019, Management reassessed the useful life of generators and plant facilities to 15 years, resulting in an increase of the depreciation expense in the amount of US$536,457 as of September 30, 2019.

Current and Deferred Income Tax Estimation
The Companies are subject to income tax. Significant judgment is required in determining the provision for income tax. There are many transactions and calculations for which the ultimate tax determination is uncertain during the ordinary course of business. The Companies recognizes liabilities for anticipated tax issues based on estimates of whether additional taxes will be due. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the income tax and deferred tax provisions in the period in which such determination is made.

5. Cash and Cash Equivalents

Cash and Cash Equivalents are detailed as follows:

	September 30, 2020	September 30, 2019
Cash in U.S. currency	4,176,853	7,333,061

6. Trade and Other Receivables

Trade and other receivables are detailed as follows:

	September 30, 2020	September 30, 2019
Clients	1,330,262	1,231,731
Related parties (Note 13)	470	3,631,342
Others	37,526	80,322
	1,368,258	4,943,395

Account receivables are less than two months. At September 30, 2020, there were no past due receivables; therefore, the Companies have not recorded any provision for impairment.

7. Plant and Equipment, Net

Following is the movement of plant and equipment:

	Generators and Plant Facilities	Transmission Line	Vehicles	Right of Use Assets	Construction in Progress	Total
Cost at December 31, 2019	40,359,413	2,983,185	27,450	1,040,227	23,707	44,433,982
Accumulated depreciation	(3,579,160)	(159,104)	(4,606)	(57,789)	-	(3,800,659)
Net Book Amount at December 31, 2019	36,780,253	2,824,081	22,844	982,438	23,707	40,633,323
Period ended September 30, 2020						
Opening Net Book Amount	36,780,253	2,824,081	22,844	982,438	23,707	40,633,323
Additions	3,164	-	25,680	-	48,899	77,743
Depreciation charge	(2,018,169)	(89,496)	(6,216)	(43,343)	-	(2,157,224)
Closing Net Book Amount at September 30, 2020	34,765,248	2,734,585	42,308	939,095	72,606	38,553,842
Cost at September 30, 2019	40,362,577	2,983,185	53,130	1,040,227	72,606	44,511,725
Accumulated depreciation	(5,597,329)	(248,600)	(10,822)	(101,132)	-	(5,957,883)
Net Book Amount at September 30, 2019	34,765,248	2,734,585	42,308	939,095	72,606	38,553,842

7. Plant and Equipment, Net (Continued)

	Generators and Plant Facilities	Transmission Line	Vehicles	Right of Use Assets	Construction in Progress	Total
Cost at December 31, 2018	40,234,228	2,983,185	-	-	-	43,217,413
Accumulated depreciation	(536,455)	(39,776)	-	-	-	(576,231)
Net Book Amount at December 31, 2018	39,697,773	2,943,409	-	-	-	42,641,182
Period ended September 30, 2019						
Opening Net Book Amount	39,697,773	2,943,409	-	-	-	42,641,182
Adjustment for change in accounting policy (Note 8)	-	-	-	1,040,227	-	1,040,227
Additions	164,793	-	27,450	-	23,707	215,950
Depreciation charge	(2,370,045)	(89,496)	(3,431)	(43,342)	-	(2,506,314)
Closing Net Book Amount at September 30, 2019	37,492,521	2,853,913	24,019	996,885	23,707	41,391,045
Cost at September 30, 2019	40,399,021	2,983,185	27,450	1,040,227	23,707	44,473,590
Accumulated depreciation	(2,906,500)	(129,272)	(3,431)	(43,342)	-	(3,082,545)
Net Book Amount at September 30, 2019	37,492,521	2,853,913	24,019	996,885	23,707	41,391,045

The Companies recognized as of January 1, 2019 a right of use asset for US$1,040,227 and a lease liability of US$1,040,227. (See Note 8).

8. Leases

As of September 30, 2020, property, plant and equipment include leases corresponding to the operating land lease located in David, Chiriquí province, Republic of Panama. The lease term is 20 years with a variable increase according to the consumer price index of the United States of America until expiration (Note 7).

The leased properties are presented below:

	September 30, 2020	September 30, 2019
Right-of-use assets		
Cost	1,040,227	1,040,227
Accumulated depreciation	(101,132)	(43,342)
Net balance	939,095	996,885
Lease liabilities		
Current	32,517	31,343
Non-current	962,880	979,726
	995,397	1,011,069

8. Leases (Continued)

In applying IFRS 16 for the first time on January 1, 2019, the Companies have used the following practical expedients permitted by the standard:

(a) Applying a single discount rate (7.5%) to a portfolio of leases with reasonably similar characteristics, for nine months the Companies have recognised in the combined statements of comprehensive income US$37,917 (2019: US$78,016) as interest expense related to lease liabilities,

(b) Relying on previous assessments on whether leases are onerous,

(c) Accounting for operating leases with a remaining lease term of less than 12 months as at 1 January 2019 as short-term leases,

(d) Excluding initial direct costs for the measurement of the right-of-use asset at the date of initial application, and

(e) using hindsight in determining the lease term where the contract contains options to extend or terminate the lease.

9. Intangible Assets

The movement of intangible assets is as follows:

	September 30, 2020	September 30, 2019
Cost		
At January 1	261,814	245,814
Additions	-	-
Balance at the end of the period	261,814	245,814
Accumulated amortization		
At January 1	(13,325)	(3,278)
Depreciation charge	(7,854)	(7,354)
Balance at the end of the period	(21,179)	(10,632)
Net balance at the end of the period	240,635	235,182

Intangible assets correspond to contracts with landowners, these contracts correspond to the construction of a high voltage transmission line for a period of 25 years.

10. Trade and Other Payables

Trade and other payables are detailed as follows:

	September 30, 2020	September 30, 2019
Suppliers	1,955,987	3,796,770
Related parties (Note 13)	1,593,305	371,374
Interest payable on shareholder's loans (Note 13)	609,146	1,087,734
Income tax payable	141,138	250,797
Other account payable	5,901	16,812
	4,305,477	5,523,487

11. Parent Company Investment

The authorized share capital of the Companies is made up of each parent company investment for a total amount of US$40,000, as follows:

Company	Common Shares	Value per Share	Total
Tecnisol I, S. A.	100	US$100	US$10,000
Tecnisol II, S. A.	100	US$100	US$10,000
Tecnisol III, S. A.	100	US$100	US$10,000
Tecnisol IV, S. A.	100	US$100	US$10,000

The Companies are wholly owned by InterEnergy Renewables SLU.

12. Costs and Expenses

The Companies classify its expenses by nature, as follows:

	September 30, 2020	September 30, 2019
Cost of goods and service		
Energy purchases from reserve contracts (Note 13)	2,700,211	1,615,679
Depreciation and amortization (Notes 7, 8 and 9)	2,165,078	2,513,668
Energy purchases to the spot market	489,046	2,543,851
Repairs and maintenance	261,901	64,181
Fees transmission cost	22,685	21,428
	5,638,921	6,758,807

12. Costs and Expenses (Continued)

	September 30, 2020	September 30, 2019
Administrative expenses		
Other expenses	301,981	553,690
Professional fees	100,995	50,111
Insurance costs	94,989	-
Regulator fees	50,923	-
Management services (Note 13)	40,000	-
Office maintenance	4,283	10,602
Fuel	2,375	1,932
Office expenses	1,025	18,481
Donations	-	8,210
	596,571	643,026
Operating expenses		
Repairs and maintenance	187,502	7,756
Security	53,194	-
	240,696	7,756
	6,476,188	7,409,589

13. Balances and Transactions with Related Parties

The Companies are fully controlled by Interenergy Partners, L. P., their ultimate parent company. The Companies carried out transactions and maintained balances with related companies, as described below:

	September 30, 2020	September 30, 2019
Transactions		
Interest paid - shareholders' loan (a)	304,906	-
Professional fees expenses (b)	40,000	-
Energy sold in the spot market (d)	1,334	34,642

13. Balances and Transactions with Related Parties (Continued)

	September 30, 2020	September 30, 2019
Transactions (continued)		
Energy purchases in the spot market (d)	11,676	37,281
Energy purchases under reserve contracts (e)	1,552,546	1,615,679
	1,564,222	1,652,960
Balances		
Accounts receivable energy spot market (d)	470	1,736
Accounts receivable to services rendered(c)	-	3,629,606
	470	3,631,342
Accounts payable energy spot market (d)	758	6,058
Accounts payable energy reserve contracts (e)	1,552,547	365,315
	1,553,305	371,373
Accounts payable professional fees (b)	40,000	-
	1,593,305	371,373
Shareholders' loan payable (a)	39,943,927	47,812,496
Interest payable on shareholder's loans (a)	609,146	1,087,734
	40,553,073	48,900,230

(a) Shareholders' loan granted by a related party for the construction of the plants, with a maturity date on December 20th, 2021 and annual interest rate of 3%.

(b) Administrative and asset management services rendered by related parties.

(c) Account receivable for services rendered to a related party.

(d) Sales and purchases of energy with related parties in the energy spot market.

(e) Energy Reserve Contracts described in Note 16.

14. Cash Flows Information – Net Debt Reconciliation

The combined analysis of net debt and the movements in the net debt for each of the periods presented is detailed below:

	September 30, 2020	September 30, 2019
Cash and cash equivalents	4,376,260	7,333,061
Lease liabilities	(995,397)	(1,011,069)
Shareholder's loans	(39,943,927)	(47,812,496)
Net debt	(36,563,064)	(41,490,504)

	Liabilities from Financing Activities			Other Assets	
	Leases	Shareholder's Loans	Subtotal	Cash and Equivalents	Total
Net debt as at January 1, 2019	(1,040,225)	(47,812,496)	(48,852,721)	6,302,020	(42,550,701)
Cash flows	29,156	-	29,156	1,031,041	1,060,197
Net debt as September 30, 2019	(1,011,069)	(47,812,496)	(48,823,565)	7,333,061	(41,490,504)
Net debt as January 1, 2020	(1,011,069)	(40,654,266)	(41,665,335)	2,968,453	(38,696,882)
Cash flows	15,672	710,339	726,011	1,407,807	2,133,818
Net debt as September 30, 2020	(995,397)	(39,943,927)	(40,939,324)	4,376,260	(36,563,064)

15. Income Tax

The income tax is presented as follows:

	September 30, 2020	September 30, 2019
Income tax	141,138	250,797

Under current tax legislation in the Republic of Panama, the profits of the Companies from local operations are subject to income tax.

15. Income Tax (Continued)

Income tax is based on the higher of the following computations:

a. The rate of 25% on taxable income (traditional method).

b. The net taxable profit resulting from applying 4.67% to the total taxable income times the rate of 25% which represents 1.17% of taxable income (alternative minimum tax - "CAIR").

In certain circumstances, if the application of 1.17% of revenue results in the entity incurring losses for tax reasons, or the effective tax rate is higher than 25%, then the entity may choose to request not to apply minimum tax. In such cases, the Companies must file a petition with the Tax Administration, who may authorize the no application for a term of three years

According Tax Legislation of Panama, income tax returns for the last three (3) years are subject to review by fiscal authorities, including year ending December 31, 2019.

The income tax resultant by applying the in-force rates to the income before tax (Traditional Method) is reconciled with the income tax provision presented in the combined financial statements, as follows:

	September 30, 2020	September 30, 2019
Profit before income tax	311,972	662,282
Plus: Net results of Companies subject to CAIR	244,656	340,906
Non-deductible expenses	7,924	-
Taxable income	564,552	1,003,188
Income Tax - Traditional Method	141,138	250,797

Management requested to the Tax Authority the non-application of the CAIR for the 2019 fiscal year of Tecnisol I, S. A. The request was accepted and approved for the fiscal years 2019, 2020 and 2021.

15. Income Tax (Continued)

Transfer Pricing

Law No.52 of August 28, 2012 established the transfer pricing regime oriented to regulate tax purposes transactions between related parties, and applicable to the taxpayer to perform operations with related parties that are tax residents of other jurisdictions. The most important aspects of this regulation include:

- Taxpayers must submit annually an information return related operations with related parties, within nine (9) months following the close of the relevant fiscal period. This obligation applies to transactions from fiscal year 2012.

- Failure to submit the report shall be punishable by a fine equivalent to 1% of the total amount of transactions with related parties.

- Persons required to submit the report referred to in the preceding paragraph, shall maintain a transfer pricing study, which shall contain the information and analysis to assess and document their transactions with related parties, in accordance by Law. The taxpayer must present study only at the request of the Department of Revenue of the Ministry of Economy and Finance within 45 days of your request.

16. Commitments

The Companies have eight Energy Supply Contracts (PPAs) for fifteen years. Beginning in 2018 and ending in 2033 with Large Clients. The signed contracts have as counterparties: Coca-Cola FEMSA, Industrias Lacteas (Estrella Azul and Jugos del Prado), Clinica Hospital San Fernando, Riba Smith, S. A., Delyris, S. A., Ice Gaming Corp. and Iron Tower, S. A. For Ice Gaming and Iron Tower the supply period started in 2019.

The price is indexed based on the regulated tariff to the end customer which is published by ASEP every six months. The newest tariff published is compared against the last applicable tariff to define a proportion that shall apply to the energy price in the PPA. The result of the operation will determine, according to the provisions in the PPA, the adjustment that shall apply to the energy price to set the new price applicable for the six months. Four large clients have a price threshold of a maximum of 125 US$ / MWh and three large clients have 135 US$ /MWH and a minimum of 83 US$ / MWh.

The Companies have five energy reserve contracts with the Companies UEP Penonome II (related company), Generadora del Istmo (GENISA), Saltos del Francoli, Hydro Caisan, Generadora Pedregalito, Generadora Alto Valle and Generadora Río Chico. In the event that the Companies are unable to fulfill its obligations under any of the contracts, the performance bonds that support the obligations may be drawn by the customers. The amounts of the performance bonds outstanding as at September 30, 2020 were US$1,639,136 (2019: US$360,000).

16. Commitments (Continued)

The supply period for the reserve contract with UEP Penonome II is until March 31st, 2025 per Amendment No.1. The Contract Price is fixed but can be changed by the parties through mutual agreement.

The supply period for the reserve contracts with GENISA and Saltos del Francoli are one year, beginning on December 31st, 2019 for GENISA and 14 months beginning on November 1st, 2019 for Saltos del Francoli. The Contract Price is variable per month and period.

The supply period for the reserve contracts with Hydro Caisan, Generadora Pedregalito, Generadora Alto Valle and Generadora Río Chico is for 16 months beginning on May 1st, 2020.

The supply period for the reserve contracts with Electron Investment is until December 31st, 2020, beginning on July 17th, 2020.

ASEP (the regulator) granted the Definitive Licenses for Tecnisol I, II, III and IV through Resolutions AN No. 8545-Elec from May 6th, 2015, AN No.8547-Elec from May 6th, 2015, Resolution AN No.8546-Elec from May 6th, 2015 and AN No.8548-Elec from May 6th, 2015 lasting for forty (40) years with the possibility of renewal for an equal period.

In December 2018, the Companies detected some insulation problems on the conduction cables. Once analyzed and detected the cables with problems, it was decided to change the circuits of the cable affected. The Contractor assume the full obligation of the issue. In April 2019, cable samples were taken to the CEIS laboratory in Spain to analyze the cable's insulation characteristics to see if it complied with the regulations. The Contractor proposed removing all the cables from the conduits and making the journey through trays. In August 2019, works began on the installation of the trays. Even though new strings were already detected in trays with problems insulation and they were replaced. The final works to complete the replacement will start tentatively in September 2020 once the replacement cables arrive on site. During 2020, a total of 10% of the cables have been substituted (233) but not all at the same time. This process started in February 2020 and ended in September 2020, the works have been continuous with the methodology of checking, opening, and replacing the cables of the affected circuits.

It is estimated that up to a 10% of the plant has been affected by this problem after the relocation of the cables. The total estimated loss is US$300,116 which is going to be claimed to the insurance company as a business interruption.

17. Impact of Covid-19

On March 11, 2020, the World Health Organization declared the coronavirus strain (COVID-19) in the category of pandemic.

The COVID-19 pandemic has affected the Wholesale Electricity Market (The Market) in Panama, since March the Government decreed a total quarantine with movement restrictions, this caused many businesses and industries to remain closed or reduce their production capacity, which in turn caused a wave of layoffs and work contract suspensions, this caused an economic crisis in the country and in the electricity sector since many people did not have the resources to pay for their electricity bills.

Since most of the businesses were closed or partially opened due to the pandemic, ASEP (The Regulator) sent letter DSAN No.0806 of April 7, 2020 to the CND (National Dispatch Center) in which has been established that, those Large Clients that do not meet the requirement of Minimum Monthly Demand of 100kW for four (4) consecutive months, will not be disengaged provided that the Large Client and the Generator have expressly and jointly decided to avail themselves of the fortuitous event clause or force majeure of their supply contract, whether they notify the CND prior to the breach, or so notify the CND once it contacts them regarding the fourth breach.

All Companies clients were affected in a way or another by the Government measures decreasing their consumption specially Ice Gaming Corp. and Iron Tower, S. A. (hereinafter "Hilton"), but this affectations were less than most of the industries since Companies' clients continues operating full or at least partially except for Hilton as mentioned before, this affected of the Companies revenues since the client's consumption was lower than budgeted.

To minimize the effect of the pandemic the Government approved the Decree No.291 of May 13, 2020 that established a moratorium for the months from March to September to establish a non-obligation of payment for the people affected by the pandemic. With great part of the regulated clients not paying, this decreased the cash flow of the Distribution Companies and these could not keep with their payments to the Generation Companies. The foregoing caused a domino effect in the Market since the lack of liquidity of the Distribution Companies prevented them from fulfilling the full payments of the PPAs with the Generation Companies and ASEP (The Regulator) through resolution AN No.16095-Ele of May 21th, 2020 let the Distribution Companies to pay proportionally with their income the commitments with the Market and also allows the Generation Companies affected by the pandemic due to this lack of payment by the Distribution Companies to pay their DTE (Economic Transactions - Document) obligations proportionally without their payment guarantee being executed by the CND (National Dispatch Center).

17. Impact of Covid-19 (Continued)

The Companies continue to make its full payments to the DTE (Economic Transactions Document), but the payments received from March to September due to ASEP (The Regulator) resolution, have been partial since other generation companies have been making partial payments due to being affected by the partial payments of the Distribution Companies. During July and August 2020 pending payments were received from generators companies.

Tecnisol I, S. A.

Report and Financial Statements
December 31, 2019

Tecnisol I, S. A.

Index to the Financial Statements
December 31, 2019

Independent Auditors' Report

To the Board of Directors and Shareholders of
Tecnisol I, S. A.

Our opinion

In our opinion, the financial statements of Tecnisol I, S. A. (the "Company") present fairly, in all material respects, the financial position of the Company as at December 31, 2019, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

What we have audited

The Company's financial statements comprise:
- the statement of financial position as at December 31, 2019;
- the statement of comprehensive loss for the year then ended;
- the statement of changes in equity for the year then ended;
- the statement of cash flows for the year then ended; and
- the notes to the financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Company in accordance with the International Ethics Standards Board for Accountants' Code of Ethics for Professional Accountants (IESBA Code), and the ethical requirements that are relevant to our audit of the financial statements in the Republic of Panama. We have fulfilled our other ethical responsibilities in accordance with the IESBA Code and the ethical requirements of the Republic of Panama.

Other matter

The comparative information as at, and for the period ended December 31, 2018 has not been audited.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with ISAs, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

PricewaterhouseCoopers

June 26, 2020
Panama, Republic of Panama

Tecnisol I, S. A.

Statement of Financial Position
December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019	2018 *(Unaudited)*
Assets			
Current assets			
Cash and cash equivalents	2 and 5	1,045,810	5,256,854
Trade and other receivables	2, 6 and 13	623,752	1,314,319
Prepaid expenses and other assets		311,795	875
Total current assets		1,981,357	6,572,048
Non-current assets			
Plant and equipment, net	2, 7 and 8	12,822,365	13,459,957
Intangible assets, net	9	248,489	242,536
Total non-current assets		13,070,854	13,702,493
Total assets		15,052,211	20,274,541
Liabilities and Equity			
Current liabilities			
Lease liabilities short-term debt	2 and 8	7,112	-
Shareholder's loan	2 and 13	14,697,179	19,725,842
Trade and other payables	2, 10 and 13	952,070	717,422
Total current liabilities		15,656,361	20,443,264
Non-current liabilities			
Lease liabilities long term	2 and 8	222,318	-
Total liabilities		15,878,679	20,443,264
Equity			
Common shares with US$100 par value each authorized and issued 100 shares	2 and 11	10,000	10,000
Accumulated deficit		(831,725)	(178,723)
Prepaid tax		(4,743)	-
Total equity		(826,468)	(168,723)
Total liabilities and equity		15,052,211	20,274,541

The accompanying notes are an integral part of these financial statements.

Tecnisol I, S. A.

Statement of Comprehensive Loss
For the year then ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019	2018 *(Unaudited)*
Revenues	13	4,620,629	2,379,580
Costs of goods and services	2, 7, 12 and 13	(3,934,164)	(1,855,024)
Gross profit		686,465	524,556
Expenses	12		
Administrative expenses		(607,473)	(702,054)
Operating expenses		(81,539)	-
Total expenses		(689,012)	(702,054)
Operating loss		(2,547)	(177,498)
Finance costs	13	(610,933)	(1,225)
Loss before income tax		(613,480)	(178,723)
Income tax	14	(39,522)	-
Total comprehensive loss for the year		(653,002)	(178,723)

The accompanying notes are an integral part of these financial statements.

Tecnisol I, S. A.

Statement of Changes in Equity
For the year then ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Common Shares	Capital Contribution	Accumulated Deficit	Prepaid Tax	Total Equity
Balance at December 31, 2017 *(Unaudited)*	-	2,916,960	-	-	2,916,960
Comprehensive loss:					
Net loss	-	-	(178,723)	-	(178,723)
Transactions with shareholders:					
Capital contribution	-	16,818,882	-	-	16,818,882
Transfer to shareholder loan	10,000	(19,735,842)	-	-	(19,725,842)
Balance at December 31, 2018 *(Unaudited)*	10,000	-	(178,723)	-	(168,723)
Comprehensive loss:					
Prepaid tax	-	-	-	(4,743)	(4,743)
Net loss	-	-	(653,002)	-	(653,002)
Balance at December 31, 2019	10,000	-	(831,725)	(4,743)	(826,468)

The accompanying notes are an integral part of these financial statements.

Tecnisol I, S. A.

Statement of Cash Flows
For the year then ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019	2018 *(Unaudited)*
Cash flows from operating activities			
Loss before income tax		(613,480)	(178,723)
Adjustments to reconcile loss before income tax to net cash provided by (used in) operating activities:			
Depreciation and amortization	7, 8 and 12	989,611	185,169
Finance cost, interest on borrowings		610,933	1,225
Changes in assets and liabilities:			
Trade and other receivables		690,567	(1,217,486)
Trade and other payables		234,648	700,966
Prepaid expenses and other assets		(310,920)	132,678
Interest paid		(610,933)	(1,225)
Income tax paid		(39,522)	-
Net cash provided by (used in) operating activities		950,904	(377,396)
Cash flows from investing activities			
Additions of plant and equipment	7	(105,926)	(11,062,206)
Additions of intangible assets	9	(16,000)	(122,426)
Net cash used in investing activities		(121,926)	(11,184,632)
Cash flows from financing activities			
Repayment of long-term debt		(5,028,663)	-
Equity contributed by shareholders		-	16,818,882
Prepaid tax		(4,743)	-
Finance lease payments	8	(6,616)	-
Net cash (used in) provided by financing activities		(5,040,022)	16,818,882
Net (decrease) increase in cash and cash equivalents during the year		(4,211,044)	5,256,854
Cash and cash equivalents at the beginning of year		5,256,854	-
Cash and cash equivalents at the end of year	5	1,045,810	5,256,854

The accompanying notes are an integral part of these financial statements.

1. General Information

Tecnisol I, S. A. (the "Company") is incorporated on February 20, 2014 under the laws of the Republic of Panama. The Company is engaged in the production of electricity through its photovoltaic panel parks located in David, Province of Chiriqui, Republic of Panama.

The ultimate parent company of Tecnisol I, S. A. is Interenergy Partners, L. P., incorporated in Cayman Island.

The Company is located in Torres de las Americas, Punta Pacifica, Republic of Panama, and the photovoltaic panel are in David, Republic of Panama. The local regulator, Autoridad Nacional de los Servicios Publicos (ASEP, by its acronym in Spanish), approved the Company's electricity generation license to 10 MW capacity (Note 15).

These financial statements have been approved for issue by the Finance Manager on June 26, 2020.

2. Summary of Significant Accounting Policies

The principal accounting policies applied in the preparation of these financial statements are set out below.

Basis of Preparation

The financial statements of the Company have been prepared in accordance with the International Financial Reporting Standards (IFRS) and the related interpretations adopted by the International Accounting Standards Board (IASB). The financial statements have been prepared on the historical cost convention.

The preparation of financial statements in conformity with IFRS requires the use of certain critical accounting estimates. It also requires Management to exercise its judgement in the process of applying the Company's accounting policies. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in Note 4.

New Standards, Amendments and Interpretations Adopted by the Company

The Company has applied the following standard and amendment for the first time in its annual reporting period commencing January 1, 2019:

- IFRS 16 - Leases

  The Company has initially applied IFRS 16, for the first time for their annual reporting period commencing January 1, 2019. It has applied using the cumulative effect method, under which the comparative information is not restated.

2. Summary of Significant Accounting Policies (Continued)

Basis of Preparation (continued)

New Standards, Amendments and Interpretations Adopted by the Company (continued)

IFRS 16 – Leases

- IFRS 16 - Leasing. The IASB issued in January 2016, IFRS 16, which replaces IAS 17- Leases. This standard introduces significant changes in accounting by lessee.
- The Company applied the simplified approach, in which the comparative figures are not restate at the date of initial application. The right-of-use assets for property leases will be initially measured on a retrospective basis as if the new standard had always been applied. All other right-of-use assets will be measured at the amount equal to the lease liability at the time of adoption (adjusted for prepaid or accrued lease payments relating to that lease recognized). In addition, the Company has decided not to apply the new standard to leases whose term will end within twelve months of the date of initial application. In such cases, the leases are accounted for as short-term leases and the lease payments associated with them are recognized as an expense from short-term leases.

In the context of the transition, the Company recognized as of January 1, 2019 a right of use asset for US$236,046 and a lease liability of US$236,046.

Accounting policy applied until December 31, 2018

A lease agreement in which the lessor transfers to the lessee, in exchange for a payment or a series of payments, the right to use an asset for an agreed period is classified as a finance lease.

A lease agreement was defined as an agreement in which the lessor conveys to the lessee the right to use an asset for a specified period in return for a payment or several payments. In accordance with IAS 17, beneficial ownership of the leased assets was attributed to the lessee if the lessee substantially bore all the risks and rewards inherent to ownership of the leased asset.

To the extent that beneficial ownership was attributable to the Company as a lessee. Financial leases were capitalized at the beginning of the lease, either at fair value of the leased property or, if less, at the present value of the minimum lease payments. A lease liability in the same amount was recognized as a non-current liability. The lease was subsequently measured at amortized cost using the effective interest method. The depreciation methods and estimated useful lives corresponded to those comparable purchased assets.

2. Summary of Significant Accounting Policies (Continued)

Basis of Preparation (continued)

New Standards, Amendments and Interpretations Adopted by the Company (continued)

IFRS 16 - Leases (continued)

Accounting policy applied until December 31, 2018 (continued)

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to the statement of comprehensive loss on a straight-line basis over the period of the lease

Accounting policy applied as of January 1, 2019

Lease liabilities include the following lease payments:

- Fixed payments, less any lease incentives receivable,
- variable lease payment that are based on an index or a rate,
- amounts expected to be payable by the group under residual value guarantees
- the exercise price of a purchase option if the group is reasonably certain to exercise that option, and
- payments of penalties for terminating the lease, if the lease term reflects the group exercising that option.

The lease payments are discounted using the interest rate implicit in the lease, to the extent that this can be determined. Otherwise, the discount is the lessee's incremental borrowing rate.

Right-of-use assets are measured at cost comprising the following:

- The amount of the initial measurement of lease liability

New Standards, Amendments and Interpretations not yet Adopted
Certain new accounting standards and interpretations have been published that are not mandatory for December 31, 2019 reporting periods and have not been early adopted by the Company. These standards are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

2. Summary of Significant Accounting Policies (Continued)

Monetary Unit and Functional Currency
The financial statements are expressed in U.S. Dollars (US$), monetary unit of the United States of America, which is at par with the Balboa (B/.), monetary unit of the Republic of Panama. The U.S. Dollar (US$) circulates and is freely exchangeable in the Republic of Panama and is the functional currency.

Financial Assets
The Company classifies its financial assets in the category of loans and receivables and assets at fair value through profit or loss, based on the purpose for which the financial assets were acquired. Management determines the classification of its financial assets at initial recognition.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Loans and receivables with maturities not greater than 12 months are included in current assets.

Cash and Cash Equivalents
For purposes of the cash flow statement, cash and cash equivalents include cash in hand.

Trade and Other Receivables
The Company maintains trade and other receivables in order to collect the contractual cash flows and, therefore, subsequently measures them at amortized cost using the effective interest method, less any estimate for impairment.

Plant and Equipment and Depreciation
Plant and equipment are stated at cost, less accumulated depreciation and impairment losses. Depreciation is calculated on the straight-line method over the estimated useful lives of the assets. Costs of maintenance, repairs, minor refurbishments and improvements are charged to expense. Subsequent costs are capitalized only when it is probable that a future economic benefit associated with the item will flow to the Company and the cost of the item can be measured reliably. The Company has a maintenance program that includes inspecting, testing and repairing all operational power equipment based on the equivalent operating hours (EOH).

Expenditure on the construction, installation or completion of infrastructure facilities, such as constructions. No depreciation or amortization is charged during the construction phase. The Company begins depreciating an item of property, plant and equipment when it is available for use.

2. Summary of Significant Accounting Policies (Continued)

Plant and Equipment and Depreciation (continued)
Right-of-use assets are generally depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. If the Company is reasonably certain to exercise a purchase option, the right-of-use asset is depreciated over the underlying asset's useful life.

Depreciation rates used are described as follows:

Buildings	2.50%
Generators and plant facilities	5% - 10%
Leasehold	5% - 5.5%
Tools and minor equipment	25%
Equipment of transportation	25%
Furniture and office equipment	25%

Intangible assets

Right of use
Represent the value attributable to the right of use of a high voltage transmission for a 25 years period, by virtue of a long-term contract with the landowners and the Company. The intangible assets are recognised at cost and subsequently measured at cost less accumulated amortization, which is calculated using the straight-line method to allocate the cost of the intangible assets over its estimated useful life of 25 years.

Shareholder's Loan
Borrowings are initially recognized at fair value, net of transaction costs incurred. Borrowings are subsequently carried at amortized cost, using the effective interest method.

Trade and Other Payables
Trade and other payables are obligations to pay for goods or services that have been acquired in the normal course of the business from suppliers. Trade and other payables are classified as current liabilities as payments are due within one year or less.

Trade and other payables are initially recognized at fair value and subsequently measured at amortized cost using the effective interest method.

Common Share
Common shares are classified as equity.

2. Summary of Significant Accounting Policies (Continued)

Revenue Recognition
The Company recognizes revenue in the periods that it delivers electricity. Contracted prices are billed in accordance to provisions of applicable power sales agreements and spot sales are billed in accordance with prevailing market prices. The unit of measurement of the contract prices is megawatts (MW). The following criteria should be met in order to recognize revenue: (1) persuasive evidence of an arrangement exists; (2) delivery has occurred or services have been rendered; (3) the price to the buyer is fixed or determinable; and (4) collection is reasonably assured. Revenues are measured at fair value of the consideration received or receivable for the sale of the energy.

Finance Cost
Comprise interest expense on borrowings, unwinding of the discount of provision and deferred consideration.

3. Financial Risk Management

Financial Risk Factors
The Company's activities expose it to a variety of financial risks: market risk (including currency risk, fair value interest rate risk and cash flow interest rate risk), credit risk and liquidity risk.

Risk management is carried out by the General Manager and the Director of Financial Department under the supervision of the Board of Directors. They identify and evaluate financial risks in close co-operation with management of departments within the Company.

Market Risk
Foreign exchange risk.

The Company is not substantially exposed to the foreign exchange risk fluctuation, since its revenues and expenses are mainly expressed in U. S. dollars.

Interest Rate Risk
Interest rate risk is mainly originated from long-term debt with variable interest rates that expose the Company to the cash flows risk.

Credit Risk
Credit risk arises mainly from cash and cash equivalents, restricted cash, trade and other receivables. The Company works only with well-known foreign and local financial institutions and energy distribution companies.

3. Financial Risk Management (Continued)

Financial Risk Factors (continued)

Credit Risk (continued)
The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit rating.

The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit rating.

	2019	2018 (Unaudited)
Cash at banks and short-term bank deposits international credit rating:		
Fitch (BBB-/BBB+)	962,809	5,229,610
Fitch (B/BB)	83,001	27,244
	1,045,810	5,256,854

The Company has a concentration of its revenues and accounts receivable with large clients in the Republic of Panama. Sales of energy made to these customers represent approximately 65% (2018: 25%) of total revenues and 88% (2018: 74%) of total accounts receivable at the end of the period. This concentration of risk is mitigated by the fact that demand for electricity in Panama continues to grow steadily and that the energy market is very well structured and regulated by government authorities. For each PPA a guarantee is required and the payment term of invoices originating in the electric market of Panama is averaged in a range of 30 days from the date of presentation of the invoice. The guarantee is a performance bond payable to the collection against any event of default for bad debts or bad debt. There were no default events for unpaid bills as of December 31, 2019

Liquidity Risk
Liquidity risk is the risk that the Company might not be able to comply with all its obligations. The Company minimizes this risk by maintaining adequate levels of cash on hand or in current accounts for fulfilling commitments with recurring suppliers and borrowers.

Cash flow forecasting is performed by the operating entities of the Company in and aggregated by Company finance. The Company finance monitors rolling forecasts of the Company's liquidity requirements to ensure it has sufficient cash to meet operational needs while maintaining sufficient headroom on its undrawn committed borrowing facilities at all times so that the Company does not breach borrowing limits or covenants on any of its borrowing facilities. Such forecasting takes into consideration the Company's debt financing plans, covenant compliance, compliance with internal statement of financial position ratio targets and, if applicable external regulatory or legal requirements.

3. Financial Risk Management (Continued)

Financial Risk Factors (continued)

Liquidity Risk (continued)
The table below analyses the Company's financial liabilities into relevant maturity groupings based on the remaining period at the statement of financial position to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows. Balances due within 12 months approximate their carrying balances as the impact of discounting is not significant.

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
December 31, 2019				
Shareholder's loan	14,697,179	-	-	14,697,179
Trade and other payables	952,070	-	-	952,070
	15,649,249	-	-	15,649,249

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
December 31, 2018				
(Unaudited)				
Shareholder's loan	19,725,842	-	-	19,725,842
Trade and other payables	717,422	-	-	717,422
	20,443,264	-	-	20,443,264

Capital Risk Management
The Company's objectives when managing capital are to safeguard the Company's ability to continue as a going concern in order to provide returns for the shareholders and to maintain an optimal capital structure to reduce the cost of capital.

In order to maintain or adjust the capital structure, the Company may adjust the number of dividends paid to the shareholders, return capital to the shareholders, issue new shares or sell assets to reduce debt. The Company monitors capital on the basis of the "liabilities to tangible net worth ratio", which is one of the ratios that the Company should consider at the time of paying dividends or incurring debt. Capital is defined by Management as the Company's shareholders' equity. This ratio is calculated as liabilities divided by tangible net worth. Liabilities are calculated as total long-term debt, including current portion of long-term debt. Tangible net worth is calculated as "equity" as shown in the statement of financial position.

3. Financial Risk Management (Continued)

Capital Risk Management (continued)
This ratio basically measures the leverage of the Company as a percent of the equity invested by the shareholder and provides the percentage of the funding of the Company with borrowing versus shareholders' equity.

The liabilities to tangible net worth ratio were as follows:

	2019	**2018** *(Unaudited)*
Shareholder's loan (Note 13)	14,697,179	19,725,842
Total tangible net worth	(1,068,460)	(411,536)
Total liabilities to tangible net worth ratio	(0.09)	(0.04)

Fair Value Estimation
For disclosure purposes, the International Financial Reporting Standards specify a fair value hierarchy that categorizes into three levels based on the inputs used in valuation techniques to measure fair value: The hierarchy is based on the transparency of variables used in the valuation of an asset at the date of valuation. These three levels are:

- Quoted prices (unadjusted) in active markets for identical assets and liabilities (Level 1).
- Inputs other than quoted prices included within level 1 that are observable for the asset and liability, either directly (that is, as prices) or indirectly (that is, derived from prices) (Level 2).
- Inputs for the asset and liability that are not based on observable market data (that is, unobservable inputs) (Level 3).

The carrying value of cash and cash equivalents, trade and other receivables, trade and other payables approximates its fair value due to the short-term nature.

4. Critical Accounting Estimates and Judgement

Estimates and judgements are continually evaluated by Management and are based on historical experience and on various other assumptions that management believes to be reasonable under the circumstances, the results of which form the basis for making judgements.

4. Critical Accounting Estimates and Judgement (Continued)

Critical Accounting Estimates and Assumptions
The resulting accounting estimates will, by definition, seldom equal the related actual results. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

Depreciation of Plant and Equipment
The Company makes judgements in assessing its assets estimated useful lives and in determining estimated residual values, as applicable. Depreciation is calculated on the straight-line method, based on the estimated useful lives of the assets.

These estimates are based on analysis of the assets' lifecycles and potential value at the end of its useful life. The assets residual values and useful lives are reviewed, and adjusted if appropriate, at each statement of financial position date.

During the year ended December 31, 2019, Management reassessed the 15 years useful life of generators and plant facilities, resulting in an increase of the depreciation expense in US$311,701.

5. Cash and Cash Equivalents

	2019	**2018** *(Unaudited)*
Cash in U. S. currency	1,045,810	5,256,854

6. Trade and Other Receivables

Trade and other receivables are detailed as follows:

	2019	**2018** *(Unaudited)*
Clients	433,546	452,920
Related parties (Note 13)	152,706	861,399
Others	37,500	-
	623,752	1,314,319

Account receivables are less than two months. At December 31, 2019 and 2018, there were no past due receivables, therefore, the Company has not recorded any provision for impairment.

7. Plant and Equipment, Net

Following is the movement of plant and equipment:

	Generators and Plant Facilities	Transmission line	Vehicles	Leasehold	Construction in Progress	Total
Cost at January 1, 2019	11,670,479	1,971,369	-	-	-	13,641,848
Additions	54,769	-	27,450	-	23,707	105,926
Adjustment for change in accounting policy, (Note 8)	-	-	-	236,046	-	236,046
Cost at December 31, 2019	11,725,248	1,971,369	27,450	236,046	23,707	13,983,820
Accumulated depreciation at January 1, 2019	(155,606)	(26,285)	-	-	-	(181,891)
Depreciation charge	(882,990)	(78,855)	(4,606)	(13,113)	-	(979,564)
Accumulated depreciation at December 31, 2019	(1,038,596)	(105,140)	(4,606)	(13,113)	-	(1,161,455)
Net balance at December 31, 2019	10,686,652	1,866,229	22,844	222,933	23,707	12,822,365

	Generators and Plant Facilities	Transmission line	Vehicles	Leasehold	Construction in Progress	Total
Cost at January 1, 2018 *(Unaudited)*	-	-	-	-	2,579,642	2,579,642
Additions	-	-	-	-	11,062,206	11,062,206
Capitalization	11,670,479	1,971,369	-	-	(13,641,848)	-
Cost at December 31, 2018 *(Unaudited)*	11,670,479	1,971,369	-	-	-	13,641,848
Accumulated depreciation at January 1, 2018 *(Unaudited)*	-	-	-	-	-	-
Depreciation charge	-	-	-	-	-	-
Accumulated depreciation at December 31, 2018 *(Unaudited)*	(155,606)	(26,285)	-	-	-	(181,891)
Net balance at December 31, 2018 *(Unaudited)*	11,514,873	1,945,084	-	-	-	13,459,957

In 2019, the Company recognized additions for the right to use leased property, which are included as part of the leasehold improvements. (Note 8).

8. Lease

As of December 31, 2019, property, plant and equipment include leases corresponding to the operating land lease located in David, Chiriquí province, Republic of Panama. The lease term is 20 years with a variable increase according to the consumer price index of the United States of America until expiration. (Note 7).

8. Lease (Continued)

The leased properties are presented below:

	2019
Right-of-use assets	
Cost	236,046
Additions	-
Accumulated depreciation	(13,113)
Net balance	222,933
Lease liabilities	
Current	7,112
Non-current	222,318
Net balance	229,430

In applying IFRS 16 for the first time, the Company has used the following practical expedients permitted by the standard:

(a) Applying a single discount rate (7.5%) to a portfolio of leases with reasonably similar characteristics, for the year end 2019 the Company has recognised US$ 17,704 (2018: US$0) as interest expense related to lease liabilities.

(b) Relying on previous assessments on whether leases are onerous.

(c) Accounting for operating leases with a remaining lease term of less than 12 months as at 1 January 2019 as short-term leases.

(d) Excluding initial direct costs for the measurement of the right-of-use asset at the date of initial application, and

(e) using hindsight in determining the lease term where the contract contains options to extend or terminate the lease.

9. Intangible Assets

The movement of intangible assets is as follows:

	2019	2018 *(Unaudited)*
Cost		
At January	245,814	123,388
Additions	16,000	122,426
Balance at the end of the year	261,814	245,814
Accumulated amortization		
At January	(3,278)	-
Depreciation charge	(10,047)	(3,278)
Balance at the end of the year	(13,325)	(3,278)
Net balance at end of year	248,489	242,536

Intangible assets correspond to contracts with landowners, these contracts correspond to the construction of a high voltage transmission line for a period of 25 years.

10. Trade and Other Payables

	2019	2018 *(Unaudited)*
Suppliers	595,043	443,558
Related parties (Note 13)	285,528	262,367
Other account payable	71,499	11,497
	952,070	717,422

11. Shareholders' Equity

The authorized share capital of the Company is US$10,000, composed by 100 common shares, with a value of US$100 each.

The Company is fully owned by Interenergy Holding UK Limited.

12. Costs and Expenses

The Company classifies its expenses by nature, as follows:

	2019	2018 *(Unaudited)*
Cost of goods and service		
Energy purchases from reserve contracts (Note 13)	1,473,971	1,172,792
Energy purchases to the spot market	1,385,188	485,419
Depreciation and amortization (Notes 7 and 8)	989,611	185,169
Repairs and maintenance	78,190	9,339
Fees transmission cost	7,204	2,305
	3,934,164	1,855,024
Administrative expenses		
Other expenses	435,894	187,327
Insurance costs	56,585	39,913
Professional fees	38,873	449,882
Donations	28,690	-
Office expenses	23,633	-
Office maintenance	11,273	-
Regulator fees	9,368	-
Fuel	3,157	-
Land rent	-	24,932
	607,473	702,054
Operating expenses		
Repairs and maintenance	81,539	-
	4,623,176	2,557,078

13. Balances and Transactions with Related Parties

The Company is fully controlled by Interenergy Holdings, its ultimate parent company. The Company carried out transactions and maintained balances with related companies, as described below:

	2019	2018 *(Unaudited)*
Transactions		
Interest paid - shareholders' loan (a)	591,775	-

13. Balances and Transactions with Related Parties (Continued)

	2019	2018 *(Unaudited)*
Sales in spot market (b)	3,744	383
Energy purchases and associated costs (b)	1,468,046	778,889
Balances		
Related companies - accounts receivable (b)	152,706	861,399
Related companies - accounts payable (b)	285,528	262,367
Shareholders' loan payable (c)	14,697,179	19,725,842
	14,982,707	19,988,209

(a) Interest paid to shareholders.

(b) Transactions related to sales and purchase of the energy in the spot market and energy purchases from reserve contracts with related companies. (Note 15).

(c) The shareholders' loan payable is due to Interenergy Holding UK Limited, this loan has an established maturity date on December 20th, 2021 and is agreed at an interest rate of 3%. (Note 11).

14. Income Tax

The income tax is presented as follows:

	2019	2018 *(Unaudited)*
Income tax	39,522	-

Under current tax legislation in the Republic of Panama, the profits of the Company from local operations are subject to income tax.

Income tax is based on the higher of the following computations:

a. The rate of 25% on taxable income.

14. Income Tax (Continued)

b. The net taxable profit resulting from applying 4.67% to the total taxable income times the rate of 25% which represents 1.17% of taxable income (alternative minimum tax).

In certain circumstances, if the application of 1.17% of revenue results in the entity incurring losses for tax reasons, or the effective tax rate is higher than 25%, then the entity may choose to request not to apply minimum tax. In such cases, the Company must file a petition with the Tax Administration, who may authorize the no application for a term of three years.

According Tax Legislation of Panama, income tax returns for the last three (3) years are subject to review by fiscal authorities, including year ending December 31, 2019.

The income tax resultant by applying the in-force rates to the net loss, is reconciled with the income tax provision presented in the financial statements, as follows:

	2019	**2018** *(Unaudited)*
Loss before income tax	(653,002)	(178,723)
Plus: Non-deductible expenses	172,933	336,810
Effect of non-taxable loss (taxable income)	(480,069)	158,087
Income tax (traditional method)	-	39,522
Previous year income tax adjustment	39,522	-
Total income tax (traditional method)	39,522	-

Management will request to the Tax Authority the non-application of the CAIR for the 2019 fiscal year and they expect to obtain a positive outcome on the request.

Transfer Pricing
Law No.52 of August 28, 2012, established the transfer pricing regime oriented to regulate tax purposes transactions between related parties, and applicable to the taxpayer to perform operations with related parties that are tax residents of other jurisdictions. The most important aspects of this regulation include:

- Taxpayers must submit annually an information return related operations with related parties, within six (6) months following the close of the relevant fiscal period. This obligation applies to transactions from fiscal year 2012.

14. Income Tax (Continued)

Transfer Pricing (continued)

- Failure to submit the report shall be punishable by a fine equivalent to 1% of the total amount of transactions with related parties.

- Persons required to submit the report referred to in the preceding paragraph, shall maintain a transfer pricing study, which shall contain the information and analysis to assess and document their transactions with related parties, in accordance by Law. The taxpayer must present study only at the request of the Department of Revenue of the Ministry of Economy and Finance within 45 days of your request.

15. Commitments

- The Company Tecnisol I, S. A. has four Energy Supply Contracts (PPAs) for fifteen years. Beginning in 2018 and ending in 2033 with Large Clients. The signed contracts have as counterparties: Coca-Cola FEMSA, Industrias Lacteas (Estrella Azul and Jugos del Prado) and Clinica Hospital San Fernando. The price is indexed based on the regulated tariff to the end customer, in a proportion between 100% and 70%, depending on the price of the tariff that would have been applied to the customer that would had been applied if remained at the distributor. All the contracts have a threshold in which the sale price of energy can be moved, having a maximum and a minimum price. If as a result of the indexation the price is equal to or greater than 125 $/MWh (maximum price), the price remains at said value, and if, on the contrary, the price falls below 83 $/MWh (minimum price), the price remains at the latter value.

- The Company has five energy reserve contracts with the Companies Tecnisol II, Tecnisol IV, UEP Penonome II (related companies) and with Generadora del Istmo (GENISA) and Saltos del Francoli.

- The supply period for the reserve contracts with related companies are ten years, beginning on December 4th, 2019 for Tecnisol II and Tecnisol IV; and 1 year beginning on July 1st, 2019 for UEP Penonome II. The Contract Price is fixed but can be changed by the parties through mutual agreement.

- The supply period for the reserve contracts with GENISA and Saltos del Francoli are one year, beginning on December 31st, 2018 for GENISA and 14 months beginning on November 1st, 2019 for Saltos del Francoli. The Contract Price is variable per month and time period.

15. Commitments (Continued)

- ASEP (the regulator) granted the Definitive License through Resolution AN No.8545-Elec on May 6th, 2015; lasting for forty (40) years with the possibility of renewal for an equal period.

16. Subsequent Event

Impact of Covid-19

On March 11, 2020, the World Health Organization declared the coronavirus strain (COVID-19) in the category of pandemic. The Company's operations and its business could be affected by the future effects of this pandemic; however, due to the recent nature of this situation, the Company's operations have not been affected. To date, Company's management is not aware of any issues related to liquidity, regulatory, legal or other aspects that affect the Company.

Tecnisol II, S. A.

Report and Financial Statements
December 31, 2019

Tecnisol II, S. A.

Index to the Financial Statements
December 31, 2019

Independent Auditors' Report

To the Board of Directors and Shareholders of
Tecnisol II, S. A.

Our opinion

In our opinion, the financial statements of Tecnisol II, S. A. (the "Company") present fairly, in all material respects, the financial position of the Company as at December 31, 2019, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

What we have audited

The Company's financial statements comprise:
- the statement of financial position as at December 31, 2019;
- the statement of comprehensive income for the year then ended;
- the statement of changes in equity for the year then ended;
- the statement of cash flows for the year then ended; and
- the notes to the financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Company in accordance with the International Ethics Standards Board for Accountants' Code of Ethics for Professional Accountants (IESBA Code), and the ethical requirements that are relevant to our audit of the financial statements in the Republic of Panama. We have fulfilled our other ethical responsibilities in accordance with the IESBA Code and the ethical requirements of the Republic of Panama.

To the Board of Directors and Shareholders of
Tecnisol II, S. A.
Page 2

Other matter

The comparative information as at, and for the period ended December 31, 2018 has not been audited.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with ISAs, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

PricewaterhouseCoopers

June 26, 2020
Panama, Republic of Panama

Tecnisol II, S. A.

Statement of Financial Position
December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019	2018 *(Unaudited)*
Assets			
Current assets			
Cash and cash equivalents	2 and 5	552,104	135,217
Trade and other receivables	2, 6 and 12	194,666	244,229
Prepaid expenses and other assets		24,556	375
Total current assets		771,326	379,821
Non-current asset			
Plant and equipment, net	2, 7 and 8	9,156,607	9,599,355
Total assets		9,927,933	9,979,176
Liabilities and Equity			
Current liabilities			
Lease liabilities short-term debt	2 and 8	8,226	-
Shareholder's loan	2 and 12	8,558,035	9,247,683
Trade and other payables	2, 9 and 12	905,533	834,246
Total current liabilities		9,471,794	10,081,929
Non-current liability			
Lease liabilities long term	2 and 8	257,148	-
Total liabilities		9,728,942	10,081,929
Equity			
Common shares with US$100 par value each authorized and issued 100 shares	2 and 10	10,000	10,000
Retained earnings (accumulated deficit)		191,812	(112,753)
Prepaid tax		(2,821)	-
Total equity		198,991	(102,753)
Total liabilities and equity		9,927,933	9,979,176

The accompanying notes are an integral part of these financial statements.

Tecnisol II, S. A.

Statement of Comprehensive Income
For the year then ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019	2018 *(Unaudited)*
Revenues	12	1,562,520	378,687
Costs of goods and services	2, 7, 11 and 12	(752,078)	(133,662)
Gross profit		810,442	245,025
Expenses			
Administrative expenses	11	(99,299)	(355,335)
Operating profit (loss)		711,143	(110,310)
Finance costs	12	(298,630)	-
Income (loss) before income tax		412,513	(110,310)
Income tax	13	(107,948)	(2,443)
Total comprehensive income (loss) for the year		304,565	(112,753)

The accompanying notes are an integral part of these financial statements.

Tecnisol II, S. A.

Statement of Changes in Equity
For the year then ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Common Shares	Capital Contribution	Retained Earnings (Accumulated Deficit)	Prepaid Tax	Total Equity
Balance at December 31, 2017 *(Unaudited)*	-	1,803,800	-	-	1,803,800
Comprehensive loss:					
Net loss	-	-	(112,753)	-	(112,753)
Transactions with shareholders:					
Capital contribution	-	7,453,883	-	-	7,453,883
Transfer to shareholder loan	10,000	(9,257,683)	-	-	(9,247,683)
Balance at December 31, 2018 *(Unaudited)*	10,000	-	(112,753)	-	(102,753)
Comprehensive income:					
Prepaid tax	-	-	-	(2,821)	(2,821)
Net income	-	-	304,565	-	304,565
Balance at December 31, 2019	10,000	-	191,812	(2,821)	198,991

The accompanying notes are an integral part of these financial statements.

Tecnisol II, S. A.

Statement of Cash Flows
For the year then ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019	2018 *(Unaudited)*
Cash flows from operating activities			
Income (loss) before income tax		412,513	(110,310)
Adjustments to reconcile income (loss) before income tax to net cash provided by operating activities:			
Depreciation and amortization	7, 8 and 11	739,247	129,721
Finance cost, interest on borrowings		298,630	-
Changes in assets and liabilities:			
Trade and other receivables		49,563	(244,229)
Trade and other payables		71,287	817,790
Prepaid expenses and other assets		(24,181)	129,438
Interest paid		(298,630)	-
Income tax paid		(107,948)	(2,443)
Net cash provided by operating activities		1,140,481	719,967
Cash flows from investing activities			
Additions of plant and equipment	7	(23,472)	(8,038,633)
Net cash used in investing activities		(23,472)	(8,038,633)
Cash flows from financing activities			
Repayment of long-term debt		(689,648)	-
Equity contributed by shareholders		-	7,453,883
Prepaid tax		(2,821)	-
Finance lease payments	8	(7,653)	-
Net cash (used in) provided by financing activities		(700,122)	7,453,883
Net increase in cash and cash equivalents during the year		416,887	135,217
Cash and cash equivalents at the beginning of year		135,217	-
Cash and cash equivalents at the end of year	5	552,104	135,217

The accompanying notes are an integral part of these financial statements.

1. General Information

Tecnisol II, S. A. (the "Company") is incorporated on February 20, 2014 under the laws of the Republic of Panama. The Company is engaged in the production of electricity through its photovoltaic panel parks located in David, Province of Chiriqui, Republic of Panama.

The ultimate parent company of Tecnisol II, S. A. is Interenergy Partners, L. P., incorporated in Cayman Island.

The Company is located in Torres de las Americas, Punta Pacifica, Republic of Panama, and the photovoltaic panel are in David, Republic of Panama. The local regulator, Autoridad Nacional de los Servicios Publicos (ASEP, by its acronym in Spanish), approved the Company's electricity generation license to 10 MW capacity (Note 14).

These financial statements have been approved for issue by the Finance Manager on June 26, 2020.

2. Summary of Significant Accounting Policies

The principal accounting policies applied in the preparation of these financial statements are set out below.

Basis of Preparation

The financial statements of the Company have been prepared in accordance with the International Financial Reporting Standards (IFRS) and the related interpretations adopted by the International Accounting Standards Board (IASB). The financial statements have been prepared on the historical cost convention.

The preparation of financial statements in conformity with IFRS requires the use of certain critical accounting estimates. It also requires Management to exercise its judgement in the process of applying the Company's accounting policies. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in Note 4.

New Standards, Amendments and Interpretations Adopted by the Company

The Company has applied the following standard and amendment for the first time in its annual reporting period commencing January 1, 2019:

<u>IFRS 16 – Leases</u>

- The Company has initially applied IFRS 16, for the first time for their annual reporting period commencing January 1, 2019. It has applied using the cumulative effect method, under which the comparative information is not restated.

2. Summary of Significant Accounting Policies (Continued)

Basis of Preparation (continued)

New Standards, Amendments and Interpretations Adopted by the Company (continued)

IFRS 16 – Leases (continued)

- IFRS 16 - Leasing. The IASB issued in January 2016, IFRS 16, which replaces IAS 17-Leases. This standard introduces significant changes in accounting by lessee.
- The Company applied the simplified approach, in which the comparative figures are not restate at the date of initial application. The right-of-use assets for property leases will be initially measured on a retrospective basis as if the new standard had always been applied. All other right-of-use assets will be measured at the amount equal to the lease liability at the time of adoption (adjusted for prepaid or accrued lease payments relating to that lease recognized). In addition, the Company has decided not to apply the new standard to leases whose term will end within twelve months of the date of initial application. In such cases, the leases are accounted for as short-term leases and the lease payments associated with them are recognized as an expense from short-term leases.

In the context of the transition, the Company recognized as of January 1, 2019 a right of use asset for US$273,027 and a lease liability of US$273,027.

Accounting policy applied until December 31, 2018

A lease agreement in which the lessor transfers to the lessee, in exchange for a payment or a series of payments, the right to use an asset for an agreed period is classified as a finance lease.

A lease agreement was defined as an agreement in which the lessor conveys to the lessee the right to use an asset for a specified period in return for a payment or several payments. In accordance with IAS 17, beneficial ownership of the leased assets was attributed to the lessee if the lessee substantially bore all the risks and rewards inherent to ownership of the leased asset.

To the extent that beneficial ownership was attributable to the Company as a lessee. Financial leases were capitalized at the beginning of the lease, either at fair value of the leased property or, if less, at the present value of the minimum lease payments. A lease liability in the same amount was recognized as a non-current liability. The lease was subsequently measured at amortized cost using the effective interest method. The depreciation methods and estimated useful lives corresponded to those comparable purchased assets.

2. Summary of Significant Accounting Policies (Continued)

Basis of Preparation (continued)

New Standards, Amendments and Interpretations Adopted by the Company (continued)

IFRS 16 - Leases (continued)

Accounting policy applied until December 31, 2018 (continued)

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to the statement of comprehensive income on a straight-line basis over the period of the lease

Accounting policy applied as of January 1, 2019

Lease liabilities include the following lease payments:

- Fixed payments, less any lease incentives receivable,
- variable lease payment that are based on an index or a rate,
- amounts expected to be payable by the group under residual value guarantees
- the exercise price of a purchase option if the group is reasonably certain to exercise that option, and
- payments of penalties for terminating the lease, if the lease term reflects the group exercising that option.

The lease payments are discounted using the interest rate implicit in the lease, to the extent that this can be determined. Otherwise, the discount is the lessee's incremental borrowing rate.

Right-of-use assets are measured at cost comprising the following:

- The amount of the initial measurement of lease liability

New Standards, Amendments and Interpretations not yet Adopted
Certain new accounting standards and interpretations have been published that are not mandatory for December 31, 2019 reporting periods and have not been early adopted by the Company. These standards are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

2. Summary of Significant Accounting Policies (Continued)

Monetary Unit and Functional Currency
The financial statements are expressed in U.S. Dollars (US$), monetary unit of the United States of America, which is at par with the Balboa (B/.), monetary unit of the Republic of Panama. The U.S. Dollar (US$) circulates and is freely exchangeable in the Republic of Panama and is the functional currency.

Financial Assets
The Company classifies its financial assets in the category of loans and receivables and assets at fair value through profit or loss, based on the purpose for which the financial assets were acquired. Management determines the classification of its financial assets at initial recognition.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Loans and receivables with maturities not greater than 12 months are included in current assets.

Cash and Cash Equivalents
For purposes of the cash flow statement, cash and cash equivalents include cash in hand.

Trade and Other Receivables
The Company maintains trade and other receivables in order to collect the contractual cash flows and, therefore, subsequently measures them at amortized cost using the effective interest method, less any estimate for impairment.

Plant and Equipment and Depreciation
Plant and equipment are stated at cost, less accumulated depreciation and impairment losses. Depreciation is calculated on the straight-line method over the estimated useful lives of the assets. Costs of maintenance, repairs, minor refurbishments and improvements are charged to expense. Subsequent costs are capitalized only when it is probable that a future economic benefit associated with the item will flow to the Company and the cost of the item can be measured reliably. The Company has a maintenance program that includes inspecting, testing and repairing all operational power equipment based on the equivalent operating hours (EOH).

Expenditure on the construction, installation or completion of infrastructure facilities, such as constructions. No depreciation or amortization is charged during the construction phase. The Company begins depreciating an item of property, plant and equipment when it is available for use.

2. Summary of Significant Accounting Policies (Continued)

Plant and Equipment and Depreciation (continued)
Right-of-use assets are generally depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. If the Company is reasonably certain to exercise a purchase option, the right-of-use asset is depreciated over the underlying asset's useful life.

Depreciation rates used are described as follows:

Buildings	2.50%
Generators and plant facilities	5% - 10%
Leasehold	5% - 5.5%
Tools and minor equipment	25%
Equipment of transportation	25%
Furniture and office equipment	25%

Shareholder's Loan
Borrowings are initially recognized at fair value, net of transaction costs incurred. Borrowings are subsequently carried at amortized cost, using the effective interest method.

Trade and Other Payables
Trade and other payables are obligations to pay for goods or services that have been acquired in the normal course of the business from suppliers. Trade and other payables are classified as current liabilities as payments are due within one year or less.

Trade and other payables are initially recognized at fair value and subsequently measured at amortized cost using the effective interest method.

Common Share
Common shares are classified as equity.

Revenue Recognition
The Company recognizes revenue in the periods that it delivers electricity. Contracted prices are billed in accordance to provisions of applicable power sales agreements and spot sales are billed in accordance with prevailing market prices. The unit of measurement of the contract prices is megawatts (MW). The following criteria should be met in order to recognize revenue: (1) persuasive evidence of an arrangement exists; (2) delivery has occurred or services have been rendered; (3) the price to the buyer is fixed or determinable; and (4) collection is reasonably assured. Revenues are measured at fair value of the consideration received or receivable for the sale of the energy.

2. Summary of Significant Accounting Policies (Continued)

Finance Cost
Comprise interest expense on borrowings, unwinding of the discount of provision and deferred consideration.

3. Financial Risk Management

Financial Risk Factors
The Company's activities expose it to a variety of financial risks: market risk (including currency risk, fair value interest rate risk and cash flow interest rate risk), credit risk and liquidity risk.

Risk management is carried out by the General Manager and the Director of Financial Department under the supervision of the Board of Directors. They identify and evaluate financial risks in close co-operation with management of departments within the Company.

Market Risk
Foreign exchange risk.

The Company is not substantially exposed to the foreign exchange risk fluctuation, since its revenues and expenses are mainly expressed in U. S. dollars.

Interest Rate Risk
Interest rate risk is mainly originated from long-term debt with variable interest rates that expose the Company to the cash flows risk.

Credit Risk
Credit risk arises mainly from cash and cash equivalents, restricted cash, trade and other receivables. The Company works only with well-known foreign and local financial institutions and energy distribution companies.

The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit rating.

3. Financial Risk Management (Continued)

Financial Risk Factors (continued)
The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit rating.

	2019	2018 *(Unaudited)*
Cash at banks and short-term bank deposits international credit rating:		
Fitch (B/BB)	552,104	135,217
	552,104	135,217

The Company has a concentration of its revenues and accounts receivable with related companies and customers from the spot market in the Republic of Panama. Sales of energy made to these customers represent approximately 17% (2018: 10%), 83% (2018: 90%) of total revenues and 15% (2018: 12%), 85% (2018: 88%) of total accounts receivable, respectively at the end of the period. This concentration of risk is mitigated by the fact that demand for electricity in Panama continues to grow steadily and that the energy market is very well structured and regulated by government authorities. For each PPA a guarantee is required and the payment term of invoices originating in the electric market of Panama is averaged in a range of 30 days from the date of presentation of the invoice. The guarantee is a performance bond payable to the collection against any event of default for bad debts or bad debt. There were no default events for unpaid bills as of December 31, 2019.

Liquidity Risk
Liquidity risk is the risk that the Company might not be able to comply with all its obligations. The Company minimizes this risk by maintaining adequate levels of cash on hand or in current accounts for fulfilling commitments with recurring suppliers and borrowers.

Cash flow forecasting is performed by the operating entities of the Company in and aggregated by Company finance. The Company finance monitors rolling forecasts of the Company's liquidity requirements to ensure it has sufficient cash to meet operational needs while maintaining sufficient headroom on its undrawn committed borrowing facilities at all times so that the Company does not breach borrowing limits or covenants on any of its borrowing facilities. Such forecasting takes into consideration the Company's debt financing plans, covenant compliance, compliance with internal statement of financial position ratio targets and, if applicable external regulatory or legal requirements.

3. Financial Risk Management (Continued)

Financial Risk Factors (continued)

Liquidity Risk (continued)
The table below analyses the Company's financial liabilities into relevant maturity groupings based on the remaining period at the statement of financial position to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows. Balances due within 12 months approximate their carrying balances as the impact of discounting is not significant.

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
December 31, 2019				
Shareholder's loan	8,558,035	-	-	8,558,035
Trade and other payables	905,533	-	-	905,533
	9,463,568	-	-	9,463,568

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
December 31, 2018				
(Unaudited)				
Shareholder's loan	9,247,683	-	-	9,247,683
Trade and other payables	834,246	-	-	834,246
	10,081,929	-	-	10,081,929

Capital Risk Management

The Company's objectives when managing capital are to safeguard the Company's ability to continue as a going concern in order to provide returns for the shareholders and to maintain an optimal capital structure to reduce the cost of capital.

In order to maintain or adjust the capital structure, the Company may adjust the number of dividends paid to the shareholders, return capital to the shareholders, issue new shares or sell assets to reduce debt. The Company monitors capital on the basis of the "liabilities to tangible net worth ratio", which is one of the ratios that the Company should consider at the time of paying dividends or incurring debt. Capital is defined by Management as the Company's shareholders' equity. This ratio is calculated as liabilities divided by tangible net worth. Liabilities are calculated as total long-term debt, including current portion of long-term debt. Tangible net worth is calculated as "equity" as shown in the statement of financial position.

3. Financial Risk Management (Continued)

Capital Risk Management (continued)
This ratio basically measures the leverage of the Company as a percent of the equity invested by the shareholder and provides the percentage of the funding of the Company with borrowing versus shareholders' equity.

The liabilities to tangible net worth ratio were as follows:

	2019	**2018** *(Unaudited)*
Shareholder's loan (Note 12)	8,558,035	9,247,683
Total tangible net worth	206,506	(102,753)
Total liabilities to tangible net worth ratio	0.13	0.09

Fair Value Estimation
For disclosure purposes, the International Financial Reporting Standards specify a fair value hierarchy that categorizes into three levels based on the inputs used in valuation techniques to measure fair value: The hierarchy is based on the transparency of variables used in the valuation of an asset at the date of valuation. These three levels are:

- Quoted prices (unadjusted) in active markets for identical assets and liabilities (Level 1).
- Inputs other than quoted prices included within level 1 that are observable for the asset and liability, either directly (that is, as prices) or indirectly (that is, derived from prices) (Level 2).
- Inputs for the asset and liability that are not based on observable market data (that is, unobservable inputs) (Level 3).

The carrying value of cash and cash equivalents, trade and other receivables, trade and other payables approximates its fair value due to the short-term nature.

4. Critical Accounting Estimates and Judgement

Estimates and judgements are continually evaluated by Management and are based on historical experience and on various other assumptions that management believes to be reasonable under the circumstances, the results of which form the basis for making judgements.

4. Critical Accounting Estimates and Judgement (Continued)

Critical Accounting Estimates and Assumptions
The resulting accounting estimates will, by definition, seldom equal the related actual results. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

Depreciation of Plant and Equipment
The Company makes judgements in assessing its assets estimated useful lives and in determining estimated residual values, as applicable. Depreciation is calculated on the straight-line method, based on the estimated useful lives of the assets.

These estimates are based on analysis of the assets' lifecycles and potential value at the end of its useful life. The assets residual values and useful lives are reviewed, and adjusted if appropriate, at each statement of financial position date.

During the year ended December 31, 2019, Management reassessed the 15 years useful life of generators and plant facilities, resulting in an increase of the depreciation expense in US$251,003.

5. Cash and Cash Equivalents

	2019	2018 *(Unaudited)*
Cash in U. S. currency	552,104	135,217

6. Trade and Other Receivables

Trade and other receivables are detailed as follows:

	2019	2018 *(Unaudited)*
Clients	165,842	206,685
Related parties (Note 12)	28,824	37,544
	194,666	244,229

Account receivables are less than two months. At December 31, 2019 and 2018, there were no past due receivables, therefore, the Company has not recorded any provision for impairment.

7. Plant and Equipment, Net

Following is the movement of plant and equipment:

	Generators and Plant Facilities	Transmission line	Leasehold	Construction in Progress	Total
Cost at January 1, 2019	9,404,833	324,243	-	-	9,729,076
Additions	23,472	-	-	-	23,472
Adjustment for change in accounting policy, (Note 8)	-	-	273,027	-	273,027
Cost at December 31, 2019	9,428,305	324,243	273,027	-	10,025,575
Accumulated depreciation at January 1, 2019	(125,398)	(4,323)	-	-	(129,721)
Depreciation charge	(711,109)	(12,970)	(15,168)	-	(739,247)
Accumulated depreciation at December 31, 2019	(836,507)	(17,293)	(15,168)	-	(868,968)
Net balance at December 31, 2019	8,591,798	306,950	257,859	-	9,156,607

	Generators and Plant Facilities	Transmission line	Leasehold	Construction in Progress	Total
Cost at January 1, 2018 *(Unaudited)*	-	-	-	1,690,443	1,690,443
Additions	-	-	-	8,038,633	8,038,633
Capitalization	9,404,833	324,243	-	(9,729,076)	-
Cost at December 31, 2018 *(Unaudited)*	9,404,833	324,243	-	-	9,729,076
Accumulated depreciation at January 1, 2018 *(Unaudited)*	-	-	-	-	-
Depreciation charge	-	-	-	-	-
Accumulated depreciation at December 31, 2019 *(Unaudited)*	(125,398)	(4,323)	-	-	(129,721)
Net balance at December 31, 2019 *(Unaudited)*	9,279,435	319,920	-	-	9,599,355

In 2019, the Company recognized additions for the right to use leased property, which are included as part of the leasehold improvements. (Note 8).

8. Lease

As of December 31, 2019, property, plant and equipment include leases corresponding to the operating land lease located in David, Chiriquí province, Republic of Panama. The lease term is 20 years with a variable increase according to the consumer price index of the United States of America until expiration (Note 7).

The leased properties are presented below:

	2019
Right-of-use assets	
Cost	273,027
Additions	-
Accumulated depreciation	(15,168)
Net balance	257,859

8. Lease (Continued)

	2019
Lease liabilities	
Current	8,226
Non-current	257,148
Net balance	265,374

In applying IFRS 16 for the first time, the Company has used the following practical expedients permitted by the standard:

(a) Applying a single discount rate (7.5%) to a portfolio of leases with reasonably similar characteristics, for the year end 2019 the Company has recognised US$20,477 (2018: US$0) as interest expense related to lease liabilities.
(b) Relying on previous assessments on whether leases are onerous.
(c) Accounting for operating leases with a remaining lease term of less than 12 months as at 1 January 2019 as short-term leases.
(d) Excluding initial direct costs for the measurement of the right-of-use asset at the date of initial application, and
(e) using hindsight in determining the lease term where the contract contains options to extend or terminate the lease.

9. Trade and Other Payables

	2019	2018 *(Unaudited)*
Suppliers	765,537	831,795
Other account payable	112,798	2,443
Related parties (Note 12)	27,198	8
	905,533	834,246

10. Shareholders' Equity

The authorized share capital of the Company is US$10,000, composed by 100 common shares, with a value of US$100 each.

The Company is fully owned by Interenergy Holding UK Limited.

11. Costs and Expenses

The Company classifies its expenses by nature, as follows:

	2019	2018 *(Unaudited)*
Cost of goods and service		
Depreciation and amortization (Note 7 and 8)	739,247	129,721
Fees transmission cost	6,798	2,066
Energy purchases to the spot market	6,033	1,875
	752,078	133,662
Administrative expenses		
Other expenses	59,206	131,113
Donations	19,230	-
Professional fees	17,589	195,384
Regulator fees	3,274	-
Land rent	-	28,838
	99,299	355,335
	851,377	488,997

12. Balances and Transactions with Related Parties

The Company is fully controlled by Interenergy Holdings, its ultimate parent company. The Company carried out transactions and maintained balances with related companies, as described below:

	2019	2018 *(Unaudited)*
Transactions		
Interest paid - shareholders' loan (a)	277,430	-
Energy sales in reserve contracts (b)	268,622	37,295
Sales in spot market (b)	14,990	898
Energy purchases and associated costs (b)	105	11

12. Balances and Transactions with Related Parties (Continued)

	2019	2018 *(Unaudited)*
Balances		
Related companies - accounts receivable (b)	28,824	37,544
Related companies - accounts payable (b)	27,198	8
Shareholders' loan payable (c)	8,558,035	9,247,683
	8,585,233	9,247,691

(a) Interest paid to shareholders.

(b) Transactions related to sales and purchases of the energy in the spot market and energy sales in reserve contracts with related companies. (Note 14)

(c) The shareholders' loan payable is due to Interenergy Holding UK Limited, this loan has an established maturity date on December 20th, 2021 and is agreed at an interest rate of 3%. (Note 10)

13. Income Tax

The income tax is presented as follows:

	2019	2018 *(Unaudited)*
Income tax	107,948	2,443

Under current tax legislation in the Republic of Panama, the profits of the Company from local operations are subject to income tax.

Income tax is based on the higher of the following computations:

a. The rate of 25% on taxable income.

b. The net taxable profit resulting from applying 4.67% to the total taxable income times the rate of 25% which represents 1.17% of taxable income (alternative minimum tax).

13. Income Tax (Continued)

In certain circumstances, if the application of 1.17% of revenue results in the entity incurring losses for tax reasons, or the effective tax rate is higher than 25%, then the entity may choose to request not to apply minimum tax. In such cases, the Company must file a petition with the Tax Administration, who may authorize the no application for a term of three years.

According Tax Legislation of Panama, income tax returns for the last three (3) years are subject to review by fiscal authorities, including year ending December 31, 2019.

The income tax resultant by applying the in-force rates to the net loss, is reconciled with the income tax provision presented in the financial statements, as follows:

	2019	**2018** *(Unaudited)*
Income before income tax	412,513	(110,310)
Plus: Non-deductible expenses	19,279	120,080
Effect of taxable income	431,792	9,770
Income tax (traditional method)	107,948	2,443

Management will request to the Tax Authority the non-application of the CAIR for the 2019 fiscal year and they expect to obtain a positive outcome on the request.

Transfer Pricing
Law No.52 of August 28, 2012, established the transfer pricing regime oriented to regulate tax purposes transactions between related parties, and applicable to the taxpayer to perform operations with related parties that are tax residents of other jurisdictions. The most important aspects of this regulation include:

- Taxpayers must submit annually an information return related operations with related parties, within six (6) months following the close of the relevant fiscal period. This obligation applies to transactions from fiscal year 2012.

- Failure to submit the report shall be punishable by a fine equivalent to 1% of the total amount of transactions with related parties.

- Persons required to submit the report referred to in the preceding paragraph, shall maintain a transfer pricing study, which shall contain the information and analysis to assess and document their transactions with related parties, in accordance by Law. The taxpayer must present study only at the request of the Department of Revenue of the Ministry of Economy and Finance within 45 days of your request.

14. Commitments

- The Company Tecnisol II, S. A. is part of an Interenergy Group strategy called SER (from its Spanish acronym for “Suministro de Energía Renovable”) that consist in supplying 100% renewable energy to Large Clients (in private PPAs). To fulfill this, the company has signed Reserve Contracts with affiliated companies to supply renewable energy to comply with the Clients requirements.

- The Company Tecnisol II, S. A. has two Reserve Contracts for energy supply, these contracts are signed with: Tecnisol I, S. A. and Tecnisol III, S. A. (related companies).

- The supply period for these contracts is 10 years, beginning on December 4th, 2019, the Contract Price is fixed but can be changed through mutual agreement by the parties.

- ASEP (the regulator) granted Definitive License for the construction, operation, maintenance, power generation and sale of Solar Power Plant Ikako I through the Resolution AN No.8546-Elec from May 6th, 2015. This Definitive License is granted for a term of forty (40) years, with the possibility of renewal for an equal period.

15. Subsequent Event

Impact of Covid-19
On March 11, 2020, the World Health Organization declared the coronavirus strain (COVID-19) in the category of pandemic. The Company's operations and its business could be affected by the future effects of this pandemic; however, due to the recent nature of this situation, the Company's operations have not been affected. To date, Company's management is not aware of any issues related to liquidity, regulatory, legal or other aspects that affect the Company.

Tecnisol III, S. A.

Report and Financial Statements
December 31, 2019

Tecnisol III, S. A.

Index to the Financial Statements
December 31, 2019

Independent Auditors' Report

To the Board of Directors and Shareholders of
Tecnisol III, S. A.

Our opinion

In our opinion, the financial statements of Tecnisol III, S. A. (the "Company") present fairly, in all material respects, the financial position of the Company as at December 31, 2019, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

What we have audited

The Company's financial statements comprise:
- the statement of financial position as at December 31, 2019;
- the statement of comprehensive income for the year then ended;
- the statement of changes in equity for the year then ended;
- the statement of cash flows for the year then ended; and
- the notes to the financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Company in accordance with the International Ethics Standards Board for Accountants' Code of Ethics for Professional Accountants (IESBA Code), and the ethical requirements that are relevant to our audit of the financial statements in the Republic of Panama. We have fulfilled our other ethical responsibilities in accordance with the IESBA Code and the ethical requirements of the Republic of Panama.

To the Board of Directors and Shareholders of
Tecnisol III, S. A.
Page 2

Other matter

The comparative information as at, and for the period ended December 31, 2018 has not been audited.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with ISAs, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

PricewaterhouseCoopers

June 26, 2020
Panama, Republic of Panama

Tecnisol III, S. A.

Statement of Financial Position
December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019	2018 *(Unaudited)*
Assets			
Current assets			
Cash and cash equivalents	2 and 5	861,114	759,641
Trade and other receivables	2, 6 and 12	732,776	750,533
Prepaid expenses and other assets		260,485	375
Total current assets		1,854,375	1,510,549
Non-current asset			
Plant and equipment, net	2, 7 and 8	9,931,017	10,473,318
Total assets		11,785,392	11,983,867
Liabilities and Equity			
Current liabilities			
Lease liabilities short-term debt	2 and 8	7,097	-
Shareholder's loan	2 and 12	8,954,614	9,714,040
Trade and other payables	2, 9 and 12	2,361,591	2,343,651
Total current liabilities		11,323,302	12,057,691
Non-current liability			
Lease liabilities long term	2 and 8	221,837	-
Total liabilities		11,545,139	12,057,691
Equity			
Common shares with US$100 par value each authorized and issued 100 shares	2 and 10	10,000	10,000
Retained earnings (accumulated deficit)		236,934	(83,824)
Prepaid tax		(6,681)	-
Total equity		240,253	(73,824)
Total liabilities and equity		11,785,392	11,983,867

The accompanying notes are an integral part of these financial statements.

Tecnisol III, S. A.

Statement of Comprehensive Income
For the year then ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019	2018 *(Unaudited)*
Revenues	12	4,996,373	1,611,064
Costs of goods and services	2, 7, 11 and 12	(4,151,400)	(1,203,704)
Gross profit		844,973	407,360
Expenses	11		
Administrative expenses		(41,552)	(491,184)
Operating expenses		(1,330)	-
Total expenses		(42,882)	(491,184)
Operating profit (loss)		802,091	(83,824)
Finance costs	12	(310,166)	-
Income (loss) before income tax		491,925	(83,824)
Income tax	13	(171,167)	-
Total comprehensive income (loss) for the year		320,758	(83,824)

The accompanying notes are an integral part of these financial statements.

Tecnisol III, S. A.

Statement of Changes in Equity
For the year then ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Common Shares	Capital Contribution	Retained Earnings (Accumulated Deficit)	Prepaid Tax	Total Equity
Balance at December 31, 2017 *(Unaudited)*	-	1,767,403	-	-	1,767,403
Comprehensive loss:					
Net loss	-	-	(83,824)	-	(83,824)
Transactions with shareholders:					
Capital contribution	-	7,956,637	-	-	7,956,637
Transfer to shareholder loan	10,000	(9,724,040)	-	-	(9,714,040)
Balance at December 31, 2018 *(Unaudited)*	10,000	-	(83,824)	-	(73,824)
Comprehensive income:					
Prepaid tax	-	-	-	(6,681)	(6,681)
Net income	-	-	320,758	-	320,758
Balance at December 31, 2019	10,000	-	236,934	(6,681)	240,253

The accompanying notes are an integral part of these financial statements.

Tecnisol III, S. A.

Statement of Cash Flows
For the year then ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019	2018 *(Unaudited)*
Cash flows from operating activities			
Income (loss) before income tax		491,925	(83,824)
Adjustments to reconcile income (loss) before income tax to net cash provided by operating activities:			
Depreciation and amortization	7, 8 and 11	801,310	141,531
Finance cost, interest on borrowings		310,166	-
Changes in assets and liabilities:			
Trade and other receivables		17,757	(750,534)
Trade and other payables		17,940	2,327,196
Prepaid expenses and other assets		(260,110)	129,438
Interest paid		(310,166)	-
Income tax paid		(171,167)	-
Net cash provided by operating activities		897,655	1,763,807
Cash flows from investing activities			
Additions of plant and equipment	7	(23,472)	(8,960,803)
Net cash used in investing activities		(23,472)	(8,960,803)
Cash flows from financing activities			
Repayment of long-term debt		(759,426)	-
Equity contributed by shareholders		-	7,956,637
Prepaid tax		(6,681)	-
Finance lease payments	8	(6,603)	-
Net cash (used in) provided by financing activities		(772,710)	7,956,637
Net increase in cash and cash equivalents during the year		101,473	759,641
Cash and cash equivalents at the beginning of year		759,641	-
Cash and cash equivalents at the end of year	5	861,114	759,641

The accompanying notes are an integral part of these financial statements.

1. General Information

Tecnisol III, S. A. (the "Company") is incorporated on February 20, 2014 under the laws of the Republic of Panama. The Company is engaged in the production of electricity through its photovoltaic panel parks located in David, Province of Chiriqui, Republic of Panama.

The ultimate parent company of Tecnisol III, S. A. is Interenergy Partners, L. P., incorporated in Cayman Island.

The Company is located in Torres de las Americas, Punta Pacifica, Republic of Panama, and the photovoltaic panel are in David, Republic of Panama. The local regulator, Autoridad Nacional de los Servicios Publicos (ASEP, by its acronym in Spanish), approved the Company's electricity generation license to 10 MW capacity (Note 14).

These financial statements have been approved for issue by the Finance Manager on June 26, 2020.

2. Summary of Significant Accounting Policies

The principal accounting policies applied in the preparation of these financial statements are set out below.

Basis of Preparation

The financial statements of the Company have been prepared in accordance with the International Financial Reporting Standards (IFRS) and the related interpretations adopted by the International Accounting Standards Board (IASB). The financial statements have been prepared on the historical cost convention.

The preparation of financial statements in conformity with IFRS requires the use of certain critical accounting estimates. It also requires Management to exercise its judgement in the process of applying the Company's accounting policies. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in Note 4.

New Standards, Amendments and Interpretations Adopted by the Company

The Company has applied the following standard and amendment for the first time in its annual reporting period commencing January 1, 2019:

IFRS 16 - Leases

The Company has initially applied IFRS 16, for the first time for their annual reporting period commencing January 1, 2019. It has applied using the cumulative effect method, under which the comparative information is not restated.

2. Summary of Significant Accounting Policies (Continued)

Basis of Preparation (continued)

New Standards, Amendments and Interpretations Adopted by the Company (continued)

IFRS 16 – Leases (continued)

- IFRS 16 - Leasing. The IASB issued in January 2016, IFRS 16, which replaces IAS 17- Leases. This standard introduces significant changes in accounting by lessee.
- The Company applied the simplified approach, in which the comparative figures are not restate at the date of initial application. The right-of-use assets for property leases will be initially measured on a retrospective basis as if the new standard had always been applied. All other right-of-use assets will be measured at the amount equal to the lease liability at the time of adoption (adjusted for prepaid or accrued lease payments relating to that lease recognized). In addition, the Company has decided not to apply the new standard to leases whose term will end within twelve months of the date of initial application. In such cases, the leases are accounted for as short-term leases and the lease payments associated with them are recognized as an expense from short-term leases.

In the context of the transition, the Company recognized as of January 1, 2019 a right of use asset for US$235,537 and a lease liability of US$235,537.

Accounting policy applied until December 31, 2018

A lease agreement in which the lessor transfers to the lessee, in exchange for a payment or a series of payments, the right to use an asset for an agreed period is classified as a finance lease.

A lease agreement was defined as an agreement in which the lessor conveys to the lessee the right to use an asset for a specified period in return for a payment or several payments. In accordance with IAS 17, beneficial ownership of the leased assets was attributed to the lessee if the lessee substantially bore all the risks and rewards inherent to ownership of the leased asset.

To the extent that beneficial ownership was attributable to the Company as a lessee. Financial leases were capitalized at the beginning of the lease, either at fair value of the leased property or, if less, at the present value of the minimum lease payments. A lease liability in the same amount was recognized as a non-current liability. The lease was subsequently measured at amortized cost using the effective interest method. The depreciation methods and estimated useful lives corresponded to those comparable purchased assets.

2. Summary of Significant Accounting Policies (Continued)

Basis of Preparation (continued)

New Standards, Amendments and Interpretations Adopted by the Company (continued)

IFRS 16 - Leases (continued)

Accounting policy applied until December 31, 2018 (continued)

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to the statement of comprehensive income on a straight-line basis over the period of the lease.

Accounting policy applied as of January 1, 2019

Lease liabilities include the following lease payments:

- Fixed payments, less any lease incentives receivable,
- variable lease payment that are based on an index or a rate,
- amounts expected to be payable by the group under residual value guarantees
- the exercise price of a purchase option if the group is reasonably certain to exercise that option, and
- payments of penalties for terminating the lease, if the lease term reflects the group exercising that option.

The lease payments are discounted using the interest rate implicit in the lease, to the extent that this can be determined. Otherwise, the discount is the lessee's incremental borrowing rate.

Right-of-use assets are measured at cost comprising the following:

- The amount of the initial measurement of lease liability.

New Standards, Amendments and Interpretations not yet Adopted

Certain new accounting standards and interpretations have been published that are not mandatory for December 31, 2019 reporting periods and have not been early adopted by the Company. These standards are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

2. Summary of Significant Accounting Policies (Continued)

Monetary Unit and Functional Currency
The financial statements are expressed in U.S. Dollars (US$), monetary unit of the United States of America, which is at par with the Balboa (B/.), monetary unit of the Republic of Panama. The U.S. Dollar (US$) circulates and is freely exchangeable in the Republic of Panama and is the functional currency.

Financial Assets
The Company classifies its financial assets in the category of loans and receivables and assets at fair value through profit or loss, based on the purpose for which the financial assets were acquired. Management determines the classification of its financial assets at initial recognition.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Loans and receivables with maturities not greater than 12 months are included in current assets.

Cash and Cash Equivalents
For purposes of the cash flow statement, cash and cash equivalents include cash in hand.

Trade and Other Receivables
The Company maintains trade and other receivables in order to collect the contractual cash flows and, therefore, subsequently measures them at amortized cost using the effective interest method, less any estimate for impairment.

Plant and Equipment and Depreciation
Plant and equipment are stated at cost, less accumulated depreciation and impairment losses. Depreciation is calculated on the straight-line method over the estimated useful lives of the assets. Costs of maintenance, repairs, minor refurbishments and improvements are charged to expense. Subsequent costs are capitalized only when it is probable that a future economic benefit associated with the item will flow to the Company and the cost of the item can be measured reliably. The Company has a maintenance program that includes inspecting, testing and repairing all operational power equipment based on the equivalent operating hours (EOH).

Expenditure on the construction, installation or completion of infrastructure facilities, such as constructions. No depreciation or amortization is charged during the construction phase. The Company begins depreciating an item of property, plant and equipment when it is available for use.

2. Summary of Significant Accounting Policies (Continued)

Plant and Equipment and Depreciation (continued)
Right-of-use assets are generally depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. If the Company is reasonably certain to exercise a purchase option, the right-of-use asset is depreciated over the underlying asset's useful life.

Depreciation rates used are described as follows:

Buildings	2.50%
Generators and plant facilities	5% - 10%
Leasehold	5% - 5.5%
Tools and minor equipment	25%
Equipment of transportation	25%
Furniture and office equipment	25%

Shareholder's Loan
Borrowings are initially recognized at fair value, net of transaction costs incurred. Borrowings are subsequently carried at amortized cost, using the effective interest method.

Trade and Other Payables
Trade and other payables are obligations to pay for goods or services that have been acquired in the normal course of the business from suppliers. Trade and other payables are classified as current liabilities as payments are due within one year or less.

Trade and other payables are initially recognized at fair value and subsequently measured at amortized cost using the effective interest method.

Common Share
Common shares are classified as equity.

Revenue Recognition
The Company recognizes revenue in the periods that it delivers electricity. Contracted prices are billed in accordance to provisions of applicable power sales agreements and spot sales are billed in accordance with prevailing market prices. The unit of measurement of the contract prices is megawatts (MW). The following criteria should be met in order to recognize revenue: (1) persuasive evidence of an arrangement exists; (2) delivery has occurred or services have been rendered; (3) the price to the buyer is fixed or determinable; and (4) collection is reasonably assured. Revenues are measured at fair value of the consideration received or receivable for the sale of the energy.

Finance Cost
Comprise interest expense on borrowings, unwinding of the discount of provision and deferred consideration.

3. Financial Risk Management

Financial Risk Factors
The Company's activities expose it to a variety of financial risks: market risk (including currency risk, fair value interest rate risk and cash flow interest rate risk), credit risk and liquidity risk.

Risk management is carried out by the General Manager and the Director of Financial Department under the supervision of the Board of Directors. They identify and evaluate financial risks in close co-operation with management of departments within the Company.

Market Risk
Foreign exchange risk.

The Company is not substantially exposed to the foreign exchange risk fluctuation, since its revenues and expenses are mainly expressed in U. S. dollars.

Interest Rate Risk
Interest rate risk is mainly originated from long-term debt with variable interest rates that expose the Company to the cash flows risk.

Credit Risk
Credit risk arises mainly from cash and cash equivalents, restricted cash, trade and other receivables. The Company works only with well-known foreign and local financial institutions and energy distribution companies.

The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit rating.

The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit rating.

	2019	**2018** *(Unaudited)*
Cash at banks and short-term bank deposits international credit rating:		
Fitch (B/BB)	861,114	759,641
	861,114	759,641

3. Financial Risk Management (Continued)

Financial Risk Factors (continued)
The Company has a concentration of its revenues and accounts receivable with large clients in the Republic of Panama. Sales of energy made to these customers represent approximately 96% (2018: 94%) of total revenues and 86% (2018: 86%) of total accounts receivable at the end of the period. This concentration of risk is mitigated by the fact that demand for electricity in Panama continues to grow steadily and that the energy market is very well structured and regulated by government authorities. For each PPA a guarantee is required and the payment term of invoices originating in the electric market of Panama is averaged in a range of 30 days from the date of presentation of the invoice. The guarantee is a performance bond payable to the collection against any event of default for bad debts or bad debt. There were no default events for unpaid bills as of December 31, 2019

Liquidity Risk
Liquidity risk is the risk that the Company might not be able to comply with all its obligations. The Company minimizes this risk by maintaining adequate levels of cash on hand or in current accounts for fulfilling commitments with recurring suppliers and borrowers.

Cash flow forecasting is performed by the operating entities of the Company in and aggregated by Company finance. The Company finance monitors rolling forecasts of the Company's liquidity requirements to ensure it has sufficient cash to meet operational needs while maintaining sufficient headroom on its undrawn committed borrowing facilities at all times so that the Company does not breach borrowing limits or covenants on any of its borrowing facilities. Such forecasting takes into consideration the Company's debt financing plans, covenant compliance, compliance with internal statement of financial position ratio targets and, if applicable external regulatory or legal requirements.

The table below analyses the Company's financial liabilities into relevant maturity groupings based on the remaining period at the statement of financial position to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows. Balances due within 12 months approximate their carrying balances as the impact of discounting is not significant.

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
December 31, 2019				
Shareholder's loan	8,954,614	-	-	8,954,614
Trade and other payables	2,361,591	-	-	2,361,591
	11,316,205	-	-	11,316,205

3. Financial Risk Management (Continued)

Liquidity Risk (continued)

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
December 31, 2018				
(Unaudited)				
Shareholder's loan	9,714,040	-	-	9,714,040
Trade and other payables	2,343,651	-	-	2,343,651
	12,057,691	-	-	12,057,691

Capital Risk Management

The Company's objectives when managing capital are to safeguard the Company's ability to continue as a going concern in order to provide returns for the shareholders and to maintain an optimal capital structure to reduce the cost of capital.

In order to maintain or adjust the capital structure, the Company may adjust the number of dividends paid to the shareholders, return capital to the shareholders, issue new shares or sell assets to reduce debt. The Company monitors capital on the basis of the "liabilities to tangible net worth ratio", which is one of the ratios that the Company should consider at the time of paying dividends or incurring debt. Capital is defined by Management as the Company's shareholders' equity. This ratio is calculated as liabilities divided by tangible net worth. Liabilities are calculated as total long-term debt, including current portion of long-term debt. Tangible net worth is calculated as "equity" as shown in the statement of financial position.

This ratio basically measures the leverage of the Company as a percent of the equity invested by the shareholder and provides the percentage of the funding of the Company with borrowing versus shareholders' equity.

The liabilities to tangible net worth ratio were as follows:

	2019	2018 *(Unaudited)*
Shareholder's loan (Note 12)	8,954,614	9,714,040
Total tangible net worth	246,735	(73,824)
Total liabilities to tangible net worth ratio	0.28	0.24

3. Financial Risk Management (Continued)

Fair Value Estimation
For disclosure purposes, the International Financial Reporting Standards specify a fair value hierarchy that categorizes into three levels based on the inputs used in valuation techniques to measure fair value: The hierarchy is based on the transparency of variables used in the valuation of an asset at the date of valuation. These three levels are:

- Quoted prices (unadjusted) in active markets for identical assets and liabilities (Level 1).
- Inputs other than quoted prices included within level 1 that are observable for the asset and liability, either directly (that is, as prices) or indirectly (that is, derived from prices) (Level 2).
- Inputs for the asset and liability that are not based on observable market data (that is, unobservable inputs) (Level 3).

The carrying value of cash and cash equivalents, trade and other receivables, trade and other payables approximates its fair value due to the short-term nature.

4. Critical Accounting Estimates and Judgement

Estimates and judgements are continually evaluated by Management and are based on historical experience and on various other assumptions that management believes to be reasonable under the circumstances, the results of which form the basis for making judgements.

Critical Accounting Estimates and Assumptions
The resulting accounting estimates will, by definition, seldom equal the related actual results. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

Depreciation of Plant and Equipment
The Company makes judgements in assessing its assets estimated useful lives and in determining estimated residual values, as applicable. Depreciation is calculated on the straight-line method, based on the estimated useful lives of the assets.

These estimates are based on analysis of the assets' lifecycles and potential value at the end of its useful life. The assets residual values and useful lives are reviewed, and adjusted if appropriate, at each statement of financial position date.

During the year ended December 31, 2019, Management reassessed the 15 years useful life of generators and plant facilities, resulting in an increase of the depreciation expense in US$272,539.

5. Cash and Cash Equivalents

	2019	2018 *(Unaudited)*
Cash in U. S. currency	861,114	759,641

6. Trade and Other Receivables

Trade and other receivables are detailed as follows:

	2019	2018 *(Unaudited)*
Clients	641,541	715,392
Related parties (Note 12)	91,235	35,141
	732,776	750,533

Account receivables are less than two months. At December 31, 2019 and 2018, there were no past due receivables, therefore, the Company has not recorded any provision for impairment.

7. Plant and Equipment, Net

Following is the movement of plant and equipment:

	Generators and Plant Facilities	Transmission line	Leasehold	Construction in Progress	Total
Cost at January 1, 2019	10,212,431	402,418	-	-	10,614,849
Additions	23,472	-	-	-	23,472
Adjustment for change in accounting policy, (Note 8)	-	-	235,537	-	235,537
Cost at December 31, 2019	10,235,903	402,418	235,537	-	10,873,858
Accumulated depreciation at January 1, 2019	(136,165)	(5,366)	-	-	(141,531)
Depreciation charge	(772,128)	(16,097)	(13,085)	-	(801,310)
Accumulated depreciation at December 31, 2019	(908,293)	(21,463)	(13,085)	-	(942,841)
Net balance at December 31, 2019	9,327,610	380,955	222,452	-	9,931,017

	Generators and Plant Facilities	Transmission line	Leasehold	Construction in Progress	Total
Cost at January 1, 2018 *(Unaudited)*	-	-	-	1,654,046	1,654,046
Additions	-	-	-	8,960,803	8,960,803
Capitalization	10,212,431	402,418	-	(10,614,849)	-
Cost at December 31, 2018 *(Unaudited)*	10,212,431	402,418	-	-	10,614,849
Accumulated depreciation at January 1, 2018 *(Unaudited)*	-	-	-	-	-
Depreciation charge	-	-	-	-	-
Accumulated depreciation at December 31, 2018 *(Unaudited)*	(136,165)	(5,366)	-	-	(141,531)
Net balance at December 31, 2018 *(Unaudited)*	10,076,266	397,052	-	-	10,473,318

7. Plant and Equipment, Net (Continued)

In 2019, the Company recognized additions for the right to use leased property, which are included as part of the leasehold improvements. (Note 8).

8. Lease

As of December 31, 2019, property, plant and equipment include leases corresponding to the operating land lease located in David, Chiriquí province, Republic of Panama. The lease term is 20 years with a variable increase according to the consumer price index of the United States of America until expiration (Note 7).

The leased properties are presented below:

	2019
Right-of-use assets	
Cost	235,537
Additions	-
Accumulated depreciation	(13,085)
Net balance	222,452
Lease liabilities	
Current	7,097
Non-current	221,837
Net balance	228,934

In applying IFRS 16 for the first time, the Company has used the following practical expedients permitted by the standard:

(a) Applying a single discount rate (7.5%) to a portfolio of leases with reasonably similar characteristics, for the year end 2019 the Company has recognised US$17,665 (2018: US$0) as interest expense related to lease liabilities.
(b) Relying on previous assessments on whether leases are onerous.
(c) Accounting for operating leases with a remaining lease term of less than 12 months as at 1 January 2019 as short-term leases.
(d) Excluding initial direct costs for the measurement of the right-of-use asset at the date of initial application, and
(e) using hindsight in determining the lease term where the contract contains options to extend or terminate the lease

9. Trade and Other Payables

	2019	2018 *(Unaudited)*
Suppliers	1,934,842	2,003,031
Related parties (Note 12)	337,157	340,620
Other account payable	89,592	-
	2,361,591	2,343,651

10. Shareholders' Equity

The authorized share capital of the Company is US$10,000, composed by 100 common shares, with a value of US$100 each.

The Company is fully owned by Interenergy Holding UK Limited.

11. Costs and Expenses

The Company classifies its expenses by nature, as follows:

	2019	2018 *(Unaudited)*
Cost of goods and service		
Energy purchases to the spot market	2,036,681	392,487
Energy purchases from reserve contracts (Note 12)	1,306,196	667,641
Depreciation and amortization (Note 7 and 8)	801,310	141,531
Fees transmission cost	7,213	2,045
	4,151,400	1,203,704
Administrative & generals		
Donations	19,230	-
Professional fees	9,442	331,403
Regulator fees	7,505	-
Other expenses	4,427	131,112
Insurance costs	948	3,791
Land rent	-	24,878
	41,552	491,184
Operative expensive		
Repairs and maintenance	1,330	-
	4,194,282	1,694,888

12. Balances and Transactions with Related Parties

The Company is fully controlled by Interenergy Holdings, its ultimate parent company. The Company carried out transactions and maintained balances with related companies, as described below:

	2019	2018 *(Unaudited)*
Transactions		
Interest paid - shareholders' loan (a)	291,421	-
Sales in spot market (b)	3,559	377
Energy purchases and associated costs (b)	1,161,075	350,573
Balances		
Related companies - accounts receivable (b)	91,235	35,141
Related companies - accounts payable (b)	337,157	340,620
Shareholders' loan payable (c)	8,954,614	9,714,040
	9,291,771	10,054,660

(a) Interest paid to shareholders.

(b) Transactions related to sales and purchases of the energy in the spot market and energy purchases from reserve contracts with related companies. (Note 14).

(c) The shareholders' loan payable is due to Interenergy Holding UK Limited, this loan has an established maturity date on December 20th, 2021 and is agreed at an interest rate of 3%. (Note 10).

13. Income Tax

The income tax is presented as follows:

	2019	2018 *(Unaudited)*
Income tax	171,167	-

13. Income Tax (Continued)

Under current tax legislation in the Republic of Panama, the profits of the Company from local operations are subject to income tax.

Income tax is based on the higher of the following computations:

a. The rate of 25% on taxable income.

b. The net taxable profit resulting from applying 4.67% to the total taxable income times the rate of 25% which represents 1.17% of taxable income (alternative minimum tax).

In certain circumstances, if the application of 1.17% of revenue results in the entity incurring losses for tax reasons, or the effective tax rate is higher than 25%, then the entity may choose to request not to apply minimum tax. In such cases, the Company must file a petition with the Tax Administration, who may authorize the no application for a term of three years.

According Tax Legislation of Panama, income tax returns for the last three (3) years are subject to review by fiscal authorities, including year ending December 31, 2019.

The income tax resultant by applying the in-force rates to the net loss, is reconciled with the income tax provision presented in the financial statements, as follows:

	2019	**2018** *(Unaudited)*
Income (loss) before income tax	491,925	(83,824)
Plus: Non-deductible expenses	32,686	306,534
Effect of taxable income	524,611	222,710
Other adjustments	(62,655)	-
Net taxable gain	461,956	222,710
Income tax (traditional method)	115,489	55,678
Previous year income tax adjustment	55,678	-
Total income tax (traditional method)	171,167	-

Management will request to the Tax Authority the non-application of the CAIR for the 2019 fiscal year and they expect to obtain a positive outcome on the request.

13. Income Tax (Continued)

Transfer Pricing

Law No.52 of August 28, 2012, established the transfer pricing regime oriented to regulate tax purposes transactions between related parties, and applicable to the taxpayer to perform operations with related parties that are tax residents of other jurisdictions. The most important aspects of this regulation include:

- Taxpayers must submit annually an information return related operations with related parties, within six (6) months following the close of the relevant fiscal period. This obligation applies to transactions from fiscal year 2012.

- Failure to submit the report shall be punishable by a fine equivalent to 1% of the total amount of transactions with related parties.

- Persons required to submit the report referred to in the preceding paragraph, shall maintain a transfer pricing study, which shall contain the information and analysis to assess and document their transactions with related parties, in accordance by Law. The taxpayer must present study only at the request of the Department of Revenue of the Ministry of Economy and Finance within 45 days of your request.

14. Commitments

- The Company Tecnisol III, S. A. has four Long-Term PPAs to sell energy to: Riba Smith, S.A., Delyris, S.A., Ice Gaming Corp. and Iron Tower, S.A. Each PPA states that the energy supply period is for 15 years, starting supply in 2018 for Riba Smith and Delyris, S.A; and in 2019 for Ice Gaming and Iron Tower.

- The price is indexed based on the regulated tariff to the end customer, in a proportion between 100% and 70%, depending on the price of the tariff that would have been applied to the customer that would had been applied if remained at the distributor. All the contracts have a threshold in which the sale price of energy can be moved, having a maximum and a minimum price. If as a result of the indexation the price is equal to or greater than 135 $/MWh (maximum price), the price remains at said value, and if, on the contrary, the price falls below 83 $/MWh (minimum price), the price remains at the latter value.

14. Commitments (Continued)

- The Company Tecnisol III, S. A. has five Energy Reserve Contracts with: Tecnisol II, S.A., Tecnisol IV, S.A., UEP Penonome II, S.A. (related companies), Generadora del Istmo, S.A. (GENISA) and Saltos del Francolí, S.A. The supply period with the related companies are 10 years, beginning on December 4th, 2019 for Tecnisol II and Tecnisol IV; and 1 year beginning on July 1st, 2019 for UEP Penonome II. The Contract Price is fixed but can be changed through mutual agreement by the parties. The supply period for the reserve contracts with GENISA and Saltos del Francoli is 1 year, beginning on December 31st, 2018 for GENISA and 14 months beginning on November 1st, 2019 for Saltos del Francoli. The Contract Price is variable per month and time period.

- ASEP (the regulator) granted Definitive License for the construction, operation, maintenance, power generation and sale of Solar Power Plant Ikako II, through resolution AN No.8547-Elec from May 6th, 2015. This final license is granted for a term of forty (40) years, with the possibility of renewal for an equal period.

15. Subsequent Event

Impact of Covid-19
On March 11, 2020, the World Health Organization declared the coronavirus strain (COVID-19) in the category of pandemic. The Company's operations and its business could be affected by the future effects of this pandemic; however, due to the recent nature of this situation, the Company's operations have not been affected. To date, Company's management is not aware of any issues related to liquidity, regulatory, legal or other aspects that affect the Company.

Tecnisol IV, S. A.

Report and Financial Statements
December 31, 2019

Tecnisol IV, S. A.

Index to the Financial Statements
December 31, 2019

Independent Auditors' Report

To the Board of Directors and Shareholders of
Tecnisol IV, S. A.

Our opinion

In our opinion, the financial statements of Tecnisol IV, S. A. (the "Company") present fairly, in all material respects, the financial position of the Company as at December 31, 2019, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

What we have audited

The Company's financial statements comprise:

- the statement of financial position as at December 31, 2019;
- the statement of comprehensive income for the year then ended;
- the statement of changes in equity for the year then ended;
- the statement of cash flows for the year then ended; and
- the notes to the financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Company in accordance with the International Ethics Standards Board for Accountants' Code of Ethics for Professional Accountants (IESBA Code), and the ethical requirements that are relevant to our audit of the financial statements in the Republic of Panama. We have fulfilled our other ethical responsibilities in accordance with the IESBA Code and the ethical requirements of the Republic of Panama.

Other matter

The comparative information as at, and for the period ended December 31, 2018 has not been audited.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with ISAs, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

PricewaterhouseCoopers

June 26, 2020
Panama, Republic of Panama

Tecnisol IV, S. A.

Statement of Financial Position
December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019	2018 *(Unaudited)*
Assets			
Current assets			
Cash and cash equivalents	2 and 5	509,425	150,308
Trade and other receivables	2, 6 and 12	232,956	222,129
Prepaid expenses and other assets		29,982	375
Total current assets		772,363	372,812
Non-current asset			
Plant and equipment, net	2, 7 and 8	8,723,334	9,108,552
Total assets		9,495,697	9,481,364
Liabilities and Equity			
Current liabilities			
Lease liabilities short-term debt	2 and 8	8,907	-
Shareholder's loan	2 and 12	8,444,438	9,124,931
Trade and other payables	2, 9 and 12	430,497	343,399
Total current liabilities		8,883,842	9,468,330
Non-current liability			
Lease liabilities long term	2 and 8	278,424	-
Total liabilities		9,162,266	9,468,330
Equity			
Common shares with US$100 par value each authorized and issued 100 shares	2 and 10	10,000	10,000
Retained earnings		326,897	3,034
Prepaid tax		(3,466)	-
Total equity		333,431	13,034
Total liabilities and equity		9,495,697	9,481,364

The accompanying notes are an integral part of these financial statements.

Tecnisol IV, S. A.

Statement of Comprehensive Income
For the year then ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019	2018 *(Unaudited)*
Revenues	12	1,575,219	371,681
Costs of goods and services	2, 7, 11 and 12	(717,323)	(128,168)
Gross profit		857,896	243,513
Expenses			
Administrative expenses	11	(122,274)	(239,467)
Operating profit		735,622	4,046
Finance costs	12	(296,642)	-
Income before income tax		438,980	4,046
Income tax	13	(115,117)	(1,012)
Total comprehensive income for the year		323,863	3,034

The accompanying notes are an integral part of these financial statements.

Tecnisol IV, S. A.

Statement of Changes in Equity
For the year then ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Common Shares	Capital Contribution	Retained Earnings	Prepaid Tax	Total Equity
Balance at December 31, 2017 *(Unaudited)*	-	1,797,621	-	-	1,797,621
Comprehensive income:					
Net income	-	-	3,034	-	3,034
Transactions with shareholders:					
Capital contribution	-	7,337,310	-	-	7,337,310
Transfer to shareholder loan	10,000	(9,134,931)	-	-	(9,124,931)
Balance at December 31, 2018 *(Unaudited)*	10,000	-	3,034	-	13,034
Comprehensive income:					
Prepaid tax	-	-	-	(3,466)	(3,466)
Net income	-	-	323,863	-	323,863
Balance at December 31, 2019	10,000	-	326,897	(3,466)	333,431

The accompanying notes are an integral part of these financial statements.

Tecnisol IV, S. A.

Statement of Cash Flows
For the year then ended December 31, 2019
(All amounts in US$ unless otherwise stated)

	Notes	2019	2018 *(Unaudited)*
Cash flows from operating activities			
Income before income tax		438,980	4,046
Adjustments to reconcile income before income tax to net cash provided by operating activities:			
Depreciation and amortization	7, 8 and 11	704,307	123,088
Finance cost, interest on borrowings		296,642	-
Changes in assets and liabilities:			
Trade and other receivables		(10,827)	(222,129)
Trade and other payables		87,098	326,943
Prepaid expenses and other assets		(29,607)	129,438
Interest paid		(296,642)	-
Income tax paid		(115,117)	(1,012)
Net cash provided by operating activities		1,074,834	360,374
Cash flows from investing activities			
Additions of plant and equipment	7	(23,472)	(7,547,376)
Net cash used in investing activities		(23,472)	(7,547,376)
Cash flows from financing activities			
Repayment of long-term debt		(680,493)	-
Equity contributed by shareholders		-	7,337,310
Prepaid tax		(3,466)	-
Finance lease payments	8	(8,286)	-
Net cash (used in) provided by financing activities		(692,245)	7,337,310
Net increase in cash and cash equivalents during the year		359,117	150,308
Cash and cash equivalents at the beginning of year		150,308	-
Cash and cash equivalents at the end of year	5	509,425	150,308

The accompanying notes are an integral part of these financial statements.

1. General Information

Tecnisol IV, S. A. (the "Company") is incorporated on February 20, 2014 under the laws of the Republic of Panama. The Company is engaged in the production of electricity through its photovoltaic panel parks located in David, Province of Chiriqui, Republic of Panama.

The ultimate parent company of Tecnisol IV, S. A. is Interenergy Partners, L. P., incorporated in Cayman Island.

The Company is located in Torres de las Americas, Punta Pacifica, Republic of Panama, and the photovoltaic panel are in David, Republic of Panama. The local regulator, Autoridad Nacional de los Servicios Publicos (ASEP, by its acronym in Spanish), approved the Company's electricity generation license to 10 MW capacity (Note 14).

These financial statements have been approved for issue by the Finance Manager on June 26, 2020.

2. Summary of Significant Accounting Policies

The principal accounting policies applied in the preparation of these financial statements are set out below.

Basis of Preparation

The financial statements of the Company have been prepared in accordance with the International Financial Reporting Standards (IFRS) and the related interpretations adopted by the International Accounting Standards Board (IASB). The financial statements have been prepared on the historical cost convention.

The preparation of financial statements in conformity with IFRS requires the use of certain critical accounting estimates. It also requires Management to exercise its judgement in the process of applying the Company's accounting policies. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in Note 4.

New Standards, Amendments and Interpretations Adopted by the Company

The Company has applied the following standard and amendment for the first time in its annual reporting period commencing January 1, 2019:

IFRS 16 – Leases

The Company has initially applied IFRS 16, for the first time for their annual reporting period commencing January 1, 2019. It has applied using the cumulative effect method, under which the comparative information is not restated.

2. Summary of Significant Accounting Policies (Continued)

Basis of Preparation (continued)

New Standards, Amendments and Interpretations Adopted by the Company (continued)

IFRS 16 – Leases (continued)

- IFRS 16 - Leasing. The IASB issued in January 2016, IFRS 16, which replaces IAS 17- Leases. This standard introduces significant changes in accounting by lessee.
- The Company applied the simplified approach, in which the comparative figures are not restate at the date of initial application. The right-of-use assets for property leases will be initially measured on a retrospective basis as if the new standard had always been applied. All other right-of-use assets will be measured at the amount equal to the lease liability at the time of adoption (adjusted for prepaid or accrued lease payments relating to that lease recognized). In addition, the Company has decided not to apply the new standard to leases whose term will end within twelve months of the date of initial application. In such cases, the leases are accounted for as short-term leases and the lease payments associated with them are recognized as an expense from short-term leases.

In the context of the transition, the Company recognized as of January 1, 2019 a right of use asset for US$295,617 and a lease liability of US$295,617.

Accounting policy applied until December 31, 2018

A lease agreement in which the lessor transfers to the lessee, in exchange for a payment or a series of payments, the right to use an asset for an agreed period is classified as a finance lease.

A lease agreement was defined as an agreement in which the lessor conveys to the lessee the right to use an asset for a specified period in return for a payment or several payments. In accordance with IAS 17, beneficial ownership of the leased assets was attributed to the lessee if the lessee substantially bore all the risks and rewards inherent to ownership of the leased asset.

To the extent that beneficial ownership was attributable to the Company as a lessee. Financial leases were capitalized at the beginning of the lease, either at fair value of the leased property or, if less, at the present value of the minimum lease payments. A lease liability in the same amount was recognized as a non-current liability. The lease was subsequently measured at amortized cost using the effective interest method. The depreciation methods and estimated useful lives corresponded to those comparable purchased assets.

2. Summary of Significant Accounting Policies (Continued)

Basis of Preparation (continued)

New Standards, Amendments and Interpretations Adopted by the Company (continued)

IFRS 16 - Leases (continued)

Accounting policy applied until December 31, 2018 (continued)

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to the statement of comprehensive income on a straight-line basis over the period of the lease

Accounting policy applied as of January 1, 2019

Lease liabilities include the following lease payments:

- Fixed payments, less any lease incentives receivable,
- variable lease payment that are based on an index or a rate,
- amounts expected to be payable by the group under residual value guarantees
- the exercise price of a purchase option if the group is reasonably certain to exercise that option, and
- payments of penalties for terminating the lease, if the lease term reflects the group exercising that option.

The lease payments are discounted using the interest rate implicit in the lease, to the extent that this can be determined. Otherwise, the discount is the lessee's incremental borrowing rate.

Right-of-use assets are measured at cost comprising the following:

- The amount of the initial measurement of lease liability

New Standards, Amendments and Interpretations not yet Adopted

Certain new accounting standards and interpretations have been published that are not mandatory for December 31, 2019 reporting periods and have not been early adopted by the Company. These standards are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

2. Summary of Significant Accounting Policies (Continued)

Monetary Unit and Functional Currency

The financial statements are expressed in U.S. Dollars (US$), monetary unit of the United States of America, which is at par with the Balboa (B/.), monetary unit of the Republic of Panama. The U.S. Dollar (US$) circulates and is freely exchangeable in the Republic of Panama and is the functional currency.

Financial Assets

The Company classifies its financial assets in the category of loans and receivables and assets at fair value through profit or loss, based on the purpose for which the financial assets were acquired. Management determines the classification of its financial assets at initial recognition.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Loans and receivables with maturities not greater than 12 months are included in current assets.

Cash and Cash Equivalents

For purposes of the cash flow statement, cash and cash equivalents include cash in hand.

Trade and Other Receivables

The Company maintains trade and other receivables in order to collect the contractual cash flows and, therefore, subsequently measures them at amortized cost using the effective interest method, less any estimate for impairment.

Plant and Equipment and Depreciation

Plant and equipment are stated at cost, less accumulated depreciation and impairment losses. Depreciation is calculated on the straight-line method over the estimated useful lives of the assets. Costs of maintenance, repairs, minor refurbishments and improvements are charged to expense. Subsequent costs are capitalized only when it is probable that a future economic benefit associated with the item will flow to the Company and the cost of the item can be measured reliably. The Company has a maintenance program that includes inspecting, testing and repairing all operational power equipment based on the equivalent operating hours (EOH).

Expenditure on the construction, installation or completion of infrastructure facilities, such as constructions. No depreciation or amortization is charged during the construction phase. The Company begins depreciating an item of property, plant and equipment when it is available for use.

2. Summary of Significant Accounting Policies (Continued)

Plant and Equipment and Depreciation (continued)
Right-of-use assets are generally depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. If the Company is reasonably certain to exercise a purchase option, the right-of-use asset is depreciated over the underlying asset's useful life.

Depreciation rates used are described as follows:

Buildings	2.50%
Generators and plant facilities	5% - 10%
Leasehold	5% - 5.5%
Tools and minor equipment	25%
Equipment of transportation	25%
Furniture and office equipment	25%

Shareholder's Loan
Borrowings are initially recognized at fair value, net of transaction costs incurred. Borrowings are subsequently carried at amortized cost, using the effective interest method.

Trade and Other Payables
Trade and other payables are obligations to pay for goods or services that have been acquired in the normal course of the business from suppliers. Trade and other payables are classified as current liabilities as payments are due within one year or less.

Trade and other payables are initially recognized at fair value and subsequently measured at amortized cost using the effective interest method.

Common Share
Common shares are classified as equity.

Revenue Recognition
The Company recognizes revenue in the periods that it delivers electricity. Contracted prices are billed in accordance to provisions of applicable power sales agreements and spot sales are billed in accordance with prevailing market prices. The unit of measurement of the contract prices is megawatts (MW). The following criteria should be met in order to recognize revenue: (1) persuasive evidence of an arrangement exists; (2) delivery has occurred or services have been rendered; (3) the price to the buyer is fixed or determinable; and (4) collection is reasonably assured. Revenues are measured at fair value of the consideration received or receivable for the sale of the energy.

2. Summary of Significant Accounting Policies (Continued)

Finance Cost

Comprise interest expense on borrowings, unwinding of the discount of provision and deferred consideration.

3. Financial Risk Management

Financial Risk Factors

The Company's activities expose it to a variety of financial risks: market risk (including currency risk, fair value interest rate risk and cash flow interest rate risk), credit risk and liquidity risk.

Risk management is carried out by the General Manager and the Director of Financial Department under the supervision of the Board of Directors. They identify and evaluate financial risks in close co-operation with management of departments within the Company.

Market Risk

Foreign exchange risk.

The Company is not substantially exposed to the foreign exchange risk fluctuation, since its revenues and expenses are mainly expressed in U. S. dollars.

Interest Rate Risk

Interest rate risk is mainly originated from long-term debt with variable interest rates that expose the Company to the cash flows risk.

Credit Risk

Credit risk arises mainly from cash and cash equivalents, restricted cash, trade and other receivables. The Company works only with well-known foreign and local financial institutions and energy distribution companies.

The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit rating.

The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit rating.

	2019	**2018** *(Unaudited)*
Cash at banks and short-term bank deposits international credit rating:		
Fitch (B/BB)	509,425	150,308
	509,425	150,308

3. Financial Risk Management (Continued)

Financial Risk Factors (continued)

The Company has a concentration of its revenues and accounts receivable with related companies and customers from the spot market in the Republic of Panama. Sales of energy made to these customers represent approximately 27% (2018: 11%), 23% (2018: 89%) of total revenues and 30% (2018: 19%), 70% (2018: 81%) of total accounts receivable, respectively at the end of the period. This concentration of risk is mitigated by the fact that demand for electricity in Panama continues to grow steadily and that the energy market is very well structured and regulated by government authorities. For each PPA a guarantee is required and the payment term of invoices originating in the electric market of Panama is averaged in a range of 30 days from the date of presentation of the invoice. The guarantee is a performance bond payable to the collection against any event of default for bad debts or bad debt. There were no default events for unpaid bills as of December 31, 2019

Liquidity Risk

Liquidity risk is the risk that the Company might not be able to comply with all its obligations. The Company minimizes this risk by maintaining adequate levels of cash on hand or in current accounts for fulfilling commitments with recurring suppliers and borrowers.

Cash flow forecasting is performed by the operating entities of the Company in and aggregated by Company finance. The Company finance monitors rolling forecasts of the Company's liquidity requirements to ensure it has sufficient cash to meet operational needs while maintaining sufficient headroom on its undrawn committed borrowing facilities at all times so that the Company does not breach borrowing limits or covenants on any of its borrowing facilities. Such forecasting takes into consideration the Company's debt financing plans, covenant compliance, compliance with internal statement of financial position ratio targets and, if applicable external regulatory or legal requirements.

The table below analyses the Company's financial liabilities into relevant maturity groupings based on the remaining period at the statement of financial position to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows. Balances due within 12 months approximate their carrying balances as the impact of discounting is not significant.

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
December 31, 2019				
Shareholder's loan	8,444,438	-	-	8,444,438
Trade and other payables	430,497	-	-	430,497
	8,874,935	-	-	8,874,935

3. Financial Risk Management (Continued)

Financial Risk Factors (continued)

Liquidity Risk (Continued)

	Less than 1 year	Between 1 and 5 years	Over 5 years	Total
December 31, 2018 ***(Unaudited)***				
Shareholder's loan	9,124,931	-	-	9,124,931
Trade and other payables	343,399	-	-	343,399
	9,468,330	-	-	9,468,330

Capital Risk Management

The Company's objectives when managing capital are to safeguard the Company's ability to continue as a going concern in order to provide returns for the shareholders and to maintain an optimal capital structure to reduce the cost of capital.

In order to maintain or adjust the capital structure, the Company may adjust the number of dividends paid to the shareholders, return capital to the shareholders, issue new shares or sell assets to reduce debt. The Company monitors capital on the basis of the "liabilities to tangible net worth ratio", which is one of the ratios that the Company should consider at the time of paying dividends or incurring debt. Capital is defined by Management as the Company's shareholders' equity. This ratio is calculated as liabilities divided by tangible net worth. Liabilities are calculated as total long-term debt, including current portion of long-term debt. Tangible net worth is calculated as "equity" as shown in the statement of financial position.

This ratio basically measures the leverage of the Company as a percent of the equity invested by the shareholder and provides the percentage of the funding of the Company with borrowing versus shareholders' equity.

The liabilities to tangible net worth ratio were as follows:

	2019	2018 *(Unaudited)*
Shareholder's loan (Note 12)	8,444,438	9,124,931
Total tangible net worth	341,568	13,034
Total liabilities to tangible net worth ratio	0.08	0.04

3. Financial Risk Management (Continued)

Fair Value Estimation
For disclosure purposes, the International Financial Reporting Standards specify a fair value hierarchy that categorizes into three levels based on the inputs used in valuation techniques to measure fair value: The hierarchy is based on the transparency of variables used in the valuation of an asset at the date of valuation. These three levels are:

- Quoted prices (unadjusted) in active markets for identical assets and liabilities (Level 1).
- Inputs other than quoted prices included within level 1 that are observable for the asset and liability, either directly (that is, as prices) or indirectly (that is, derived from prices) (Level 2).
- Inputs for the asset and liability that are not based on observable market data (that is, unobservable inputs) (Level 3).

The carrying value of cash and cash equivalents, trade and other receivables, trade and other payables approximates its fair value due to the short-term nature.

4. Critical Accounting Estimates and Judgement

Estimates and judgements are continually evaluated by Management and are based on historical experience and on various other assumptions that management believes to be reasonable under the circumstances, the results of which form the basis for making judgements.

Critical Accounting Estimates and Assumptions
The resulting accounting estimates will, by definition, seldom equal the related actual results. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

Depreciation of Plant and Equipment
The Company makes judgements in assessing its assets estimated useful lives and in determining estimated residual values, as applicable. Depreciation is calculated on the straight-line method, based on the estimated useful lives of the assets.

These estimates are based on analysis of the assets' lifecycles and potential value at the end of its useful life. The assets residual values and useful lives are reviewed, and adjusted if appropriate, at each statement of financial position date.

During the year ended December 31, 2019, Management reassessed the 15 years useful life of generators and plant facilities, resulting in an increase of the depreciation expense in US$238,781.

5. Cash and Cash Equivalents

	2019	2018 *(Unaudited)*
Cash in U. S. currency	509,425	150,308

6. Trade and Other Receivables

Trade and other receivables are detailed as follows:

	2019	2018 *(Unaudited)*
Clients	162,256	180,231
Related parties (Note 12)	70,700	41,898
	232,956	222,129

Account receivables are less than two months. At December 31, 2019 and 2018, there were no past due receivables, therefore, the Company has not recorded any provision for impairment.

7. Plant and Equipment, Net

Following is the movement of plant and equipment:

	Generators and Plant Facilities	Transmission line	Leasehold	Construction in Progress	Total
Cost at January 1, 2019	8,946,485	285,155	-	-	9,231,640
Additions	23,472	-	-	-	23,472
Adjustment for change in accounting policy, (Note 8)	-	-	295,617	-	295,617
Cost at December 31, 2019	8,969,957	285,155	295,617	-	9,550,729
Accumulated depreciation at January 1, 2019	(119,286)	(3,802)	-	-	(123,088)
Depreciation charge	(676,478)	(11,406)	(16,423)	-	(704,307)
Accumulated depreciation at December 31, 2019	(795,764)	(15,208)	(16,423)	-	(827,395)
Net balance at December 31, 2019	8,174,193	269,947	279,194	-	8,723,334

	Generators and Plant Facilities	Transmission line	Leasehold	Construction in Progress	Total
Cost at January 1, 2018 *(Unaudited)*	-	-	-	1,684,264	1,684,264
Additions	-	-	-	7,547,376	7,547,376
Capitalization	8,946,485	285,155	-	(9,231,640)	-
Cost at December 31, 2018 *(Unaudited)*	8,946,485	285,155	-	-	9,231,640
Accumulated depreciation at January 1, 2018 *(Unaudited)*	-	-	-	-	-
Depreciation charge	-	-	-	-	-
Accumulated depreciation at December 31, 2018 *(Unaudited)*	(119,286)	(3,802)	-	-	(123,088)
Net balance at December 31, 2018 *(Unaudited)*	8,827,199	281,353	-	-	9,108,552

7. Plant and Equipment, Net (Continued)

In 2019, the Company recognized additions for the right to use leased property, which are included as part of the leasehold improvements. (Note 8).

8. Lease

As of December 31, 2019, property, plant and equipment include leases corresponding to the operating land lease located in David, Chiriquí province, Republic of Panama. The lease term is 20 years with a variable increase according to the consumer price index of the United States of America until expiration (Note 7).

The leased properties are presented below:

	2019
Right-of-use assets	
Cost	295,617
Additions	-
Accumulated depreciation	(16,423)
Net balance	279,194
Lease liabilities	
Current	8,907
Non-current	278,424
Net balance	287,331

In applying IFRS 16 for the first time, the Company has used the following practical expedients permitted by the standard:

(a) Applying a single discount rate (7.5%) to a portfolio of leases with reasonably similar characteristics, for the year end 2019 the Company has recognised US$22,171 (2018: US$0) as interest expense related to lease liabilities.
(b) Relying on previous assessments on whether leases are onerous.
(c) Accounting for operating leases with a remaining lease term of less than 12 months as at 1 January 2019 as short-term leases.
(d) Excluding initial direct costs for the measurement of the right-of-use asset at the date of initial application, and
(e) using hindsight in determining the lease term where the contract contains options to extend or terminate the lease.

9. Trade and Other Payables

	2019	2018 *(Unaudited)*
Suppliers	314,800	342,379
Other account payable	114,213	1,012
Related parties (Note 12)	1,484	8
	430,497	343,399

10. Shareholders' Equity

The authorized share capital of the Company is US$10,000, composed by 100 common shares, with a value of US$100 each.

The Company is fully owned by Interenergy Holding UK Limited.

11. Costs and Expenses

The Company classifies its expenses by nature, as follows:

	2019	2018 *(Unaudited)*
Cost of goods and service		
Depreciation and amortization (Note 7 and 8)	704,307	123,088
Fees transmission cost	6,960	1,901
Energy purchases to the spot market	6,056	3,179
	717,323	128,168
Administrative expenses		
Other expenses	53,903	131,113
Administration fee	20,524	-
Professional fees	25,413	77,130
Donations	19,230	-
Regulator fees	3,204	-
Land rent	-	31,224
	122,274	239,467
	839,597	367,635

12. Balances and Transactions with Related Parties

The Company is fully controlled by Interenergy Holdings, its ultimate parent company. The Company carried out transactions and maintained balances with related companies, as described below:

	2019	2018 *(Unaudited)*
Transactions		
Interest paid - shareholders' loan (a)	273,747	-
Energy sales in reserve contracts (b)	365,945	40,101
Sales in spot market (b)	14,837	3,034
Energy purchases and associated costs (b)	104	1
Balances		
Related companies - accounts receivable (b)	70,700	41,898
Related companies - accounts payable (b)	1,484	8
Shareholders' loan payable (c)	8,444,438	9,124,931
	8,445,922	9,124,939

(a) Interest paid to shareholders.

(b) Transactions related to sales and purchases of the energy in the spot market and energy sales in reserve contracts with related companies. (Note 14)

(c) The shareholders' loan payable is due to Interenergy Holding UK Limited, this loan has an established maturity date on December 20th, 2021 and is agreed at an interest rate of 3%. (Note 10)

13. Income Tax

The income tax is presented as follows:

	2019	2018 *(Unaudited)*
Income tax	115,117	1,012

13. Income Tax (Continued)

Under current tax legislation in the Republic of Panama, the profits of the Company from local operations are subject to income tax.

Income tax is based on the higher of the following computations:

a. The rate of 25% on taxable income.

b. The net taxable profit resulting from applying 4.67% to the total taxable income times the rate of 25% which represents 1.17% of taxable income (alternative minimum tax).

In certain circumstances, if the application of 1.17% of revenue results in the entity incurring losses for tax reasons, or the effective tax rate is higher than 25%, then the entity may choose to request not to apply minimum tax. In such cases, the Company must file a petition with the Tax Administration, who may authorize the no application for a term of three years.

According Tax Legislation of Panama, income tax returns for the last three (3) years are subject to review by fiscal authorities, including year ending December 31, 2019.

The income tax resultant by applying the in-force rates to the net loss, is reconciled with the income tax provision presented in the financial statements, as follows:

	2019	**2018** *(Unaudited)*
Income before income tax	438,980	4,046
Plus: Non-deductible expenses	21,486	-
Effect of taxable income	460,466	4,046
Income tax (traditional method)	115,117	1,012

Management will request to the Tax Authority the non-application of the CAIR for the 2019 fiscal year and they expect to obtain a positive outcome on the request.

Transfer Pricing

Law No.52 of August 28, 2012, established the transfer pricing regime oriented to regulate tax purposes transactions between related parties, and applicable to the taxpayer to perform operations with related parties that are tax residents of other jurisdictions. The most important aspects of this regulation include:

- Taxpayers must submit annually an information return related operations with related parties, within six (6) months following the close of the relevant fiscal period. This obligation applies to transactions from fiscal year 2012.

13. Income Tax (Continued)

Transfer Pricing (continued)

- Failure to submit the report shall be punishable by a fine equivalent to 1% of the total amount of transactions with related parties.

- Persons required to submit the report referred to in the preceding paragraph, shall maintain a transfer pricing study, which shall contain the information and analysis to assess and document their transactions with related parties, in accordance by Law. The taxpayer must present study only at the request of the Department of Revenue of the Ministry of Economy and Finance within 45 days of your request.

14. Commitments

- The Company Tecnisol IV, S. A. is part of an Interenergy Group strategy called SER (from its Spanish acronym for “Suministro de Energía Renovable”) that consist in supplying 100% renewable energy to Large Clients (in private PPAs). To fulfill this, the company has signed Reserve Contracts with affiliated companies to supply renewable energy to comply with the Clients requirements.

- The Company Tecnisol IV, S. A. has two Reserve Contracts for energy supply, these contracts are signed with: Tecnisol I, S. A. and Tecnisol III, S. A. (related companies).

- The supply period for these contracts is 10 years, beginning on December 4th, 2019, the Contract Price is fixed but can be changed through mutual agreement by the parties.

- ASEP (the regulator) granted Definitive License for the construction, operation, maintenance, power generation and sale of Solar Power Plant Ikako III through the Resolution AN No.8548-Elec from May 6th, 2015. This Definitive License is granted for a term of forty (40) years, with the possibility of renewal for an equal period.

15. Subsequent Event

Impact of Covid-19

On March 11, 2020, the World Health Organization declared the coronavirus strain (COVID-19) in the category of pandemic. The Company's operations and its business could be affected by the future effects of this pandemic; however, due to the recent nature of this situation, the Company's operations have not been affected. To date, Company's management is not aware of any issues related to liquidity, regulatory, legal or other aspects that affect the Company.

ANNEX A

INDEPENDENT ENERGY MARKET REPORT

estudios energéticos consultores.
GRUPO MERCADOS ENERGÉTICOS CONSULTORES

Panama: Market due diligence for solar pv and wind projects

INTERENERGY

NOVEMBER 30TH, 2020

R1125-20

Table of Contents

List of Exhibits

INTRODUCTION

InterEnergy (or "the Client" hereafter) is in the process of seeking to re-finance certain solar pv and wind generators in Panama totalizing near 255 MW (Tecnisol solar pv -40 MW- and UEP II wind farm -215 MW-, collectively the "Project") that are selling their energy output mostly under PPAs with large users (non-regulated customers) and with distributors.

Next table shows then main characteristics of evaluated plants.

Exhibit 1: Main characteristics of the Projects

Project	Type	Install Cap. (MW)
Tecnisol I	Solar	10.0
Tecnisol II	Solar	10.0
Tecnisol III	Solar	10.0
Tecnisol IV	Solar	10.0
Nuevo Chagres (UEP II)	Wind	62.5
Rosa de los Vientos (UEP II)	Wind	102.5
Portobello (UEP II)	Wind	32.5
Marañón (UEP II)	Wind	17.5
Total Solar (Tecnisol)		40.0
Total Wind (UEP II)		215.0
Total InterEnergy		**255.0**

Source: InterEnergy

InterEnergy retained Estudios Energéticos Consultores S.A. (or "EEC") to conduct an independent market study and a price forecast of the Panamanian power market for the time-period 2020 - 2035.

This document is organized in four parts. Its description is shown below:

- **Power Market Overview**: shows key aspects of the Panamanian electricity market, its regulatory framework, spot price formation mechanism and the commercial transactions.
- **Prospective Report**: with the main assumptions agreed upon to run the dispatch model for the Reference Scenario and its achieved results.
- **Assessment of the supply and purchase agreements**: analyzes the Project´s PPAs from a market perspective
- **Project´s positioning: key market risks and opportunities**: aims to identify the main opportunities and risks incurred by Tecnisol and UEP II projects

CHAPTER 1: POWER MARKET OVERVIEW

In this Chapter of the report, EEC will shows key aspects of the Panamanian electricity market, its regulatory framework, spot price formation mechanism and the commercial transactions.

The first Section introduces the reader in the recent evolution of the regional context where the country under analysis is located, including a description of the regional electricity market and its main statistics and agents.

In Section II, this report gives more details regarding Panama, in particular, the country profile and the energy market outlook as well as the story of the sector and the regulatory framework.

This document reflects EEC's professional judgment based on accepted standards of professional investigation and, as applicable, the data and information available in the public domain. In line with those accepted standards, this document does not, in any way, constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein.

The opinions expressed herein are subject to the generally accepted uncertainties associated with the interpretation of engineering and commercial data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing circumstances.

SECTION I: GENERAL CONTEXT FOR CENTRAL AMERICA

1. GENERAL CONTEXT

During the early 90s, the power sectors in Central American countries (Guatemala, El Salvador, Honduras, Nicaragua, Costa Rica and Panama)[1] were basically managed by vertically-integrated state-owned utilities that concentrated the production and supply of electric power.

Exhibit 2: Central America map

Like in the vast majority of Latin-American countries, the main characteristics of the power industry before the restructuring of the sector were electric power shortages, vertically integrated state-owned utilities, lack of fresh funds, poorly-maintained power plants, and unavailability of public financing resources.

On top of that, consecutive dry years in the Central American region (1991 and 1994) seriously damaged the highly hydro-dependent systems, like Guatemala and Honduras, increasing supply shortages.

In response to this situation, most of the countries underwent a reform of the electricity sector to boost the needed investment in generation and meet the demand growth that was expected to occur.

Electricity market reform and development have progressed at varying speeds in the six countries. As a result, the region is characterized by a range of market structures and uneven market development.

[1] Belize is not considered in the analysis because it is not interconnected with the rest of the countries.

Broadly speaking, the stage of reform in the region can be divided into two groups:

- Panama, Guatemala, El Salvador, and Nicaragua have reformed their generation, transmission and distribution sectors and have competitive generation markets in place. In the same way, Honduras is inside of a reform process to liberalize its electricity market.
- Costa Rica retains a vertically-integrated utility, and competition is limited to contracts for generation with the single buyer (ICE).

As a member of the more active reform group, Panama has had the most success in terms of attracting private investment (nearly all existing generation was privatized in 2000) and improving operational efficiency. El Salvador implemented a highly deregulated structure which has encountered some difficulties in the context of a small sector, and has recently migrated from a bid-based wholesale market towards a cost-based market. Nicaragua has also had some difficulties, and private operators have been unable to reduce the high level of electricity losses.

Panama, Guatemala, El Salvador and Nicaragua all have active private sector participation in generation and distribution activities. The ability of these countries to attract and retain private investors is an indicator of their success in creating credible investor protections.

Honduras approved its new General Law of the Electricity Industry (Act. 404-2014). This law provides a legal framework for a new liberalized electricity sector. At present, Honduras is still in a market reform process.

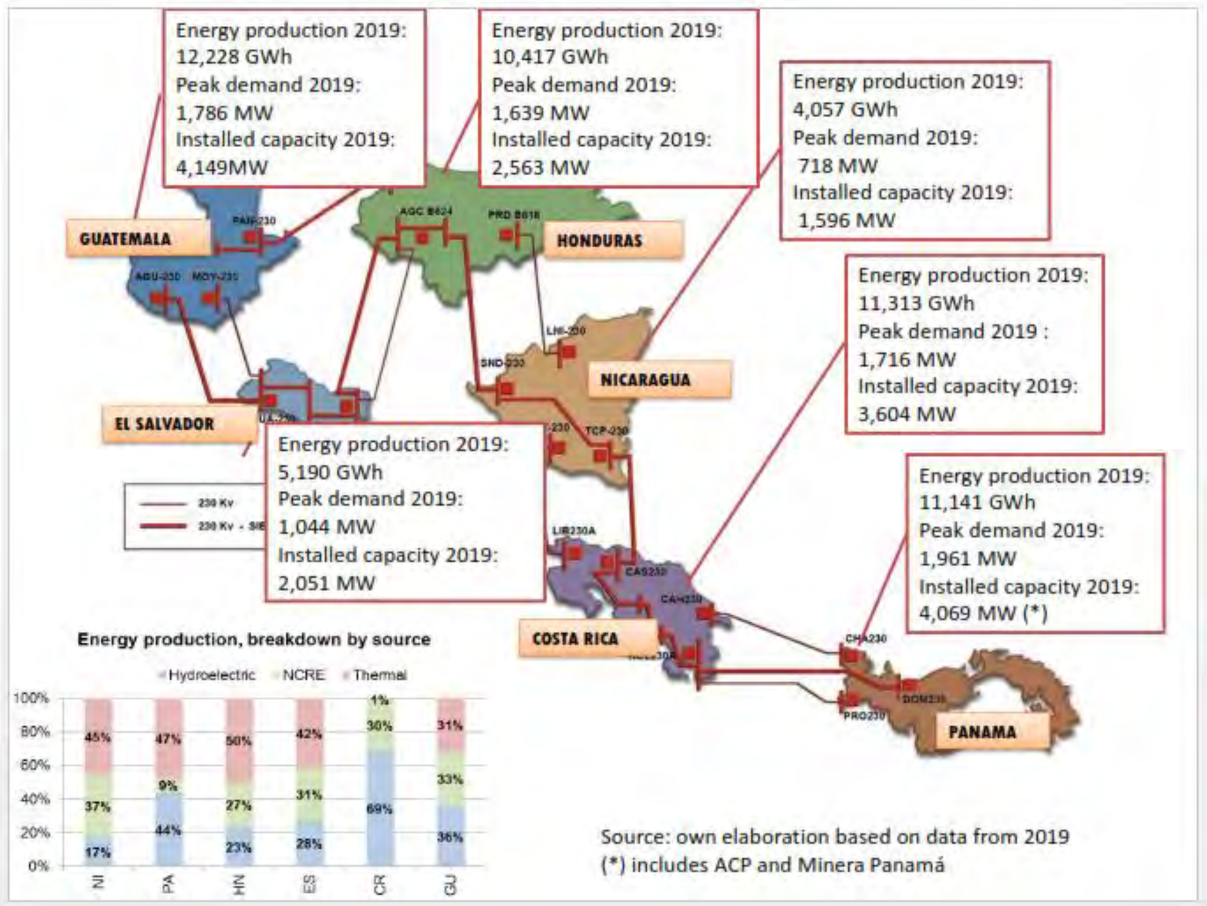
Costa Rica continues to operate centrally planned system, with the private sector participating in relatively small-sized renewable-based generation, mainly through power purchase agreements (PPAs).

Compared to the situation prior to the Reform, most of the countries have improved their energy sectors, succeeding in attracting new private investment, increasing efficiency, and improving the system's reliability and quality of service.

However, many countries lack the institutional development and human resources necessary to conduct the regulatory oversight that the models adopted require. The condition of open access to the transmission system is crucial for the expansion of generating capacity, and the public sector has an active role in the expansion of the transmission grids.

Although the generation segment was, to some extent, open to competition in all the countries of the isthmus, the achievement of strong competition in relatively small markets is still a challenge. The trend towards contracting a significant share of the load is a way to minimize the exercise of market power and to lower price volatility while providing incentives for timely investments. The following graph presents key electricity statistics for each country and main operative interconnection nodes and transmission lines among them (Source: Ente Operador Regional EOR):

Exhibit 3: Energy production Peak demand and Installed capacity in Central America



2. REGIONAL ELECTRICITY MARKET (MER)

The original design of the Regional Market (MER) consists in a seventh market that coexists with the six existing domestic markets or systems, with independent rules and in contact with them only at the points in the Regional Transmission Grid (RTR) defined as borders between the domestic markets and the regional market. It is presently operative (since July 2013).

Generators and Demands located in any of the member countries can freely decide to carry out their energy purchase and sale transactions in the MER or in their own domestic markets. This is how a generator located in any of these countries can sell its production to a demand located in another country.

The so-called SIEPAC project was built so that energy could flow between the countries involved in the transactions in the MER. It consists in a 230 kV circuit with a transmission capacity of 300 MW running through the six member countries.

In practice, the MER operation rules (RMER) has migrated to the setup of a single market with a mandatory 3-steps daily dispatch for the system operators in each country:

1. Isolated pre-dispatch of each domestic system (disregarding regional interconnections).
2. Regional pre-dispatch: generators that do not participate in the domestic dispatch provide generation supply (injections) in the spot market (MOR) of the MER. The potential demand

(withdrawals) in the MOR comprises those generators that were actually dispatched in step 1 and whose variable cost is higher than generation supply (injections) in the MOR.

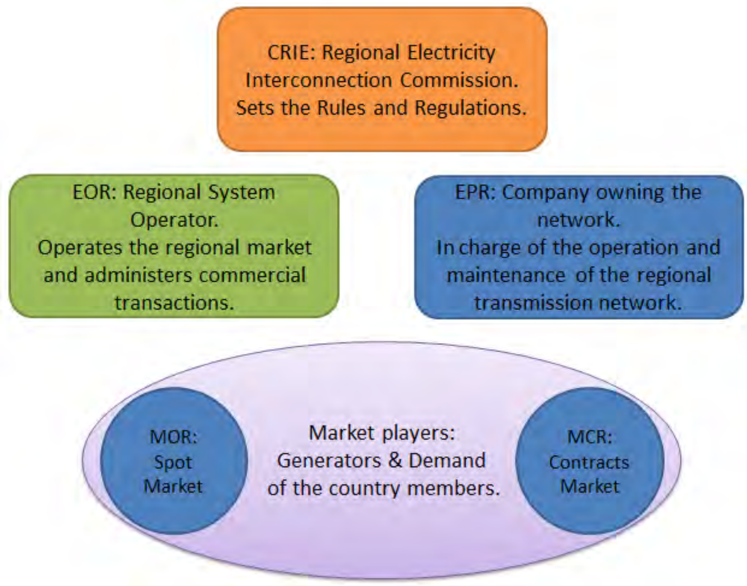
3. Final domestic pre-dispatch: the operator of each domestic system adjusts the dispatch carried out in step 1 according to the results of the regional dispatch in step 2: it substitutes local generation (imports) or increases local generation (exports) to comply with the exchanges calculated in step 2 at each border node.

These operation rules (RMER) are currently in force but certain restrictions apply. Their implementation has proved to be difficult for technical reasons and for other reasons related to security of operation and to the allocation of responsibilities between the operators in each country and the Regional Operator (EOR).

As mentioned, the regulation of the MER allows for opportunity transactions based on price bids as well as the possibility to enter into long-term contracts between generation and demand of the different member countries.

Transactions between a MER agent and third countries (non-member countries) are also allowed in the MER as long as such countries' networks are linked to the regional one, either directly or through the national network of a member country. Mexico is an example of this; Colombia could also be an example if the interconnection project with Panama finally develops; which seems unlikely.

Exhibit 4: MER Institutions



The MER is organized into a Regional Contract Market and a Regional Spot Market. The transactions that can be carried out are the following:

- Firm Energy Contracts
- Non-Firm Energy Contracts
- Opportunity Transactions

Firm Energy Contracts imply physical obligations to be performed, meaning the amounts of contracted energy must be injected into and withdrawn from the regional transmission network (RTR) at the nodes indicated by the parties to the contract. Therefore, the amounts contracted under Firm Energy Contracts are not subject to the regional economic dispatch but are considered to be dispatched ex-ante.

Firm Energy Contracts may additionally include flexible bids expressed as the price of additional injection to the contracted amount, or withdrawal prices under which firm injection is reduced. Such flexible bids are considered Opportunity Transactions, as described below.

Non-Firm Energy Contracts differ from those above in that there are no Transmission Rights and therefore, the physical amounts contracted may be limited in case of constraints in the Regional Transmission Network.

Finally, opportunity transactions are bids to physically inject and withdraw energy into and from the RTR, made by licensed agents for each market period of the following day (the adopted market period is one hour).

REGIONAL ELECTRICITY MARKET MAIN BARRIERS

The commissioning of the Regional Electricity Market (MER) has made it possible to observe aspects of improvement in regulatory aspects that are expected to be incorporated in the Third Protocol of the Framework Treaty of the Central American Electricity Market. The main barriers observed and that should be tackle are:

- Development and full implementation of regional regulation
    - Understanding and outreach of regulation: many agents do not understand in depth the regulation of the MER and they perceive it as difficult.
    - Lack of definition of indicators and market monitoring: There is a need for additional regulatory and technical indicators. The lack of indicators difficult the monitoring and execution of improvements by the institutions and agents of the MER.
    - Penalties: It is necessary to adjust the penalties for a strong, coordinated and harmonious development of the MER.
    - Short-term transmission right: A harmonized market for fixed transmission rights for long-term power purchase agreements is required. Currently, the firm transmission rights have an annual duration.
- Promote the expansion of regional generation and transmission
    - Lack of consolidated regional planning to optimize the use of regional resources.
    - Deficient of coordination in the expansion of national transmission networks with the maintenance of the regional expansion network.
    - Promote the development of an harmonized regulation
    - Supremacy of regional rules on MER rules: The rules and regulations published by the CRIE should take precedence over national rules and regulations.
    - Expand and improve extra-regional interconnections.

Regarding the number of agents of the MER, in 2019, 256 agents were registered, most of them in Guatemala, Panama and El Salvador, while Honduras and Costa Rica have a single and state owned agent each (ICE and ENEE respectively).

SECTION II: PANAMA - MARKET OUTLOOK AND REGULATORY ANALYSIS

1. PANAMA – MARKET OUTLOOK

1.1. Panama – Country Profile

Panama, officially the Republic of Panama, is the third smallest country of the Central America isthmus (it has an area of 75,420 km^2). To the north, Panama borders with the Caribbean Sea; on the west, with Costa Rica, on the south with the Pacific Ocean and finally on the east with Colombia. Its capital and largest city is Panama City.

The population is estimated at 4.2 million (2019[2]) with a density of 56 habitants/km2. Most of the population lives in the largest cities (68%). GDP per capita is around 15,700 USD/cap, above the region average. It is divided into 9 provinces (provincias) and sub-divided into about 77 municipalities (municipios).

Panama was inhabited by several indigenous tribes prior to settlement by the Spanish in the 16th century. It broke away from Spain in 1821 and joined a union of Nueva Granada, Ecuador, and Venezuela named the Republic of Gran Colombia. When Gran Colombia dissolved in 1831, Panama and Nueva Granada remained joined, eventually becoming the Republic of Colombia. With the backing of the United States, Panama seceded from Colombia in 1903, allowing the Panama Canal to be built by the U.S. Army Corps of Engineers between 1904 and 1914. In 1977, an agreement was signed for the total transfer of the Canal from the United States to Panama by the end of the 20th century, which culminated on December 31st 1999.

Panama's dollar-based economy rests primarily on a well-developed services sector that accounts for more than two thirds of GDP. Services include operating the Panama Canal, logistics, banking, the Colon Free Zone, insurance, container ports, flagship registry, and tourism. Economic growth has been bolstered by the Panama Canal expansion project that began in 2007 and was completed in 2016 at a cost of USD 5.3 billion.

Panama has also constructed a metro system in Panama City, valued at USD 1.2 billion and completed by 2014. Panama's booming transportation and logistics services sectors, along with aggressive infrastructure development projects, have lead the economy to continued high growth which tends to slow down in the last years (8% average growth from 2004 to 2014, 5% from 2014

[2] Source: World Bank

to 2017 and around 3% in 2018-2019). Foreign investment, at around 9% of GDP in 2019, has continued to be a source of growth. Strong economic performance has not translated into broadly shared prosperity, as Panama has the third worst income distribution in Latin America. About 13% of the population lives below the poverty line of US$5,5 a day. The US-Panama Trade Promotion Agreement was approved by Congress and signed into law in October 2011, and entered into force in October 2012. Panama also achieved removal from the Organization of Economic Development's gray-list of tax havens by signing various double taxation treaties with other nations[3].

Tourism in Panama has been growing rapidly. It has maintained its growth over the past years due to government tax and price discounts to foreign guests and retirees. These economic incentives have caused Panama to be regarded as a relatively good place to retire in the world. Real estate developers in Panama have increased the number of tourism destinations in the past five years because of the interest for these visitor incentives. 2,300,000 tourists arrived in 2019, slightly less than in 2018.

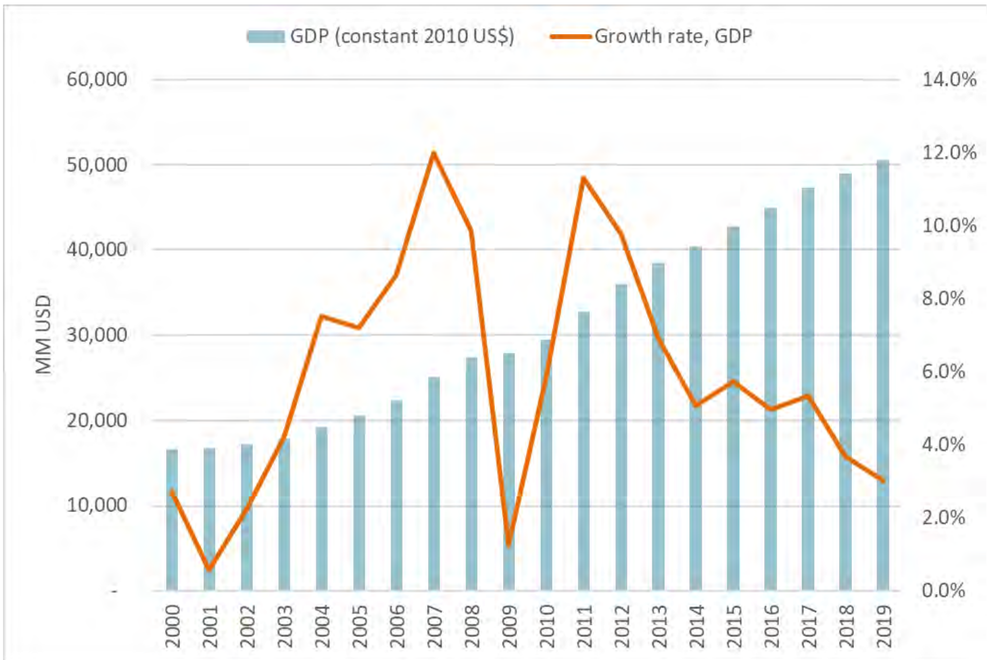
The Panamanian currency is officially the balboa, fixed at a rate of 1:1 with the United States dollar since independence in 1903. However, in practice the country is dollarized: US dollars are legal tender and used for all paper currency, while Panama has its own coinage. Because of the tie to US dollars, Panama has traditionally had low inflation on consumer's prices (2.4% average since year 2000).

The high levels of Panamanian trade are in large part from the Colón Free Trade Zone, the largest free trade zone in the Western Hemisphere. Panama's economy is also very much supported by the trade and export of coffee and other agricultural products.

Revenue from canal tolls continues to represent a significant portion of Panama's GDP, although commerce, banking, and tourism are major and growing sectors. Panama has the second largest economy in Central America and it is also the largest per capita consumer in Central America. In 2019, Panama ranked 5th among Latin American countries in terms of the Human Development Index, and 67th in the world. In 2019 Panama was the 7th most competitive economy in Latin America, according to the World Economic Forum's Global Competitiveness Index. Covering around 40 percent of its land area, Panama's jungles are home to an abundance of tropical plants, animals and birds – some of them to be found nowhere else in the world.

[3] Source: CIA´s World factbook. https://www.cia.gov/library/publications/the-world-factbook/geos/pm.html

Exhibit 5: PA - Evolution of GDP, 2000-2019

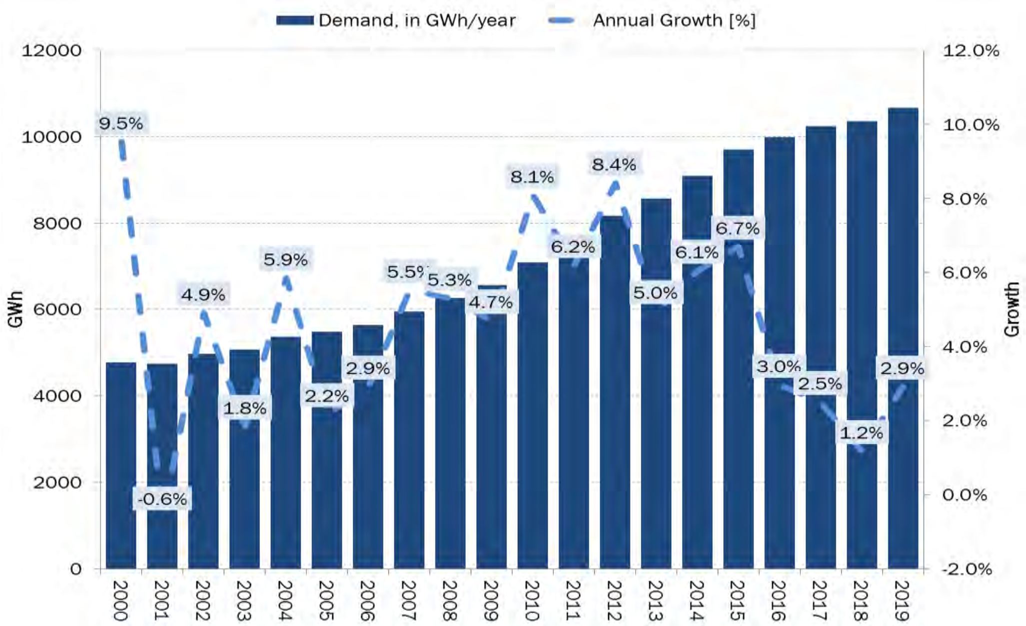


Source: Own elaboration based on World Bank information

1.2. Demand

The electricity demand in Panama has grown at an average rate of 4.6% since 2000. However, in the last four years, demand's growth has slowed down. Electricity demand in 2019 reached 10,726 GWh and peak demand reached 1,961 MW. Average annual growth from 2016 to 2019 was 2.4%.

Exhibit 6: PA - Demand evolution 2000-2019 (GWh)



Source: prepared by the Consultant, data from CND

The most important hydro power plants in Panama, Bayano (260 MW) and Fortuna (300 MW), have the possibility to manage the use of water between seasons, and also daily to meet the demand's variations. The optimal use of the energy stored in the water reservoirs is to dispatch during the peak hours, thus stabilizing energy prices during the day. In a normal condition, thermal dispatch is required during the whole day, being the technology that sets the marginal cost of the system. In normal conditions, the maximum load is between 11am and 5pm.

Most of the demand comes from households, commercial and services sectors. The industrial sector represents a relative small proportion, consistent with the structure of the Panama´s economy.

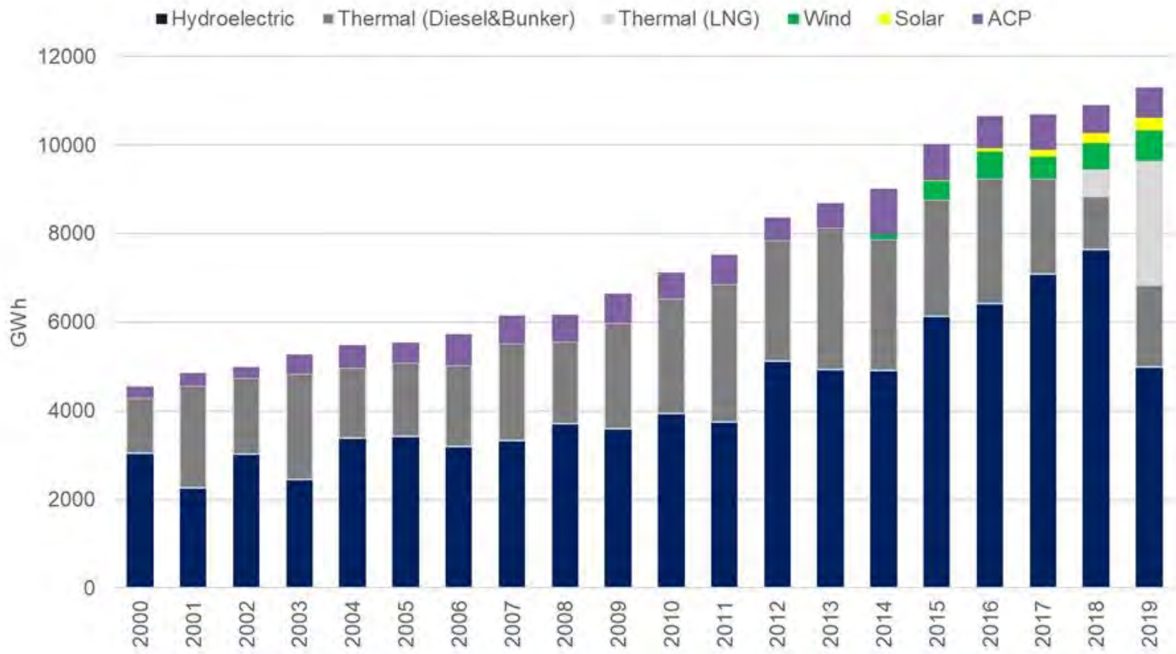
Demand composition by type of customer (Source: ASEP, 2019): 45% commercial, 36% residential, 14% Government, 3% industrial and 2 % public lighting.

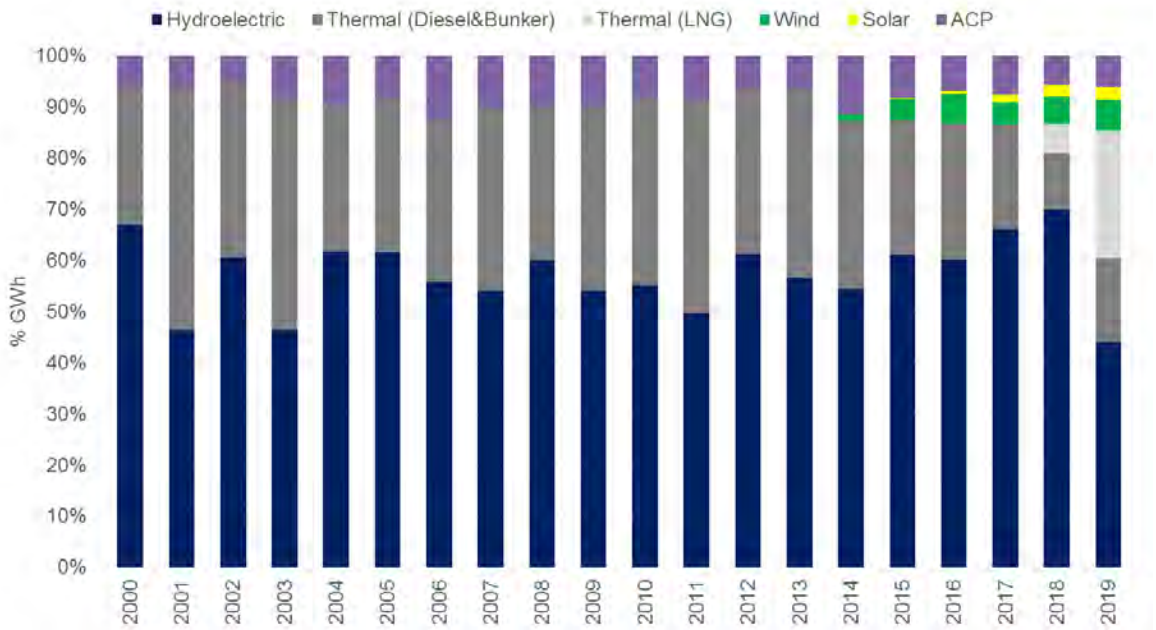
1.3. Supply

The generation installed capacity in Panama has a high component of hydroelectricity (the rainy season runs from May to October). Fortuna (ENEL Group, 300 MW) and Bayano (AES, 260 MW) are the two major hydropower plants of the generation fleet with regulating capacity (reservoir). Together, they produce around 30% of total hydro generation, on average conditions. The hydro generation accounted for about 70% of the total generation in 2018 and 44% in 2019. 2019 has been characterized by the unavailability of Changuinola hydro power plant (223 MW) during a large portion of the year and dryer conditions. Thermal power plants mainly use liquid fuels and coal. Since the start of operation of Costa Norte CCGT in 2018, LNG is also part of the fuel mix for thermal power plants. In 2019, it contributed for 25% of the total generation.

The following Exhibit presents the evolution of the generation by source. The hydroelectric generation has an average participation of 57% on total generation with a maximum participation of 70% in rainy years and a minimum participation of 44% in dry years.

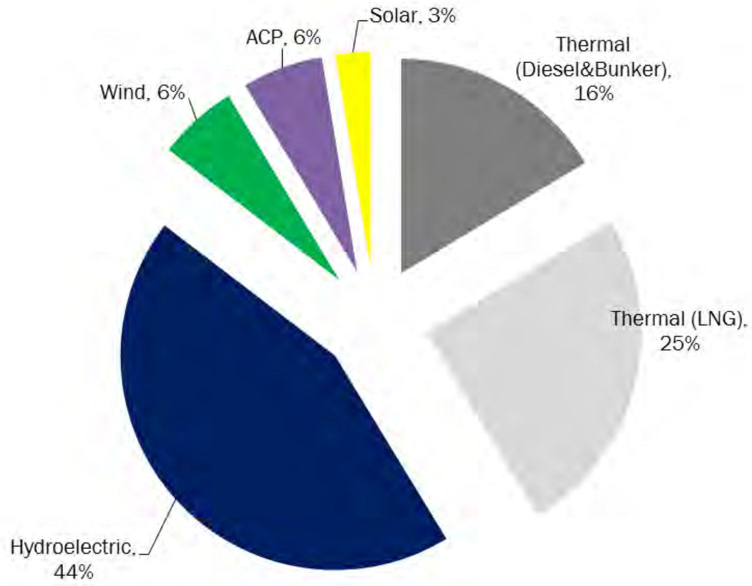
Exhibit 7: PA - Energy supply (2000 – 2019)





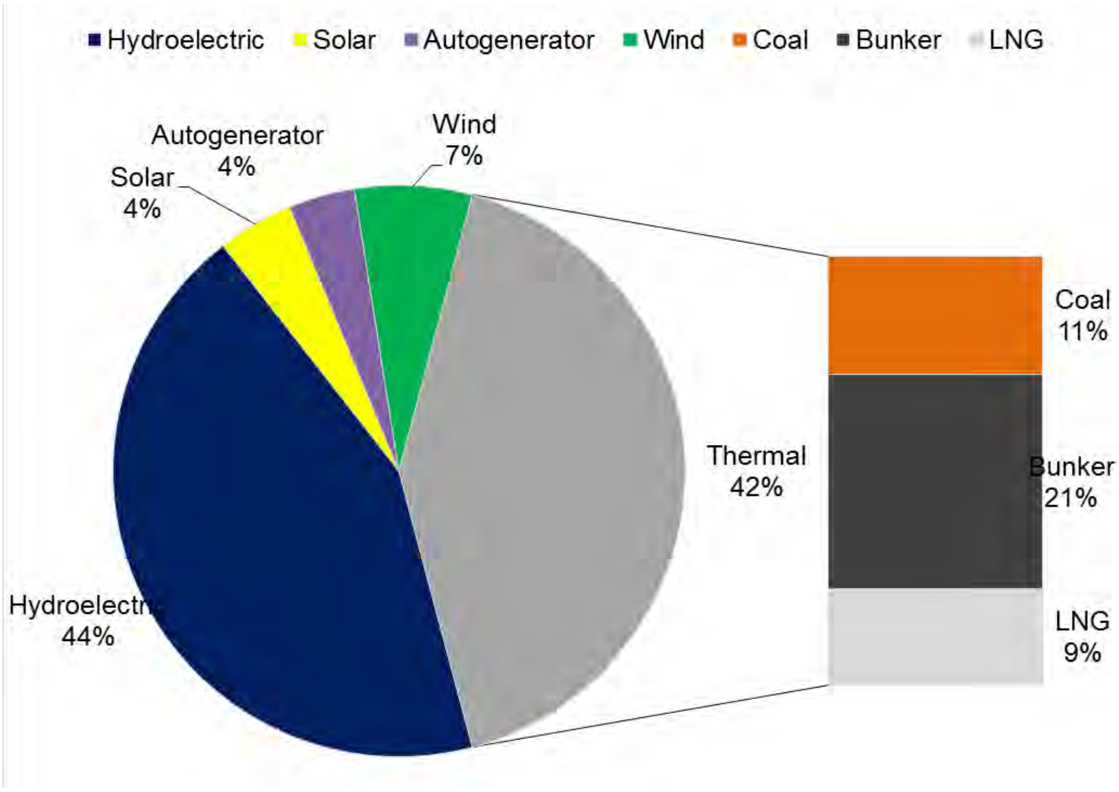
Source: CND

Exhibit 8: PA - Generation by source (2019)



Hydroelectric power plants represent around 44% of total installed capacity (1776 MW in January 2020), thermal power plants and ACP 45% (mix of hydro, diesel, bunker, LNG and coal), wind with 7% and solar with the remaining 4%.

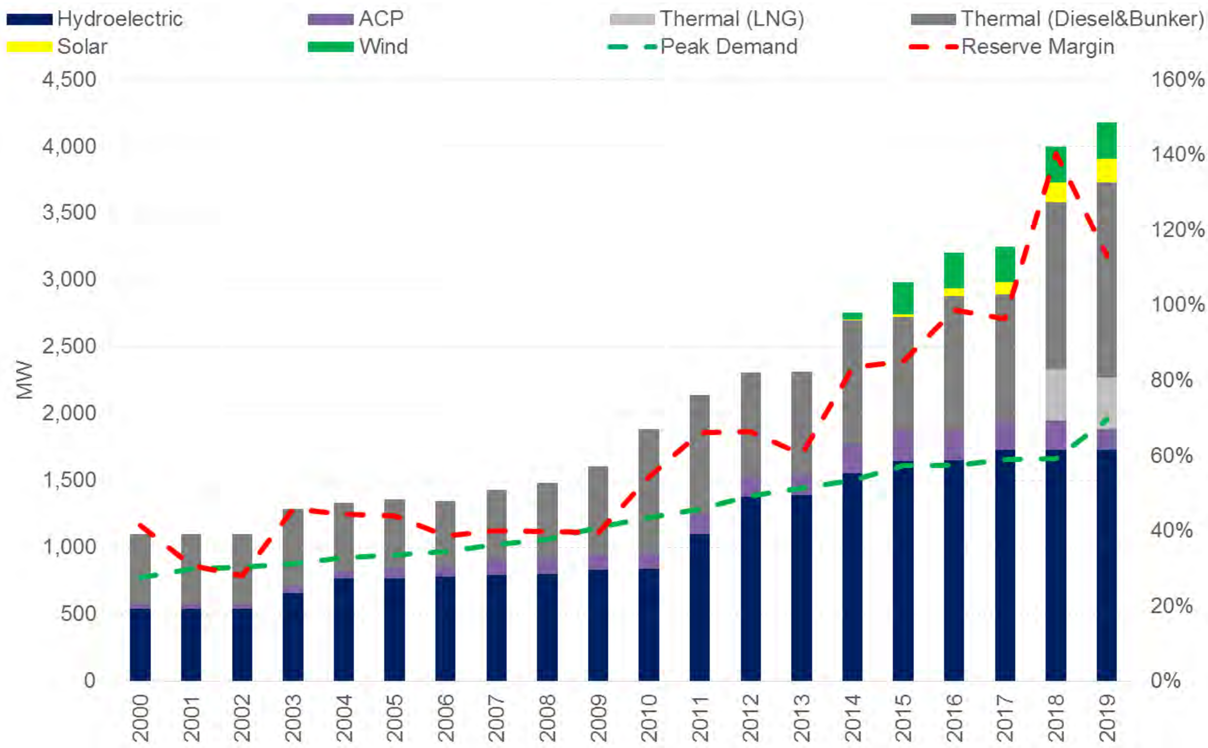
Exhibit 9: PA - Installed capacity by technology (Jan. 2020)



Source: own elaboration based on CND information

In the last five years, the expansion of the system has been dominated by thermal power plants and renewables. The next Exhibit presents the evolution of the installed capacity, peak demand and reserve margin of the Panamanian system:

Exhibit 10: PA - Nominal installed capacity, peak demand and reserve margin, 2000-2019



Source: own elaboration

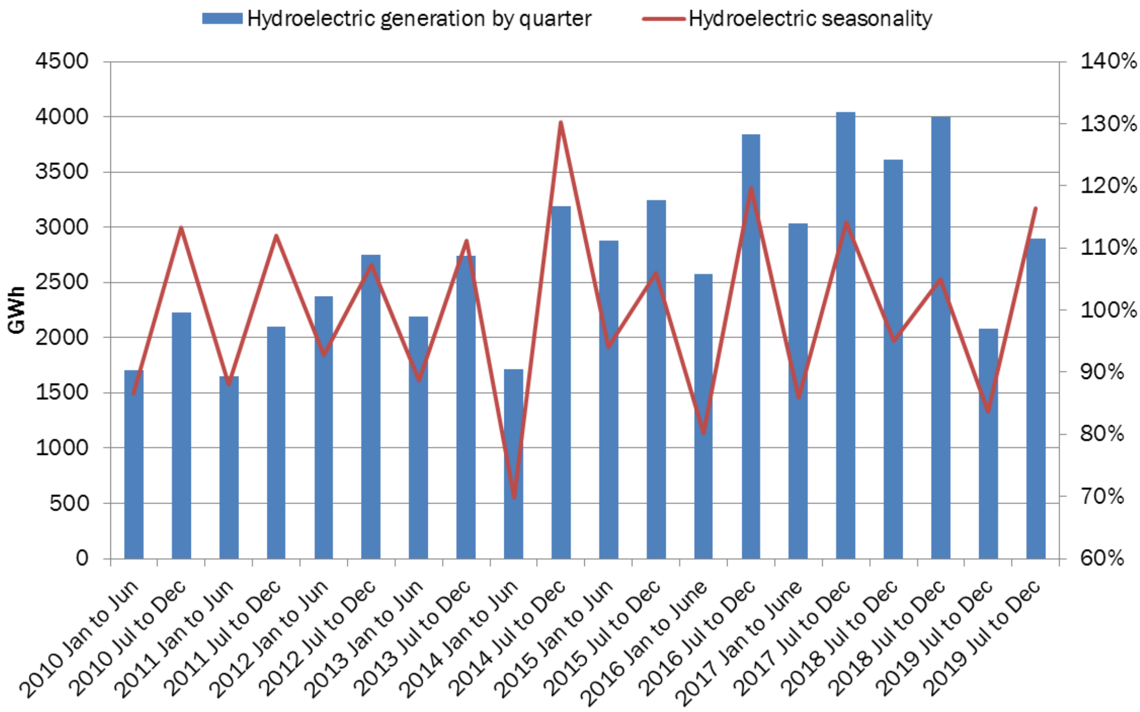
From 2000 to 2009, the system´s reserve margin has been close to 40% on average. Since 2010, it has a growing tendency reaching values over 140% recently. This high reserve margin is explained by the large participation of hydro and renewable resources in the generation mix. During the dry season, the availability of hydro resources (firm energy) is low and they need to be complemented with thermal generation in order to guarantee enough supply to meet demand. In the last five years, the addition of wind and solar projects also contributed at increasing the reserve margin measured in terms of installed capacity (although their firm energy is much lower).

Electricity prices rise when hydro generation diminishes. This happens mainly during the dry season (January to May). In these months it is necessary to dispatch costly thermal generation in order to meet demand.

The supply curve is affected by hydrological conditions; during dry years hydroelectricity diminishes and *viceversa*. In this respect, maximum demand in Panama reached 1,961 MW in 2019 while total installed capacity of hydro power plants at that time was near 1,776 MW. However, this does not mean that demand can be supplied mainly by hydro resources all the time. In fact, during 2014, there was rationing because available capacity was not enough to meet demand (due to very dry weather and low water inflows).

The next Exhibit presents the seasonality of hydroelectricity generation: there is a dry season (from Jan to May) and a rainy season. This weather pattern influences on the electricity spot prices. Thus during the dry season spot prices tend to be higher than in the rainy season because it is necessary to call to dispatch more costly thermal units to supply the demand.

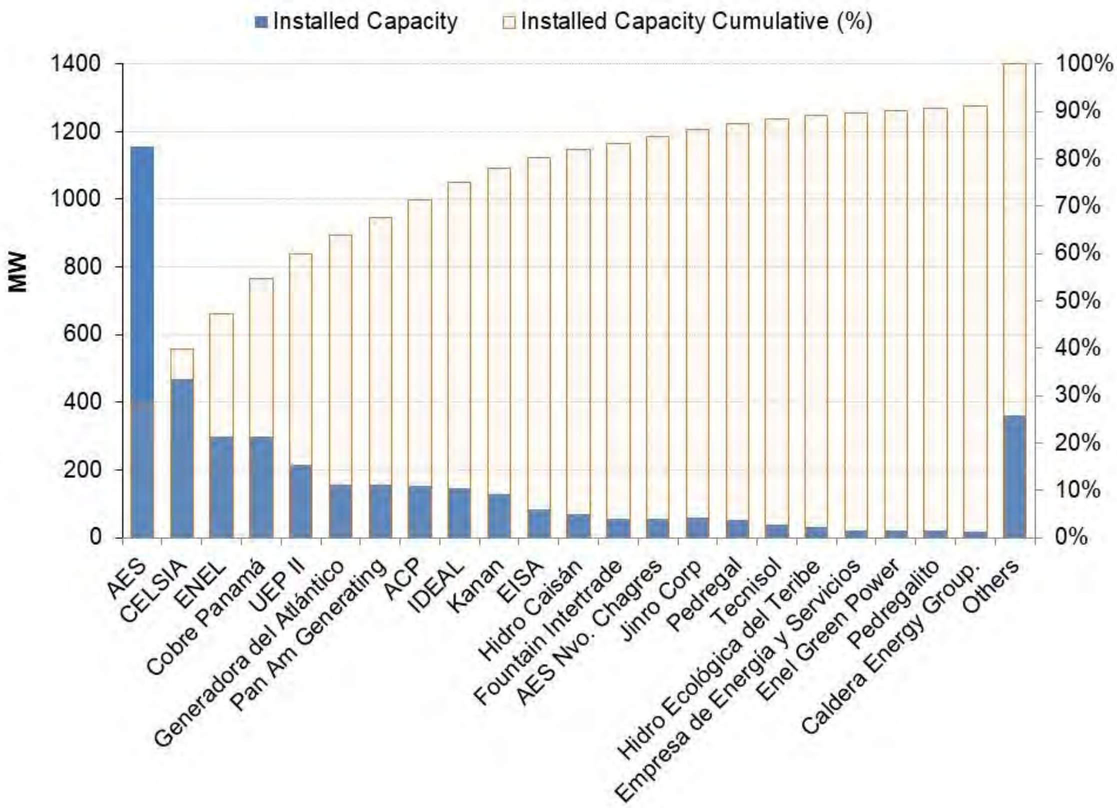
Exhibit 11: PA - Hydroelectric generation seasonality (2010-2019)



Power generation is almost entirely in private hands. The main players in the generation business are AES (owner of two of the three biggest hydro power plants – Bayano and Changuinola –as well as the CCGT Costa Norte, totalizing around 1,200 MW of capacity), Celsia (that bought GDF Suez assets in 2014, owner of Bahía Las Minas, Cativá and some hydro power plants) and ENEL together with Enel Green Power (owner of C.H Fortuna and several solar power plants).

The following exhibit presents the installed capacity per owner/company.

Exhibit 12: PA – Installed capacity per company, Jan. 2020



Source: own elaboration

Almost all of the listed agents are private companies. The Panama Canal Authority (ACP) is the agency of the government of Panama responsible for the operation and management of the Panama Canal.

Bayano (260 MW) and Fortuna (300 MW) are the only hydroelectric plants with regulating capacity, they have a seasonal reservoir which enables them to store water during the rainy season to produce energy during the dry season. The rest of the hydro power plants in the system (1216 MW in total in January 2020) are run-of-river, with no significant regulating capacity.

The bulk power market in Panama is a “marginal market”: the most expensive variable cost of an active generating unit is the electricity spot price of the system at that time. The system operator (CND) centrally dispatches all the available power units in the generation fleet by ranking them in ascendant order of variable costs, thus assuring to supply demand at the minimum possible cost at each point in time (“merit order dispatch”). It is worth mentioning that the variable costs of renewable-based projects are very low, therefore they are ranked first in the merit order dispatch (dispatch priority *vis a vis* thermal generation and hydro power plants with reservoirs)

The Panamanian electricity market was designed so that the transmission grid operates without congestions (congestion means that the energy flow reaches the maximum transmission capacity), even if one circuit goes off line (known as (N-1) condition). ETESA is in charge of planning the necessary expansions of the transmission lines to meet this goal.

Historically, the power market operated with no curtailment of the transmission capacity. From 2013 to 2018, a delay in the expansion of the West – East transmission corridor triggered congestion events. The project to expand the corridor recently came online significantly reducing the risk of congestion. It is expected that hydro generation, together with other renewable-based technologies like wind and solar, will continue playing a significant role in the electricity supply; although the recent drop in fuel prices may slow down some new developments. Almost all future developments are solar and wind projects, small to medium size run-of-river power plants, as well as CCGT fueled with LNG. The expected share participation by solar and wind sources is around 50 % of new installed capacity.

1.4. Electricity prices in the spot market

CND, the system operator, determines the spot price of electricity in each hour of operation. The spot price is set by the variable cost of the most expensive plant actually called upon to generate in the hour.

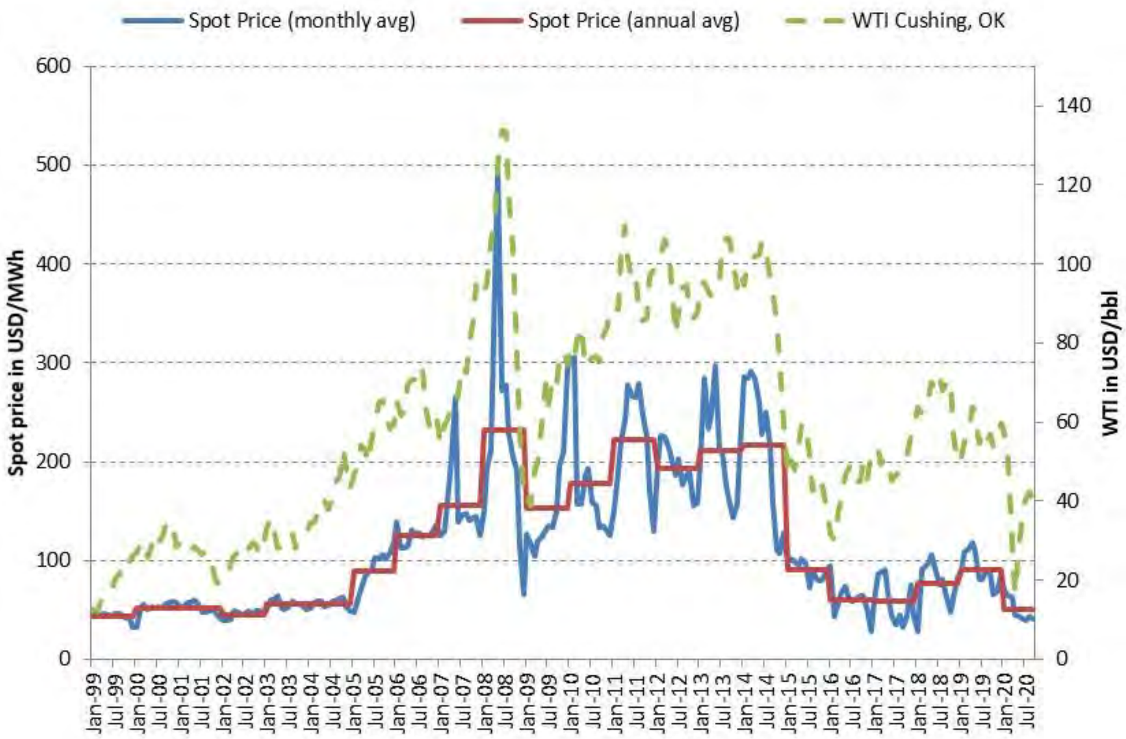
Thermal plants report to the CND their actual thermal efficiency, fuel cost and variable O&M cost, all of them being auditable. Hydroelectric plants with large reservoirs do not report such costs, but rather are assigned a "shadow price" (named "water value") based on a value allocated to the water, which is calculated as an opportunity cost[4]. Once calculated, this shadow price is equivalent to a variable operating cost and is used as such in the dispatch of the system. Self-generators bid prices, not costs.

May is a critical month for the system, as it is the end of the dry season when there are no large contributions from rainfall and reservoirs are at their lowest levels.

In the past, energy prices in Panama were directly correlated to the price of liquid fuels, since most thermal generation used these fuels to produce energy. This caused energy prices to have a direct relation to crude oil prices (WTI). In the near future, prices will most probably depend mainly on Henry Hub prices, although they may continue depending on the evolution of WTI prices in a context of a dry year. Less sensitivity to WTI prices is expected due to the incorporation of new efficient generation (coal, LNG) and an increasing proportion of renewable-based technologies in the generation mix.

[4] The least-cost operational policy compares the immediate benefit of using the water now to the future benefit of storing it.

Exhibit 13: Evolution of electricity spot prices and crude oil prices (WTI), Jan-99/Sep-20



Source: prepared by the Consultant

The main drivers to explain the evolution of electricity prices in Panama are the price of fuels and the availability of hydro generation. Historically, energy prices in Panama were directly correlated with the price of liquid fuels, since most of the thermal generation used these fuels to produce energy. Until year 2005, electricity prices were relatively low and stable mainly because crude oil prices were low and stable (red line in the above Exhibit). Since year 2006, crude oil price started to rise, reaching maximum levels during year 2008. Electricity prices followed the same trend. Between 2008 and 2014, crude oil prices were in the range of 100 USD/bbl and, correspondingly, electricity prices stayed near 200 USD/MWh, with seasonal variations due to hydrology. Since July 2014, crude oil prices drastically decreased and reached values close to 50 USD/bbl).

At the end of 2018, the CCGT Costa Norte started operation, introducing less dependence of electricity prices on crude oil prices, except in drought situations. In the near future, prices will continue to depend partially on the evolution of WTI prices, especially in dry years, although much less sensitivity is expected due to the incorporation of new efficient generation (based on LNG) and a larger portion of renewables in the generation matrix.

Spot prices are the same for the whole system, regardless of location (uninodal system). Therefore, there are no congestion charges or variable transmission charges (transmission losses). Market participants pay a fixed transmission charge to remunerate investment in the interconnected grid. Energy withdrawals made by distributors are grossed up to account for transmission losses.

If Tecnisol or UEP II had the possibility to sell surplus in the spot market, the occurrence and price would they access will have to do with the production curve of themselves, on the hourly and seasonally periods. In this sense, Tecnisol could show surplus during the daylight hours (solar hours) and UEP II more concentrated towards the dry months.

1.5. Energy exchanges

Panama participates in the Regional Electricity Market (MER) where generators and demands located in any of the member countries can freely decide to carry out their energy purchase and sale transactions in the MER or in their own domestic markets. The MER is based on the framework treaty approved by the countries that comprise it, which are: Costa Rica, El Salvador, Honduras, Panama, Nicaragua and Guatemala. The MER operates with a bid price market, which allows agents to make offers that they consider depending on the investment made in their generation plants.

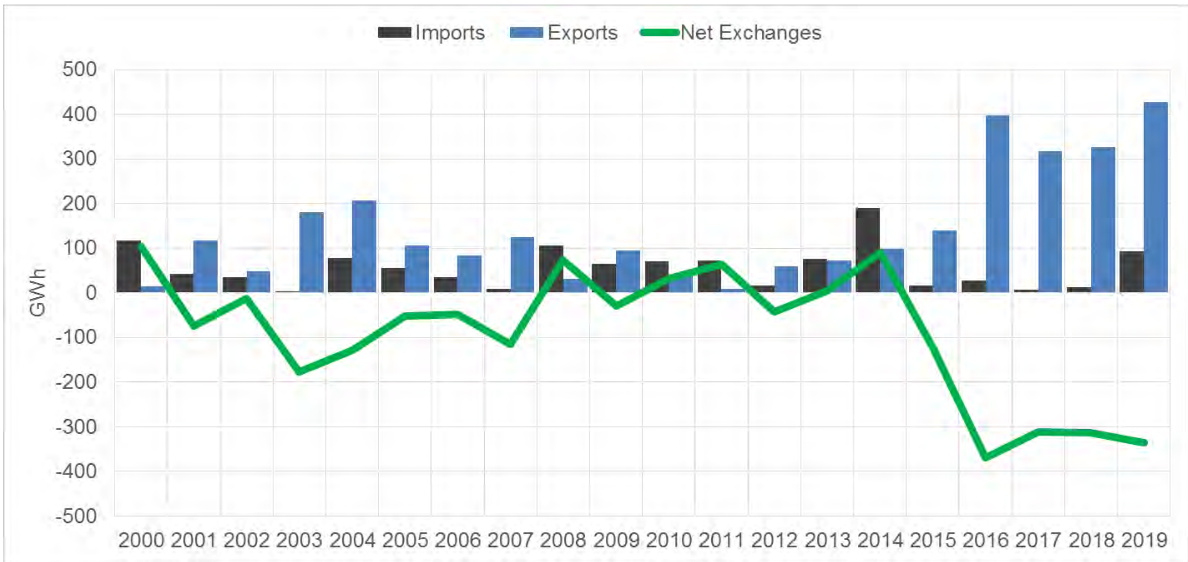
The first interconnection between Panama and Costa Rica was a 230 kV circuit in operation since year 1986, it links Río Claro (CR) and Progreso (PA).

In December 2010, a second 230 kV circuit between Panama and Costa Rica was commissioned, which is part of SIEPAC project connecting the six countries of Central America. The SIEPAC project contributes to optimize energy resources and to reduce energy costs due to economies of scale and complement of energy resources. At present, all transmission lines of SIEPAC project are fully constructed. All these transmission lines allow energy exchanges between Panama and Costa Rica up to 300 MW both ways (when there are no internal constraints in one of the two countries). Since year 2011, the third 230 kV circuit was in operation, named “Anillo de la Amistad”. It links Changuinola substation (on the Panamanian side) to Cahuita substation (Costa Rica side).

Regarding the interconnection with Colombia, there is a project to connect Panama and Colombia (600 km, 400 MW of transmission capacity and estimated cost of 450 million USD). However, the interconnection project has numerous difficulties related to environmental issues and security reasons (the threat of terrorist attacks) in the first place. Secondly, it is not clear the mechanism by which the investment cost will be recovered. Additionally, it is not yet defined how the firm capacity of the imported energy will be computed, which is a requirement of the electricity market in Panama to enter into long term supply contracts.

The following exhibit presents the evolution of annual imports, exports and net exchanges between Panama and Costa Rica. In the past, exchanges have been generally reduced between both countries, but in the last 4 years, Panama has become a net exporter towards Costa Rica and the Central America region. In the last years, there has been limitation for Costa Rica to export to Panama due to internal constraints in Panama.

Exhibit 14: PA - Energy exchanges (2000 – 2019)



1.6. Transmission segment

1.6.1. Description

In Panama, both transmission and distribution are considered natural monopolies by the National State and are therefore regulated. Transmission is wholly performed by Empresa de Transmisión Eléctrica S.A. (ETESA), with state-owned capital. ETESA oversees the planning, operation and maintenance of the grid, and receives in return a regulated tariff (revised every 4 years).

The transmission grid crosses Panama from east to west, allowing it to interconnect the existing generation in the west of the country with the main loading centers in the metropolitan area. The country is also divided into 10 tariff zones and the tariff is correlated to the distance to Panama City.

In addition, Panama is connected to Costa Rica through three different connections, the first one dating from 1986, the second form 2010 (SIEPAC) and the last one called "Anillo de la Amistad", in 2011.

Exhibit 15: PA – Panama's transmission grid

Source: ETESA

The length of the 230 KV in double circuit lines is 2,713 km and in single circuit is 95 km. While the 115 KV in double circuit lines are 268 km long and in single 40 km.

The Main Transmission System has 20 substations, of which 17 are owned by ETESA (6 sectioning and 11 transformer substations).

Next Exhibits shown a detail of lines and substations of ETESA.

Exhibit 16: PA –ETESA - Main Transmission System Lines

LINEA		PROYECTO DE LINEA	AÑO	NUMERACIÓN	SUBESTACIONES	AÑO MOD	LONGITUD (Km.)	CONDUCTOR	CAPACIDAD (MVA)	
									Normal	Cont.
LINEAS 230KV	DOBLE CIRCUITO	Linea Bayano - Panama	1976	230-1A	BAYANO - PACORA (1)	1999	49.14	636 ACSR	202.0	350.0
				230-1B	PACORA - PANAMA II (1)	1999	19.00	636 ACSR	202.0	350.0
				230-1C	PANAMA II - PANAMA		12.94	605 ACSS	335.0	366.0
				230-2A	BAY - 24 DICIEMBRE (1)	2016	59.04	636 ACSR	202.0	350.0
				230-2B	24 DICIEMBRE - PANAMA II (1)	2016	9.10	636 ACSR	202.0	350.0
				230-2C	PANAMA II - PANAMA		12.94	605 ACSS	335.0	366.0
		Linea 1 - Panama - Mata de Nance	1978	230-3A	PANAMA - CHORRERA		40.30	750 ACAR	247.0	366.0
				230-3B	CHORRERA - EL HIGO	2015	60.50	750 ACAR	247.0	366.0
				230-3C	EL HIGO - LL.SANCHEZ	2015	81.55	750 ACAR	247.0	366.0
				230-4A	PANAMA - CHORRERA		40.30	750 ACAR	247.0	366.0
				230-4B	CHORRERA - EL HIGO	2015	60.50	750 ACAR	247.0	366.0
				230-4C	EL HIGO - LL.SANCHEZ	2015	81.55	750 ACAR	247.0	366.0
				230-5A	LL.SANCHEZ - VELADERO		109.36	750 ACAR	247.0	366.0
				230-6A	LL.SANCHEZ - BELLA VISTA (6)	2016	103.36	750 ACAR	247.0	366.0
				230-6B	BELLA VISTA - VELADERO (6)	2016	6.00	750 ACAR	247.0	366.0
			1979	230-5B	VELADERO - MATA NANCE		84.49	750 ACAR	247.0	366.0
				230-6C	VELADERO - MATA NANCE		84.49	750 ACAR	247.0	366.0
		Linea Fortuna - Mata de Nance	1984	230-7	MATA NANCE - FORTUNA		37.50	750 ACAR	193.0	366.0
				230-8	MATA NANCE - FORTUNA		37.50	750 ACAR	193.0	366.0
		Linea 2 - Panama II - Guasquita	2004	230-14A	LL. SANCHEZ - S. BARTOLO	2015	67.70	1200 ACAR	275.0	500.0
				230-14B	S. BARTOLO - VELADERO	2015	42.30	1200 ACAR	275.0	500.0
				230-15A	LL. SANCHEZ - S. BARTOLO	2015	67.70	1200 ACAR	275.0	500.0
				230-15B	S. BARTOLO - VELADERO	2015	42.30	1200 ACAR	275.0	500.0
				230-16	VELADERO - GUASQUTAS		84.30	1200 ACAR	275.0	500.0
				230-17	VELADERO - GUASQUTAS		84.30	1200 ACAR	275.0	500.0
			2006	230-12A	PANAMA II - BURUNGA (4)(5)	2014/2017	35.34	1200 ACAR	275.0	500.0
				230-12B	BURUNGA - EL COCO (4)(5)	2014/2017	114.98	1200 ACAR	275.0	500.0
				230-12C	EL COCO - LL.SANCHEZ (4)	2014	44.67	1200 ACAR	275.0	500.0
				230-13A	PANAMA II - EL COCO (4)	2014	150.33	1200 ACAR	275.0	500.0
				230-13B	EL COCO - LL.SANCHEZ (4)	2014	44.67	1200 ACAR	275.0	500.0
		Linea Interconexion Changuinola	2009	230-20A	FORTUNA - LA ESPERANZA (2)		96.87	750 ACAR	304.0	366.0
				230-20B	LA ESPERANZA - CHANGUINOLA (2)		24.88	750 ACAR	304.0	366.0
			2012	230-29	GUASQUITAS - CAÑAZAS (2)		44.00	750 ACAR y 1200 ACAR	275.0	366.0
				230-30	CAÑAZAS - CHANGUINOLA (2)		76.65	750 ACAR	304.0	366.0
		3era Linea	2017	230-47	PANAMA - CHORRERA		37.50	1200 ACAR	500.0	500.0
				230-48	PANAMA - CHORRERA		37.50	1200 ACAR	500.0	500.0
				230-49	CHORRERA - LLANO SANCHEZ		154.94	1200 ACAR	500.0	500.0
				230-50	CHORRERA - LLANO SANCHEZ		154.94	1200 ACAR	500.0	500.0
				230-51	VELADERO - LLANO SANCHEZ		110.21	1200 ACAR	500.0	500.0
				230-52	VELADERO - LLANO SANCHEZ		110.21	1200 ACAR	500.0	500.0
		Conexión Costa Norte - Panama II	2018	230-54	CONEXIÓN COSTA NORTE - PANAMA II		48.55	1200 ACAR	500.0	500.0
				230-55	CONEXIÓN COSTA NORTE - PANAMA II		48.55	1200 ACAR	500.0	500.0
	CIRCUITO SENCILLO	Linea Mata de Nance - Frontera	1986	230-9A	MATA NANCE - BOQUERON III		24.33	750 ACAR	248.0	366.0
				230-9B	BOQUERON III - PROGRESO		29.75	750 ACAR	248.0	366.0
				230-10	PROGRESO - FRONTERA		9.50	750 ACAR	193.0	366.0
		Interconexion Fortuna	2003	230-18	GUASQUITAS - FORTUNA		16.00	1200 ACAR	275.0	500.0
		Interconexion Changuinola - Costa Rica	2011	230-21	CHANGUINOLA - FRONTERA		15.00	750 ACAR	248.0	366.0
				Total 230KV			**2,807.53**			
LINEAS DE 115KV	DOBLE CIRCUITO	Linea Caceres - Las Minas 1	1970	115-1A	CACERES - STA. RITA	2004	46.60	636 ACSR	150.0	175.0
				115-2A	CACERES - STA. RITA	2004	46.60	636 ACSR	150.0	175.0
				115-1B	STA. RITA - CATIVA 2 (7)(8)	2004/2009	6.20	636 ACSR	211.0	211.0
				115-1C	CATIVA 2 - LAS MINAS 1 (7)(8)	2004/2009	0.80	636 ACSR	211.0	211.0
				115-2B	STA. RITA - LAS MINAS 1 (8)	2004	6.20	605 ACSS	211.0	211.0
		Linea Panama - Las Minas 2	1972	115-3A	PANAMA - CHILIBRE (3)	2016	22.50	605 ACSS	168.0	211.0
				115-3B	CHILIBRE - LAS MINAS 2 (3)	2016	31.50	605 ACSS	168.0	211.0
				115-4A	PANAMA - CEMENTO PANAMA (3)	2016	40.70	605 ACSS	168.0	211.0
				115-4B	CEMENTO PANAMA - LAS MINAS 2 (3)	2016	16.70	605 ACSS	168.0	211.0
		Linea Mata de Nance - Caldera	1979	115-15	MATA NANCE - CALDERA		25.00	636 ACSR	93.0	175.0
				115-16	MATA NANCE - CALDERA		25.00	636 ACSR	93.0	175.0
	CIRCUITO SENCILLO	Linea 1 - Panama - Caceres	1976	115-12	PANAMA - CACERES		0.80	636 ACSR	120.0	175.0
		Interconexion La Estrella - Los Valles	1979	115-17	CALDERA - LA ESTRELLA		5.80	636 ACSR	93.0	175.0
				115-18	CALDERA - LOS VALLES		2.00	636 ACSR	93.0	175.0
		Linea Estacion de Bombeo	1982	115-19	CALDERA - PAJA DE SOMBRERO		0.50	636 ACSR	93.0	175.0
		Interconexion Charco Azul	1988	115-25	PROGRESO - CHARCO AZUL		30.00	636 ACSR	93.0	175.0
		Linea Subterranea - Panama - Caceres	2008	115-37	PANAMA - CACERES SUBT.		0.80	750 XLPE	142.0	178.0
				TOTAL 115KV			**307.70**			

Source: ETESA – Expansion Plan 2019-2033,

Exhibit 17: PA –ETESA´s transformers

No. de S/E	SUBESTACION	No.	CAPACIDAD (MVA)					CAPACIDAD	REDUCTOR	VOLTAJES (KV)			CONEXION	ENTRADA EN OPERACIÓN
			230KV	115KV	34.5KV	13.8KV	4.16KV			ALTA	BAJA	TERCI.		
1	PANAMA 2	1	175	175		30		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	1999
	PANAMA 2	2	175	175		30		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	1999
	PANAMA 2	3	175	175		30		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	2019
2	PANAMA	1	175	175		30		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	1993
	PANAMA	2	175	175		30		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	1974
	PANAMA	3	350	350		75		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	1981
	PANAMA	4	350	350		75		OA/FA/FOA	REDUCTOR	230	115	13.8	EST/EST/DEL	2018
3	CHORRERA	1	50	50	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	1995
	CHORRERA	2	50	50	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	1975
	CHORRERA	3	100	100	100			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2013
4	LLANO SANCHEZ	1	70	60	30			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	1975
	LLANO SANCHEZ	2	70	60	30			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	1995
	LLANO SANCHEZ	3	100	100	33			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2012
5	MATA DE NANCE	1	70	60	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	1975
	MATA DE NANCE	2	70	60	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2012
	MATA DE NANCE	3	70	60	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2003
6	PROGRESO	1	50	50	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2003
	PROGRESO	2	50	50	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	1975
7	CHARCO AZUL	1		24			24	OA/FA	REDUCTOR	115	4.16		DEL/EST	1988
8	CHANGUINOLA	1	50	50	50			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2009
9	CALDERA	1		62.5	62.5			OA/FA/FOA	REDUCTOR	115	34.5		EST/DEL	2010
10	BOQUERON III	1	83.3		83.3			OA/FA/FOA	REDUCTOR	230	34.5		EST/DEL	2010
	BOQUERON III	2	83.3		83.3			OA/FA/FOA	REDUCTOR	230	34.5		EST/DEL	2016
11	SAN BARTOLO	1	100	100	100			OA/FA/FOA	REDUCTOR	230	115	34.5	EST/EST/DEL	2015
	TOTAL		2,641.6	2,511.5	922.1	300.0	24.0							

Source: ETESA – Expansion Plan 2019-2033,

1.6.2. Regulatory Framework

The remuneration of the services provided by ETESA is subject to regulation and comprises several charges, which can be invoiced to the supply (generators) or the demand (distributors/users).

To calculate these charges, a Maximum Allowed Revenue (IMP, in Spanish) is initially determined. It refers to the following elements:

- The efficient operation, maintenance and administration costs with respect to the New Replacement Value (NRV) of the assets in the Main Transmission System (SPT) and the Connection System, and the depreciation, according to the average percentages by asset type on their net value at the original cost accepted by the Regulator.
- The allowed rate of return on the net value of the assets in the Main Transmission System (SPT) and the Connection System.
- The forced generation expenses and other additional costs of the Wholesale Market relating to the application of security criterion n-1.

Once the IMP has been established, the charges for each service offered by ETESA are calculated: the charge for main transmission system usage, the connection charge, and the charge for integrated operation services.

a) Efficient Operation, Maintenance and Administration Costs

The recognized operation, maintenance and administration costs arise from a benchmarking of companies, which allows us to obtain an efficient COMA/NRV indicator. Once the percentage has been obtained, it is applied on the efficient gross fixed asset of the main transmission system and the connection system.

b) Capital Base

The regulatory capital base is the sum of the efficient values of the asset base as of the base year, plus the investment, retirements and depreciations in the tariff year.

In the case of the Main Transmission System, the New Replacement Value of the total assets, and their depreciation, are considered.

In the case of the Connection System, the book value is considered, adjusting capitalizations according to efficiency criteria.

c) Annuity of Capital

The recognized rate of return arises from applying a WACC model. A rate that does not differ by more than two points from the sum of the annual interest rate of the 30-year US Treasury bonds and a seven-point prime for the risk of the transmission business in the country (using data from the last twelve months) is considered reasonable.

1.6.3. Network Expansion

In particular, the regulation establishes that the Transmission Expansion Plan will contain, at least, a Long Term Replacement Plan for the existing assets, which will include the renovations and enhancement of assets and facilities in operation, without assuming an increase in installed capacity. It will include the following studies:

- Estimation of the additional costs produced in the operation and maintenance of the installed equipment if such equipment is not replaced.
- Estimation and justification of the reduction in the useful life of the installed equipment based on operation and maintenance costs and the cost of drops in quality of service, including obsolescence of the equipment when it is due to technical reasons.
- Plan to replace the existing assets in the long term (over 10 years).
- Justification that the request for replacement is not due to lack of maintenance of the equipment.

In addition, a Replacement Plan of the Facilities in the short term is required. It will include the following studies:

- Estimation of the additional costs to continue operating the installed equipment and not replace it.
- Estimation and justification of the reduction in the useful life of the installed equipment based on operation and maintenance costs and drops in quality of service.
- Evolution of maintenance costs if there is no replacement and economic justification of its convenience.
- Extension of the useful life of the equipment (in case of partial replacement)

1.7. Distribution segment

In Panama, both transmission and distribution are considered natural monopolies by the National State and are therefore regulated. Distribution is organized in a monopolistic way for each exclusive concession area. Three private companies participate in the sector.

As to vertical integration, it is allowed, though limited. Distribution companies can only participate in transmission and/or generation activities in two cases, after separating their accounting and management:

- in the case of Isolated Systems or;
- when the annual generation installed capacity is lower than 15% of the distributor's demand.

1.7.1. Description

Power distribution in Panama is considered a natural monopoly and is therefore regulated. Distribution companies hold the concession of the services provided in exchange for the obligation to supply the current and projected demand for energy and firm capacity of captive consumers or "regulated clients" (those which do not qualify as Large Users and are therefore obliged to buy from the Distributor). The contracts resulting from a regulated process may be passed through to tariffs. This procedure is defined in the Commercial Rules, where it is established that it can be conducted through an international tender supervised by ASEP to guarantee transparency and competitive conditions.

The activity is largely conducted by three companies that serve 95% of the market: *Elektra Noreste* (ENSA), *Empresa de Distribución Eléctrica Metro Oeste* (EDEMET) and *Empresa de Distribución Eléctrica Chiriquí* (EDECHI); the last two are controlled by Naturgy.

Exhibit 18: PA – Panama's Distribution Companies

Source: ETESA

Demand in Panama includes a high percentage of contracted energy by Distributors (90.5% in 2019).

Exhibit 19: PA - Energy purchase by Distributors, 2019

Source: Statistics, ASEP December 2019

Panama is served by three distributors: *Empresa de Distribución Eléctrica Metro Oeste* (EDEMET), *Empresa de Distribución Eléctrica Noreste* (ENSA) and EDECHI (*Empresa de Distribución Eléctrica Chiriquí*). EDEMET and EDECHI are in the hands of Naturgy.

EDEMET serves the west of Panama City and Panama province together with the provinces of Coclé, Herrera, Los Santos and Veraguas; 523,777 total clients, 45% of total demand.

ENSA's concession area comprises the east of Panama City and Panama province, the Gulf of Panama, the Province of Colón and two isolated systems (Darién and Kuna Yala); 470,433 total customers, 41% of total demand.

EDECHI's concession area is located in Chiriquí and Bocas del Toro provinces (161,597 clients, 14% of total demand). The Bocas *Fruit Company* self-generator selling its energy surpluses within said province is also located in Bocas del Toro province.

1.7.2. Regulatory Framework

Distribution is regulated under a Revenue-Cap scheme in which the Regulator fixes the Maximum Allowed Revenue (IMP, in Spanish) for distribution activities every four years.

a) Operation, Maintenance and Administration Costs

They include direct and indirect expenses, as well as remuneration costs, system operation and grid maintenance costs, planning costs and the cost of equipment in warehouses.

b) Remuneration for Assets

The tariff base is estimated from the book value in the company's accounting and the efficiency analysis established in the Tariff Regime (under which the investment levels are obtained).

ASEP defines a reasonable rate of return, considering efficiency, quality of its service, the investment scheme for the effective period of the formulas, and any other factor deemed relevant.

The rate cannot differ by more than two points from the rate resulting from the sum of the effective annual interest rate, the average of the twelve months prior to the date when the tariff formula is fixed, the 30-year US Treasury bonds, and an eight-point premium for power distribution business risk in the country.

c) Pass-Through of Power Purchase Costs

Energy purchases from the utility are remunerated through tariffs that reflect the economic costs of supply and cover, on average, all energy and capacity costs, ancillary services, and other charges.

If the distribution company contracts a supply of bulk energy with a company other than the utility, a cost based on the average price of purchases from the utility is allocated.

d) Tariff Structure

In Panama, regulated tariffs to final users are set by adding charges for transmission grid usage, charges for distribution network usage, and commercialization costs to the electric power purchase cost component.

Thus, tariffs are composed by the following elements:

- Generation cost (cost of purchasing energy and capacity to supply the distributor's demand, which basically arises from the price of contracts between the distributor and the generators, and from the cost of purchasing energy/capacity in the spot market).
- Transmission cost (cost of using transmission grids, based on a regulated tariff).
- Distribution cost (arises from calculating the distribution IMP, based on a regulated tariff).
- Trading cost (arises from calculating the distribution IMP, based on a regulated tariff).
- Public lighting cost
- Cost of losses in the transmission and distribution networks.

As to the tariff options, the companies may freely submit tariff specifications that must consider the following criteria to be approved by the ASEP:

- They will induce efficient use of the service and the electric product;
- They will reflect the real costs of the service;
- They will show, at least, a breakdown by voltage level according to the following classification:
  - High voltage (115 kV and over)
  - Medium voltage (between 115 kV and 0.6 kV)
  - Low voltage (0.6 kV and under)
- They will discriminate by type of measurement.
- Tariff classes (client types) will match those approved in the Regulator's resolutions to approve the current tariff specifications. The distributor can propose new tariffs within each voltage level based on an analysis of the load characterization.
- There will be no restrictions on the tariff charges to be applied, only specifying that fixed and/or variable charges can be applied subject to the possibility of taking full advantage of the type of measurement of each client type.

Broadly speaking, the tariff structure is divided by voltage level, discriminating the charges for users connected at low, medium and high voltage. In addition, non-regulated large users have a different tariff chart, which shows the charges for distribution network usage.

e) Subsidies

In Panama, there is no social tariff, but there is an explicit subsidy available to end users of the public service of electricity that consume less than 100 kWh every month. It originates in an explicit surcharge of up to 0.6% on the invoice of clients consuming over 500 kWh every month and is destined to reduce up to 20% of the invoice of subsidized users.

There are also subsidies of up to 25% of the invoices (with a cap of 600 kWh) of other specific groups, such as retirees, pensioners, and another for handicapped users.

f) Adjustment Factors

The approved tariff charges are adjusted semi-annually by means of adjustment formulas defined during the current period. The adjustments made on the commercialization, distribution and public lighting charges are based on the Consumer Price Index of the last month of the six-month period, according to publications by the Comptroller General of Panama.

There is no efficiency factor or adjustment factor based on economies of scale.

2. PANAMA – REGULATORY FRAMEWORK

2.1. Introduction

The Panamanian electricity market is a deregulated mature market; operating as such since 1999 (the reform process and privatization of the electricity sector began in 1997, with Electricity Law No.6-97).

Although the generation segment is organized as a competitive market, there are five major players (together they concentrate 61 % of the total generating capacity): AES, Celsia (previous owner GdF Suez), Americas Generation Corp. (ENEL), Cobre Panama[5] and InterEnergy Group, owner of 308.53 MW: UEPII (215 MW), Tecnisol I, II II y IV (40 MW) and Pedregal Power (53.53 MW).

In the last decade, the regulatory framework reinforced the long term supply contracts, aiming at attracting new investment in generating capacity: ETESA (the transmission company), on behalf of the distributors, carries out public tenders periodically to guarantee supply for the regulated market. Generators with firm capacity not yet committed under long-term contracts must bid in ETESA's public auctions.

2.2. Main institutions and players

2.2.1. Main Institutions

The main institutions and participants in the power sector are the following:

[5] Punta Rincón coal power plant (owned by Cobre Panama) represents a dedicated project for the power supply of the Punta Rincón mining activity (264 MW approx.). From the total installed capacity of 300 MW, the rest 36 MW are traded in the spot market.

- The Energy Secretary is responsible for energy policy. (www.energia.gob.pa)

- *Autoridad Nacional de Servicios Públicos* (ASEP, regulatory authority) autonomous and independent agency of the Panamanian government in charge of monitoring public services (electricity, water and sewerage, and communications). Its functions include (i) granting power generation and distribution concessions and generation licenses, (ii) establishing the methodologies and formulas for setting tariffs for distribution and transmission services, (iii) issuing regulations and rules applicable to the energy sector, such as the guidelines for the public tenders for contracting energy and capacity, and (iv) imposing sanctions and fines to violators of the energy law and its regulations. Also, it is the ultimate authority in dispute resolution/amendments re PPAs. (www.asep.gob.pa)

- ETESA (*Empresa de Transmisión Eléctrica SA*) is the state-owned transmission company in charge of the operation and maintenance of the high voltage transmission network. ETESA must allow the nondiscriminatory access of third parties to the transmission grid (open access). ETESA also elaborates an indicative (non-mandatory) expansion plan of the power system that must be approved by ASEP. Since the enactment of Law No. 57/09, ETESA has coordinated the public auctions to secure supply to regulated customers. (www.etesa.com.pa)
- The National Dispatch Center (CND) centrally coordinates the system's operations and administers commercial transactions between market agents. CND is part of ETESA. (www.cnd.com.pa)

- *Ministerio de Ambiente* is the grantor of the concession for the use of water for hydro projects and for geothermal fields, pursuant to environmental laws. (www.anam.gob.pa). All generation projects require an environmental assessment that must be approved by ANAM.

2.2.2. Players

Market participants:

- Producers: **generators** and **self-generators.** The latter produce electric energy for their own use and may trade energy surpluses in the wholesale market (the Panama Canal Authority, ACP, belongs to this category), and co-generators (energy is produced as a by-product of an industrial process) can sell energy surpluses in the wholesale market. Generators can sell their energy production in the spot market (merchant) and/or enter into contracts. Currently in the market there are 62 Generators and 5 self-generators.

- **Consumers** are classified into
  - i) **distributors** providing the bundle service to regulated customers, currently, there are 3 distributors (Empresa de Distribución Eléctrica Metro Oeste (EDEMET), Empresa de Distribución Eléctrica Chiriquí (EDECHI) and Empresa de Distribución Eléctrica Noreste (ENSA)); and
  - ii) **large users** with their demand over 100 kW in any given hour (there are 82 large users)[6]; they can purchase their energy needs through bilateral contracts with prices freely agreed upon by the parties and/or purchase the bundled service from a Distributor at regulated tariffs.

    In turn, large users can choose to directly participate in the wholesale market (*gran cliente activo*) or through a supply agreement with a market participant (*gran cliente pasivo*). In the first option, the large user is responsible for paying all system charges and for the connection equipment and maintenance. In the second, the large user passes on such payments and activities to the market participant with whom it enters into the supply contract. The supply contracts Tecnisol entered into belong to the latter category (the Project carries the payment obligation of the system´s charges).
- **Transmission**: The only transport company of the Panamanian Electricity Market is ETESA.
- International Interconnections

2.3. Energy policy

2.3.1. Main characteristics

In 1997, the Government of Panama started a reform process of the power sector, including the privatization of its vertically integrated electricity utility (IRHE). The privatization of IRHE was part of a broader reform program that involved establishing a new regulatory framework, introducing a wholesale electricity market, and adopting a new tariff regulation. IRHE was to be restructured into four generation companies (Bayano, 192 MW; Bahia Las Minas, 292 MW; Fortuna, 300 MW; and Chiriqui, 222 MW); three distribution companies (EDEMET, ENSA, EDECHI); and one transmission company that would remain in state hands (ETESA).

Law No.6/97 set the broad parameters underlying the privatization process and the new regulatory guidelines. The new electricity market in Panama began its operations as such in 1999. Generation, transmission, and distribution activities were unbundled. The generation segment was structured as a competitive market while transmission and distribution activities were considered public services and thus regulated.

Panama also participates in the Regional Electricity Market (MER) for Central America, with a trend towards energy exports. The country members of MER are the six interconnected countries of the isthmus (Panama, Costa Rica, Nicaragua, Honduras, El Salvador and Guatemala). A generator located in Panama can sell its energy production to any other country member of the MER through the regional transmission lines that have a transmission capacity of 300 MW.

Panamanian wholesale market:

[6] Source: http://www.cnd.com.pa/participantes.php

Commercially speaking, the wholesale electricity market (WEM) consists of two markets, a relatively small one accounting for opportunity exchanges (spot market) and another for long term contracts.

Distribution Companies must contract in advance 100% of their expected peak capacity (and regulatory reserve) and energy needs, one year in advance, to guarantee the supply of their regulated customers. This percentage of obligation is reduced for following years (Res. AN 991 and amendments). Contract prices are passed through to end user tariffs. Distribution companies can self-generate up to 15% of their demand.

Two products are traded in the wholesale market: energy (hourly) and capacity (daily and yearly through the long-term reserve service). A generator receives the hourly spot price (short run marginal cost of the system) for the amount of energy produced during such hour. If it is not dispatched, it does not receive energy payments. In addition, if a generator participates in the long-term reserve service (where the product traded is capacity), it receives a capacity payment whether or not it is being dispatched.

Large users (over 100 kW) can either purchase their energy needs in the wholesale market (through bilateral contracts and/or on a spot basis) or they can be supplied by the Distributor at a regulated tariff (Res. 5864/06 and Res. 961/2007). Those large users who decide to purchase their energy needs in the spot market must also purchase firm capacity in the long-term reserve service, to secure their supply. In other words, if there is a portion of the large user´s demand that is not contracted, such portion has to be considered in the demand to be secured by the long term reserve service, annually auctioned by the system operator for the year ahead (LTRS).

The long-term reserve service is similar to a one-year firm capacity contract awarded through a public auction. The system operator aggregates all demands not yet contracted for the year ahead (both of distributors and large users) and carries out a public auction for the generators to offer their firm capacity (not yet committed in contracts). There is a cap price for the capacity offered which is the regulated capacity price, currently at 8.96 USD/kW-month[7].

At present, Resolution AN No. 961-ELEC of June 2007 establishes the criteria and procedures to sell energy and capacity to large customers. Some of the most relevant aspects of this Resolution are stated below:

- The Large Customer opting for buying directly in the WEM will need a supply contract with a participating producer at the time of doing so to guarantee that its energy demand is met.
- Said supply contract will contain, at least:

  a) the prices of energy, capacity, and other services, if any, (charges for slow payment, compensations, fines, discounts, etc.);

  b) the party responsible for paying forced generation overruns;

  c) the duration of the contract;

  d) how to adjust prices while the contract is effective; e) the party responsible for financing, installing, and measuring the meters (if applicable).

2.3.2. Public auctions

Public auctions (does not apply to contracts between private parties): Law No. 57/2009 modified

[7] See Resolution AN No. 3037-Elec (price indicated in Balboas, 1 Balboa=1 USD).

several articles of Electricity Law No. 6/97 to ensure competitive bids in public auctions, secure electric supply to regulated customers, and attract new investment in generation. It is mandatory for generators to bid their firm capacity not yet committed in previous public auctions. Although generators cannot enter into firm contracts for more than their firm capacity, they can have a combination of firm capacity contracts up to their firm capacity, and only energy contracts for the period of the year when production is higher, so as to cover energy surpluses.

ETESA, the transmission company, acts as a single buyer and coordinates the public tenders on behalf of the distribution companies, following the criteria established by ASEP for such auctions. The off takers are the distributors, each one in a given proportion that is established in the public tender documents.

The contract prices that result from public tenders are fully passed-through to end user tariffs. Bilateral contracts agreed upon by private parties are passed-through to end user tariffs at a price equal to the average price of contracts awarded through public auctions and the distributor´s energy purchases in the spot market. Such spot purchases must be approved by the regulator.

The seller can terminate the contract if the buyer goes bankrupt and/or fails to honor its monthly payments without a valid cause. In addition, the off taker has to keep a guarantee of payment for the amount indicated in the contract, which is usually one month, during the term of the supply contract. This guarantee may be established in cash or in bonds of insurance companies, through bank guarantees or cash from the first month of supply, for annual periods and will remain in force after the end of the contract (usually for 60 days).

The following Exhibit summarizes key features of the short and long-term supply contracts awarded through public tenders carried out by ETESA, on behalf of the distribution companies, since 2010.

Exhibit 20: PA - Recent public auctions carried out by ETESA (long-term supply contracts)

Public auction	Type of contract	Price range (USD/MWh)	Technology	Comments
ETESA 02-10 (Apr-2011)	150 MW firm capacity and associated energy, 15-year contract (2015-2029)	100.2 –120.2	Hydro and thermal, existing units and new projects	12 awardees (all hydro) out of 34 bidders. Regulator did not accept bids greater than 121 USD/MWh. Only 83 MW out of 150 MW were awarded due to said price limit. Maximum price bid was 151.37 USD/MWh for hydro plants.
ETESA 03-10 (Oct-2011)	Energy only (approx. 40 MW) 10-year contract (2014 - 2024)	99.9 – 109.9	Hydro projects	Regulator did not accept bids greater than 110 USD/MWh.
ETESA 05-11 (Nov-2011)	Energy only, 15-year contract (2014 - 2028)	95.0 – 110.0	Wind farms only	158 MW awarded to Grupo Unión Eólica Panameña, Helium Energy Panama and Innovent. In operation.
ETESA 01-12 (Aug-	270 MW (2016 - 2018)	113.9 – 124.5	Hydro	42 bids, 5 awardees, all hydro (the most important one in terms of MW offered is AES, with its 214

Public auction	Type of contract	Price range (USD/MWh)	Technology	Comments
2012)	350 MW (2019 - 2030)			MW project Changuinola I).
ETESA 06-12 (Dec-2012)	Coal-fired plant 150 MW (2017 - 2031)	141.59	New coal-fired thermal plants	1 bid (Termo Energía). This Project is paused due to permitting disputes awaiting resolution in the Panama courts.
ETESA 01-13 (Feb-2013)	Gas-fired combined cycle (LNG). 400 MW initially up to 550 MW in year 5, (2017- 2036)	137.87	New gas-fired thermal plants The project envisioned a 670 MW CCGT power plant dubbed Telfers in Colón province. The commissioning date was scheduled for March 2017.	1 bid (Panama NG Power). This project was cancelled by ASEP (Regulatory Authority) in late 2014. Since April 2011 and after several extensions requested, the ASEP granted Panama NG Power the definitive license in May 2014. The requirement of the financial closure should have been presented before the end of October 2014, but the company asked the ASEP, for an extension for its submission (NG Power argued the need for more time because of delays by ETESA, in the construction contract for a transmission line). In November 2014, the ASEP cancelled the license after the company missed the deadline. Finally, in November 2015, the Supreme Court reinstated the company's license.
ETESA 03-13 (Oct-2013)	Energy only, 15-year contract, starting Jan-2019	93.7 – 97.5	Wind farms only	5 bids, 4 awardees.
ETESA 01-14	150 MW of firm capacity, 20 years as of year 2021	140.93	Only for new hydro power projects with a regulating capacity of at least 90 days	1 bid, 1 awardee. Firm capacity offered: 120 MW as of 2020 (Changuinola II)[8]. The capacity price for this project is 32.06 USD/kW-month.
ETESA 02-14	Firm capacity	Thermal generation located in electrical zones 6, 7 & 9.		This tender was cancelled
ETESA 03-14	Approx. 15 MW; Jan-2017 / Dec-2036		Solar only	29 bids, 5 awardees. Maximum price bid was 190 USD / MWh.

[8] This project from the State and Odebrecht was cancelled due to the scandals of corruption, which implicate the Brazilian company. It is now in hands of EGESA with an expected start of operation in 2025. EGESA is currently looking for a private company to replace Odebrecht. The uncertainty is high with respect to the project.

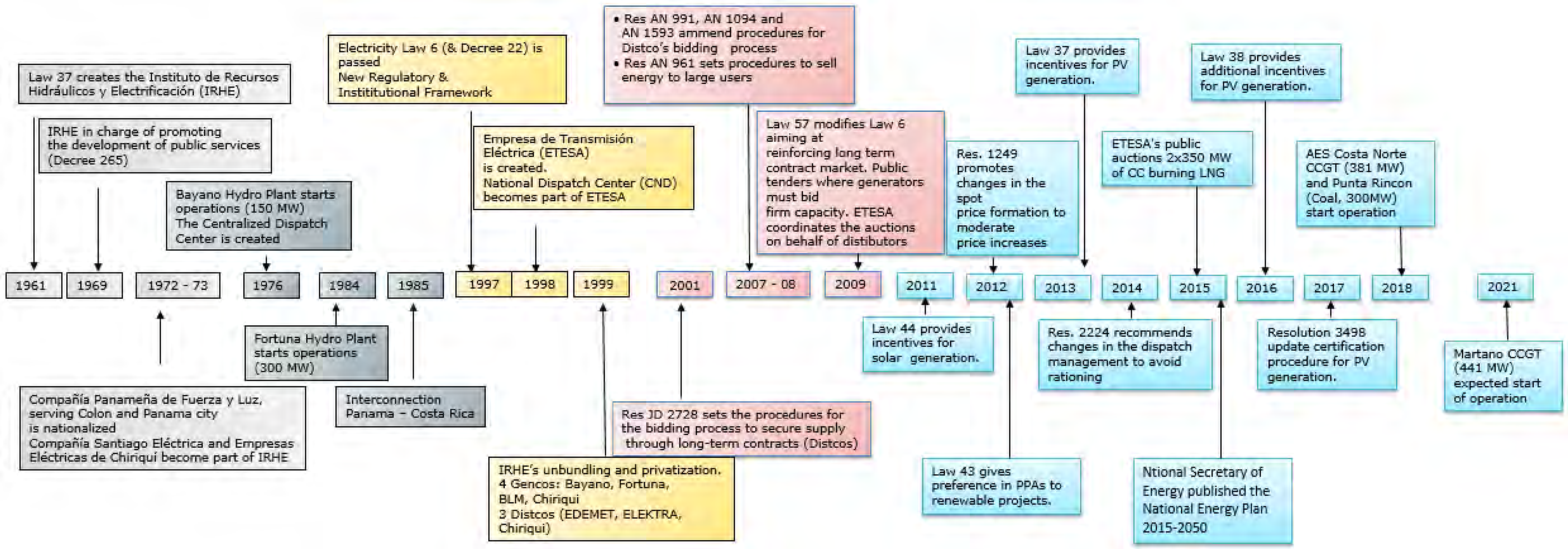
Public auction	Type of contract	Price range (USD/MWh)	Technology	Comments
ETESA 04-14	Short-term tender: 200 MW of firm capacity Jun-2015 / Jun-2020	Average 236.65 USD/MWh (short term price)	Thermal generation (gas turbines and combustion engines)	15 bids, 3 awardees for Summer 2015 (six months) and 4 awardees (2016-2020): 70 % running on bunker and 30 % on diesel. Capacity prices awarded between 14 and 46 USD/kW-month. Energy prices between 148 USD/MWh and 191 USD/MWh. The 4 companies signed contracts. ERRYL transferred the PPA to Estrella de Mar (AES Panamá).
ETESA 01-15	350MW firm capacity and associated energy, 10 year-contract (2017-2027)	Up to 293.17 USD/MWh	Thermal generation	27 bids, 1 awardee that covers 100% of the requirement (Gas Natural Atlántico, subsidy of AES). The firm capacity of the project is 350MW, the offered energy 13,699 GWh and the monomial price near 113 USD/MWh. This CCGT began operation in Sep 2018.
ETESA 02-15	350MW firm capacity and associated energy, 14 year-contract as of 2019 ending 2033	Up to 156.71 USD/MWh for most of the bids (except one which offered 54940 USD/MWh)	Thermal generation	14 bids, 1 awardee which covers 100% of the requirement (Martano Inc.). The firm capacity of the project is 350MW, the offered energy 16,383 GWh and the monomical price 84.95 USD/MWh.
ETESA 03-15	Energy only, firm capacity or both energy and firm capacity, short-term contract (2017-2019)	For both energy and capacity: 93.63-100.96 USD/MWh	All type of generation (thermal, hydro, wind generation)	39 bids received. Awarded to a combination of existing generators (Enel Fortuna, Alternegy, ACP, etc.).
ETESA 02-16	Energy and firm capacity, short-term contract (2017-2020)	81.31 - 96.49 USD/MWh	All type of generation	17 bids received. Awarded to a combination of existing generators (Enel Fortuna, Hidroecologica del Teribe, Urbalia Panama, Enel Green Power Panama).
ETESA 01-17	Energy and firm capacity for isolated systems, long-term contracts (2018/2020-2030)	237.39 USD/MWh	All type of generation	2 bids received. Awarded to Pearl Island Power SA.
ETESA 02-17	Energy and/or firm capacity, short-term contract (2017-2020)	66.4 USD/MWh for energy, 5.40 – 7.19 USD/kW-month for capacity	All type of generation	31 bids received. Capacity awarded to Enel Fortuna, Hidroibérica, Pedregal Power Company and Fountain Intertrade. Energy Awarded to Generadora del Istmo SA.

Public auction	Type of contract	Price range (USD/MWh)	Technology	Comments
ETESA 01-19	Energy and firm capacity, short-term contract (2020-2022)		All type of generation	Cancelled
ETESA 02-19	Energy and/or firm capacity, short-term contract (04/2020-12/2022)		All type of generation	34 bids received, 22 bids awarded of energy and/or capacity.

Except for those auctions that have been cancelled by the regulatory authority ASEP (large thermal coal-fired), the general experience is that most of the projects that are awarded a long-term contract reach completion (the existence of the contract facilitates the financing process, among others).

The following chart presents the timeline of the main regulatory and market events.

Exhibit 21: PA - Timeline of regulatory and market events



Source: prepared by the Consultant

2.3.3. Renewable energy and climate change policy initiatives

According to the National Energy Plan 2015-2050, Panama aims to make 70% of its energy produced by alternative renewable sources. Among the objectives is that the production of 15% to 30% of Panama's electricity derives from renewable and non-hydraulic energy, by 2030 and 2050, respectively.

Energy policy guidelines seek to promote renewable-based projects to reduce dependence on costly fossil fuels. In particular, some laws or decrees have set up incentives for the development of renewable sources:

Executive Decree No. 45 of June 10, 2009: "Regime of Incentives for the Promotion of Hydroelectric Generation Systems and other New, Renewable and Clean Sources, contemplated in Law No. 45 of August 4, 2004."

This Decree defines different incentives per category of power plants (up to 500 kW, up to 10 MW, from 10 to 20 MW, more than 20 MW).

- Up to 500 KW and not connected to the distribution network: They do not pay tax of import for the equipment and spare parts required for the construction and operation of the plants.
- Up to 10 MW: They do not pay transmission or distribution fee. They do not pay import tax for the equipment and spare parts required for the construction and operation of the plants. They are entitled to tax incentives. They can contract directly with any distribution company regardless of where the plant is located. They can sell energy in the occasional market. They can sell their firm power to the distributor, to another generator or distributor. They can offer their energy in the Central American market.
- 10 to 20 MW: They have the same benefits as renewable and clean energy plants of up to 10 MW with the following exceptions. They do not pay a transmission fee for the first 10 MW during the first 10 years of commercial operation. They cannot contract directly with the distributor; they have less tax incentives.
- More than 20 MW and up to any power: They have the same benefits as renewable and clean energy plants up to 20 MW but pay normal transmission rate.

Additionally to this Decree, the adoption of laws for specific technologies was deemed convenient; they are described below.

Law 18 of March 26, 2013: "That modifies and adds articles to Law 44 of 2011, relating to **wind** power plants."

Description: It establishes a legal framework that encourages the development of wind generation activities. Some of the benefits are:

- Allows public tenders for the purchase of energy and / or capacity, exclusive for wind power plants, with contracts for up to fifteen years;

- Exemption from the import tax, tariffs, fees, contributions and levies, as well as the Personal Property Transfer Tax and Provision of Services (ITBMS);

- Granting of a tax credit applicable to the Income Tax;

- Allows the use of the accelerated depreciation method of the equipment for wind generation.

Law 37 of June 10, 2013: "That establishes the incentive regime for the promotion of the construction, operation and maintenance of **solar** power plants".

It allows public tenders for the purchase of energy and / or capacity, exclusive for solar technologies, with contracts for up to twenty years.

Law No. 38/2016, for its part, encourages the importation of solar panels and photovoltaic screens, at cost, without taxes, without tariffs or tariff rates, so that people could produce their own electricity.

Additionally, **Law 42 of April 20, 2011** establishes the general guidelines of the national policy for the promotion and development of the production and use of biofuels and the generation and / or cogeneration of electrical energy from **biomass** in the national territory. It offers tax exemptions, payment of license exemptions, distribution and transmission charges exemptions.

It is completed by Law No. 47/2015, which establishes guidelines for the national policy on biofuels and electricity from biomass in the national territory.

Effects for Tecnisol & UEP II: both Tecnisol and UEP II apply to the tax benefits listed in Law 45 of August, 2004, regulated through Executive Decree No. 45 of June, 2009. Tax benefits (Article 10 of the Law) are applied in accordance with the provisions of Article 6 of the Executive Decree.

Regarding the benefit of exemption from transmission and distribution charges mentioned in Articles 8 and 9 of the Law, these apply only to Tecnisol and Marañón (wind farm of UEPII). This is so because Tecnisol is considered as four projects of 10 MW, each one with individually generation license. Marañón wind farm has its own generation license too and therefore applies to the incentive regulated in Article 9 of the Law.

2.3.4. Market Barriers for a new conventional Power Plant

Panama is one of the most attractive countries of the region in terms of private investments. Additionally, to the recent incorporation of wind and solar capacity, a new efficient thermal power plant (CCGT running on regasified LNG) was introduced in 2018 and one more is expected to coming online in the coming years, and will confirm the exporting tendency of the country. Exchanges occur according to the price difference between marginal costs of the different countries of the region. We expect that Panama will remain competitive compared to the other Central American countries.

Considering a new conventional power plant, the main obstacles to tackle are:

i) **Financing access**: This barrier is closely linked to the country risk and to the access that the project sponsor has to financing sources.
ii) **Over installation**: As mentioned in the paragraph above, the recent capacity expansions based on NCRE and CCGT base on LNG move the off-balance between supply and demand towards an over installation in the following years.
iii) **Competitiveness against renewable sources**: The technology improvements and cost reduction (specially for solar pv and wind) during the last few years makes projects more competitive given the local resources in the country. The installation of these technologies will reduce spot market prices especially during the daylight hours affecting the dispatch factor of conventional technologies.

2.4. Generation segment: wholesale market organization

The Wholesale Market in Panama started its operations in 1999. It operates mainly as a contract market because Distribution Companies must comply with Res. AN 991/ 2007 and its amendments (they have to contract in advance a given percentage of their total demand for the years ahead).

Large users (over 100 kW) can either purchase their energy needs in the wholesale market (through bilateral contracts and/or on a spot basis) or they can be supplied by the Distributor at a regulated tariff (Res. 961/2007). Those large customers who choose to purchase their energy needs in the spot market must also pay for the system's long-term reserve service.

The Wholesale Electricity Market is administered by the National Dispatch Center (CND), in charge of operating and dispatching generation plants at the lowest possible cost, determining spot prices and settlement procedures between agents.

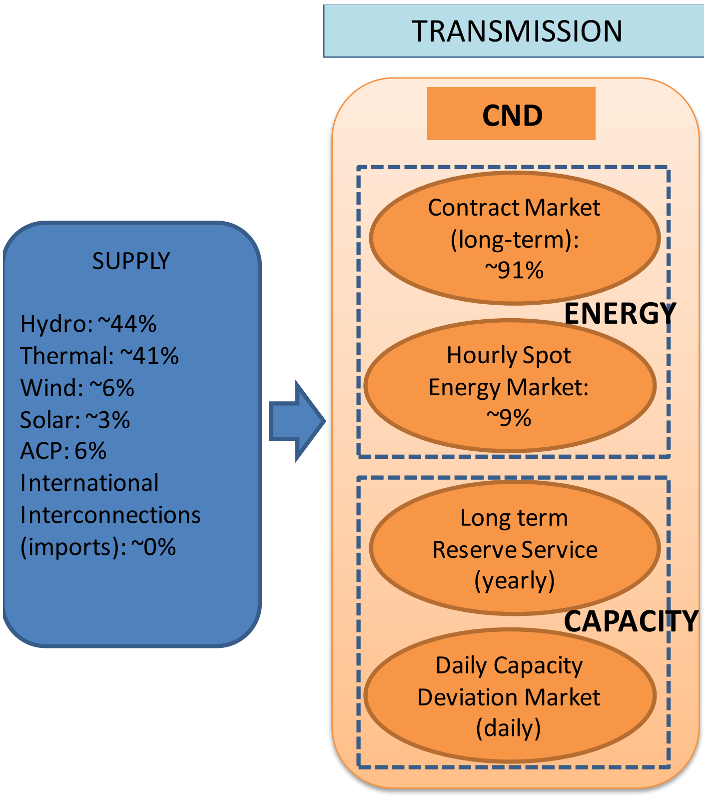
2.4.1. Market structure and products

The Panamanian wholesale electricity market comprises the following markets and products:

- **Contract market (90.5 % of total energy supplied):** this is a long-term market, where Distribution companies (and large users) seek to guarantee supply to their regulated clients. The contract market stabilizes prices and promotes investment in new capacity, which, in turn, guarantees long-term supply. Contracts usually have a constant capacity payment for committed firm capacity and a variable energy payment based on the energy actually delivered. In general, revenues for the power plants are largely based on the payment received from long-term contracts.
- **Long Term Reserve Service (LTRS, *Servicio Auxiliar de Reserva de Largo Plazo*):** once a year, usually on January / February of each year, the system operator (CND) computes the portion of the projected demand not yet committed under long term contracts and conducts a tender among generators to bid in the so-called Long-Term Reserve Service (LTRS). The purpose of this service is to guarantee the supply to all customers not yet covered under long-term contracts. Any generator can participate in said tender by bidding a price for its not committed firm capacity. The system operator ranks the bids in ascending price order until they meet the system's long-term reserve capacity requirement. The highest-priced accepted bid defines the price of firm capacity in the LTRS. All the generators whose bid has been accepted are recognized this price. The price bid has a cap defined by regulation (same cap as for the daily capacity deviation market, currently 8.96 USD/kW-month).
- **Hourly energy spot market (9.5 % of total energy supplied):** opportunity market, intended to compensate deviations between hourly energy contracted and actual hourly consumption. Whenever a generator sells its production in the spot market, it receives the hourly spot price (short run marginal cost of the system) for the amount of energy produced.
- **Daily capacity compensation market:** it compensates short-term (daily) deviations between committed firm capacity and actual capacity. Pursuant to present commercial rules, each market agent with a capacity surplus can bid a price at which it is willing to sell said capacity surplus. It is a market for opportunity exchanges and it is not intended to represent a significant source of income for a generator in the steady state. The bidding price cannot exceed the maximum price set by the CND for each day, estimated as the maximum capacity price of long-term supply contracts that are passed-through to end user tariffs. In addition, the Regulatory Authority can enforce the regulated price cap (8.96

USD/kW-month). [9]

Exhibit 22: PA - Market Structure, 2019



Source: prepared by the Consultant based on regulatory and market information

a) Long Term Contracts

The merit order dispatch of the power units is not influenced by contractual commitments, which are financial. In each hour, if the generator produces more energy than the amount committed under contracts (long position), it can sell the energy surpluses in the spot market. If the generator delivers less energy to the grid than the amount committed (short position), it can purchase the energy shortages in the spot market.

Commercial rules allow for three types of financial supply contracts:

- **Capacity and Energy contract:** Seller commits a certain amount of firm capacity and associated energy (in general, it follows the demand load curve). The Buyer has priority of supply if the seller can honor its commitment with its own generation. In a rationing situation, the CND will consider this contract as a physical contract and will deliver the energy produced by the Seller to the Buyer.
- **Capacity contract:** The product traded is firm capacity. The Seller commits a maximum amount of firm capacity to be available when the Buyer needs it to comply with regulatory obligations. In exchange, the Buyer will pay for the contracted capacity, whether it generates or not.
- **Energy contract:** The Seller commits itself to deliver a certain amount of energy to the

[9] In 2019, the average price in the daily compensation market was 0.3 USD/kW-month, evidencing a supply surplus in the market.

Buyer.

b) Reserve contracts

The chapter 4.5 of the Commercial Rules set the main rules for the Reserve Contracts. The reserve contracts are private contracts between generators in which they trade energy and capacity.

A generator can buy power and/or energy from another generator through Reserve Contracts to sell on the market and/or to back the reserve obligations under the supply contracts in which are the seller.

A generator may sell surplus power and/or energy to another generator through Reserve Contracts. Surplus power and/or energy is the not (n) committed capacity from the generator (in contracts or the LTRS).

A generator may sell contracts to other participants to its “Potencia Máxima para compromisos de Productores (Maximum capacity for Producers Commitments)” that it is calculated as the sum of the actual output of the generator, minus the power sold by supply contracts to other consumers.

When making a contract, a generator must keep in mind that can only sell firm power that is not yet committed in another contract and that is installed for the duration of the contract.

c) Hourly energy spot market

The National Dispatch Center (*Centro Nacional de Despacho*, CND) centrally operates the interconnected system in real time and runs the economic dispatch, minimizing the system’s variable cost of production in each hour. CND is part of the transmission company, ETESA.

The CND is responsible for short to medium term operation and its optimization, aiming at fulfilling the expected demand at minimum cost. CND computes a water value for each reservoir so that energy resources are optimally allocated (the economic dispatch generally uses the water of reservoirs during peak hours when the supply cost is higher).

Regulations related to the declaration of variable costs: the variable cost for dispatch purposes is set by: the variable operation cost of the thermal and self-generation units, the “water value” for dam hydroelectric power plants, the assigned price for imports and zero variable cost for cogeneration, wind and solar plants, as well as run of river hydro plants. The variable cost declared by the thermal generators for the merit order dispatch includes the fuel variable cost and O&M variable costs.

Generators declare costs (excluding transmission costs), and not prices, to compete for dispatch. The variable costs of production of thermal plants are auditable.

d) Capacity market

In the Panamanian market, Distributors are obliged to contract their DMG (“Demanda Máxima de Generación” or maximum generation demand) in advance. The commercial rules establish three ways in which capacity requirements and capacity offers are balanced.

- **Capacity Contracts:** supply and reserve contracts
- **Long Term Reserve Service (LTRS or SARLP** (“Servicio Auxiliar de Reserva de Largo Plazo”)**:** It’s an annual tender designed for the distributors to contract their capacity requirements for the next year (not already covered by the actual contracts). The cap price is set by the regulated capacity price (near 9 USD/kW-month).

- **Daily capacity market:** a daily market in which the participants settle the capacity positions. In this market, the consumers and generators trade capacity in the hour of maximum generation of the day. Consumer buy the demand not cover by the contracts or the LTRS. Generators purchase the contracted capacity that has not backed with contract or the generators availability. In the last years, prices were 0.5 USD/kW*month in average.

In the first two markets (contracts and LTRS), generators can offer capacity until they reach their long term firm capacity. The long-term firm capacity is defined as the capacity that the generator is capable to warranty in a maximum requirement condition. For example, in the case of hydroelectric power plants it is calculated for a P95 condition of energy output (dry hydrology).

In the third market (daily capacity compensations), generators can offer capacity until they reach their Maximum Commercial Capacity, defined as the maximum capacity that the generator can provide for a maximum period of 15 minutes considering the operative restrictions of the unit (own restrictions, fuel constraints in case of thermal plants and transmission restrictions). In the case of a hydroelectric unit, depending on the hydroelectric conditions, the available capacity for the daily compensation market may be higher than the long-term firm reserve. Only in a very dry condition, the long-term firm capacity will equal the commercial capacity.

It is worth mentioning that there is not yet a methodology defined to compute firm capacity for wind and solar pv technologies, although this matter is being analyzed by the system operator CND. Therefore, firm capacity for wind and solar pv is zero.

With respect to regulated capacity price, it is calculated by the regulator. Since 2010, it is set as 8.96 USD/kW-month.

2.5. Payments among market participants

The system operator (CND) commercially administers the hourly energy spot market, the daily capacity market and the ancillary services (including the long-term reserve service and other ancillary services). Commercial transactions are computed monthly. The economic transactions are between debtors and creditors, where debtors owe all creditors.

With respect to bilateral contracts between private parties, CND does not commercially administer such contracts. It only provides physical information (energy and capacity amounts) to the parties involved to compute the commercial transaction.

Relative to transmission charges, CND provides all market participants with the physical information necessary to compute transmission charges to be paid to the transmission company.

CHAPTER 2: PROSPECTIVE REPORT, REFERENCE SCENARIO

This Chapter of document presents, in its Section I, the main assumptions agreed upon to run the dispatch model (SDDP) for the Reference Scenario. The most important variables are:

- Fuel prices expectations and availability,
- Expected demand,
- Generation expansion plan – short-/midterm,
- Costs of the new entrants in the long term
- SIEPAC and Regional Electricity Market (MER)
- Participation of non-conventional renewables in the energy matrix

In Section II, the results of the SDDP model, in terms of energy prices and capacity and generation balance are presented.

This document reflects EEC's professional judgment based on accepted standards of professional investigation and, as applicable, the data and information available in the public domain. In line with those accepted standards, this document does not, in any way, constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein.

The opinions expressed herein are subject to the generally accepted uncertainties associated with the interpretation of engineering and commercial data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing circumstances.

All the monetary values mentioned in this document are expressed in real US dollars of 2020, i.e. they have not been inflation-adjusted.

SECTION I: MAIN ASSUMPTIONS FOR THE PROSPECTIVE ANALYSIS

1. REFERENCE SCENARIO ASSUMPTIONS

1.1. Summary for the Reference Scenario

The purpose of this Section is to provide the Client with a compendium of the assumptions that have been used in the simulation of the Reference scenario for the Central American markets. The following table summarizes the proposed set of assumptions for the Reference scenario.

Exhibit 23: PA - Summary for the Reference Scenario

<table>
<tr><th></th><th>Guatemala</th><th>El Salvador</th><th>Honduras</th><th>Nicaragua</th><th>Costa Rica</th><th>Panama</th></tr>
<tr><td>Regional Market</td><td colspan="6">• SIEPAC period 2020-2032: 300 MW of interconnection capacity amongst countries. Until 2028, the simulation model includes restrictions in some of the interconnection lines in order to reflect current limitation in the exchanges.
• SIEPAC period 2033-onwards: 600 MW of interconnection capacity amongst countries.
• Interconnection Guatemala – Mexico modeled.
• Interconnection project Panama – Colombia: not considered.</td></tr>
<tr><td rowspan="2">Demand</td><td colspan="6">Projection based on historical correlation between GDP and country's demand.
Demand growth rate 2020-2035:</td></tr>
<tr><td>3.0%</td><td>1.7%</td><td>2.8%</td><td>2.3%</td><td>1.7%</td><td>3.3%</td></tr>
<tr><td>Expansion Plan mid-term</td><td>88 MW</td><td>701 MW</td><td>537 MW</td><td>108 MW</td><td>79 MW</td><td>787 MW</td></tr>
<tr><td>Fuels</td><td colspan="6">EIA commodity price forecast – January and May 2020</td></tr>
<tr><td>LCOE CCGT, US$/MWh</td><td>94.7</td><td>95.4</td><td>94.2</td><td>95.6</td><td>94.0</td><td>91.8</td></tr>
<tr><td>Energy Price, US$/MWh</td><td>85.0</td><td>86.9</td><td>84.4</td><td>88.5</td><td>84.2</td><td>82.1</td></tr>
</table>

1.2. Electricity Demand

1.2.1. Summary of Demand Assumptions

The following table summarizes the historical and projected demand according to the assumptions made to forecast the electricity demand of each country:

Exhibit 24: Summary of demand projection (Central America)

Year	Costa Rica		El Salvador		Guatemala		Honduras		Nicaragua		Panama	
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	%	GWh	%
2000	6,431		4,073		5,229		3,929		2,211		4,659	
2001	6,697	4.1%	3,956	-2.9%	5,456	4.3%	4,183	6.5%	2,310	4.5%	4,705	1.0%
2002	7,073	5.6%	4,249	7.4%	5,799	6.3%	4,492	7.4%	2,416	4.6%	4,951	5.2%
2003	7,494	5.9%	4,403	3.6%	6,159	6.2%	4,851	8.0%	2,516	4.1%	5,074	2.5%
2004	7,833	4.5%	4,538	3.1%	6,586	6.9%	5,223	7.7%	2,641	5.0%	5,297	4.4%
2005	8,221	5.0%	4,765	5.0%	6,908	4.9%	5,554	6.3%	2,758	4.4%	5,434	2.6%
2006	8,740	6.3%	5,197	9.1%	7,357	6.5%	5,948	7.1%	2,908	5.5%	5,614	3.3%
2007	9,160	4.8%	5,353	3.0%	7,805	6.1%	6,274	5.5%	3,082	6.0%	5,953	6.0%
2008	9,343	2.0%	5,566	4.0%	7,846	0.5%	6,536	4.2%	3,035	-1.5%	6,175	3.7%
2009	9,250	-1.0%	5,575	0.2%	7,921	1.0%	6,561	0.4%	2,984	-1.7%	6,511	5.4%
2010	9,528	3.0%	5,736	2.9%	8,137	2.7%	6,752	2.9%	3,268	9.5%	7,045	8.2%
2011	9,790	2.7%	5,842	1.9%	8,479	4.2%	7,169	6.2%	3,417	4.6%	7,481	6.2%
2012	10,093	3.1%	5,920	1.3%	8,734	3.0%	7,566	5.5%	3,666	7.3%	8,167	9.2%
2013	10,183	0.9%	6,095	3.0%	8,949	2.5%	7,941	5.0%	3,766	2.7%	8,512	4.2%
2014	10,323	1.4%	6,174	1.3%	9,284	3.7%	8,067	1.6%	3,953	5.0%	8,923	4.8%
2015	10,607	2.8%	6,425	4.1%	9,799	5.6%	8,609	6.7%	4,160	5.2%	9,711	8.8%
2016	10,932	3.1%	6,470	0.7%	10,290	5.0%	8,757	1.7%	4,297	3.3%	9,995	2.9%
2017	11,019	0.8%	6,464	-0.1%	10,524	2.3%	8,949	2.2%	4,379	1.9%	10,280	2.9%
2018	11,115	0.9%	6,538	1.1%	10,848	3.1%	9,485	6.0%	4,388	0.2%	10,457	1.7%
2019	11,334	2.0%	6,484	-0.8%	11,179	3.1%	10,543	11.2%	4,450	1.4%	10,726	2.6%
2020	11,121	-1.9%	6,250	-3.6%	10,965	-1.9%	10,144	-3.8%	4,316	-3.0%	10,539	-1.7%
2021	11,307	1.7%	6,495	3.9%	11,548	5.3%	10,538	3.9%	4,316	0.0%	10,897	3.4%
2022	11,496	1.7%	6,621	1.9%	11,952	3.5%	10,915	3.6%	4,335	0.4%	10,964	0.6%
2023	11,703	1.8%	6,749	1.9%	12,362	3.4%	11,319	3.7%	4,378	1.0%	11,470	4.6%
2024	11,933	2.0%	6,879	1.9%	12,779	3.4%	11,746	3.8%	4,442	1.5%	11,978	4.4%
2025	12,168	2.0%	7,012	1.9%	13,172	3.1%	12,107	3.1%	4,553	2.5%	12,490	4.3%
2026	12,408	2.0%	7,148	1.9%	13,577	3.1%	12,480	3.1%	4,708	3.4%	13,012	4.2%
2027	12,652	2.0%	7,286	1.9%	13,994	3.1%	12,864	3.1%	4,868	3.4%	13,530	4.0%
2028	12,901	2.0%	7,427	1.9%	14,424	3.1%	13,259	3.1%	5,034	3.4%	14,068	4.0%
2029	13,155	2.0%	7,571	1.9%	14,868	3.1%	13,667	3.1%	5,205	3.4%	14,627	4.0%
2030	13,414	2.0%	7,718	1.9%	15,325	3.1%	14,088	3.1%	5,382	3.4%	15,209	4.0%
2031	13,678	2.0%	7,867	1.9%	15,796	3.1%	14,521	3.1%	5,565	3.4%	15,761	3.6%
2032	13,947	2.0%	8,019	1.9%	16,281	3.1%	14,968	3.1%	5,755	3.4%	16,338	3.7%
2033	14,222	2.0%	8,175	1.9%	16,782	3.1%	15,428	3.1%	5,950	3.4%	16,926	3.6%
2034	14,502	2.0%	8,333	1.9%	17,297	3.1%	15,903	3.1%	6,153	3.4%	17,529	3.6%
2035	14,788	2.0%	8,494	1.9%	17,829	3.1%	16,392	3.1%	6,362	3.4%	18,112	3.3%
2036	15,080	2.0%	8,658	1.9%	18,377	3.1%	16,896	3.1%	6,578	3.4%	18,728	3.4%
2037	15,377	2.0%	8,825	1.9%	18,943	3.1%	17,416	3.1%	6,802	3.4%	19,365	3.4%
2038	15,680	2.0%	8,996	1.9%	19,525	3.1%	17,951	3.1%	7,033	3.4%	20,023	3.4%

The following subsection presents the methodology and model´s parameters to forecast the electricity demand in Panama.

1.2.2. Methodology for Demand Projection

Given the high correlation between the GDP growth rate and the growth in energy demand shown by the historical data of the six countries of Central America, GDP is assumed to be the best variable to explain demand growth. The demand elasticity to GDP growth is estimated with a regression model based on the historical behavior of the electricity demand and the GDP.

For each year (i) the electricity demand (ETi) is determined from the demand of the previous year (ETi-1) increased by a percentage equal to the product of the demand elasticity (λ) to GDP and the expected GDP growth.

$$ET_i = \left[ET_{i-1} \times (1 + \lambda \times (\frac{GDP_i}{GDP_{i-1}} - 1) \right]$$

In order to project the evolution of GDP, this Consultant adopts the GDP growth forecasts from the International Monetary Fund (IMF, last published in April 2020) for 2020 and 2021 and the previous IMF forecast for 2022, 2023 and 2024 (published in October 2019), as presented in the following table:

Country	Historical Values										Est.	Forecast				
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	*2022*	*2023*	*2024*
Costa Rica	-1.0%	5.0%	4.3%	4.8%	2.3%	3.5%	3.6%	4.2%	3.9%	2.7%	2.1%	-3.3%	3.0%	*3.0%*	*3.2%*	*3.5%*
El Salvador	-2.1%	2.1%	3.8%	2.8%	2.2%	1.7%	2.4%	2.5%	2.3%	2.4%	2.4%	-5.4%	4.5%	*2.2%*	*2.2%*	*2.2%*
Guatemala	0.6%	2.8%	4.4%	3.1%	3.5%	4.4%	4.1%	2.7%	3.0%	3.1%	3.6%	-2.0%	5.5%	*3.6%*	*3.5%*	*3.5%*
Honduras	-2.4%	3.7%	3.8%	4.1%	2.8%	3.1%	3.8%	3.9%	4.8%	3.7%	2.7%	-2.4%	4.1%	*3.7%*	*3.9%*	*3.9%*
Nicaragua	-3.3%	4.4%	6.3%	6.5%	4.9%	4.8%	4.8%	4.6%	4.6%	-4.0%	-3.9%	-6.0%	0.0%	*0.4%*	*1.0%*	*1.5%*
Panama	1.2%	5.8%	11.3%	9.8%	6.9%	5.1%	5.7%	5.0%	5.6%	3.7%	3.0%	-2.1%	4.0%	*5.5%*	*5.5%*	*5.5%*

Source: World Economic Outlook Databases (WEO), IMF, Apr. 2020 and Oct. 2019 (in italic)

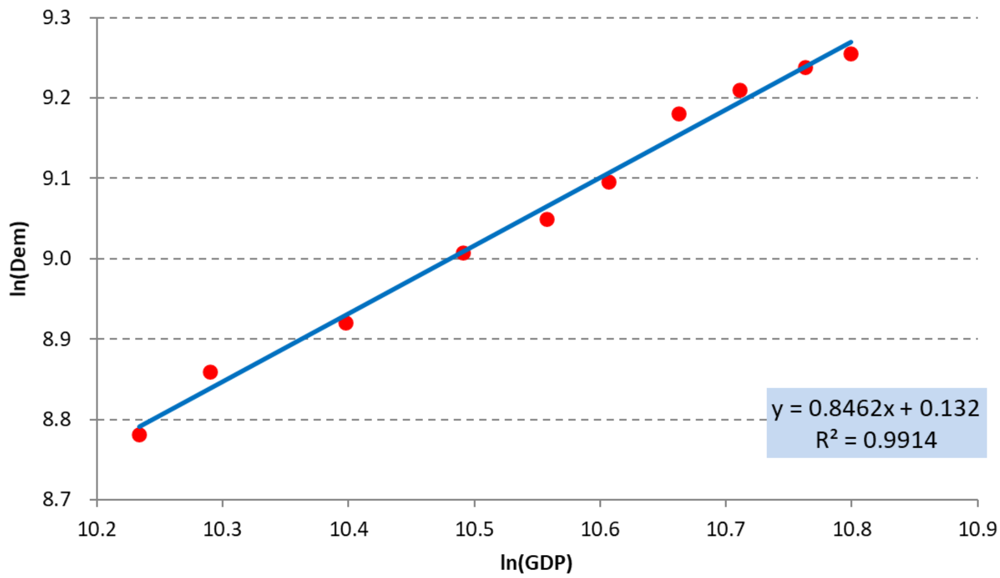
Below is shown, with more details, Panama electricity demand forecasts.

a) Panama

Panama's demand in 2019 was 10,726 GWh, with a gross generation of 11,141 GWh, maximum power of 1,961 MW and an historical load factor up to 70 %. The average growth in demand in the last 10 years was 5.1% per year with a slowdown in the last 4 years (2.5% in average). This slowdown is mainly explained by a lower GDP growth, as well as a lower elasticity in these recent years (less electricity is needed to generate the same economic growth). It is also important to remind that a portion of electricity demand growth in the past was due to the growing electrification. Nowadays, the electrification rate is close to 100% in Panama.

The following figure shows the correlation between historical demand and gross domestic product (GDP), for the years 2009 to 2018. A good correlation is observed between the two variables (R^2 = 0.9914), with an average elasticity (λ) of 0.85.

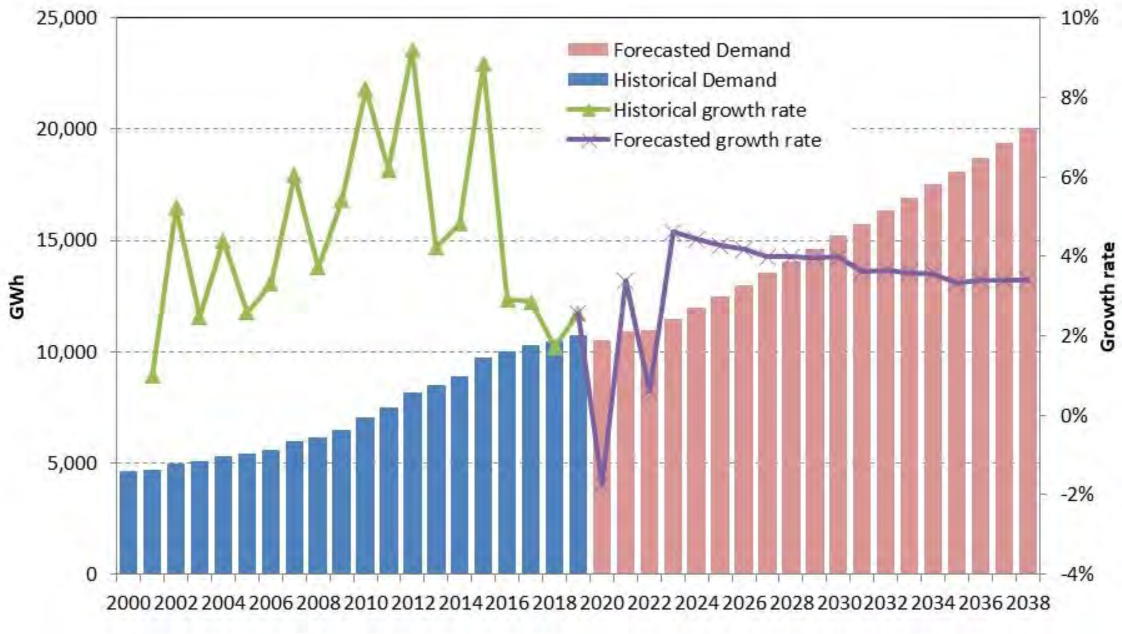
Exhibit 25: PA Correlation between demand and GDP



From 2020 to 2021, this Consultant assumes the GDP growth from the most updated forecast from the IMF (April 2020). From 2022 and after, this Consultant assumes the growth rate of the demand used in the Moderate scenario of ETESA expansion plan 2020-2034). In the long-term (2035 onwards), this Consultant assumes a regular decrease of elasticity (higher demand efficiency).

With the above-mentioned assumptions, the electricity demand grows at around 3.3% per year in the studied period. The following exhibit shows the historical and projected demand based on the assumptions made.

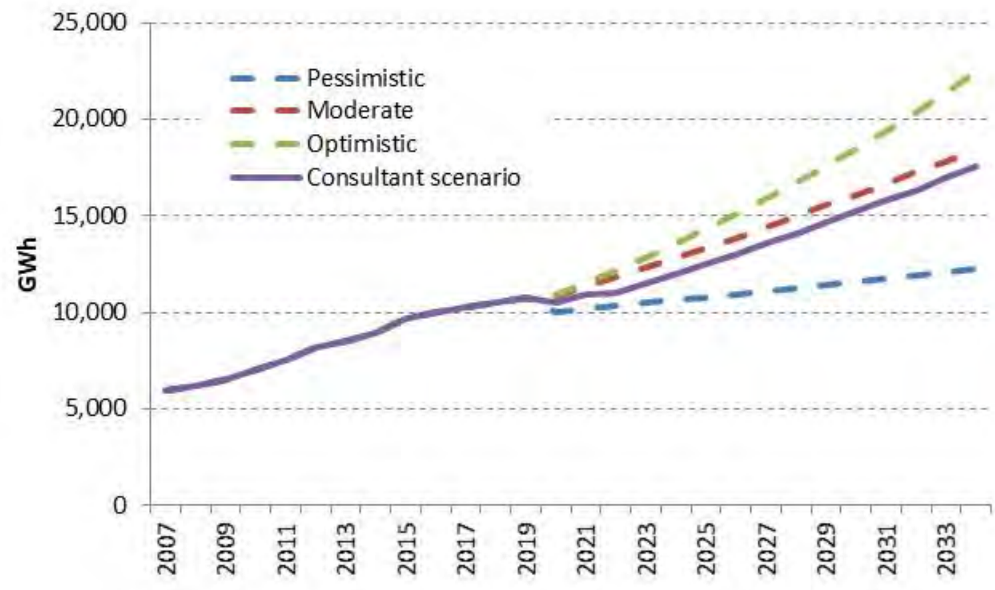
Exhibit 26: PA - Historical and Projected Demand



This projection is in line with the last demand forecast assumed in ETESA Generation Expansion

Plan 2020-2034 ("Plan Indicativo de Generación 2020-2034").

Exhibit 27: PA – Consultant scenario versus ETESA scenarios



NB: ETESA demand forecast was elaborated at the beginning of 2020 and thus does not specifically take into account the COVID-19 impact on the global economy.

1.3. Expansion Plan - Short / Mid Term in Panama

The installed capacity by January 2020 in Panamá is 4,110 MW. The following exhibit shows the current capacity.

Exhibit 28: PA - Installed capacity (January 2020 MW)

Power Plant	Type	Installed Cap. (MW)	Power Plant	Type	Installed Cap. (MW)
Hydroelectric		**1,803**	**Thermal**		**1,630**
C.H. Changuinola	Run of River	212.4	Costa Norte (AES Colón)	LNG - CCGT	381.0
C.H. Mini Chan	Run of River	9.8	Pta. Rincon (Cobre Panama)*	Autoproducer	306.0
C.H. Bayano	Reservoir	260.0	BLM Coal	Coal	166.2
C.H. La Estrella	Run of River	47.2	BLM CC	Cc Diesel	100.0
C.H. Los Valles	Run of River	54.8	PAN AM (+ ampliacion)	Bunker	149.4
C.H. Estí	Run of River	120.0	Pacora	Bunker	55.3
C.H. Lorena	Run of River	37.6	Cativá	Bunker	87.0
C.H. Prudencia	Run of River	62.8	Termocolón	CC Diesel	150.0
C.H. Gualaca	Run of River	25.6	Estrella del Mar I	Bunker	72.0
C.H. Mendre	Run of River	19.8	Barcaza La Esperanza	Bunker	92.4
C.H. Las Cruces I	Run of River	19.5	Jinro Power	Bunker	57.8
C.H. Las Cruces II	Run of River	1.0	Biogas-TG	Biogas	8.2
C.H. Mendre II	Run of River	8.1	Tropitérmica	Bunker	5.1
C.H. Monte Lirio	Run of River	53.8			
C.H. Bugaba I	Run of River	5.1	**ACP**		**223**
C.H. Bugaba II	Run of River	6.3	ACP	Thermal/Hydro	223.0
C.H. Fortuna	Reservoir	300.0			
C.H. Algarrobo	Run of River	9.9	**Wind**		**270**
C.H. Dolega	Run of River	3.1	Nueva Chagres Fase I Wind	Wind	55.0
C.H. Yeguada	Run of River	8.20	Nueva Chagres Fase II Wind	Wind	62.5
C.H. Macho Monte	Run of River	2.4	Rosa de los Vientos Wind	Wind	102.5
C.H. La Potra	Run of River	27.9	Portobello Wind	Wind	32.5
C.H. Salsipuedes	Run of River	27.9	Marañón Wind	Wind	17.5
C.H. La Potra G4	Run of River	2.1			
C.H. Cochea	Run of River	15.5	**Solar**		**184**
C.H. Barro Blanco	Run of River	26.8	Estrella Solar	Solar	4.8
C.H. Barro Blanco Mini	Run of River	1.9	Vista Alegre (Enel green power)	Solar	8.2
C.H. Pedregalito I	Run of River	21.2	Milton Solar (Enel green power)	Solar	10.3
C.H. Pedregalito II	Run of River	13.5	Sol Real (Enel green power)	Solar	10.8
C.H. Macano	Run of River	5.25	Pocri	Solar	16.0
C.H. RP 490	Run of River	14.3	Bejuco Solar	Solar	1.0
C.H. La Cuchilla	Run of River	8.4	Sarigua	Solar	2.4
C.H. Bonyic	Run of River	31.3	Chiriqui (Enel San Juan)	Solar	9.9
C.H. Bajo Totuma	Run of River	6.3	Divisa Solar	Solar	9.9
C.H. San Lorenzo	Run of River	8.7	Don Felix	Solar	2.0
C.H. El Fraile	Run of River	6.71	El Fraile Solar	Solar	0.5
C.H. El Alto	Run of River	75.0	Cocle Solar	Solar	1.0
C.H. Bajo Mina	Run of River	56.8	Farallon Solar 2	Solar	4.8
C.H. Baitún	Run of River	85.9	Bugaba Solar	Solar	2.4
C.H. Bajo Minas G3	Run of River	0.6	Miraflores Cocle	Solar	9.0
C.H. Baitún G3	Run of River	1.73	Miraflores Los Angeles	Solar	9.5
C.H. Concepción	Run of River	11.0	Miraflores Paris	Solar	9.0
C.H. Las Perlas Norte	Run of River	10.0	Caldera Solar (Enel green power)	Solar	5.3
C.H. Las Perlas Sur	Run of River	10.0	Sol de David (Enel green power)	Solar	7.9
C.H. Paso Ancho	Run of River	6.2	El Espinal	Solar	9.3
C.H. Planetas I	Run of River	4.8	Tecnisol	Solar	40.0
C.H. Planetas II	Run of River	8.9	Panasolar	Solar	9.9
CH. San Andrés	Run of River	9.9			
CH. Pando	Run of River	37.0			
TOTAL					4,110

Source: Own elaboration based on ETESA publication (Plan de Expansión del Sistema Interconectado Nacional 2020 – 2034)

(*) Note: Punta Rincón coal power plant represents a dedicated project for the power supply of the Punta Rincón mining activity (264 MW approx.). From the total installed capacity of 306 MW, near 36 MW are traded in the spot market and, therefore, considered for the simulation in the generating capacity.

In the short- and midterm (next five years), it is recommended to assume an expansion plan based on projects under construction and/or with long-term commitments as a result of public tenders. In the short-term, we take into account the projects announced in the last published information by ETESA (Plan de Expansión del Sistema Interconectado Nacional 2020 – 2034) and the CND (Operational Planning Report "Informe de Planeamiento Operativo", January 2020, CND). Other relevant market information on the status and progress of upcoming projects has been considered.

The next Exhibits present the proposed new capacity additions for the short- and midterms:

Exhibit 29: PA - Expansion Plan by technology (MW)

	Installed Cap. (MW)									Total New Additions (MW)
	Jan-20	2020	2021	2022	2023	2024	2025	2026	2027	2020/27
Thermal	**1,622**	-	-222	-	-	**670**	-	-	-	**448**
Bunker/Diesel	769	-	-222	-	-	-	-	-	-	-222
Coal	472	-	-	-	-	-	-	-	-	-
Natural Gas/LPG	381	-	-	-	-	670	-	-	-	670
Hydroelectric	**1,803**	-	1	-	-	-251	-	-	65	-185
ACP	**223**	-35	-	-	-	-	-	-	-	-35
Renewable	**462**	138	86	54	61	70	50	50	50	559
Solar	184	138	20	54	61	70	50	50	50	493
Wind	270	-	66	-	-	-	-	-	-	66
Biogas	8	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-
Total	**4,110**	103	-135	54	61	489	50	50	115	787

Exhibit 30: PA - Expansion plan (2020-2027)

Power plant	Fuel	MW	COD month	COD year
Daconan	Solar	0.2	1	2020
Pacora II	Solar	3.0	6	2020
Santiago Gen 1	Solar	5.0	6	2020
Miraflores G6	Diesel	-17.0	8	2020
Miraflores G8	Diesel	-18.0	8	2020
Ecosolar	Solar	10.0	11	2020
Penonomé	Solar	120.0	12	2020
Estrella de Mar I	Bunker	-72.0	1	2021
Esperanza	Bunker	-92.4	1	2021
Jinro	Bunker	-57.8	3	2021
Cedro Solar	Solar	10.0	7	2021
Caoba Solar	Solar	10.0	7	2021
Toabre	Wind	66.0	9	2021
El Alto G4	Hydro	1.2	12	2021
Don Félix II	Solar	8.0	7	2022
La Esperanza Solar	Solar	20.0	7	2022
Pesé Solar	Solar	16.0	7	2022
Mayorca Solar	Solar	10.0	7	2022
Puerto Pilón (*)	LNG	458.1	not	considered
Mendoza Solar	Solar	3.0	1	2023
Los Santos Solar	Solar	7.6	1	2023
Pedregalito Solar Power	Solar	10.0	1	2023
Estí Solar	Solar	9.9	1	2023
Jagüito Solar	Solar	10.0	1	2023
Celsia Solar Prudencia	Solar	10.6	7	2023
Campo Solar La Victoria	Solar	10.0	7	2023
Telfers (**)	LNG	670.0	1	2024
Bayano	Hydro	-260.0	1	2024
Chuspa	Hydro	8.8	1	2024
El Coco	Solar	10.0	1	2024
Cerro Viejo Solar	Solar	20.0	1	2024
Agua Fría	Solar	10.0	6	2024
Las Lajas	Solar	30.0	6	2024
Solar Project #1	Solar	50.0	1	2025
Solar Project #2	Solar	50.0	1	2026
Solar Project #3	Solar	50.0	1	2027
Burica	Hydro	65.3	1	2027
Total		787 2		

(*) Note: Puerto Pilón (ex Martano) has an effective capacity of 424.7 MW

(**) Note: Telfers (NG Power) has an effective capacity of 656.0 MW

1.4. Fuel Prices and availability

The main fuels used for electricity generation in Central America are the natural gas or LNG, coal, fuel oil (bunker) and diesel oil. These fuels are highly correlated with international energy commodity prices. In turn, the short-run marginal cost of electricity (spot price) is directly related to the price of the fuels used for generation. This is because the marginal power plant (last unit in the merit order dispatch) is usually a thermal or hydroelectric power plant with a "water value" equivalent to the opportunity cost of dispatching a thermal unit in the future. With respect to fuel availability, the Consultant assumes full fuels availability.

For the commodity fuel prices, this Consultant proposes to assume the EIA's long-term forecast (last forecast available: January 2020) and the EIA's short-term energy outlook (last forecast available: May 2020). The following Exhibit presents the EIA´s price projections:

Exhibit 31: EIA fuel forecast (Real 2020 USD)

Commodity	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	USD/ton	41.4	53.3	62.1	63.2	65.3	66.8	68.3	69.8	70.5	71.9
Crude oil Average	USD/bbl	40.7	52.9	61.8	63.1	65.0	66.6	68.3	69.7	70.8	72.4
Henry Hub	USD/MMbtu	2.1	2.9	2.6	2.6	2.7	2.9	3.2	3.3	3.4	3.4
WTI	USD/bbl	30.1	43.3	61.1	62.3	64.5	66.1	67.8	69.4	70.2	71.8
BRENT	USD/bbl	34.1	47.8	65.6	66.9	68.6	70.4	72.1	73.3	75.0	76.6
Commodity	**Unit**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Coal	USD/ton	73.1	74.7	75.5	78.0	79.1	80.6	82.5	82.8	84.2	85.6
Crude oil Average	USD/bbl	73.6	75.2	76.2	78.5	79.8	81.3	83.1	84.0	85.5	87.0
Henry Hub	USD/MMbtu	3.4	3.3	3.3	3.4	3.4	3.4	3.4	3.5	3.5	3.5
WTI	USD/bbl	73.1	74.8	75.7	78.4	79.7	81.3	83.4	83.8	85.4	86.9
BRENT	USD/bbl	77.7	79.3	80.5	82.5	83.9	85.4	86.9	88.3	89.8	91.3

Source: Own elaboration based on U.S. Energy Information Administration (EIA) Forecast, released in January 2020.
The price of coal is estimated from the historical correlation between Coal and WTI Price.
For year 2020 and 2021, we propose to assume the short-term energy outlook from EIA, released on 12th of May 2020, which better reflects the current trends in fuel prices

Based on the EIA forecast, the fuel prices at plant's site in Central America are calculated as follows:

Liquefied Natural Gas (LNG): This Consultant's estimation is based on an empirical market formula applied in the region, which adds approximately 5 USD/MMBTU to the Henry Hub (HH) price of gas. This value takes into account 15% of HH price representing the losses in the liquefaction process, 3 USD/MMBTU as liquefaction fee and 1.3 USD/MMBTU for transportation, port services and regasification costs. For Guatemala, El Salvador and Nicaragua, this Consultant also adds 0.2 USD/MMBTU for the crossing of the Panama Canal.

Coal: Prices for Central American countries are calculated considering the coal price in Puerto Bolivar (Colombia) along with the regional logistic costs to power plants (maritime transport, Panama Canal as necessary, port services and ground transportation). The coal internalization cost assumed from Puerto Bolivar to the Pacific coast is 30 USD/ton and 25 USD/ton for Caribbean coast (the Panama Canal fee is not included).

Liquid fuels: They represent commodities traded in international markets and keep direct correlation with crude oil prices. The Consultant forecasts bunker and diesel oil prices with a linear regression model as a function of crude oil price (explanatory variable). The parameters of the regression model are empirically adjusted to account for freight and internalization costs. The resulting CIF fuel prices are:

Exhibit 32: Fuel Prices forecast at plant's site

	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
LNG PA, HN, CR	USD/MMbtu	6.7	7.2	7.2	7.2	7.3	7.6	7.8	8.0	8.1	8.1
LNG GU, ES, NI	USD/MMbtu	6.9	7.4	7.4	7.4	7.5	7.8	8.0	8.2	8.3	8.3
Atlantic Coal	USD/MMbtu	2.6	3.0	3.4	3.4	3.5	3.5	3.6	3.7	3.7	3.7
Pacific Coal	USD/MMbtu	2.8	3.3	3.6	3.6	3.7	3.8	3.8	3.9	3.9	3.9
Bunker 3%S	USD/MMbtu	5.7	7.7	9.3	9.5	9.9	10.3	10.6	10.9	11.1	11.3
Diesel	USD/MMbtu	9.5	12.3	14.4	14.6	15.1	15.5	15.8	16.1	16.4	16.8
	Unit	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
LNG PA, HN, CR	USD/MMbtu	8.1	8.0	8.0	8.1	8.2	8.2	8.2	8.2	8.2	8.3
LNG GU, ES, NI	USD/MMbtu	8.3	8.2	8.2	8.3	8.4	8.4	8.4	8.4	8.4	8.5
Atlantic Coal	USD/MMbtu	3.8	3.8	3.9	4.0	4.0	4.1	4.1	4.1	4.2	4.2
Pacific Coal	USD/MMbtu	4.0	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.5
Bunker 3%S	USD/MMbtu	11.6	11.9	12.0	12.5	12.8	13.1	13.5	13.5	13.8	14.1
Diesel	USD/MMbtu	17.0	17.4	17.6	18.2	18.5	18.8	19.2	19.4	19.8	20.1

Source: Own elaboration

As a matter of comparison, the next exhibit presents the two latest World Bank projections (April 2020 and October 2019) for crude oil and natural gas vs. the two latest EIA projection (Jan-2020 and Jan-2019). A general trend towards lower prices in the latest forecasts is observed, compared to the previous ones.

Exhibit 33: World Bank versus EIA fuel forecasts, Natural Gas HH (Real 2020 USD)

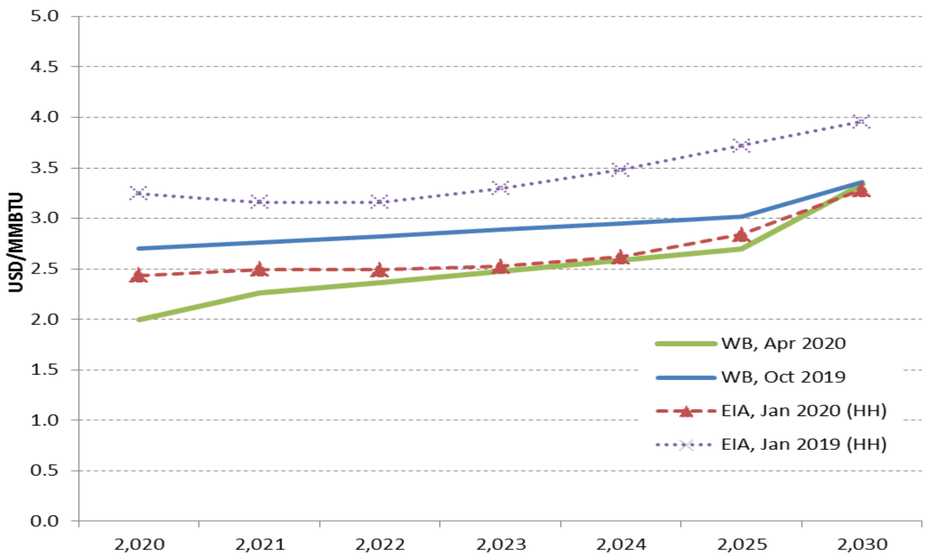
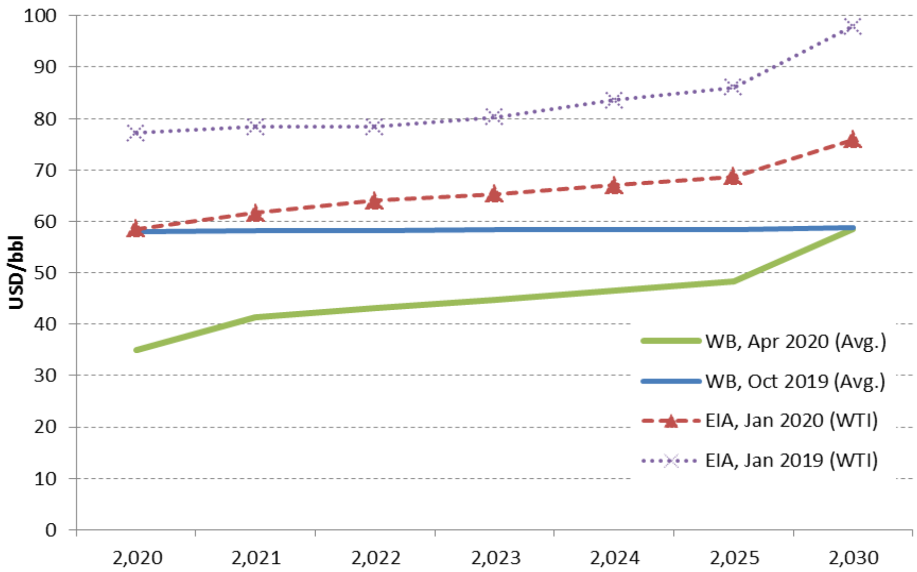


Exhibit 34: World Bank versus EIA fuel forecasts, Crude Oil (Real 2020 USD)



1.5. Expansion Plan – Long-Term

In the long-term, new entrants will depend on their investment costs, projected fuel prices, demand growth and energy policies, especially those related to the diversification of the energy matrix and regional integration.

In this study, this Consultant assumes that the market reaches the equilibrium in economic terms; the energy price signal will be aligned with the long-term marginal cost (cost of development of the candidate technology/ies to meet an additional unit of demand at minimum cost or LCOE).

This means that new generators (amongst the least cost candidate technologies) receive an average remuneration for energy from the spot market that, together with the capacity payments, is sufficient to cover their LCOEs. Under such conditions, the average energy price in the spot market equals the long-run marginal cost (LRMC).

1.5.1. Candidate technologies

In Central America, the candidate technologies for long-run expansion are:

- Combined Cycle associated with a LNG regasification plant: with the recent introduction of the LNG in the Panamanian energy matrix and the potential future introduction of the LNG in other countries of the region, the candidate technology with lowest cost capable to provide firm energy is the combined cycle (CCGT) running on regasified LNG[10].
- Non-conventional Renewables, mostly solar and wind farms: although these technologies may have a lower LCOE than the gas-fired CCGTs, they do not supply energy on a firm basis due to the resource's variability. Therefore, there is always the need to add thermal capacity to ensure an adequate reserve margin for the system's safe operation.

[10]Coal-fired power projects are discarded due to the increasing development difficulties related to environmental aspects and probability of international financing.

- Small-sized hydroelectric power plants: new hydro projects will be developed as long as they are competitive vis a vis the other technologies considered (there is high dispersion of unit investment costs among hydro projects, since they depend on the quality, accessibility and other site-specific aspects).
- With the recent boom of new renewables projects, we propose to assume a generic mid and long-term expansion of renewable projects for Panama of 50 MW of solar PV projects every year and 50 MW of wind projects every six years.
-

1.5.2. Estimation of the LCOE of the CCGT

The following table summarizes the relevant characteristics of the thermal candidate technology to expand the generation matrix in the long-run (combined cycle running on LNG). The long-run marginal cost is estimated considering standard CAPEX and OPEX costs and an IRR of 12% in real terms after taxes.

Exhibit 35: Development cost for CCGT

Technology		CCGT w/ LNG
Fuel		Natural Gas (LNG)
Gross Capacity	MW	300
Scheduled Maintenance	days/yr	15
Investment Costs		
Capex	USD/kW	750
Total Investments	MM USD	225
IRR	%	12%
Variable Costs		
Heat Rate		56%
Fuel Consumption	MBTU/MWh	6.8
Internal Consumption		3%
Fuel Cost[11]	USD/MBTU	Depends on the country
O&M Cost	USD/MWh	3.5
Transmission cost	USD/MWh	1.0
Total variable cost	USD/MWh	Depends on the country
Taxes		
Profits Tax	%	Depends on the country
VAT	%	Depends on the country

Based on the different capacity prices, fuel cost and taxes for each country[12], the levelized cost and energy price required by the thermal candidate technology in each country are calculated.

Note that the fuel cost assumed in the following exhibit corresponds to year 2035. However, this calculation is not only done for year 2035. It is done for each year of the study, with its corresponding fuel cost.

[11] Gas transport cost is different for each country as a fee for the crossing of the Panama Canal applies for some countries.

[12] In Panama, this Consultant assumes a capacity price of 4.50 USD/kW-month, which is an intermediate value for the capacity price. It assumes a Profits tax of 25% and a VAT of 7%.

Exhibit 36: LCOE for CCGT fueled with LNG, values for year 2035

CCGT with LNG		CR	ES	GU	HO	NI	PA
Energy selling price	USD/MWh	84.2	86.9	85.0	84.4	88.5	82.1
Capacity Price	USD/kW-month	4.5	3.9	4.5	5.5	3.3	4.5
Levelized Cost	USD/MWh	94.0	95.4	94.7	94.2	95.6	91.8
Avg. Energy spot price	USD/MWh	75.9	78.2	76.8	76.0	79.3	74.6

NB: Example for Panama:

91.8 USD/MWh is the levelized cost (LCOE) of the long-term project (CCGT) running on LNG at 8.2 USD/MMBtu. When this CCGT is dispatched, the energy spot price has to be 82.1 USD/MWh in average for the project to be feasible. In other words, the energy price that this project "sees" at the spot market has to be 82.1 USD/MWh. This energy price, together with capacity payments (4.5 USD/kW-month, equivalent to 10 USD/MWh), allows the project to receive its LCOE.

The regulated capacity price in Panama is established in 8.96 USD/kW-month. This figure is calculated to remunerate the fixed costs (investment costs and fixed O&M costs) of the "peak unit" that guarantees supply during the maximum demand conditions. This "peak machine" is a conventional gas turbine.

This value of 8.96 USD/kW-month is defined by the regulation as a ceiling price for both the Long Term Reserve Service (annual capacity market) and the daily capacity market. In the last years the capacity price in these two markets has cleared below the ceiling price; only when there is a capacity shortage the clearing price in these markets is the ceiling price.

In order to determine the long-term equilibrium price for the energy at the short-term market, we have considered an intermediate value for the capacity price in this long-term study, of around 4.5 USD/kW-month. The capacity remuneration ads to the energy component so that both payments (capacity and energy) allows the long term CCGT to recover its development cost (LCOE).

It is worth it to mention that any combination of energy and capacity prices is feasible in the long term equilibrium as long as the selected pair of values allows the CCGT to recover its development cost. The lower the capacity price, the higher the energy price will be. In this regard, non-conventional renewables and run-of-river hydroelectricity, which are price taker units, are benefitted if one assumes a relative low value for the capacity price because the revenues of these technologies mostly come from the energy component of the payment.

1.6. Regional electricity market

The modeling tool (SDDP) integrates the operation of all the Central American countries interconnected through the SIEPAC project.

SIEPAC PROJECT

The SIEPAC (Central American Interconnected Electrical System or Sistema de Interconexión Eléctrica de los Países de América Central) adds 1800 km of high voltage lines, with a capacity of 300 MW. Currently the six countries in the Central American isthmus are interconnected through a 230 kV single circuit. Unfortunately, the SIEPAC still presents difficulties to reach out the 100% of its transmission capacity; mainly due to different local regulations and operating conditions (internal transmission system constraints), especially between the 3 most southern countries. In the modeling of the Reference Case, we assume that this situation is maintained until 2028, which includes limitations on the ability of exchanges between countries to reflect this reality.

Exhibit 37: SIEPAC Project

SIEPAC EXPANSION PROJECT

There is a project to expand the SIEPAC capacity from the current 300 MW to 600 MW at pre-feasibility stage. The Consultant assumes that this expansion will take place in the long run, by 2033.

Link	From-To	Limit MW-Avg.		
		2020	2028	2033
GU1-ES	<----	300	300	600
	---->	300	300	600
GU2-HN	<----	300	300	600
	---->	300	300	600
ES-HN	<----	300	300	600
	---->	300	300	600
HN-NI	<----	150	300	600
	---->	190	300	600
NI-CR	<----	130	300	600
	---->	200	300	600
CR-PA	<----	100	300	600
	---->	50	300	600

MEXICO – GUATEMALA INTERCONNECTION

The interconnection between Guatemala and Mexico has a transmission capacity of 200 MW from Mexico to Guatemala and 80 MW from Guatemala to Mexico due to restrictions in Guatemala's domestic lines.

PANAMA – COLOMBIA INTERCONNECTION

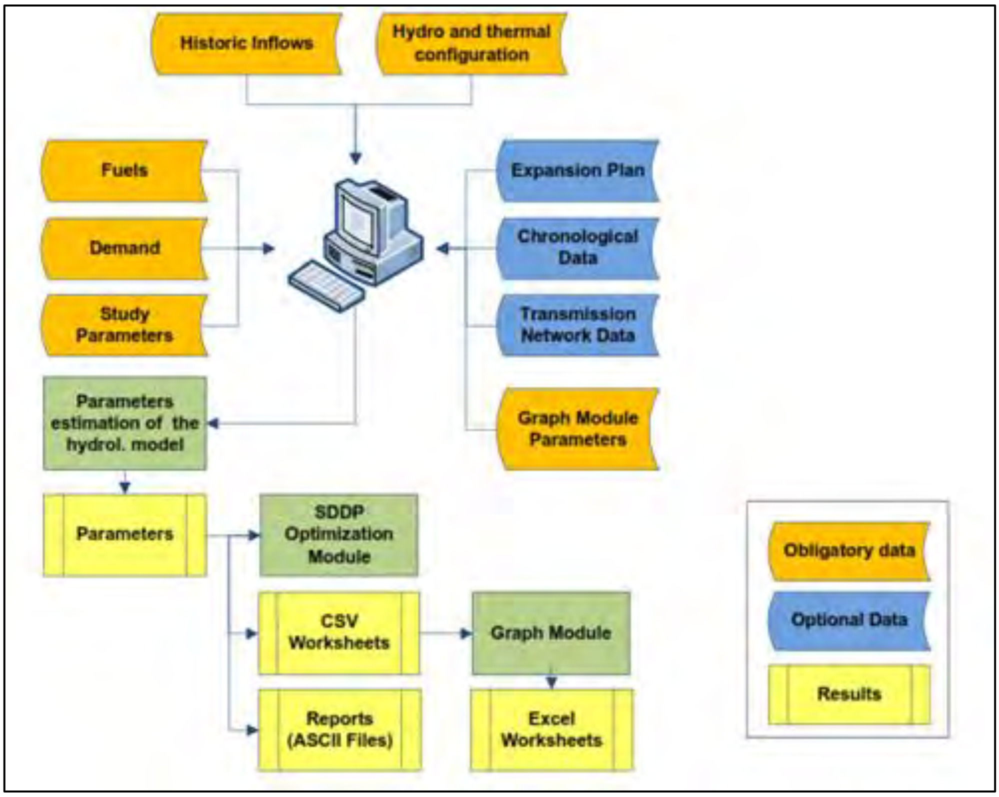
This Consultant does not consider a future interconnection between Panama and Colombia for this Reference scenario.

2. ABOUT THE SDDP SIMULATION MODEL

The simulation of the future operation of the wholesale electricity market provides valuable information on the probable evolution of the market (prices and generation balance) and, particularly, on the generation business.

The SDDP (Stochastic Dual Dynamic Programming) model is used for the simulation process. The main objective of the SDDP model is to determine the generation of each power plant in the fleet, for each period of time, so as to serve demand at minimum operational cost over the time frame of the study. Power plant dispatch depends on the merit order (based on power plant's variable cost of production, i.e. without taking into account investment costs).

Exhibit 38: SDDP Simulation Model flow chart



In the long run, it is assumed that the market reaches equilibrium in economic terms, i.e. income from new projects (energy sales at system's marginal cost plus capacity payments) are sufficient to pay the cost of development of the most efficient technology (minimum total cost, sum of CAPEX and OPEX). Under these equilibrium conditions, energy spot price is equivalent to the long-run marginal cost (LRMC) of the system. The LRMC is equal to the levelized cost of the technology with the minimal cost that is able to supply the growing demand. It represents the target price the electricity market should reach in order to make these projects feasible.

SDDP is a stochastic hydrothermal dispatch model that includes the representation of the transmission grid. The model is widely used in many countries in the region for medium and long-term projections. SDDP calculates the minimal cost operation policy for a hydrothermal generation system, considering the following aspects:

- Operational details of hydro power plants: hydraulic balance, storage and flow rate limits through turbines, spillways, head effect and others;
- Detailed model of thermal power plants: unit commitment, fuel availability constraints, efficiency curves, multiple-fuel plants and others;
- Hydrological uncertainty: stochastic inflow model representing hydrological system characteristics, such as seasonality, time and spatial inflow correlations and droughts. The database includes the historical series of all river inflows contributing to produce electricity in hydro power plants;
- Detailed transmission grid: Kirchhoff's laws, power flow limits in each circuit, losses, safety constraints, limits on imports and exports between electric areas, sum of flow constraints, grid availability and others;
- Load duration curve represented by five time blocks at system level or in each bus bar (if transmission is considered), using monthly time steps.

Power systems with a significant hydro component can use the water stored in the reservoirs to meet demand and thus avoid higher fuel costs for thermal units.

Hydroelectric power availability, however, is limited to the reservoir capacity. This introduces a relation between the operative decision of using the stored water at a certain time and the future consequences of such decision. The minimum-cost strategy used by the SDDP model leads to the optimization of the operation policy (stochastic) for systems with multiple reservoirs.

The optimum solution for the hydrothermal dispatch problem is to compare the immediate benefit of using the water now to generate power versus the future benefit of storing it. The future benefit is measured in terms of saving fuel from the displaced thermal energy. In order to know whether the hydroelectric energy stored in the reservoirs should be used today, it is necessary to simulate the system operation in the future and, thus, evaluate the impact of the decision in terms of operating costs (defining the "water values" for each reservoir and each time step). The SDDP model simulates the hydrothermal system taking into account various parameters such as the water values, the marginal costs of the power plant, technical constraints of the generation fleet, etc. The reservoir levels at the end of the simulation period depend on many parameters: the use of water of each reservoir (which results of the optimization process of the SDDP), the initial volume of the reservoir, the reservoir inflows, the minimum and maximum outflow etc.

In addition, the variability of the reservoir inflow (which fluctuates seasonally, regionally, and from year to year) contribute strongly to the dynamic decision of using the water or saving it for later. Because of the uncertainty of the inflow (which in turn depends on meteorological conditions), simulation studies should be able to represent a large number of hydrological scenarios so as to evaluate the impact of a certain operational decision on the operating costs. The SDDP model has a database of historical hydrology series for each hydro plant in the system.

The main results of the SDDP model (for each simulated hydrology series) are as follows:

- System operation statistics: hydro and thermal generation for each time step (month), thermal production costs, energy exchanges, circuit flows, fuel consumption, deficit risk, and non-supplied energy.
- Marginal costs for each system node (short-run marginal cost for each node in the transmission system).

In the case of Central America, we use 5 blocks per month, in order to approximate the monotonous curve of the region. The generation mix being largely hydro-based, we generally observe a stronger influence of hydrological conditions on the marginal costs than hourly variation of the demand. Indeed, the use of hydro can be optimized and can reduce variations in supply-demand balance.

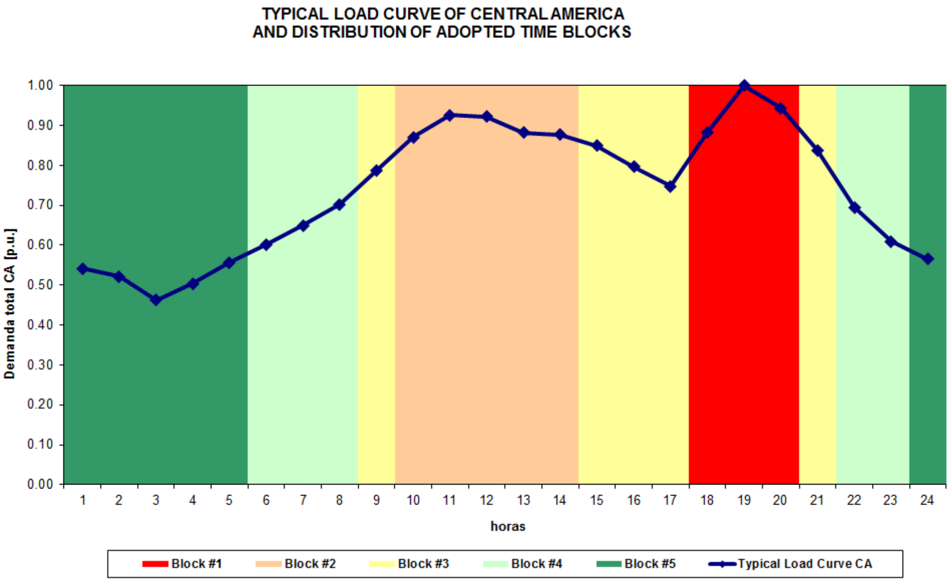
The definition of the blocks is made at the regional level, by summing the hourly demand of the 6 countries (the definition of the blocks must be identical for the 6 countries).

Block 1 contains the evening peak hours: 18, 19, 20

Block 2 contains the midday peak hours: 10, 11, 12, 13, 14

Block 3 and 4 are intermediary blocks

Block 5 contains the lowest demand (from 24 to 5 in the morning)



In the case of Panama, for which the peak demand tends to be at midday (due in part to a large amount of air conditioning), the highest demand tends to be block 2. This is not true for the rest of the countries of the region where peak demand tends to be at the end of the day, during block 1. Blocks 2 also allows us to model the peak in terms of solar generation.

SECTION II: MAIN RESULTS FOR THE PROSPECTIVE ANALYSIS

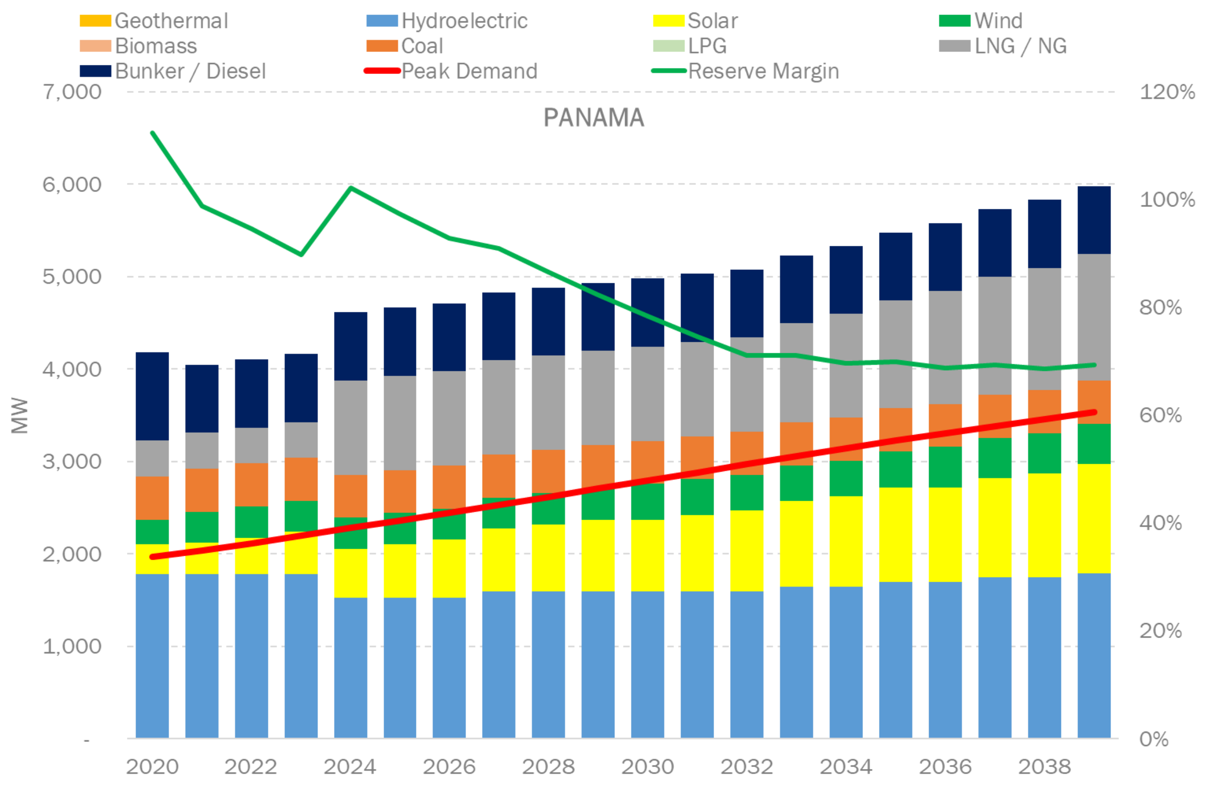
1. REFERENCE SCENARIO RESULTS

The most relevant aspects of the possible future evolution of the electricity market of Panama are presented below. The annual results shown in this Section are supplemented by an Excel file (attached to the report).

1.1. Capacity Balance, PA, Ref

The following exhibit shows the evolution of available generation capacity by type in the period 2020-2039. The evolution of the peak demand and the generation reserve margin[13] are also included. In the period 2020-2027, around 800 MW[14] of new generation capacity is added, around half of it being thermal, the rest being mainly from renewables. In the medium-term, the new thermal unit added to the system is Telfers CCGT (670 MW of installed capacity). In the long-term, it is assumed that highly efficient thermal projects (combined cycles running on LNG) are added so as to achieve energy prices that are compatible with the self-sustained development of the electricity market. Additionally, we add renewable-based projects and hydroelectric projects in order to keep a reasonably balanced generation mix.

Exhibit 39: Nominal Capacity Balance, in MW, and Reserve Margin, in %, PA, Ref



[13] Reserve margin = Installed Capacity/ Peak Demand -1. It is not equal to the firm reserve margin.

[14] Additions less Retirements (some thermal and hydro power plants have a planned decommissioning date).

Because of the new capacity incorporation, the nominal reserve margin is high in the short and medium terms and relatively low in the long term. It decreases from 112% in 2020 to 102% in 2024 and then decreases to around 70% in the long-term (the high values observed in the short-term are partly due to the high share of expensive liquid fueled power plants and the addition of Telfers CCGT). The saw tooth form of the reserve margin curve in the mid-term is related to the start of operation of Telfers CCGT.

Exhibit 40: Nominal Capacity Balance, in MW (2020-2039), PA, Ref

PANAMA		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Balance (December each year)											
Peak Demand	**MW**	**1,969**	**2,036**	**2,108**	**2,193**	**2,281**	**2,362**	**2,444**	**2,529**	**2,615**	**2,703**
Installed Capacity	**MW**	**4,180**	**4,045**	**4,099**	**4,160**	**4,611**	**4,661**	**4,711**	**4,826**	**4,876**	**4,926**
Thermal	MW	1,812	1,590	1,590	1,590	2,222	2,222	2,222	2,222	2,222	2,222
Bunker / Diesel	MW	956	734	734	734	734	734	734	734	734	734
Coal	MW	466	466	466	466	466	466	466	466	466	466
LNG / NG	MW	389	389	389	389	1,021	1,021	1,021	1,021	1,021	1,021
LPG	MW	-	-	-	-	-	-	-	-	-	-
Hydroelectric	MW	1,776	1,777	1,777	1,777	1,526	1,526	1,526	1,591	1,591	1,591
Renewables	MW	592	678	732	793	863	913	963	1,013	1,063	1,113
Solar	MW	322	342	396	457	527	577	627	677	727	777
Wind	MW	270	336	336	336	336	336	336	336	336	336
Biomass	MW	-	-	-	-	-	-	-	-	-	-
Geothermal	MW	-	-	-	-	-	-	-	-	-	-
Reserve Margin	**%**	**112%**	**99%**	**94%**	**90%**	**102%**	**97%**	**93%**	**91%**	**86%**	**82%**

PANAMA		2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Capacity Balance (December each year)											
Peak Demand	**MW**	**2,791**	**2,879**	**2,967**	**3,054**	**3,140**	**3,223**	**3,304**	**3,382**	**3,457**	**3,528**
Installed Capacity	**MW**	**4,976**	**5,026**	**5,076**	**5,226**	**5,326**	**5,476**	**5,576**	**5,726**	**5,826**	**5,976**
Thermal	MW	2,222	2,222	2,222	2,272	2,322	2,372	2,422	2,472	2,522	2,572
Bunker / Diesel	MW	734	734	734	734	734	734	734	734	734	734
Coal	MW	466	466	466	466	466	466	466	466	466	466
LNG / NG	MW	1,021	1,021	1,021	1,071	1,121	1,171	1,221	1,271	1,321	1,371
LPG	MW	-	-	-	-	-	-	-	-	-	-
Hydroelectric	MW	1,591	1,591	1,591	1,641	1,641	1,691	1,691	1,741	1,741	1,791
Renewables	MW	1,163	1,213	1,263	1,313	1,363	1,413	1,463	1,513	1,563	1,613
Solar	MW	777	827	877	927	977	1,027	1,027	1,077	1,127	1,177
Wind	MW	386	386	386	386	386	386	436	436	436	436
Biomass	MW	-	-	-	-	-	-	-	-	-	-
Geothermal	MW	-	-	-	-	-	-	-	-	-	-
Reserve Margin	**%**	**78%**	**75%**	**71%**	**71%**	**70%**	**70%**	**69%**	**69%**	**69%**	**69%**

1.2. Generation Balance, PA, Ref

The following exhibits show the generation balance by type for each year in the evaluation period, which results from the economic generation dispatch for the Reference scenario.

Exhibit 41: Generation Balance, in GWh, PA, Ref

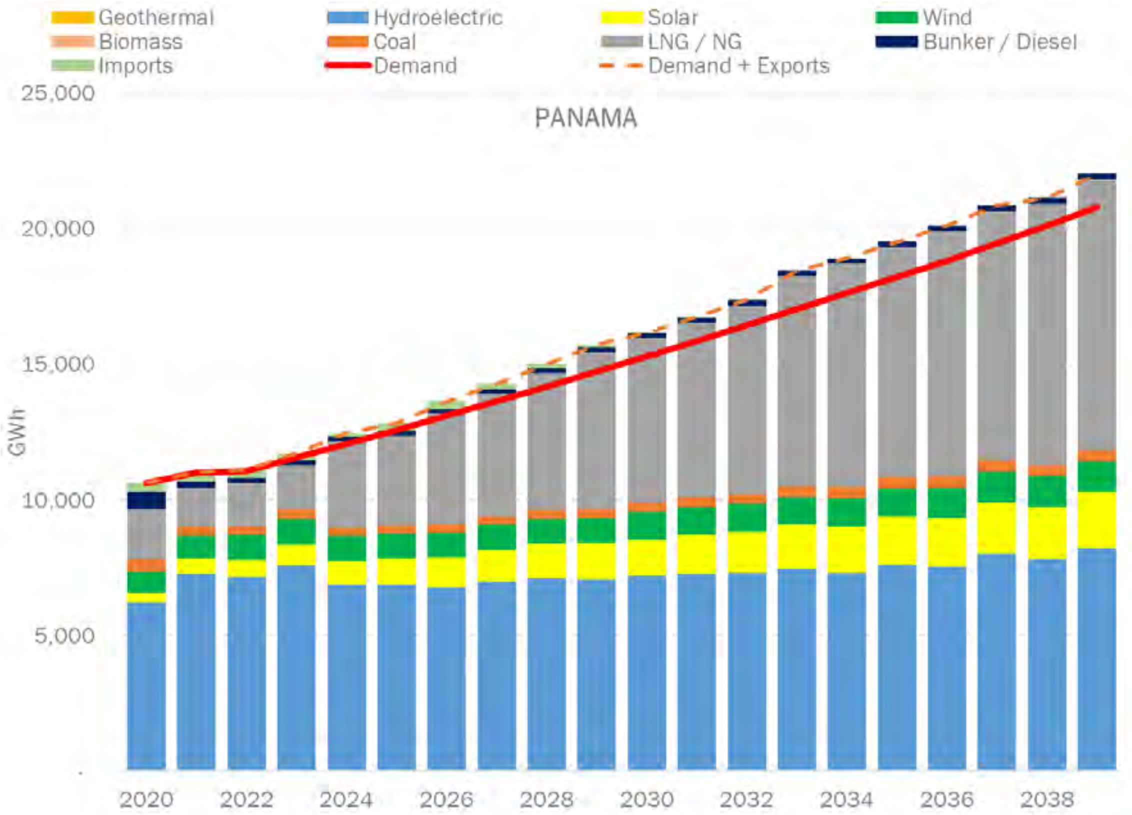
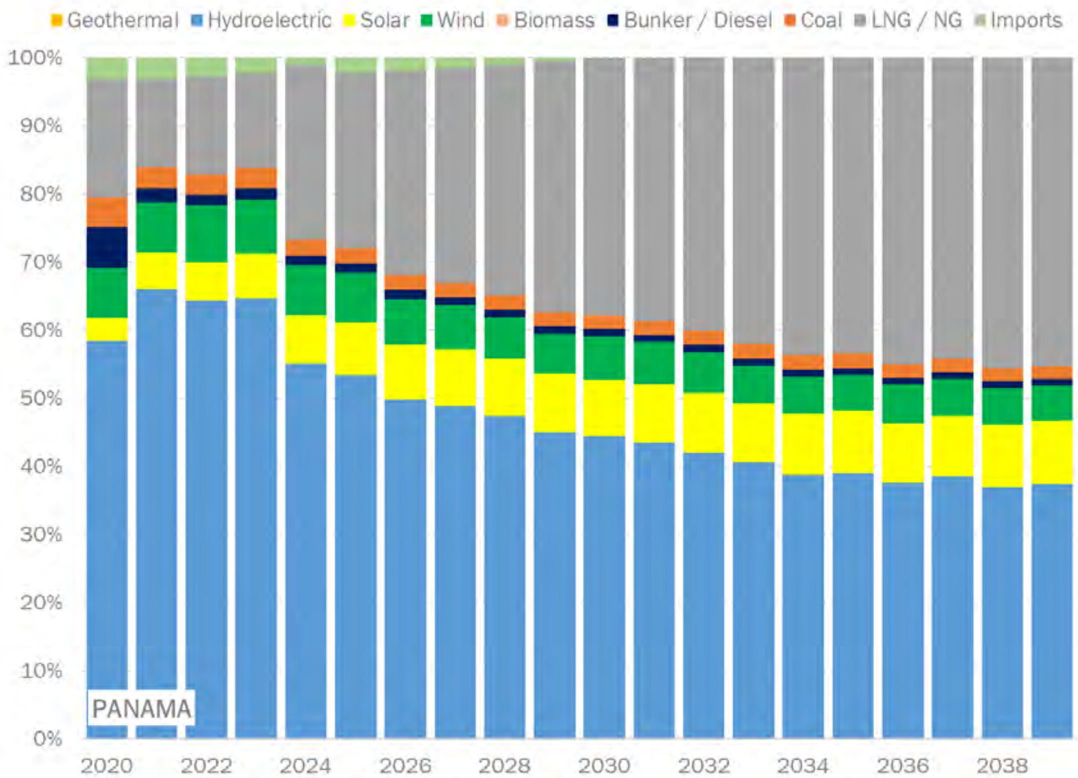


Exhibit 42: Generation Balance, in %, PA, Ref



As can be observed, thermal generation share slowly become more predominant in the energy mix, until reaching almost 50% of the total generation at the end of the studied period. Thermal generation in the long-term is mostly from LNG (LNG based projects occupies around 45% of the total share, the remaining being from coal and liquid fuels).

In the short-term, the share of renewable and hydro generation in total generation is about 70/80%, while in the long-term, it decreases to around 50%.

Exhibit 43: Generation Balance, in GWh (2020-2039), PA, Ref

PANAMA		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Energy Balance											
Demand	**GWh**	**10,635**	**10,992**	**11,059**	**11,566**	**12,074**	**12,585**	**13,107**	**13,625**	**14,164**	**14,722**
Energy not supply	GWh	-	-	-	-	-	-	-	-	-	-
Generation	**GWh**	**10,297**	**10,669**	**10,809**	**11,441**	**12,325**	**12,534**	**13,350**	**14,070**	**14,852**	**15,625**
Thermal	GWh	2,955	1,993	2,104	2,163	3,661	3,761	4,553	4,997	5,553	6,290
Bunker / Diesel	GWh	641	219	179	183	172	172	171	171	171	173
Coal	GWh	458	357	327	367	289	290	298	300	303	312
LNG / NG	GWh	1,856	1,416	1,599	1,614	3,200	3,300	4,083	4,526	5,079	5,805
LPG	GWh	-	-	-	-	-	-	-	-	-	-
Hydroelectric	GWh	6,209	7,276	7,150	7,578	6,860	6,854	6,781	6,974	7,112	7,068
Renewables	GWh	1,133	1,400	1,555	1,700	1,804	1,919	2,016	2,099	2,187	2,267
Solar	GWh	363	580	632	775	881	993	1,093	1,175	1,262	1,344
Wind	GWh	770	820	923	925	923	925	922	924	925	923
Biomass	GWh	-	-	-	-	-	-	-	-	-	-
Geothermal	GWh	-	-	-	-	-	-	-	-	-	-
Net Exchanges	**GWh**	**337**	**324**	**250**	**125**	**-251**	**52**	**-242**	**-444**	**-688**	**-903**
Imports	GWh	337	353	314	280	135	298	276	208	161	83
Exports	GWh	-	29	64	155	386	246	518	653	849	985

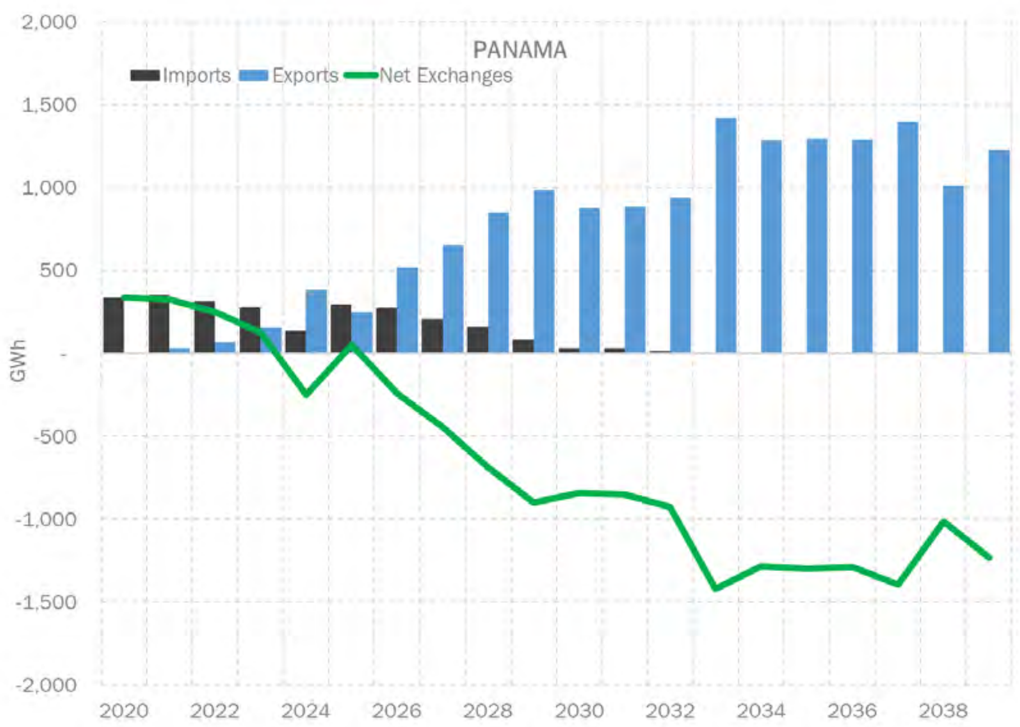
PANAMA		2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Energy Balance											
Demand	**GWh**	**15,304**	**15,857**	**16,434**	**17,022**	**17,625**	**18,208**	**18,824**	**19,460**	**20,119**	**20,800**
Energy not supply	GWh	-	-	-	-	-	-	-	-	-	-
Generation	**GWh**	**16,147**	**16,708**	**17,362**	**18,443**	**18,910**	**19,505**	**20,114**	**20,856**	**21,132**	**22,031**
Thermal	GWh	6,596	6,965	7,525	8,341	8,861	9,097	9,659	9,837	10,255	10,614
Bunker / Diesel	GWh	181	178	196	190	195	202	199	200	213	209
Coal	GWh	324	337	362	397	416	409	408	416	408	404
LNG / NG	GWh	6,091	6,450	6,967	7,754	8,251	8,486	9,051	9,221	9,634	10,001
LPG	GWh	-	-	-	-	-	-	-	-	-	-
Hydroelectric	GWh	7,187	7,275	7,296	7,467	7,322	7,599	7,547	8,020	7,801	8,236
Renewables	GWh	2,364	2,469	2,541	2,635	2,727	2,809	2,909	3,000	3,076	3,182
Solar	GWh	1,335	1,439	1,513	1,605	1,696	1,785	1,776	1,865	1,936	2,051
Wind	GWh	1,028	1,030	1,028	1,030	1,030	1,024	1,133	1,134	1,139	1,131
Biomass	GWh	-	-	-	-	-	-	-	-	-	-
Geothermal	GWh	-	-	-	-	-	-	-	-	-	-
Net Exchanges	**GWh**	**-843**	**-852**	**-928**	**-1,422**	**-1,285**	**-1,298**	**-1,291**	**-1,396**	**-1,014**	**-1,232**
Imports	GWh	31	33	11	-	-	-	-	-	-	-
Exports	GWh	874	884	939	1,422	1,285	1,298	1,291	1,396	1,014	1,232

The following exhibit shows import/export energy exchanges between Panama and the rest of the Central American countries resulting from the economic generation dispatch composed by the six countries of the regional market.

Except for the short-term period, during the rest of the studied period, Panama mainly exports its power generation as it is characterized by a competitive generation mix at the regional level. The increase of energy exchanges in the mid-term is related to the start of operation of Telfers CCGT in 2024 and the achievement of the 300 MW of transmission capacity between Panama and Costa Rica in 2028 (before that date, we assume internal congestions in Panama which limit the exchanges with Costa Rica, as can be observed nowadays). The increase of power export by 2033 is related to the achievement of the 600 MW SIEPAC interconnection.

Panama is an exporting country, as its LGN based projects tend to be competitive not only in Panama but in the whole region as well.

Exhibit 44: Energy exchanges with the neighboring countries, in GWh, PA, Ref



1.3. Energy prices, PA, Ref

The following exhibits show the expected energy prices (marginal costs) in the Panamanian WEM resulting from the economic generation dispatch for the Reference scenario together with the capacity additions. The values are expressed in real 2020 US dollars.

The intra-annual variation due to hydrology and the low regulation capacity of most existing hydro plants[15] are showed in the table below. Note, that the energy price usually has its maximum value

[15] Most of the Panamanian hydroelectric power plants are run of river and have limited regulation capacity.

during dry seasons (Feb-May) and minimum in the wet season (Sep-Nov).

Exhibit 45: Energy prices and capacity additions, in USD/MWh (in real 2020 USD), PA, Ref

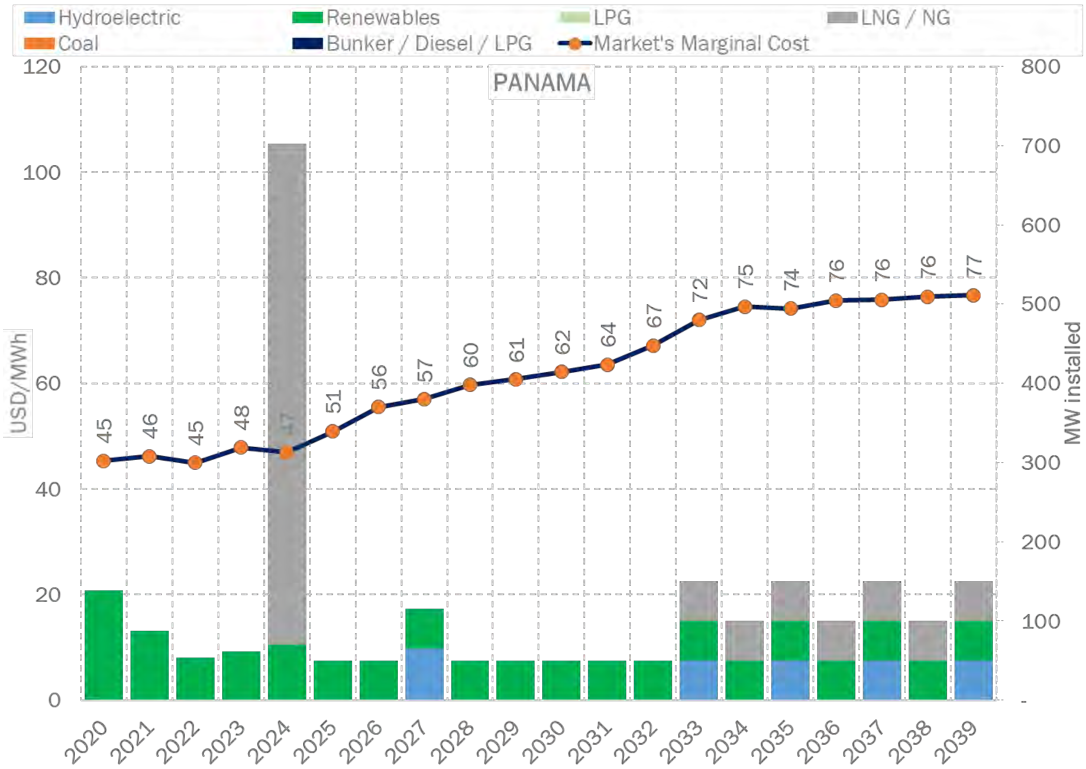


Exhibit 46: Energy prices table, in USD/MWh (in real 2020 USD), PA, Ref

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Jan	45.5	37.4	46.6	48.1	49.6	49.7	56.9	56.3	59.1	58.5	59.2	61.0	62.4	61.5	64.5	64.3	64.0	63.7	67.1
Feb	54.6	50.6	56.6	53.8	58.0	58.4	59.7	63.3	63.6	66.7	66.7	70.4	81.3	81.6	84.2	83.3	85.6	86.0	82.3
Mar	54.0	51.3	55.2	55.7	56.6	58.5	59.8	61.9	62.1	64.6	64.0	69.1	76.4	77.9	78.4	76.1	76.1	75.7	72.9
Apr	55.7	56.2	59.7	56.7	58.7	60.7	61.5	63.7	67.5	70.9	70.4	83.8	89.8	93.8	93.3	94.4	92.0	95.8	88.6
May	55.0	57.4	59.9	55.2	58.5	60.0	61.4	61.9	65.3	68.3	72.2	78.6	87.9	92.3	90.4	94.8	92.5	91.9	93.1
Jun	53.0	54.8	56.3	53.5	57.6	58.3	59.6	60.1	62.2	66.1	70.5	72.4	81.8	87.0	83.6	88.4	87.7	87.6	88.1
Jul	49.5	47.1	50.9	49.8	53.4	57.7	59.0	59.6	60.3	61.7	64.1	65.8	69.4	73.7	69.6	72.8	74.2	74.8	77.0
Aug	45.6	41.3	43.2	42.8	52.5	55.7	55.5	59.1	58.2	57.7	59.6	60.0	62.2	64.9	64.2	65.5	66.2	64.2	67.6
Sep	41.4	41.5	43.0	39.3	43.9	54.0	56.0	58.6	58.3	58.7	59.3	62.8	65.0	67.8	66.8	70.8	71.9	72.0	75.0
Oct	34.2	33.0	36.0	33.4	38.3	49.3	50.1	57.3	57.1	57.5	59.0	59.4	62.2	63.9	63.6	65.0	65.0	68.1	70.4
Nov	31.0	35.5	34.4	35.2	39.5	53.4	53.2	58.2	58.1	59.0	59.7	62.2	65.0	67.7	68.3	69.9	71.8	73.1	73.4
Dec	35.1	34.6	33.7	40.0	44.9	51.2	52.2	57.1	57.8	57.2	58.1	60.7	62.2	63.8	64.6	64.2	64.5	65.4	65.5
Annual	46.2	45.0	47.9	46.9	50.9	55.5	57.0	59.7	60.8	62.2	63.5	67.1	72.0	74.5	74.2	75.7	75.8	76.4	76.7

In the short-term, energy prices remain low in the context of low prices for commodities and relatively low demand (impact of the COVID crisis).

In 2024, once the CCGT of Telfers starts operation, the dispatch stack is modified with 670 MW of additional generation with relatively low variable cost of production and prices remain at relatively low values (47 USD/MWh).

As from 2025, marginal costs show an average upward trend, in a context of demand growth and relatively limited quantity of additions of new generation projects.

In the long-term, it is assumed that a highly efficient thermal project (combined cycles running on

LNG) is added so as to achieve energy prices that are compatible with the self-sustained development of the electricity market. Additionally, we add renewable-based projects and hydroelectric projects in order to keep a reasonably balanced generation mix.

CHAPTER 3: ASSESSMENT OF THE SUPPLY AND PURCHASE AGREEMENTS

This Chapter of the document analyzes the Project´s PPAs from a market perspective:

(1) PPAs with large non-regulated users,

(2) PPAs with DISCOs and

(3) Back-up contract with other generators,

This assessment will identify the key aspects with respect to prices, products, obligations and penalties (if any). The Client provided the necessary information on the PPAs.

The agreements analyzed are the following:

Tecnisol contracts:

- Supply contracts with large clients (Riba Smith, Coca Cola FEMSA Panamá, Clínica Hospital San Fernando, Industrias Lácteas, Ice Gaming, Iron Tower and Ventas y Mercadeo)
- Back-up contract with: UEP Penonomé II (50MW wind Rosa de los Vientos), GENISA (hydro Barro Blanco), PPH (hydros Pedregalito, Rio Chico, Caisán and Alto Valle), Saltos de Francoli (hydros Los Planetas I and Los Planetas II) and, recently, with Electron Investment (hydros Pando and Monte Lirio). The first one is between two companies of the same group (Interenergy). In general, the contracts have a duration of one year.

UEP II contracts:

- Supply contracts with distribution companies: EDEMET, EDECHI and ENSA.
- Back-up contract with Tecnisol (50MW wind Rosa de los Vientos),

1. TECNISOL (TECNISOL I, II, III & IV SOLAR PLANTS)

1.1. Supply contracts with large clients

This Consultant assessed the contracts shared by the Cliient in "2.3 Contratos GC - Ikakos" file: Riba Smith, Coca Cola, Clínica Hospital San Fernando, Industrias Lácteas, Ice Gaming, Iron Tower and Ventas y Mercadeo.

These contracts (PPAs) were entered into Tecnisol (40MW of Tecnisol I, Tecnisol II, Tecnisol III & Tecnisol IV) and large clients in the category of "Grandes Clientes Pasivos" in accordance with present regulations[16]. Each of these contracts has committed generation units and back-up units, as follows:

Seller	Cap. (MW)	Off taker (Large Clients)	Back-up unit	Cap. (MW)	Total cap. (MW)
Tecnisol I	10.0	Coca Cola Veymersa Clinica San Fernando Industrias Lácteas	UEP Penonomé II Barro Blanco PPH Saltos de Francoli Electron Investment Tecnisol II Tecnisol IV	50.0 28.6 120.2 13.6 84.2 10.0 10.0	326.6
Tecnisol III	10.0	Riba Smith Ice Gaming Iron Tower	UEP Penonomé II Barro Blanco PPH Saltos de Francoli Electron Investment Tecnisol II Tecnisol IV	50.0 28.6 120.2 13.6 84.2 10.0 10.0	326.6

All the supply contracts with large clients have similar features, which are summarized in the next table.

Exhibit 47 - Main features of the supply contracts with large clients

Terms	Definition	Comments
Type of contract	Energy contract. Each hour the Seller commits to supply the energy consumed by the off taker at the delivery node (the contract follows the load curve of the off taker)	The Seller ((TECNISOL I or III) is obliged to supply to the Buyer (large client) the energy consumed by the latter at the delivery node/s defined in the contract. The Buyer commits to pay a single price ("Cargo por energía de generación" CEG) for the energy delivered under the contract.
Contracted energy	Energy withdrew by the off taker at the delivery nodes as defined in the contract.	There is no ceiling for the contracted energy The committed unit plus the back-up units totalize 336.6 MW, of which 50.0 MW are wind farms (UEP II) and 30 MW are solar pv (Tecnisol)
Contract price ("Cargo por energía de generación" CEG)	It is the price paid by the off taker for the contracted energy, expressed in US$/MWh	Initial contract prices in the range of 90 US$ / MWh; updated every six months within a price band.
Other charges	In accordance with	• Transmission charges

[16] http://www.asep.gob.pa/Electric/Anexos/Anexo_JD-2340.asp

borne by the off taker	items 1.9 & 1.10 of Res 961[17] (rules governing the energy sales to large clients)	• Distribution charges • Capacity payments to the distributor to which the client is connected at the average capacity price paid by such distributor • System´s charges (ancillary services, must run generation, among others)
Off taker	Large client	Riba Smith, Coca Cola, Clínica Hospital San Fernando, Industrias Lácteas, Ice Gaming, Iron Tower and Ventas y Mercadeo. Each contract specifies the delivery node/s.
Contract term	15 years	
Invoice and payment	Monthly invoice.	Contract prices are net of any taxes.
Contract price (CEG) adjustment		The initial value of CEG is escalated with the variation of the regulated tariff every six months, within a price band ((ceiling 125-135 US$/MWh and floor 83 US$/MWh). $CEG_i = CEG_{i-1} \times (1 + (FAJU \times (\Delta T_{rp} - 1)))$ Where ∆T is the variation in the regulated tariff and FAJU is a factor between 1 and 0,7 that cushions subsequent tariff increases if CEG is above a certain level (in example 120 US$/MWh).

The PPA with Riba Smith has a potential risk associated to the level of savings this PPA represent with respect to the regulated tariff these same off takers would pay if they were served by the distribution company. If the said savings are below 8% within the contract´s duration term, then it can trigger the condition to extend the PPA for additional 5 years considering a price that allows the off taker to recover the foregone saving. Currently, this contract represents more than 40 % of total energy associated to PPAs.

The remanding PPAs do not include this clause as described before. However, there are several others that contemplate the possibility of renewal in the same terms and conditions.

1.2. Back-up reserve contracts

1.2.1. Tecnisol – UEP II

Tecnisol has a back-up contract with UEP Penonomé II for five (5) years term (up to March 31st, 2025) with the commitment unit Rosa de los Vientos (up to 50MW). If the energy generated by Tecnisol (40MW) is not sufficient to supply the load (all the PPAs with large clients), then it triggers the back-up contract with UEP Penonomé II. The contracted energy is the minimum between the actual generation of Rosa de los Vientos and the needed energy to supply all the loads. The contract price is 65.30 US$/MWh (Source: the Client, "Enmienda No. 2").

[17] http://www.asep.gob.pa/electric/Anexos/TEXTO%20UNIFICADO%20GRANDES%20CLIENTES%20MAYO%202010.pdf

1.2.2. Tecnisol – GENISA

Tecnisol entered into a back-up contract with GENISA (hydro Barro Blanco (28.56 MW), units: Barro Blanco 1 (BB1), Barro Blanco 2 (BB2) and Barro Blanco 3 (BB3)). In this contract, GENISA commits to supply its energy surplus to Tecnisol, if Tecnisol needs them to complete its energy resources to supply its own supply contracts with large clients. The GENISA´s energy surplus is calculated as the energy generated minus committed energy in previous contracts ("Energía Previamente Comprometida"). We have assumed the following energy curve and energy prices.

Exhibit 48: Energy and prices of the back-up contract between Tecnisol and GENISA

Barro Blanco available energy:

Energy	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
GWh=>	3.4	0	0	0	0.5	4.2	6.0	8.4	9.5	15.4	10.7	7.0

Prices in $/kWh	Jan	Feb	Mar	Apr	May	Jun
Night (22.00-08:00)	0.066	0.066	0.080	0.080	0.070	0.060
Solar (08:00-18:00)	0.080	0.085	0.085	0.085	0.085	0.085
2ª Peak (18:00-22:00)	0.070	0.075	0.080	0.080	0.070	0.065

Prices in $/kWh	Jul	Aug	Sep	Oct	Nov	Dec
Night (22.00-08:00)	0.060	0.060	0.060	0.065	0.060	0.060
Solar (08:00-18:00)	0.070	0.070	0.070	0.070	0.070	0.070
2ª Peak (18:00-22:00)	0.066	0.066	0.066	0.066	0.060	0.060

Source: PPAs information, by the Client

1.2.3. Tecnisol – PPH

Tecnisol entered into a back-up contract with PPH (hydro units: Pedregalito 1 (20 MW), Pedregalito 2 (12.5 MW), Cochea (15.5 MW) and El Alto (72.2 MW), in total 120.2 MW). In this contract, PHH commits to supply its energy surplus to Tecnisol, if Tecnisol needs them to complete its energy resources to supply its own supply contracts with large clients. The PPH´s energy surplus is calculated as the energy generated minus committed energy in previous contracts ("Energía Previamente Comprometida"). We have assumed the following energy curve and energy prices.

PPH available energy:

Note: energy surplus must be calculated as the energy generated by PPH minus its own committed energy in previous contracts

Exhibit 49: Prices of the back-up contract between Tecnisol and PPH

Prices in $/kWh	Jan	Feb	Mar	Apr	May	Jun
Night (22.00-08:00)					0.090	0.080
Solar (08:00-18:00)					0.095	0.085
2ª Peak (18:00-22:00)					0.095	0.085

Prices in $/kWh	Jul	Aug	Sep	Oct	Nov	Dec
Night (22.00-08:00)	0.080	0.070	0.070	0.070	0.075	
Solar (08:00-18:00)	0.085	0.075	0.075	0.075	0.080	
2ª Peak (18:00-22:00)	0.085	0.075	0.075	0.075	0.080	

Source: PPAs information, by the Client

1.2.4. Tecnisol – Saltos de Francoli

Tecnisol entered into a back-up contract with Saltos de Francoli (hydro units: Los Planteas I (4.752 MW) and Los Planteas II (8.886 MW), in total 13.638 MW). In this contract, Saltos de Francoli commits to supply its energy surplus to Tecnisol, if Tecnisol needs them to complete its energy resources to supply its own supply contracts with large clients. The Saltos de Francoli´s energy surplus is calculated as the energy generated minus committed energy in previous contracts (“Energía Previamente Comprometida”). We have assumed the following energy prices.

Saltos de Francoli available energy:

Note: energy surplus must be calculated as the energy generated by Saltos de Francoli minus its own committed energy in previous contracts

Exhibit 50: Prices of the back-up contract between Tecnisol and Saltos de Francoli

Prices in $/kWh	Jan	Feb	Mar	Apr	May	Jun
Night (22.00-08:00)					0.070	0.070
Solar (08:00-18:00)					0.073	0.073
2ª Peak (18:00-22:00)					0.072	0.072

Prices in $/kWh	Jul	Aug	Sep	Oct	Nov	Dec
Night (22.00-08:00)	0.070	0.070	0.070	0.070	0.070	
Solar (08:00-18:00)	0.073	0.073	0.073	0.073	0.073	
2ª Peak (18:00-22:00)	0.072	0.072	0.072	0.072	0.072	

Source: PPAs information, by the Client. We assumed that it is a mistake in the contract table, and the values there are $/MWh and not $/kWh

1.2.5. Tecnisol – Electron Investment

Tecnisol entered into a back-up contract with Electron Investment (hydro units: Pando and Monte Lirio, with a total installed capacity of 84.2 MW). In this contract, Electron Investment commits to supply its energy surplus to Tecnisol, if Tecnisol needs them to complete its energy resources to supply its own supply contracts with large clients. The Electron Investment´s energy surplus is calculated as the energy generated minus committed energy in previous contracts ("Energía Previamente Comprometida"). We have assumed the following energy prices.

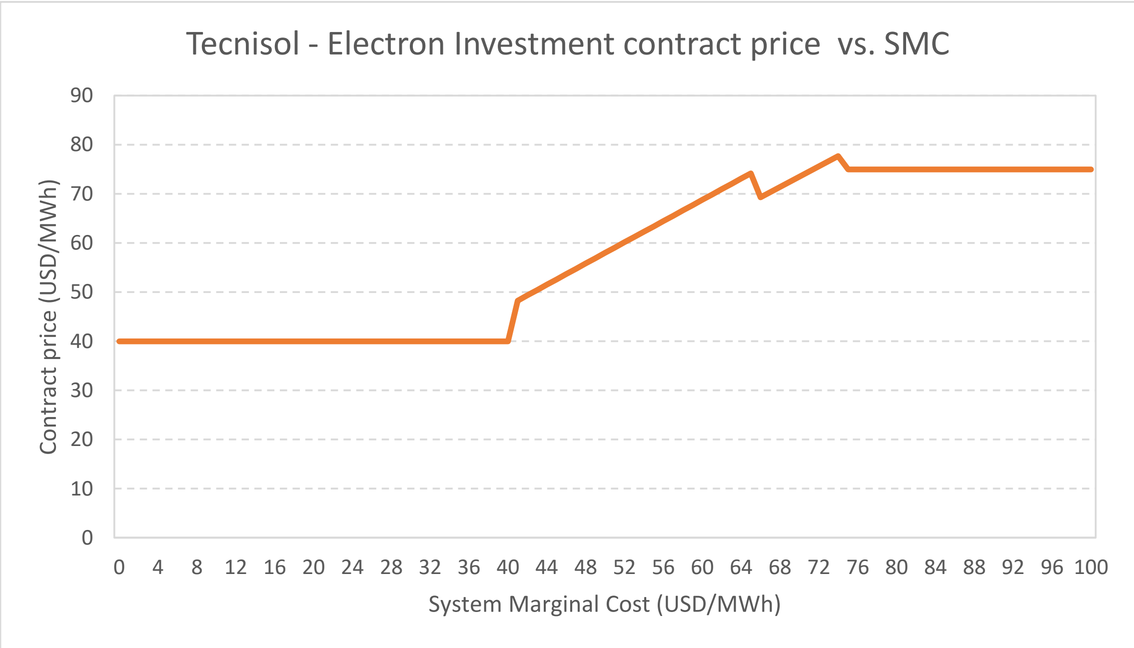
Electron Investment available energy:

Note: energy surplus must be calculated as the energy generated by Electron Investment minus its own committed energy in previous contracts

Exhibit 51: Prices of the back-up contract between Tecnisol and Electron Investment

System Marginal Cost (USD/MWh)	Energy Price (USD/MWh)
SMC <= 40.00	EP = 40
40.00 < SMC <= 65.00	EP = 4 + 1.08 SMC
65.00 < SMC < 75.00	EP = 1.05 SMC
SMC >= 75.00	EP = 75

Source: PPAs information, by the Client.



It is noted that the formulated equation is not continuous and displays jumps at each interval change. Contract has a cap price in 75 USD/MWh and a base price in 40 USD/MWh.

1.2.6. Tecnisol – Tecnisol

Both Tecnisol I and Tecnisol III have backup contracts with the remaining units of Tecnisol solar farm. Thus, both Tecnisol I and Tecnisol III have reserve contracts with Tecnisol II and IV. All these contracts have same price of 74.9 USD/MWh.

1.2.7. Backup contracts priority

Based on prices and characteristics of the backup contracts signed by Tecnisol, the Client has established a merit order in the use of surplus energy, should it be required to cover its contracts with large clients.

Next Exhibit shows the priority in the use of surplus energy that be considered:

Agente	Tecnisol III, S.A.	(Comprador)
Contratos de Reserva		
Orden de Prelación	**Agente**	**Parte**
1	Tecnisol IV, S.A.	Vendedor
2	Tecnisol II, S.A.	Vendedor
3	UEP Penonomé II, S.A.	Vendedor
4	Electron Investment, S.A.	Vendedor
5	Generadora del Istmo, S.A.	Vendedor
6	Saltos del Francolí, S.A.	Vendedor
7	Hydro Caisán, S.A.	Vendedor
8	Generadora Pedregalito, S.A.	Vendedor
9	Generadora Río Chico, S.A.	Vendedor
10	Alto Valle, S.A.	Vendedor

Source: CND note ("TEC 021-20 CND.pdf")

1.3. Prices of the supply contracts with large clients

The price paid by the off taker (large client) CEG is set initially near 90 US$/MWh (base price). It is updated every semester according to the evolution of the regulated tariff, with a price cap (near 125/135 US$/MWh, depending on the contract) and a price floor (near 83 US$/MWh, depending on the contract). The regulated tariff defined in each contract corresponds to the regulated tariff each large client is currently paying, and it depends on the Distributor[18] that is presently providing him the unbundling service and on the voltage level at which the client is connected.

The equation to update the contract price is the same for all contracts, the initial price, the price cap, the price floor and the regulated tariff is specific for each contract.

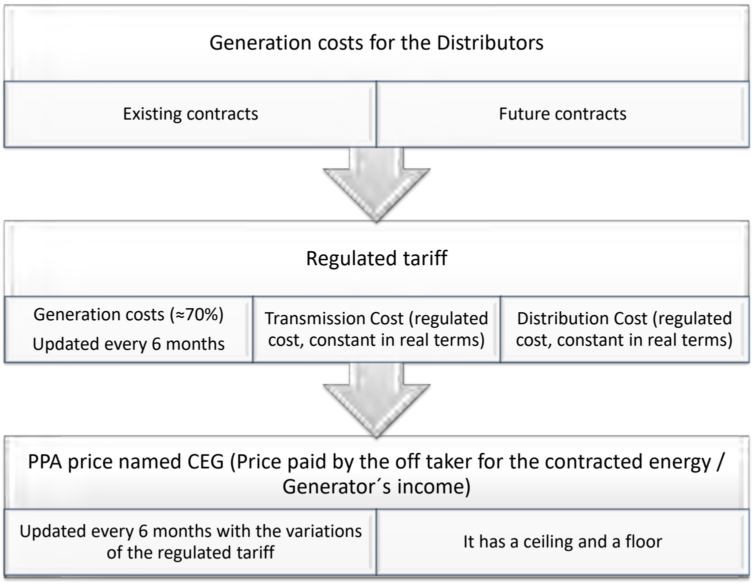
$$CEG_i = CEG_{i-1} \times (1 + (FAJU \times (\Delta T_{rp} - 1)))$$

Where ΔT is the variation in the regulated tariff and FAJU is a factor between 1 and 0,7 that cushions subsequent tariff increases if CEG is above a certain level (in example 120 US$/MWh).

Therefore, in order to project the future evolution of the CEG (contract price), it is necessary to assess the evolution of the regulated tariff which, in turn, depends on the forecast of the generation costs for the distributors. The next chart illustrates the sequence of calculations, as explained in the following sub-sections.

[18] There are three distribution companies in Panama, each one with a different tariff scheme.

Exhibit 52 - Sequence of calculations to estimate the evolution of the CEG



Source: own elaboration

1.3.1. Evolution of the regulated tariff

The regulated tariff to final users[19] is set by adding charges to cover the costs of the different segments of the value chain: generation costs, transmission costs and distribution & commercialization costs. Both the transmission and the distribution are regulated activities. The Regulator ASEP periodically sets (every four years) the maximum allowed income that these companies are entitled to receive. We have assumed that this regulated income does not change significantly over time in real terms. Therefore, the variations of the regulated tariff are mostly driven by the variations in the generation costs for the distributors.

The generation cost is the cost of purchasing energy and capacity to supply the distributor's demand, which basically arises from the price of contracts among the distributors and the generators[20]. The generation cost represents approximately 70% of the total regulated tariff. The regulated tariff is updated every six months with the variations of the generation costs.

1.3.2. Historical and present generation costs for the distributors

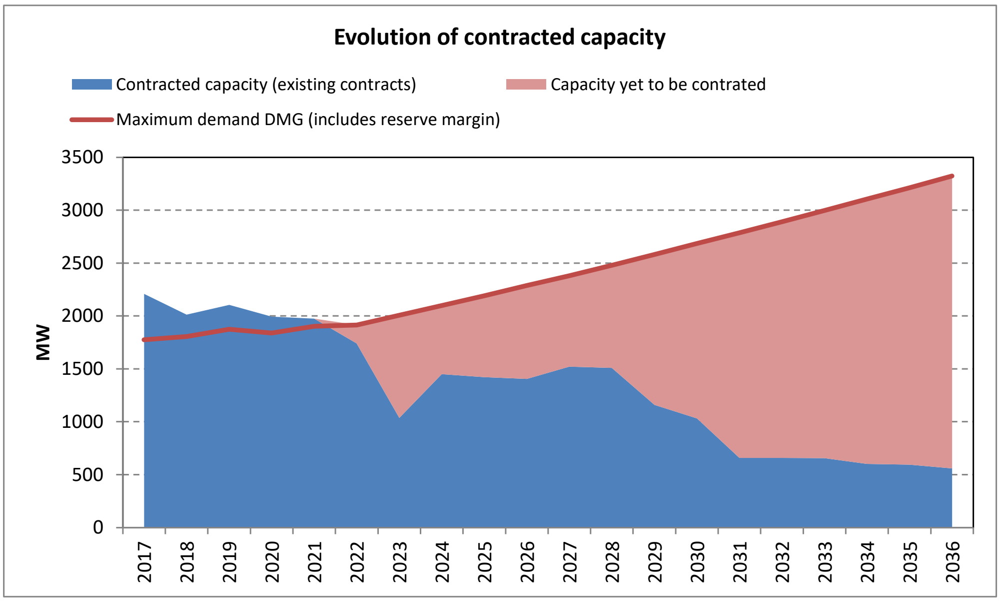
In accordance with the market rules, the Distributors in Panama have the obligation to contract their expected demand plus a reserve margin in advance. To do so, ETESA (acting on behalf of the Distributors) carries out public tenders to purchase the supply needs at competitive prices. As a result of the tenders, the contracted demand covers the needs of the distributors until year 2020 (blue area in the graph below). From this year onwards, as demand continues growing, there is the

[19] Please see Section I.2.6 for further details

[20] The cost of purchasing energy and capacity is also influenced by the cost of purchasing energy/capacity in the spot market but in a small proportion, only to cover short-term imbalances between actual demand and contracted demand.

need to renew existing contracts and / or add new capacity to the system.

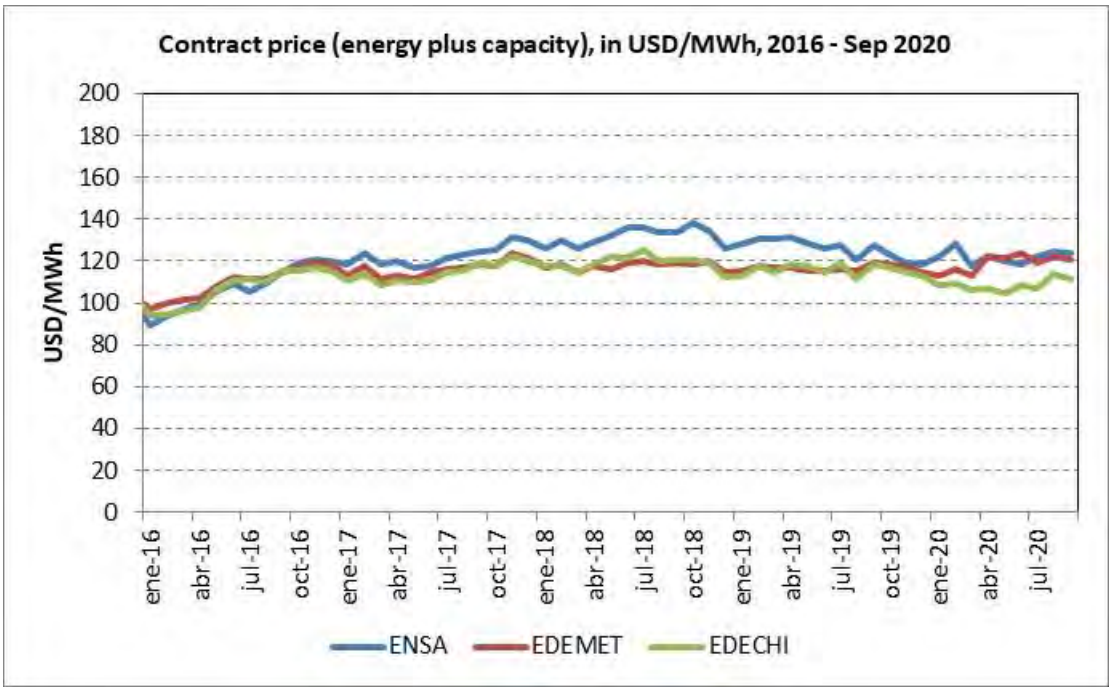
Exhibit 53 - Evolution of contracted demand



Source: own elaboration (data from ASEP and CND)

With respect to contract prices in the Panamanian market, the graph below presents the historical evolution in the last 4 years. Present contract price (average of the three distributors is 118 US$/MWh, Sep-2020):

Exhibit 54 - Historical evolution of contract prices



Source: own elaboration (data from ASEP and CND).
It includes both energy and capacity payments (monomic prices)

It is worth to mention that historically ENSA has been more expensive than EDEMET and EDECHI. However, the gap between them is reducing since year 2013 and we expect this trend to continue in the future until reaching a single generation cost for all the distributors. We believe so because since year 2009, it is ETESA (acting as single buyer on behalf of the Distributors) who carries out the tenders for the long term supply contracts, and not each Distributor independently as it was before year 2009.

1.3.3. Forecast of the generation costs for the distributors

In order to forecast the future evolution of the contract prices in Panama (the ultimate goal is to forecast the evolution of the regulated tariff to finally project the CEG), we took into consideration the following data:

a) Prices, quantities and expiration dates of the existing contracts (Source: ASEP)[21]
b) Prices and quantities of the long term contracts of the new CCGTs[22], 350MW Gas Natural Atlántico (AES) and 550MW NG Power, as follows:

New CCTs	Capacity price (*) (US$/kW-month)	Energy price (*) (US$/kWh)	Estimated monomic price (US$/MWh)	Startup date
GN Atlántico	38.83	0.0268	112	Sep 2018
Martano	32.09	0.0209	85	not considered
NG Power	18.89	0.0880	125	Jan 2024

(*): Prices awarded in the public tenders carried out by ETESA in 2015.-

c) The contract prices that maintain, through FAJU, a component that follows the real evolution of fuels were updated in time. So forth, the planned price evolution was considered in the simulation scenario of this study.

Comb	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal	USD/Ton	33.4	46.5	63.5	64.6	66.8	68.3	69.8	71.4	72.1	73.5	74.8	76.4	77.2	79.7	80.9	82.4	84.3	84.7	86.1	87.5	88.4
FO6	USD/bbl	23.2	36.6	55.3	56.6	59.2	61.3	63.4	65.4	66.4	68.3	69.7	71.7	72.7	76.0	77.6	79.4	81.9	82.5	84.4	86.2	87.4
Diesel	USD/bbl	39.1	57.0	80.7	82.4	85.0	87.3	89.5	91.4	93.0	95.1	96.7	98.9	100.4	103.5	105.3	107.3	109.8	110.9	113.0	115.0	116.6
Gas	USD/MMBtu	2.1	2.9	2.6	2.6	2.7	2.9	3.2	3.3	3.4	3.4	3.4	3.3	3.3	3.4	3.4	3.4	3.4	3.5	3.5	3.5	3.5

d) Projected capacity balance and projected spot prices in the mid-term (2020-2024) for the Reference Scenario agreed upon with the Client. We assumed a capacity price of 4.5 US$/kW-month for the contracts that are being renewed.
e) Long term equilibrium price (2030 onwards) for the Reference Scenario, estimated in 91 real 2020 US$/MWh (monomic price, it includes capacity payments at 4.50 US$/kW-month).

[21] https://www.asep.gob.pa/?page_id=12813

[22] We did not consider the NG Power CCGT (650MW) awarded in 2013 because its license was suspended in 2014. However, the Sponsor went to Court and a last minute press news says it was resolved in its favor and the startup date of the original PPA postponed to year 2020.

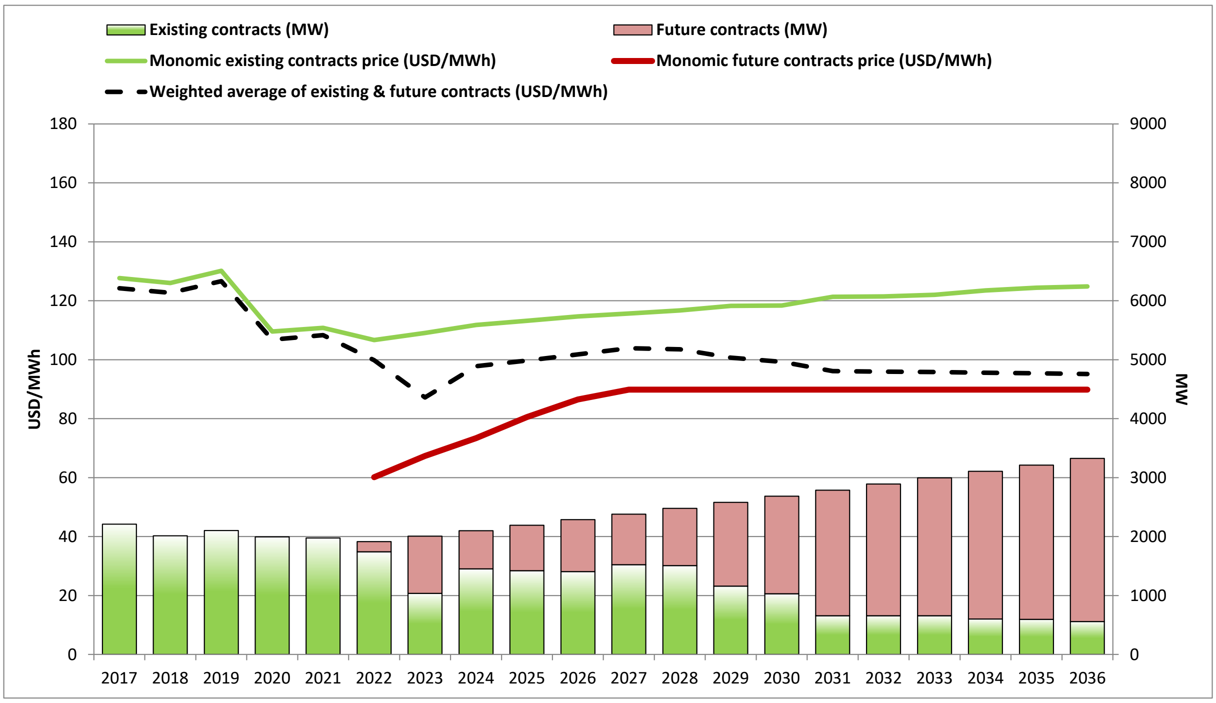
The graph below illustrates the evolution of existing contract prices and future contract prices. It is worth noting that:

i) The price of the existing contracts significantly decreases between years 2019 and 2021 because of two main reasons: the beginning of the new CCGT´s contract (350MW in total) with prices below the average price of the existing contracts and the expiration by year 2020 of near 200MW of costly existing contracts (Jinko, Kanan, among others).

ii) We have assumed that the existing contracts that expire during the time period between 2020 and 2025 are renewed at a lower price because of an increasing competition among generators (supply surplus).

iii) From 2030 onwards, we have assumed that the contract market reaches the long term equilibrium price, giving the economic signal to develop new capacity to meet the demand growth.

Exhibit 55 - Projection of generation costs (existing and future contracts) – Real 2020 USD/MWh



The graphs below show both the expected DMG ("Demanda Máxima de Generación", maximum demand at generation level) and the generation cost for the three distributors: EDEMET, ENSA and EDECHI.

Exhibit 56 - Maximum demand at generation level (DMG) – MW

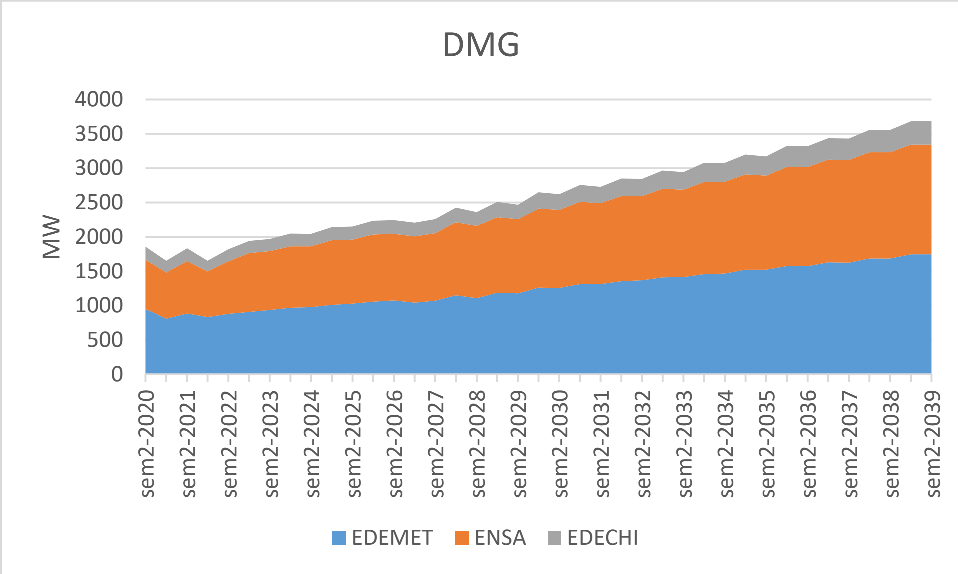
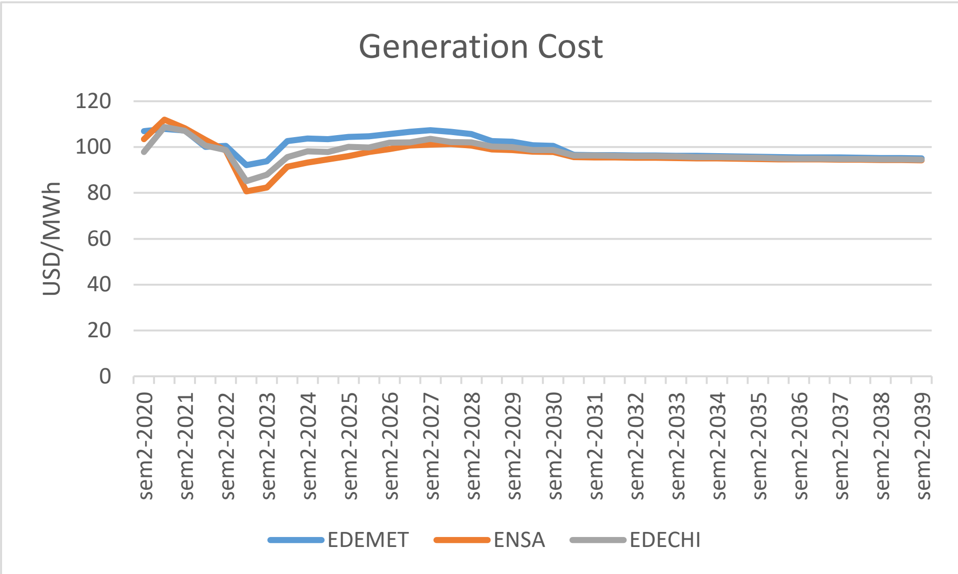


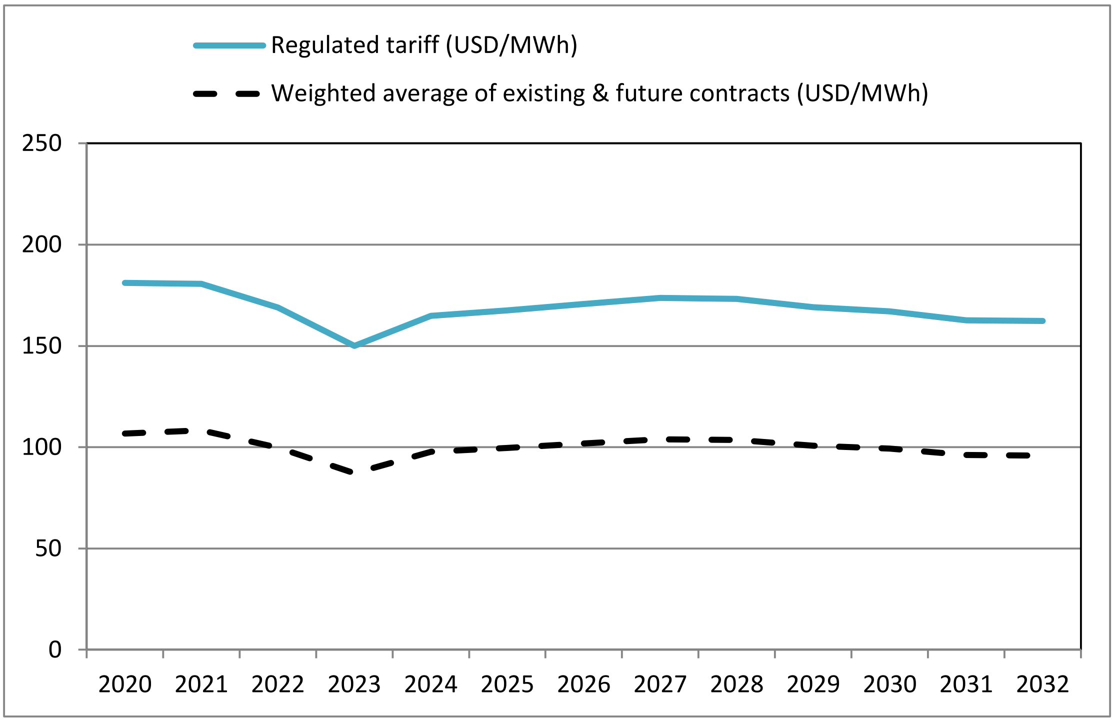
Exhibit 57 –Generation Cost expected evolution – USD/MWh



1.3.4. Forecast of the regulated tariff

The forecast of the regulated tariff is tied up to the projected generation costs (only the generation charges, transmission cost, distribution cost and losses are kept constant in real terms). The next graph illustrates the projected generation costs and the projected tariffs. For simplicity, the regulated tariff illustrated in the graph represents the average of the specific tariffs associated to the PPAs with large clients.

Exhibit 58 - Projection of the regulated tariff (real 2020 USD/MWh)



The graph below shows the annual expected average tariff for the three distributors: EDEMET, ENSA and EDECHI.

Exhibit 59 - Projection of the regulated tariff by DisCo (real 2020 USD/MWh)

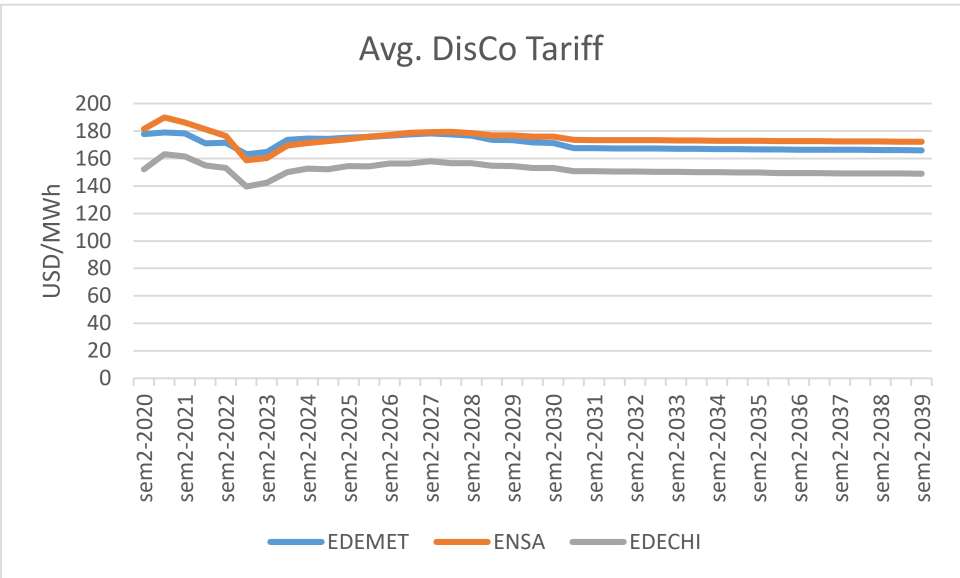
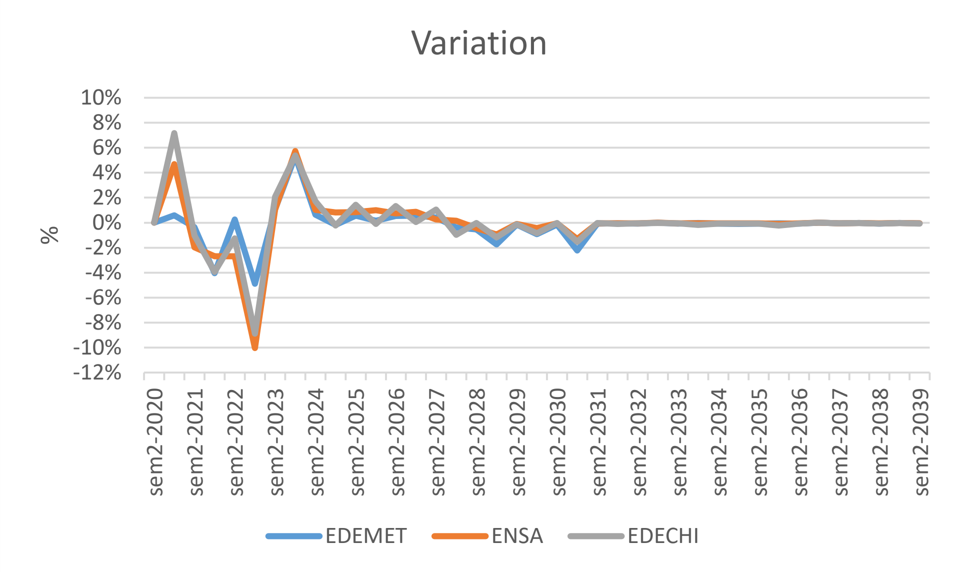


Exhibit 60 - Projection of the regulated tariff by DisCo - Moving average variation



It can be observed that in 2021, there was a relative increase based on the recovery of fuel prices (that affect those contracts tied to its evolution) and the assigned contracts whose entrance takes place within the period. Then, in 2023, there is a price drop because the expected prices for the new contracts, needed to cover the DMG, are below the prices of current contracts, due to the oversupply of the generation. In 2024, with Telfers entry, prices recover because the price at which this contract was bidden is higher. By the 2030/31, the evolution stabilizes and there are no significant changes going on.

1.3.5. Abstract of DisCo tariff results

Next table show a summary of DisCo tariff results achieved for EDEMET, ENSA and EDECHI in the reference case scenario evaluated. Similar results were shared with the Client for both sensitivities, +5% and +10% fuel prices variation.

Where:

1) "DMG": Demanda Máxima de Generación, in MW
2) "Firm capacity - Existing contracts": firm capacity in existing contracts, in MW
3) "Firm capacity price - Existing contracts": price, in USD/kW-month
4) "Firm capacity - New contracts": firm capacity in new contracts, in MW. Equal to (1)-(2)
5) "Firm capacity price - New contracts": expected price, in USD/kW-month
6) "Load Factor": DisCo load factor demand, in %
7) "Total Energy": DisCo energy demand, in GWh
8) "Energy - Existing contracts": equivalent energy in existing contracts, in GWh
9) "Energy - New contracts": equivalent energy in new contracts, in GWh. Equal to (7)-(8)
10) "Energy price - New contracts": expected price, in USD/MWh
11) "Generation Cost": expected monomic price, in USD/MWh
12) "Variation 1": variation between periods of (11), in %. Equal to [(11)i/(11)i-1]-1

13) "Other Charges (Transp+VAD)": transport fee and DisCo VAD charge, in USD/MWh
14) "Avg. DisCo Tariff": expected average DisCo Tariff, in USD/MWh
15) "Variation 1": variation between periods of (14), in %. Equal to [(14)i/(14)i-1]-1

Exhibit 60 – DisCo tariff summary results

DisCo =>	EDEMET	2020	2021	2021	2022	2022	2023	2023	2024	2024	2025	2025	2026	2026	2027	2027	2028
Ítem	Unit	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1
DMG	MW	951	812	885	832	882	909	936	968	978	1013	1031	1057	1075	1042	1074	1151
Firm capacity - Existing contracts	MW	951	812	885	716	767	576	603	793	804	776	794	759	777	755	787	795
Firm capacity price - Existing contracts	USD/kW-month	17.4	17.9	16.4	19.1	18.0	19.8	19.0	19.2	18.8	19.2	18.8	18.9	18.6	19.0	18.6	19.6
Firm capacity - New contracts	MW	0	0	0	116	116	333	333	174	174	236	236	298	298	287	287	356
Firm capacity price - New contracts	USD/kW-month	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Load Factor	p.u.	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%
Total Energy	GWh	2350	2432	2472	2447	2487	2563	2605	2679	2723	2795	2842	2915	2963	3033	3083	3156
Energy - Existing contracts	GWh	2350	2432	2472	2106	2161	1624	1679	2196	2238	2143	2190	2092	2141	2198	2260	2179
Energy - New contracts	GWh	0	0	0	341	326	938	926	482	485	653	652	823	822	835	824	977
Energy price - New contracts	USD/MWh				48.3	53.3	56.8	59.2	62.2	65.9	69.8	72.6	76.0	78.3	80.5	80.5	80.5
Generation Cost	USD/MWh	106.9	108.0	107.3	100.1	100.5	92.1	93.9	102.6	103.7	103.4	104.4	104.7	105.6	106.6	107.4	106.7
Variation	%		1.0%	-0.6%	-6.7%	0.4%	-8.4%	1.9%	9.3%	1.1%	-0.3%	0.9%	0.3%	0.9%	0.9%	0.7%	-0.7%
Other Charges (Transp+VAD)	USD/MWh	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9
Avg. DisCo Tariff	USD/MWh	177.8	178.8	178.2	171.0	171.4	163.0	164.8	173.5	174.6	174.3	175.3	175.6	176.5	177.5	178.3	177.6
Variation	%		0.6%	-0.4%	-4.0%	0.2%	-4.9%	1.1%	5.3%	0.6%	-0.2%	0.6%	0.2%	0.5%	0.6%	0.4%	-0.4%

DisCo =>	EDEMET	2028	2029	2029	2030	2030	2031	2031	2032	2032	2033	2033	2034	2034	2035	2035	2036	2036	2037	2037	2038	2038	2039	2039
Ítem	Unit	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2
DMG	MW	1007	1190	1176	1261	1258	1313	1313	1357	1367	1412	1415	1456	1468	1522	1521	1575	1574	1630	1627	1687	1687	1746	1746
Firm capacity - Existing contracts	MW	651	589	576	524	522	302	303	298	307	301	304	286	298	279	278	279	278	279	275	275	275	275	275
Firm capacity price - Existing contracts	USD/kW-month	16.2	13.5	13.9	14.2	14.1	17.2	17.2	17.4	16.9	17.2	17.1	18.2	17.4	18.6	18.7	18.6	18.7	18.6	18.9	18.9	18.9	18.9	18.9
Firm capacity - New contracts	MW	356	601	601	737	737	1011	1011	1060	1060	1111	1111	1170	1170	1243	1243	1296	1296	1351	1351	1412	1412	1471	1471
Firm capacity price - New contracts	USD/kW-month	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Load Factor	p.u.	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%
Total Energy	GWh	3209	3284	3338	3417	3473	3543	3602	3675	3736	3809	3872	3947	4012	4080	4148	4221	4291	4366	4439	4517	4592	4672	4750
Energy - Existing contracts	GWh	2073	1626	1634	1421	1440	816	830	806	840	813	831	775	814	747	758	747	758	747	752	736	748	736	748
Energy - New contracts	GWh	1136	1658	1704	1996	2033	2727	2771	2869	2896	2996	3041	3171	3198	3333	3390	3474	3533	3620	3687	3781	3843	3936	4002
Energy price - New contracts	USD/MWh	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5
Generation Cost	USD/MWh	105.7	102.6	102.4	100.7	100.5	96.7	96.5	96.5	96.3	96.3	96.2	96.2	96.0	95.9	95.7	95.7	95.5	95.5	95.4	95.4	95.3	95.2	95.1
Variation	%	-0.9%	-2.9%	-0.3%	-1.6%	-0.3%	-3.8%	-0.1%	-0.1%	-0.1%	0.0%	-0.1%	0.0%	-0.1%	-0.2%	-0.1%	-0.1%	-0.1%	0.0%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%
Other Charges (Transp+VAD)	USD/MWh	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9
Avg. DisCo Tariff	USD/MWh	176.6	173.5	173.2	171.6	171.4	167.6	167.4	167.4	167.2	167.2	167.1	167.1	166.9	166.8	166.6	166.6	166.4	166.4	166.3	166.3	166.2	166.1	166.0
Variation	%	-0.5%	-1.7%	-0.2%	-0.9%	-0.2%	-2.2%	-0.1%	0.0%	-0.1%	0.0%	-0.1%	0.0%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	0.0%	-0.1%	0.0%	-0.1%	0.0%	-0.1%

DisCo =>	ENSA	2020	2021	2021	2022	2022	2023	2023	2024	2024	2025	2025	2026	2026	2027	2027	2028
Ítem	Unit	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1
DMG	MW	718	669	762	662	761	858	855	897	884	938	931	978	971	967	981	1059
Firm capacity - Existing contracts	MW	718	669	762	647	746	320	317	488	474	473	466	474	466	472	486	524
Firm capacity price - Existing contracts	USD/kW-month	13.7	12.9	11.8	12.8	11.4	20.6	20.9	19.8	20.0	19.7	20.0	19.7	20.0	19.7	20.0	19.9
Firm capacity - New contracts	MW	0	0	0	16	16	538	538	409	409	465	465	504	504	495	495	535
Firm capacity price - New contracts	USD/kW-month	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Load Factor	p.u.	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%
Total Energy	GWh	2227	2305	2343	2319	2358	2429	2469	2539	2581	2650	2694	2763	2809	2875	2923	2992
Energy - Existing contracts	GWh	2227	2305	2343	2265	2310	907	916	1380	1386	1337	1350	1338	1350	1403	1449	1480
Energy - New contracts	GWh	0	0	0	54	48	1522	1554	1159	1196	1313	1344	1425	1459	1472	1474	1512
Energy price - New contracts	USD/MWh				48.3	53.3	56.8	59.2	62.2	65.9	69.8	72.6	76.0	78.3	80.5	80.5	80.5
Generation Cost	USD/MWh	103.5	112.0	108.2	103.2	98.4	80.7	82.3	91.5	93.2	94.6	96.1	97.8	99.1	100.7	101.1	101.4
Variation	%		8.2%	-3.3%	-4.6%	-4.7%	-18.0%	2.1%	11.2%	1.9%	1.5%	1.5%	1.8%	1.3%	1.5%	0.5%	0.3%
Other Charges (Transp+VAD)	USD/MWh	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0
Avg. DisCo Tariff	USD/MWh	181.4	189.9	186.2	181.2	176.3	158.6	160.3	169.5	171.2	172.6	174.1	175.8	177.1	178.6	179.1	179.4
Variation	%		4.7%	-2.0%	-2.7%	-2.7%	-10.0%	1.0%	5.7%	1.0%	0.8%	0.8%	1.0%	0.7%	0.9%	0.3%	0.2%

DisCo =>	ENSA	2028	2029	2029	2030	2030	2031	2031	2032	2032	2033	2033	2034	2034	2035	2035	2036	2036	2037	2037	2038	2038	2039	2039
Ítem	Unit	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2
DMG	MW	956	1099	1083	1152	1135	1197	1178	1238	1228	1288	1271	1342	1334	1387	1371	1444	1443	1494	1492	1546	1546	1600	1600
Firm capacity - Existing contracts	MW	421	394	378	373	356	254	235	250	240	253	236	239	231	238	222	222	222	222	221	220	220	220	220
Firm capacity price - Existing contracts	USD/kW-month	17.1	14.1	14.7	14.4	15.0	16.4	17.7	16.7	17.3	16.4	17.6	17.4	18.0	17.5	18.7	18.7	18.7	18.7	18.8	18.9	18.9	18.9	18.9
Firm capacity - New contracts	MW	535	705	705	779	779	943	943	989	989	1035	1035	1104	1104	1150	1150	1221	1221	1271	1271	1326	1326	1380	1380
Firm capacity price - New contracts	USD/kW-month	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Load Factor	p.u.	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%
Total Energy	GWh	3041	3113	3164	3239	3292	3358	3414	3483	3541	3611	3671	3741	3803	3868	3932	4001	4067	4139	4207	4281	4352	4429	4502
Energy - Existing contracts	GWh	1339	1115	1104	1048	1033	713	682	702	691	709	683	665	658	663	636	616	625	616	622	609	619	609	619
Energy - New contracts	GWh	1703	1998	2061	2191	2259	2646	2732	2781	2850	2902	2988	3076	3145	3205	3295	3385	3442	3523	3585	3672	3733	3820	3883
Energy price - New contracts	USD/MWh	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5
Generation Cost	USD/MWh	100.6	99.0	98.8	98.0	97.9	95.6	95.5	95.4	95.3	95.3	95.2	95.1	95.0	95.0	94.8	94.7	94.6	94.6	94.5	94.5	94.4	94.3	94.2
Variation	%	-0.8%	-1.7%	-0.2%	-0.8%	-0.1%	-2.3%	-0.1%	-0.1%	-0.1%	0.0%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.2%	-0.1%	0.0%	-0.1%	0.0%	-0.1%	-0.1%	-0.1%
Other Charges (Transp+VAD)	USD/MWh	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0
Avg. DisCo Tariff	USD/MWh	178.6	176.9	176.7	176.0	175.9	173.6	173.5	173.4	173.3	173.3	173.2	173.1	173.0	172.9	172.8	172.7	172.6	172.6	172.5	172.4	172.3	172.3	172.2
Variation	%	-0.4%	-0.9%	-0.1%	-0.4%	-0.1%	-1.3%	-0.1%	0.0%	-0.1%	0.0%	-0.1%	-0.1%	-0.1%	0.0%	-0.1%	-0.1%	-0.1%	0.0%	-0.1%	0.0%	-0.1%	0.0%	-0.1%

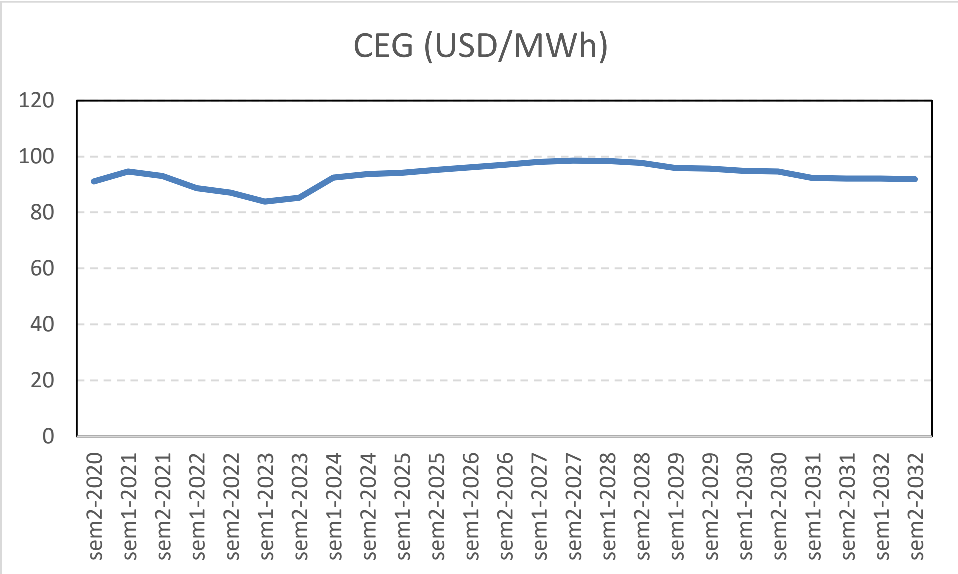
DisCo =>	EDECHI	2020	2021	2021	2022	2022	2023	2023	2024	2024	2025	2025	2026	2026	2027	2027	2028
Ítem	Unit	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1
DMG	MW	187	172	188	161	180	176	177	183	182	192	190	201	200	197	202	216
Firm capacity - Existing contracts	MW	187	172	188	161	180	94	96	131	130	130	129	130	129	129	134	137
Firm capacity price - Existing contracts	USD/kW-month	10.7	11.0	10.2	11.1	10.1	16.9	16.7	16.4	16.7	16.5	16.8	16.6	16.8	16.7	16.9	17.8
Firm capacity - New contracts	MW	0	0	0	0	0	82	82	52	52	61	61	71	71	69	69	78
Firm capacity price - New contracts	USD/kW-month	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Load Factor	p.u.	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
Total Energy	GWh	523	541	550	544	553	570	579	596	606	622	632	648	659	675	686	702
Energy - Existing contracts	GWh	523	541	550	544	553	305	313	426	431	423	428	419	425	440	453	447
Energy - New contracts	GWh	0	0	0	0	0	265	267	170	174	199	204	229	234	235	233	255
Energy price - New contracts	USD/MWh				48.3	53.3	56.8	59.2	62.2	65.9	69.8	72.6	76.0	78.3	80.5	80.5	80.5
Generation Cost	USD/MWh	97.8	108.7	107.1	100.7	98.7	85.1	88.0	95.6	98.2	97.9	100.1	99.9	102.0	102.0	103.7	102.1
Variation	%		11.2%	-1.5%	-6.0%	-1.9%	-13.8%	3.4%	8.7%	2.7%	-0.3%	2.2%	-0.2%	2.1%	0.1%	1.6%	-1.5%
Other Charges (Transp+VAD)	USD/MWh	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4
Avg. DisCo Tariff	USD/MWh	152.2	163.1	161.5	155.1	153.1	139.5	142.4	150.0	152.6	152.3	154.4	154.3	156.3	156.4	158.0	156.5
Variation	%		7.2%	-1.0%	-4.0%	-1.3%	-8.9%	2.1%	5.4%	1.7%	-0.2%	1.4%	-0.1%	1.3%	0.0%	1.0%	-1.0%

DisCo =>	EDECHI	2028	2029	2029	2030	2030	2031	2031	2032	2032	2033	2033	2034	2034	2035	2035	2036	2036	2037	2037	2038	2038	2039	2039
Ítem	Unit	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2	sem1	sem2
DMG	MW	184	222	211	237	228	248	237	255	250	266	257	281	276	290	281	304	304	315	314	326	326	337	337
Firm capacity - Existing contracts	MW	106	106	95	99	90	74	64	72	66	74	64	65	61	65	56	56	56	56	55	55	55	55	55
Firm capacity price - Existing contracts	USD/kW-month	16.2	12.7	14.3	13.1	14.4	14.0	16.3	14.5	15.7	14.1	16.2	15.9	17.0	16.0	18.7	18.6	18.7	18.6	18.9	18.9	18.9	18.9	18.9
Firm capacity - New contracts	MW	78	116	116	138	138	173	173	183	183	193	193	215	215	225	225	248	248	259	259	271	271	282	282
Firm capacity price - New contracts	USD/kW-month	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Load Factor	p.u.	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
Total Energy	GWh	714	730	743	760	773	788	801	817	831	847	861	878	892	908	923	939	954	971	987	1005	1021	1039	1057
Energy - Existing contracts	GWh	410	350	335	318	304	236	215	230	220	234	215	204	197	203	183	172	174	172	173	169	172	169	172
Energy - New contracts	GWh	304	381	408	442	468	552	586	588	610	613	646	674	696	705	740	767	780	799	814	835	849	870	884
Energy price - New contracts	USD/MWh	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5	80.5
Generation Cost	USD/MWh	102.1	100.2	100.0	98.7	98.7	96.3	96.3	96.1	96.1	96.0	96.0	95.7	95.6	95.5	95.4	95.0	94.9	94.9	94.9	94.8	94.7	94.7	94.6
Variation	%	0.0%	-1.8%	-0.2%	-1.3%	0.0%	-2.4%	-0.1%	-0.2%	-0.1%	0.0%	-0.1%	-0.3%	-0.1%	-0.1%	-0.1%	-0.3%	-0.1%	0.0%	-0.1%	0.0%	-0.1%	-0.1%	-0.1%
Other Charges (Transp+VAD)	USD/MWh	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4
Avg. DisCo Tariff	USD/MWh	156.5	154.6	154.4	153.1	153.1	150.7	150.7	150.5	150.4	150.4	150.4	150.1	150.0	149.9	149.8	149.4	149.3	149.3	149.2	149.2	149.1	149.1	149.0
Variation	%	0.0%	-1.2%	-0.1%	-0.8%	0.0%	-1.5%	0.0%	-0.1%	-0.1%	0.0%	0.0%	-0.2%	-0.1%	-0.1%	-0.1%	-0.2%	-0.1%	0.0%	-0.1%	0.0%	-0.1%	0.0%	-0.1%

1.3.6. Forecast of the CEG

Finally, we projected the evolution of the CEG (PPA price) of each contract taking into consideration the base price (initial price), the variations of the regulated tariff (calculated on 6-month basis for specific categories of tariffs) and the ceiling and floor prices specified in each PPA. The next graph presents the CEG forecast (average of all contracts).

Exhibit 61 - Projection of CEG



Year =>	2020	2021	2022	2023	2024	2025	2026
sem1	-	94.7	88.7	83.9	92.5	94.2	96.1
sem2	91.0	93.0	87.1	85.3	93.7	95.2	97.0

Year =>	2027	2028	2029	2030	2031	2032
sem1	98.0	98.4	95.9	94.8	92.3	92.2
sem2	98.5	97.7	95.7	94.6	92.2	91.9

Note: shown values are an average of all contracts between Tecnisol and large clients

2. UEP II (WIND PLANTS)

2.1. Supply contracts with distribution companies (EDEMET, EDECHI & ENSA)

UEP II was awarded long term contracts in the public auctions carried out by ETESA on behalf of the distribution companies. Each of these contracts have committed generation units as follows:

Seller	Off taker (Large Clients)	Committed unit	Cap. (MW)	Date
UEP II	EDEMET, EDECHI & ENSA	Rosa de los Vientos	53.0	July 2014 to June 2029
		Nuevo Chagres	62.0	
		Portobello	32.5	
		Marañón	17.5	
		Total	**165.0**	
UEP II	EDEMET, EDECHI & ENSA	Portobello	32.5	July 2029 to Dec. 2033
		Marañón	17.5	
		Total	**50.0**	

All the supply contracts with the distribution companies have similar features, which are summarized in the next table.

Exhibit 62 - Main features of the supply contracts with EDEMET, EDECHI & ENSA

Terms	Definition	Comments
Type of contract	Energy contract follows the generation profile	Fully hedged against the financial exposure to the spot market because it follows the generation profile of UEP II units associated to these PPAs.
Contracted energy	Energy withdrew by the off taker at the delivery nodes as defined in the contract.	Contracted energy follows generation energy.
Contract price ("Precio de la energía asociada requerida")	It is the price paid by the off taker for the contracted energy, expressed in US$/MWh	Initial contract prices in the range of 100 US$/MWh (current 105 US$/MWh); updated monthly (index IPC, "Indice de Precio al Consumidor"). Initial prices of the extension contracts for Portobello and Marañón (2029-3033) are 91.9 USD/MWh and 94.9 USD/MWh respectively.
Off taker	Distribution Companies	EDEMET, EDECHI and ENSA
Contract term	15 years 54 month	Firt contract (until June 2029): 165 MW Second contract (from July 2029): 50 MW
Invoice and payment	Monthly invoice.	Contract prices are net of any taxes.
Contract price adjustment		The adjustment of the Precio del Energía Contratada Total (PECT) is associated to the indexation of the transmission charges and the IPC: $PECT_{(i)} = PEC_{(0)} \times (1\text{-}FAJU) + FAJU \times PEC_{(0)} \times (IPC_{(i)}/IPC_{(0)}) + (CT_{(i)}/CT_{(0)})$

2.2. Back-up contract between Tecnisol and UEP II

Please, see section "Tecnisol – UEP II" for further details.

2.3. Prices of the supply contracts with distribution companies

The price paid by the off taker (distribution companies) is set initially near 100 US$/MWh (base price). It is updated monthly according to the evolution of the IPC ("Indice de Precio al Consumidor") published by "Contraloría General de la República de Panamá".

The equation to update the contract price is the same for all contracts.

$$PECT_{(i)} = PEC_{(0)} \times (1\text{-}FAJU) + FAJU \times PEC_{(0)} \times (IPC_{(i)}/IPC_{(0)}) + (CT_{(i)}/CT_{(0)})$$

Where FAJU is equal to 25%.

Current price paid by the off taker (distribution companies) is near 105 US$/MWh.

CHAPTER 4: PROJECT´S POSITIONING: KEY MARKET RISKS AND OPPORTUNITIES

This Chapter of the document aims to identify the main opportunities and risks incurred by the Projects, as well as proposed mechanisms, actions, etc. to mitigate them. The risk assessment will cover market and regulatory risks. Each identified risk & opportunity will be assessed according the experience of the Consultant's team and the numerical results achieved in this study, elaborating conclusions and recommendations.

1. TECNISOL (TECNISOL I, II, III & IV SOLAR PLANTS)

Tecnisol commercializes its energy output through long-term contracts with large clients. These contracts are energy only commitments. The energy surpluses will be sold at the spot market, valued at the hourly spot price, in accordance with the Commercial Rules.

In consequence, Tecnisol carries the resource risk. To mitigate this risk it entered into back-up contracts with other generators. The energy deficits of own generation that the Tecnisol may have are covered with back-up contracts according next the priority in the use of surplus energy,

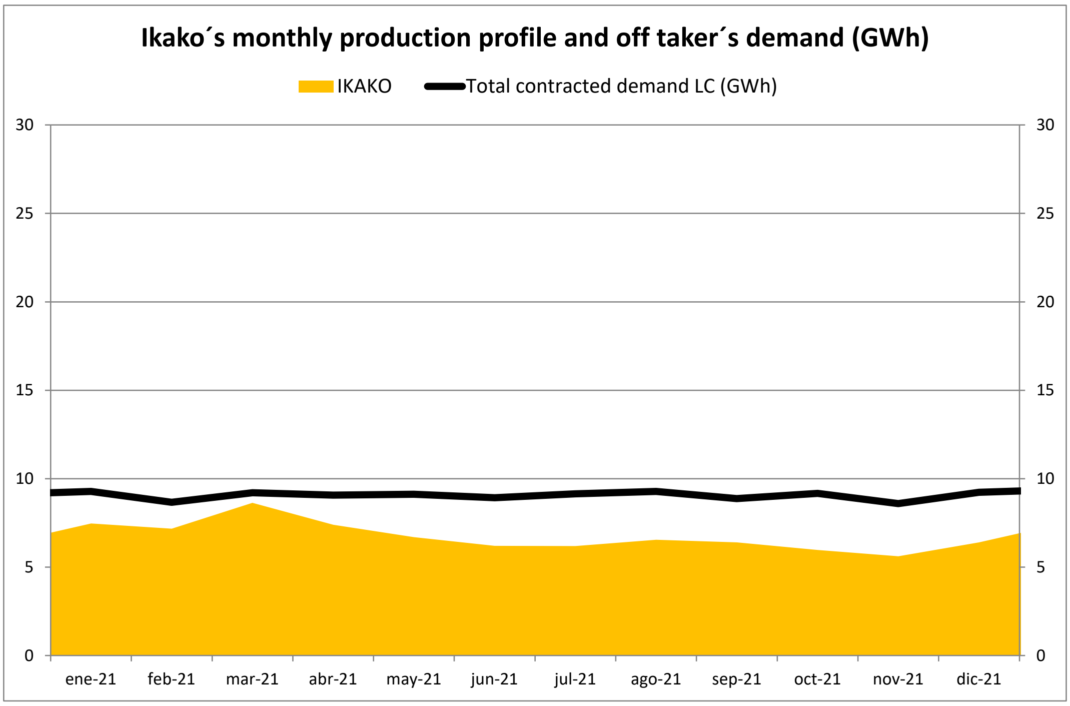
Exhibit 63: Priority in the use of surplus energy that be considered

Agente	Tecnisol III, S.A.	(Comprador)
Contratos de Reserva		
Orden de Prelación	Agente	Parte
1	Tecnisol IV, S.A.	Vendedor
2	Tecnisol II, S.A.	Vendedor
3	UEP Penonomé II, S.A.	Vendedor
4	Electron Investment, S.A.	Vendedor
5	Generadora del Istmo, S.A.	Vendedor
6	Saltos del Francolí, S.A.	Vendedor
7	Hydro Caisán, S.A.	Vendedor
8	Generadora Pedregalito, S.A.	Vendedor
9	Generadora Río Chico, S.A.	Vendedor
10	Alto Valle, S.A.	Vendedor

Source: CND note ("TEC 021-20 CND.pdf")

Both the demand of the large clients as well as Tecnisol's generation are fairly stable during the year. Tecnisol generates around 87 GWh/year (P50), while the aggregate demand of the off takers is approximately 105 GWh/year. The next graph illustrates the P50 production curves (shaded areas) and the off taker´s demand pattern (black line) for year 2021:

Exhibit 64 - Reference Scenario - Monthly production profile
of the Project (P50) and off taker´s demand, year 2021



Source: own elaboration based on the data of the Client

The next graph illustrates the daily generation of Tecnisol units p50 production level and a typical load profile curve for the off takers.

Exhibit 65 – Daily production profile of Tecnisol (p50) and Large clients´s demand, in MW

Source: own elaboration

If Tecnisol´s resources (own production plus back-up contracts) at any given hour are not enough to meet the contracted energy, Tecnisol purchases the energy deficit at the spot market at the hourly spot price. In this respect, the back-up contracts contribute to mitigate the exposure to the spot price volatility.

Net spot revenues represents the energy sales to the spot market coming from the difference between the energy generated by Tecnisol and the associated to contracts with unregulated customers (Riba Smith, Coca Cola FEMSA Panamá, Clínica Hospital San Fernando, Industrias Lácteas, Ice Gaming, Iron Tower and Ventas y Mercadeo). After contract's expiration with large clients (year 2033), all the Tecnisol's power generation will be sold to the spot market, representing the only source of incomes.

Sales to contracts with large clients are valued at the "CEG" ("Cargo por Energía de Generación" or Generation Energy Charge) established within these contracts.

Another important point to be taken into account is that the contracts established between Tecnisol and the large clients are not based on a specific consumption, which implies that Tecnisol has to provide the present and future demand of those clients, which may increase in the future or keep constant or reduce from the current levels.

Ideally, the PPAs with large clients should define an upper limit for the energy contracted to better cap the Project´s financial exposure at the spot market. However, in practice, private clients are reluctant to enter into a supply contract that sets some sort of limit to its consumption. Besides, the Project entered into back-up contracts to mitigate this risk and may celebrate additional back-up contracts in the future (or expand current contracts) in order to cover an increase in the demand of the off takers, if necessary.

The PPAs with large clients have a potential risk associated to the level of savings these PPAs represent with respect to the regulated tariff these same off takers would pay if they were served by the distribution company. If the said savings are below 8% within the contract´s duration term, then it can trigger the condition to extend the PPA for additional 5 years considering a price that allows the off taker to recover the foregone saving. Only the PPA between Tecnisol III and Riba Smith has this clause, and its represents more than 40 % of total energy associated to PPAs. The remanding PPAs do not include this clause.

2. UEP II

UEP II commercializes its energy output through long term contracts with the distributors ENSA; EDECHI and EDEMET. These contracts are only energy commitments. The energy surpluses will be sold at the spot market valued at the hourly spot price (only applies for Rosa de los Vientos II Wind Farm – 50 MW).

The PPAs with the distributors do not carry the resource risk because they follow the generation production profile of the generator. After contracts' expiration (year 2033), all the UEP II's power generation will be sold to the spot market, representing the only income source.

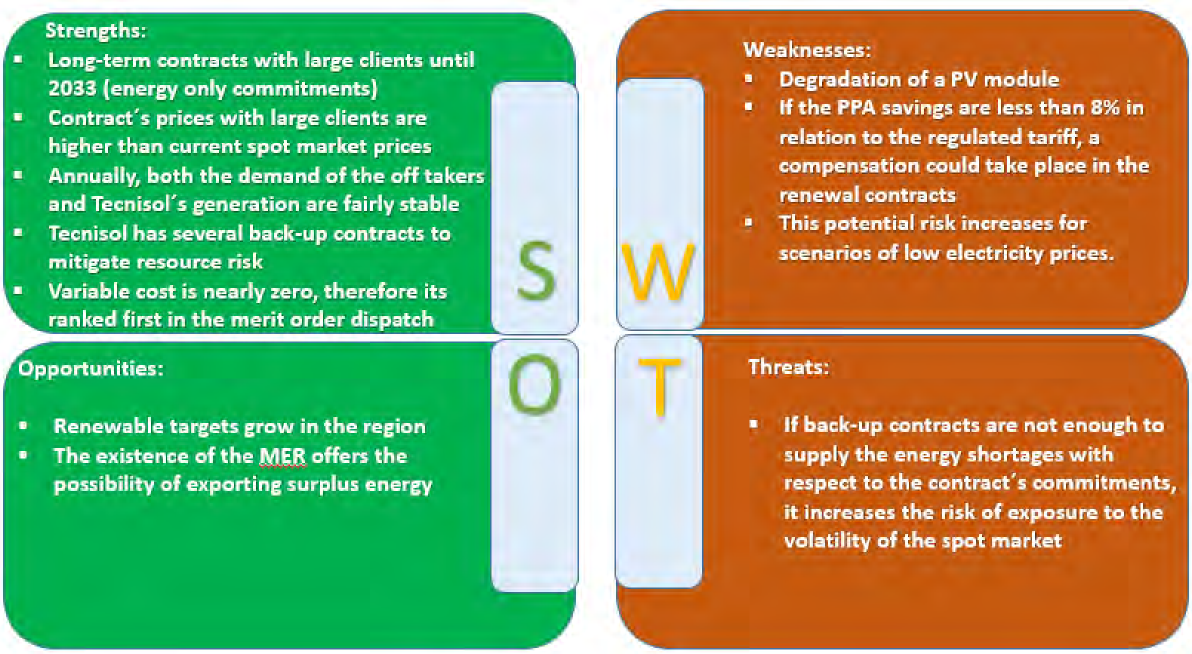
The back-up energy that UEP II supplies to Tecnisol is valued at 65.3 USD/MWh. This contract could be considered active until the year in which Tecnisol terminates its contracts with unregulated clients.

As mentioned before, the PPA with the distributors does not have the risk of financial exposure to spot price volatility. It is a take-and-pay type of contract, which means that the Buyer takes the energy generated by the committed power units at the contract price. Therefore, there is no financial exposure at the spot market and no risk associated to the demand growth of the distributors.

3. RISKS AND OPPORTUNITIES

The next Exhibits present the SWOT analysis for Tecnisol and UEP II. They summarize the key findings and main conclusions of this study.

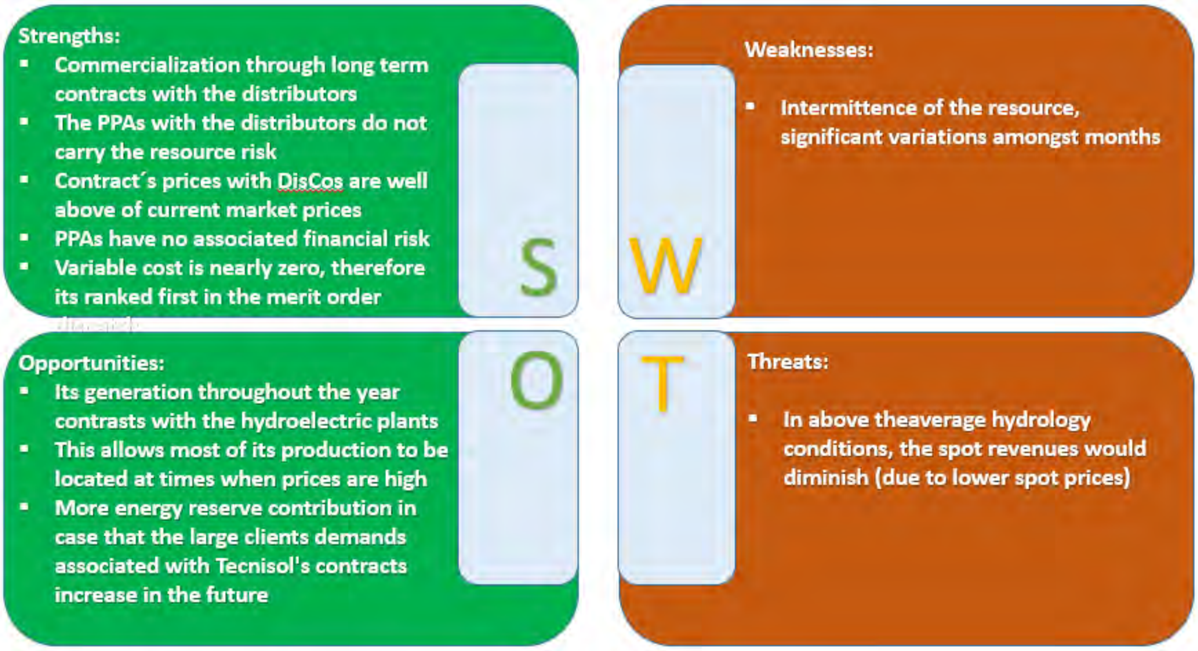
Exhibit 66 – SWOT analysis for Tecnisol



With regard to degradation of PV module, its effects can be reduced through similar back-up contracts than Tecnisol currently has, or with the incorporation of own new modules, or the usual default: the spot market.

Regarding to the threat of an exposure to the volatility of the spot market, this could be reduced with back-up contracts.

Exhibit 67 – SWOT analysis for UEP II



The expected intermittence is inherent to the wind resource. Ways to attenuate this effect is through battery storage, this allows energy to be accumulated and injected into the system at another moment.

Stability of the revenue stream / spot price volatility: contract revenues represent a large proportion of total revenues, thus mitigating the exposure to the spot market (compared to a merchant operation).

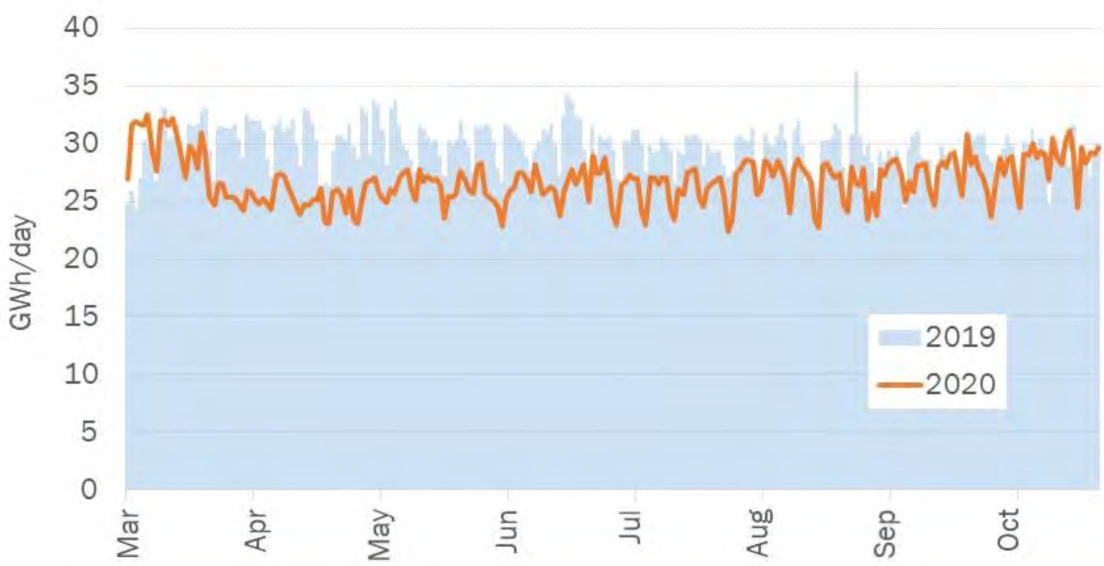
ANNEX 1: ELECTRICITY DEMAND AND SPOT PRICES DYNAMICS IN PANAMA DURING THE PANDEMIC

This Annex of the document shows the consequence of Covid-19 effects on the electricity demand and spot prices of Panamanian system.

1. ELECTRICITY DEMAND IN PANAMA DURING THE PANDEMIC

The following graph and table show the comparison between 2019/20 daily and monthly evolution of demand. As observed, between April and August, the COVID-19 Pandemic produced a strong impact on the demand, reaching a -17.2% demand drop in comparison with the same month of 2019. This plumped is a reflection of the lockdown on the country and the restrictions applied. Since April, a slow upside trend is observed and by October 2020 we can say that it has almost reached 2019 values.

Exhibit 68 – Daily evolution of electricity demand in Panama (2020 vs 2019)



Note: March to October period

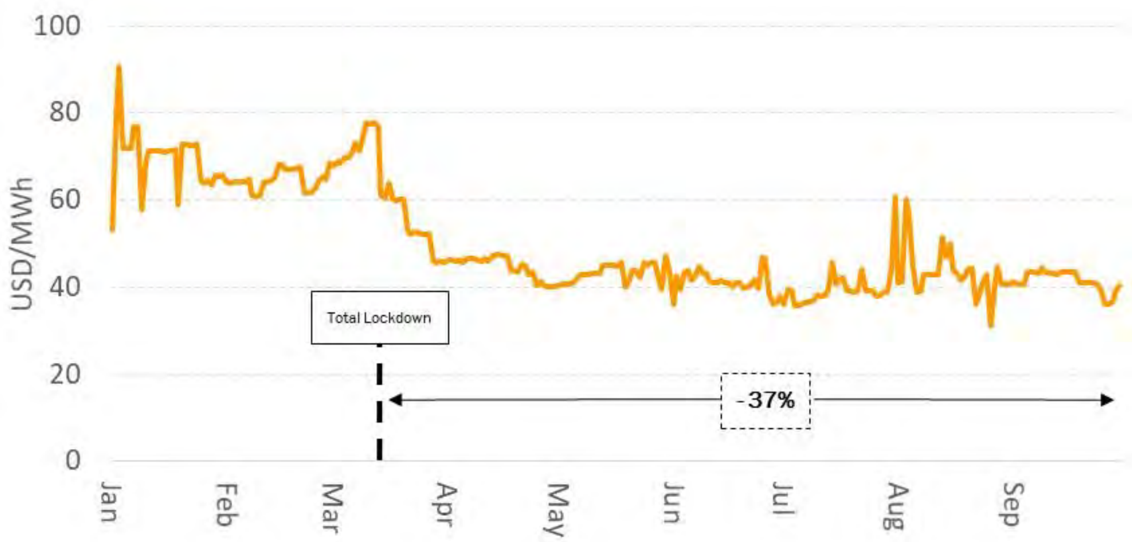
Exhibit 69 – Monthly evolution of electricity demand in Panama (2020 vs 2019)

Year/Month	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
2019	924	915	945	907	913	919	860	892
2020	885	758	808	794	814	823	823	889
Growth rate	-4.2%	-17.2%	-14.5%	-12.4%	-10.9%	-10.4%	-4.3%	-0.3%

2. SPOT PRICES IN PANAMA DURING THE PANDEMIC

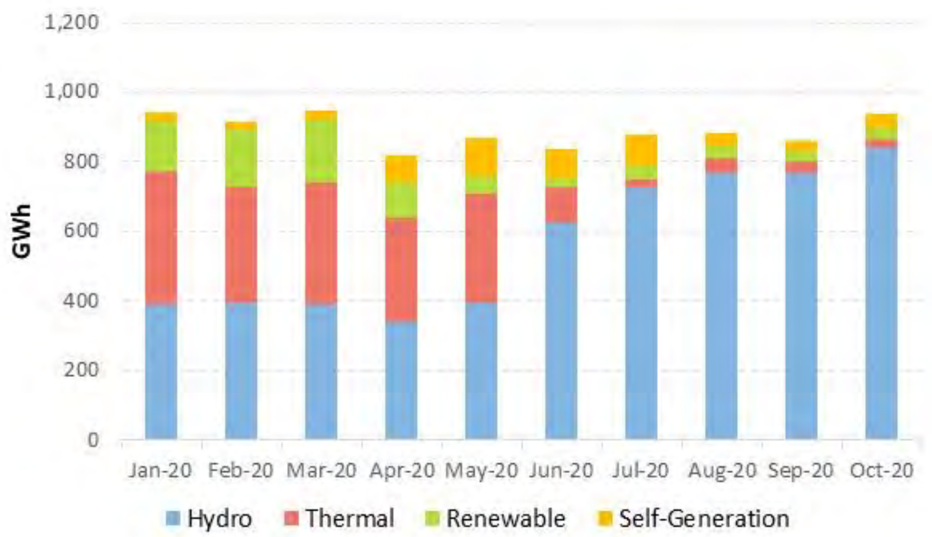
The following graph and table show the daily and monthly evolution of energy spot prices during year 2020.

Exhibit 70 – Daily evolution of energy spot prices in Panama during 2020



During the first months of the pandemic, the strong contraction on the electricity demand produced depressed energy spot prices. In September, although the demand begun to recover, the wet season arrived and with it the increase of hydroelectric plants generation the prices continue to be low reflecting the additional zero cost offer. This effect can be analyzed on the following figure that shows the generation by type.

Exhibit 71 – Monthly generation by type in Panama - Year 2020



ANNEX B

INDEPENDENT ENGINEER REPORT

TECHNICAL ADVISORY REPORT

Technical Due Diligence for Project Acquisition

PREPARED FOR:
INTERENERGY GROUP LTD.

Ref. No.: PR-005231

IKAKOS PV PROJECT AND PENONOMÉ II WIND FARM
Panamá

30 November 2020

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DOCUMENT HISTORY

ISSUE	DATE	SUMMARY
A	28 May 2020	Initial Draft
B	23 July 2020	Draft Report. Documentation Update
C	13 August 2020	Draft Report. Documentation Update
D	25 September 2020	Final Report
E	02 October 2020	Final Report, adding financial model review and Client's clarifications
F	07 October 2020	Final Report
G	06 November 2020	Final Report. Documentation Update
H	11 November 2020	Final Report. Documentation Update
I	16 November 2020	Final Report. Documentation Update
J	19 November 2020	Final Report. Documentation Update
K	24 November 2020	Final Report. Documentation Update
L	25 November 2020	Final Report. Typo correction
M	27 November 2020	Final Report. Documentation Update
N	30 November 2020	Final Report

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ACRONYMS

Acronym		Description
A	AACP	Civil Aviation Authority of Panama ("*Autoridad Aeronáutica Civil de Panamá*" in Spanish)
	AC	Alternating Current
	AMC	Asset Management Contract
	APR	Annual Performance Reduction
	ASTM	American Society for Testing Materials
B	BOP	Balance of Plant
C	CGC	China General Certification
	CND	National Dispatching Center ("*Centro Nacional de Despacho*" in Spanish)
	COD	Commercial Operations Date
	CEOC	Commercial Operation Start Certificate ("*Certificados de Entrada en Operación Comercial*" in Spanish)
	CPI	Consumer Price Index
D	DC	Direct Current
E	EIA	Environmental Impact Assessment
	EHS	Environment, Health and Safety
	EPC	Engineer, Procure, and Construct
	ETESA	Transmission System Provider ("*Empresa de Transmisión Eléctrica*" in Spanish)
	EYA	Energy Yield Assessment
F	FAC	Final Acceptance Certificate (defined in EPC Contract as "*Certificado Aceptación Definitiva*" or "CAD" in Spanish)
	FM	Financial Model
G	G&A	General and Administrative
	GCA	Grid Connection Agreement
	GIS	Gas Insulated Substation
	GPM	Green Power Monitoring
	GPR	Guaranteed Performance Ratio
	GWh	Gigawatt Hours
H	HV	High Voltage
	HVAC	Heat Ventilation and Air Conditioning
I	IA	Interconnection Agreement
	IEC	International Electrotechnical Commission
	IEH	InterEnergy Holdings
	IER	Independent Engineering Report
	IFC	Issued For Construction
	IPC	Consumer Price Index (*Indice de Precios al Consumo*)
	ISO	International Organization for Standardization
K	kW	Kilowatt
	kWh	Kilowatt Hour
	KPI	Key Performance Index
	kV	Kilovolts
	km	Kilometers

Acronym		Description
L	LeTID	Light and elevated Temperature Induced Degradation
	LID	Light-Induced Degradation
	LD	Liquidated Damage
	LV	Low Voltage
	LT	Long-term
M	m	Meters
	MCP	Measure-Correlate-Predict
	MV	Medium Voltage
	MW	Megawatt
	MWh	Megawatt Hours
	m/s	Meters per Second
	MPT	Main Power Transformer
	MPPT	Maximum Power Point Tracker
	MOR	Monthly Operations Reports
	MRA	Maintenance Reserve Account
N	NOAA	National Oceanic and Atmospheric Administration
	NTP	Notice to Proceed
O	O&M	Operations and Maintenance
	OEPR	Operational Energy Production Report
	OMA	Operation and Maintenance Agreement
P	PAC	Provisional Acceptance Certificate (defined in EPC Contract as "*Certificado de Aceptación Provisional"* in Spanish)
	PMT	Pad Mount Transformers
	PPA	Power Purchase Agreement
	PPC	Power Plant Controller
	POA	Plane of Array
	POI	Point of Interconnection
	PV	Photovoltaic
	PR	Performance Ratio
	PSS	Power System Simulator (Software)
Q	QA	Quality Assurance
	QC	Quality Control
R	RTB	Ready to build
S	SIN	National Electrical Grid (or "*Sistema Interconectado Nacional"* in Spanish)
	SINEC	SINEC "*INGENIERÍA ELÉCTRICA"*
	SLD	Single Line Diagram
	SMA	Service Maintenance Agreement
	SPT	Standard Penetration Test
T	TMY	Typical Meteorological Year
	TL	Transmission Line
U	UL	Underwriters Laboratories
	USD	US Dollars
V	VAT	Value Added Tax
W	Wp	Watt-Peak

1. INTRODUCTION

UL Services Spain SL, a UL Company ("UL"), has been engaged by InterEnergy Group Ltd., through the SPV, UEP Penonomé II, S.A. (the "Sponsor" or the "Client") to perform Technical Advisory ("TA") services in support of the evaluation of a portfolio formed by 2 projects (the "Portfolio" or the "Projects"), the Ikakos operational solar photovoltaic project ("Ikakos" or the "PV Project") and Penonomé II operational wind farm ("Penonomé II" or the "Wind Project"). The Projects are located in Panamá and consist of the following:

Table 1.1: Portfolio Overview

Project Name	**Ikakos**	**Penonomé II**
Project Capacity	45.64 MWp / 40.8 MW_{AC} limited to 40 MW_{AC} at POI	215 MW
Project location	David, Chiriquí (Panamá)	Penonomé, Cocle (Panamá)
Point of Interconnection	Mata del Nance 34.5 kV Substation	230 KV Coco Substation
Technology	PV Modules: Jinko Solar 330/325 Wp Inverter: Jema IFX6 Tracker: N-S single axis tracker	86 x Goldwind GW109 2.5 MW
Starting Operation	August 2018	During 2015 and 2016

Ikakos has a nominal capacity of 45.64 MWp / 40.8 MW_{AC} limited to 40 MW at point of interconnection ("POI"). The PV Project consists of 4 adjacent sub-plants of 10 MW_{AC} capacity at POI named Ikako 0, Ikako I, Ikako II and Ikako III. Ikakos interconnection is through an overhead 34.5 kV transmission line of approximately 13.5 km to interconnection to Mata del Nance substation. Ikakos reached the commercial operation on August 2018 and obtained the provisional acceptance ("PAC") on December 2018 for Tecnisol I, January 2019 for Tecnisol IV, and March 2019 for Tecnisol II and Tecnisol III. Final acceptance certificated ("FAC") was issued on February 2020 for all sub-plants, while commercial operation date ("COD") certificate was issued on 02 October 2020. The commercial operation start certificate ("CEOC"), as per PV Project Acceptance Agreement definition, is pending to be obtained.

"Penonomé II" has a nominal capacity of 215 MW and consist of 86 Goldwind GW190 turbines of 2.5 MW each. The Wind Project uses El Coco substation to connect to the SIN at 230 kV level. Penonomé II obtained the COD on April 2017. The Penonomé II project is adjacent to the Penonomé I project also under operation.

The scope of work performed by UL according to the agreed proposal (20-04-031026-A dated on 08 April 2020) is summarized in the following tables:

Table 1.2: Summary of the Scope of Work Covered by UL for Ikakos

Section	Status	Comment
Project Site Assessment	Completed	
Balance of Plant Design – Civil	Completed	
Balance of Plant Design – Electrical	Completed	
Technology Review	Completed	
Energy Production Report	Completed	UL's report dated 05 October 2020 included in Appendix A.

Table 1.2: Summary of the Scope of Work Covered by UL for Ikakos

Section	Status	Comment
Interconnection Agreement	Completed	
PPA	Completed	
EPC Contract	Completed	
O&M Contract	Completed	
Tests and Warranties	Completed	
Permitting review	Completed	
Financial Assessment	Completed	

Table 1.3: Summary of the Scope of Work Covered by UL for Penonomé II

Section	Status	Comment
Project Site Assessment	Completed	
Operational Energy Production Report	Completed	Work executed by UL under a separate services agreement (1101832941-4 dated on 09 April 2020). UL's report dated on 05 October 2020 included in Appendix B.
Wind Turbine Inspection and Replacement Blades Strategy	Completed	Work executed by UL under a separate services agreement (1101832941-4 dated on 09 April 2020). UL's report dated 15 September 2020 included in Appendix C.
Performance Assessment	Completed	Work executed by UL under a separate services agreement (1101832941-4 dated on 09 April 2020). UL's report dated 20 August 2020 included in Appendix D.
Life Time Extension Analysis	Completed	Work executed by UL under a separate services agreement (1101832941-4 dated on 09 April 2020). UL's report dated 18 June 2020 included in Appendix E.
Technology Review	Completed	
Balance of Plant Design – Civil	Completed	
Balance of Plant Design – Electrical	Completed	
Interconnection Agreement	Completed	
PPA	Completed	
Turbine O&M Agreement	Completed	Apart from the review of the turbine O&M agreement, UL also includes in this report the review of draft version of the First Amendment to the turbine O&M contract.
BOP O&M Contract	Completed	
Permitting review	Completed	Includes the IFC Performance standards review
Financial Assessment	Completed	

In addition, UL notes that a portfolio benefit analysis ("PBA") has been done by UL considering the production portfolio benefit of both Projects. This study has been done on 01 October 2020 and included in Appendix F.

Figure 1.1: Portfolio Location in Panamá

All capitalized terms within this report shall have the meaning given to them in the Project documents unless otherwise defined. All provision of **[Bold and Bracketed]** statements within the report represents requests for clarification, and all provision of **<Bold and Angle Bracketed>** statements within the report represent pending updates or follow-up items of the report.

2. IKAKOS PV PLANT

2.1 Executive Summary

2.1.1 Project Overview

The Project is located in San José de David in the Chiriquí province of Panama. Project site covers an area of approximately 96 hectares with a relatively flat terrain, having only a slight slope from north to south. Ikakos project is divided into 4 sub-plants of 10 MW each; Tecnisol I S.A (Ikako 0), Tecnisol II S.A. (Ikako I); Tecnisol III S.A. (Ikako II), and Tecnisol IV S.A. (Ikakos III).

The general area surrounding the PV Project site consist of agricultural and farmland including high vegetation presence in the east. The site is located approximately 15 km north of the sea; however, the surrounding area has a high presence of water streams to the sea. In addition, the Panama’s central highlands are located approximately 35 km north to PV Project site.

The Ikakos project is interconnected to Mata del Nance substation located 13.5 km from the PV Project and belongs to the state capital company (ETESA). The distribution center is located north to PV Project area (Ikako 0 sub-plant) to collect all sub-plants production at 34.5 kV. An overhead transmission line of 13.5 km with 2 independent circuits interconnects the PV Project to Mata del Nance substation.

The principal access road to the site is the Panamericana road, exit road of Agronomy University at Chiriquí town. A dirt road of approximately 2 km interconnects the Ikakos project site with the Panamericana road.

UL reviewed the operational background of the PV Project. UL notes that the main issue detected during the construction Phase of the PV Project was the isolating failure of the underground DC cabling between the strings and the combiner boxes, identified on May 2019. The underground DC cabling had isolating issues due to rainwater affection provoked by the rainy season of the area. The Client and the EPC Contractor agreed to perform a surface installation of the DC cabling with aerial trays for DC cabling placement. In addition, insulation issues were identified over a 24% the DC Cabling installed, which are Prysmian AD7 cabling (65% of the total DC cabling installed on the PV Project). The AD7 Pyrsmian insulation issue has been considered as serial defect and in order to avoid future insulation issues, Sponsor confirmed that all Pyrsmian DC cabling will be replaced.

UL was reviewed the updated DC cabling replacement status provided by the Client on 23 November 2020, which reflects a completion replacement works of 15 October 2020 (Ikako 0), 26 October 2020 (Ikako I), 16 November 2020 (Ikako II) and 19 November (Ikako III).

UL notes that the performance ratio (“PR”) calculation results for the reference testing period from 16 October to 22 November 2020 confirms the PV Project performance improvement with the DC cabling replacement. UL recommends performing a follow up on the PV Project PR on the coming months to verify that PR values are aligned with UL’s independent estimates.

2.1.2 Balance of Plant Design

2.1.2.1 Civil Review

UL was provided with a set of civil documentation of the Ikakos projects that consist on geotechnical investigation, tracker structural design, pull-out tests, drainage system and a hydrological investigation.

The geotechnical investigation was performed in the area of the PV Project and consisted of Standard Penetration Test and laboratory tests such as Atterberg limits and particle-size analysis. UL denoted that several tests normally required for a geotechnical investigation of a PV project were not included in the report.

The type of soil detected was classified as silty with high plasticity for the majority of the locations. The soil present high swelling and shrinking characteristics and the Geotechnical Engineer recommended further tests in order to determinate the expansion percentage of the soil. Also, UL denoted that groundwater level was encountered during tests. The combination of groundwater and plastic soil could lead stability problems for the civil structures; however, for the specific Ikakos Project and based on the documentation available, it is not possible to determinate if the plastic soil (with swelling and shrinking characteristics) together with the groundwater level could affect the stability of the PV structure. UL was informed that no problems have been detected during the 2 years of operation of the Project which is an indicative of a good performance of the soil till date; however, complementary geotechnical studies are recommended.

Additional tests were performed in order to qualitatively determine the swelling and shrinking properties of the soil. UL observed that according to the tests results, from the 6 locations studied, 5 of the location indicate low swelling and shrinking conditions, while only 1 indicates medium to high swelling and shrinking conditions. Based on this, UL recommends continuous monitoring of the soil conditions during the operation phase of the Ikakos Project. It is important to mention that in the case of foundation issues due to the soil conditions, these issues appear in low pace which make the early detection easy to identify. UL was informed that the Sponsor is planned to perform topographic survey when the manufacturer Gonvarri performs an annual maintenance of the tracker system UL considers this maintenance scope appropriate for the Ikakos Project.

The Geotechnical Engineer does not provide a clear recommendation for the foundation depth neither regarding the type of foundation feasible for the PV Project. However, the tracker manufacturer Gonvarri performed a complete study of the tracker system considering the soil conditions of the Ikakos Project site.

The tracker structural design was performed by the manufacturer, Solar Steel by Gonvarri on 03 October 2017. The configuration selected by the designer and manufacturer specifies that each tracker is formed by one row that will support 60 solar modules placed in landscape position in columns of three solar modules, each panels column is supported by two secondary beams, which rest on the main beams. The main beams are supported by seven piles driven into the soil. The modules are fixed to the secondary beams by mean of bolts. Each tracker will have a motor located in the central pile. The Angle range of tracker is +/-55°. Two types of trackers were designed according its position in the photovoltaic plant such as exposed and sheltered. UL considers that the materials selected for the tracker structure and the hot dipped galvanized protection are according to UL's expectations.

To perform structural calculations, solicitations and sizing of the elements Gonvarri used CYPE 2018 structural software. Three major load cases were included in the design of the tracker, dead load, wind load and seismic load. UL considers the structural verifications performed are adequate for the design. UL denoted that the tracker structural calculation did not include information regarding if the calculation considered the parameter obtained in the geotechnical investigation of the Project; however, the Sponsor confirmed that the parameters used in the structural calculation considers the specific geotechnical conditions of the Project site.

UL reviewed the pull-out tests performed by the Gonvarri on May 2017. 2 piles were tested CH-200x3 and HEB-120. Loads applied during the tests were calculated by the Structural Engineer following the same criteria and Standards used un the tracker design calculation. According to the results, the depth for the HEB-120 was 2 m and for the CH-200x3, the depth for the 68% of the piles was 1.5 m and for the 32% was 2 m. UL concurs with the results.

UL was provided by the hydrological study performed at the Project site during April 2017. The design flows was calculated for a return period of 50 years which is in line with UL´s expectations. The software HEC-RAS was used for modeling the sub-watershed in order to analyze its runoff and flooding areas during maximum events for different return periods. UL denoted that only one flooding area was determined at Ikako 0 where a natural water channel is located, and UL was informed that the existing water channel lead the water properly no further civil works were necessary. UL considers that the hydrological investigation follows the good practices of the industry.

UL was provided by a drainage system performed for the Project and denoted that a return period of 10 years was selected which is considered low, however, UL considers that this return period is low, however, considering that the drainage of the natural water channel at the east of the Project lead most of the water precipitation, 10 years of return period is acceptable. The drainage system consists of internal concrete channels of trapezoidal section and natural channels of triangular sections designed to conduct the maximum flow and velocity calculated per area of the Project.

UL concludes that civil documentation is detailed and is considered to be in line with the good practices.

2.1.2.2 Electrical Design Review

Ikakos is composed by 4 adjacent sub-plants of 10 MW. The Project has a nominal capacity of 45.64 MW_{DC} / 40.8 MW limited to 40 MW at point of interconnection (“POI”). Ikakos interconnection is through an overhead 34.5 kV transmission line of approximately 13.5 km to interconnection to Mata del Nance substation, that is the POI.

The electrical balance of plant includes: a PV array broken into 4 power blocks of 10.2 MW, four 34.5 kV medium voltage collection systems, 34.5 kV transmission line and a 34.5 kV grid connection substation. Breaking the PV array into sub-blocks allows for redundancy in system operation; if one inverter goes offline, the rest of the system is still capable of producing power.

UL notes that the Project design fulfils industry standards and includes some design studies that usually are performed later in detailed design. UL considers the design adequate and notes that pending documentation such as operative reports regarding grounding resistance, measurements, electrical losses follow up and latest final SCADA design were not available.

2.1.3 Technology Review

The PV modules installed are Jinko Solar JKM325PP (70%) and JKM330PP (30%), 72 polycrystalline cells with a nominal output power rating of 325 Wp and 330 Wp, respectively. Jinko Solar is a vertically integrated solar module manufacturer based in China. Jinko Solar began shipping standard PV modules in 2009 and has been one of the top 10 module manufacturers since 2011. The manufacturing processes, Quality Assurance/Quality Control (“QA/QC”) factory testing regime and compliance with ISO and IEC certification provided for the PV modules is consistent with the criteria for bankability of a proven PV technology. The modules have been tested and certified by IEC for operation at 1,000 V_{DC}. Jinko Solar modules have undergone PID resistance testing according to the relevant IEC standards. Jinko provides a 10-year workmanship warranty and a long term performance warranty of 80.7% at year 25, which is considered to be industry standard.

The inverter proposed for the Project is the Jema Energy central inverter with a maximum DC input voltage of 1,500 V_{DC} and a power output of 2,675 kVA at 25°C and 2,550 kVA at 50ºC. Jema is a Spanish top-tier manufacturer with a large track record with utility-scale central inverters. Jema was acquired by Irizar Group in 2009. Jema offers a 5-year standard warranty against defects in parts and workmanship for the central inverters, which warranty is considered to be industry standard. In addition, the warranty extension was purchased until year 10 and UL was informed by the Sponsor that is planning to extend the warranty until year 25.

The Hiasa-Grupo Gonvarri / Solar Steel single axis trackers proposed for the Project are constructed out of hot dipped galvanized steel and will support 60 modules mounted in 3 modules in landscape configuration. Gonvarri corporate offices are located in Madrid (Spain) and the Solar Steel group states a production background of 6.6 GW for mounting structures and trackers. The TracSmart has a tracking range of ±55° with backtracking to minimize inter row shading at the end of the day. The tracker has a 10-year warranty on the steel components, a 5-year warranty for motor and slew gear and a 20-year warranty against corrosion according to the EPC Contract. UL considers the TracSmart warranty to be aligned with industry standard.

2.1.4 Energy Production Report

Although the PV Project is under operation since August 2018, UL could not perform a reliable operational energy estimate ("OEPE") due to less than 1 year of operational data was available from the Final Acceptance (February 2020) and the lack of quantification of the DC cabling issue, detailed in Section 2.2.6, from the commercial operation start (August 2018) to Final Acceptance. Considering this, UL has performed a pre-constructive independent energy estimate ("EPE") to evaluate the long-term solar resource and energy at the proposed PV Project site.

UL performed the EPE for the PV Project current design named as standard scenario and in addition, UL estimated the energy production for the repowering scenario as per the information provided by the Client. Details of Repowering strategy is included under Section 2.5.1, with an additional capacity to be installed every 5 years of 1.7 MWp.

The energy production report ("EPR") is included in Appendix A.

Details on the project location, plant configuration parameters, and Energy Results are presented in next table:

Table 2.1: Ikakos EPE Project Summary

Project Location	Standard Scenario	Repowering Scenario
Location	Hicacos, Chiriqui (Panama)	
Project Coordinates (Lat/Lon)	8.3694, -82.3481	
Solar Resource Estimate		
Data Source	SolarGIS (1999-2019)	
GHI (kWh/m^2/year)	2,007	
DHI (kWh/m^2/year)	821	
Temperature (°C) / Wind Speed (m/s)	26.4 / 1.29	
PV Project Assumptions		
DC/AC Capacity (@40°C)	45.6 MW$_{DC}$/40.8 MW$_{AC}$	45.6 MW$_{DC}$/40.8 MW$_{AC}$ 1.7 MW$_{DC}$ to be added every 5 years
POI Capacity MW$_{AC}$	40.0 MW$_{AC}$	
DC-AC Ratio (@40°C)	1.12	1.12 (year 1-4)
DC-AC Ratio at POI (@40°C)	1.14	1.14 (year 1-4)
Evaluation Period	25 Years	

Energy Simulation Results		
POA Irradiation (kWh/m^2/year)	2,393	
Annual Degradation (material / system average)	0.51% / 0.7%	0.51% / 0.7%
First-Year Net Energy (GWh)	87.66	87.66
First-Year Performance Ratio	80.3%	80.3%

Table 2.1: Ikakos EPE Project Summary

First-Year AC Capacity Factor	24.5%	24.5%
Evaluation Period Average Net Energy (GWh)	80.80	87.51
Uncertainty Results		
First-Year Energy Uncertainty	6.4% (5,628 MWh/yr)	5.8% (116 kWh/m²/yr)
First-Year P90 (GWh) / AC Capacity Factor	80.45 / 22.5%	73.73 / 20.6%
Annual Average Energy Uncertainty	6.6% (5,349 MWh/yr)	7% (6152 MWh/yr)
Annual Average P90 (GWh) / AC Capacity Factor	73.94 / 20.7%	79.63 / 22.3%
Evaluation Period Energy Uncertainty	5.9% (4,785 MWh/yr)	6.4% (5581 MWh/yr)
Evaluation Period Average P90 (GWh) / AC Capacity Factor	74.67 / 20.9%	80.36 / 22.5%

2.1.5 Contracts Review

2.1.5.1 Interconnection Agreement

UL has reviewed four executed IA between Tecnisol I, II III and IV, the Project´s SPVs, and ETESA, the TSO that provides interconnection for the Project. UL consider the term, schedule, and conditions as typical. UL notes that the IA has not achieved COD as per ETESA letter [1] that notes the Project has not achieved the grid code compliance tests and requires PPC modification to ensure response times on reactive requirements. UL considers the issue as a risk that can be solved according typical industry practices. UL was informed that the EPC Contractor solution is still pending to be approved by the inverter manufacturer, which is going to provide a PSS simulation to verify the grid code compliance in the coming weeks. UL recommends a follow up on the EPC Contractor and the inverter manufacturer.

2.1.5.2 Power Purchase Agreement

UL performed a high level review of the amount of energy agreed and the Project capacity of the executed power purchase agreements (“PPAs”) for the sale of the PV Project energy. A total of 8 PPAs are executed for the PV Project with execution dates between March 2017 and December 2019. The PPAs CODs range from July 2019 to May 2020 with a term of 15 years, except for Petrolera Nacional S.A. that is for 10 years.

As per UL’s review, the executed PPAs covers all the PV Project capacity; 40 MW of the PV Project and in addition, part of the Wind Project capacity (117.5 MW) is assumed as back up generation and for some of them hydrological plants are also assumed as back up generation to compensate production if required.

The PPAs have a base price that range from 81.5 USD/MWh to 91.88 USD/MWh, while the price adjustment to be performed is defined by a specific formula under the PPAs considering a minimum base price adjustment (83-80 USD/MWh depending on the PPA) and a maximum base price adjustment (100-135 USD/MWh depending on the PPA.

UL notes that no specific amount of energy is defined under the PPAs since the PPA structure considers the scheme to cover all Buyers demand, considering the PV Project or the backup generation from Wind Project, hydrological plants or spot market in this order of priority.

2.1.5.3 EPC Contract

UL reviewed the executed EPC Contract of Ikakos project between each sub-project SPV and the consortium formed by Gran Solar Panamá S.A. (“Gran Solar”) and Cobra Instalaciones y Servicios (“Cobra”). The EPC Contract is for four plants of 10 MW, one for each SPV and together referred as

("Ikakos") project. For the interconnection infrastructure, a separate EPC Contract was executed for the between Tecnisol I S.A and Instalaciones y Servicios Inserpa S.A dated 24 August 2017. In addition, UL reviewed the PV Project Acceptance Agreement between the Owner and the EPC Contractor, which update the acceptance requirements for Final Acceptance and COD certificates for all sub-projects

At this stage, UL notes that the PV Project is under operation since August 2018. Ikakos reached the Provisional Acceptance Certificate ("PAC") on December 2018 (Tecnisol I), January 2019 (Tecnisol IV) and March 2019 (Tecnisol II and Tecnisol III). An amendment to the EPC Contract was executed on 01 February 2020 as PV Project Acceptance Agreement to update the requirements for acceptance certificates. All sub-plants reached the Final Acceptance Certificate ("FAC") on February 2020, while the COD certificate was issued on 02 October 2020. UL notes that the commercial operation start certificate ("CEOC"), defined in the PV Project Acceptance Agreement, is still pending (EPC Contractor responsibility) due to a pending requirement of the grid code compliance (response time). UL was informed that the EPC Contractor solution is still pending to be approved by the inverter manufacturer. UL recommends a follow up on the EPC Contractor and the inverter manufacturer solution.

The EPC Price for the scope of work including materials and installation is USD 36,849,000 (VAT excluded), equivalent to 0.81 USD/Wp for a Project Capacity of 45.64 MWp, while the interconnection infrastructure cost is equivalent to 0.06 USD/Wp. UL considers the EPC Price to be within UL's expectation based on the Project characteristics.

EPC Contract warranties are explained below (Section 2.1.5.5).

UL considers the executed EPC Contract to be consistent with industry standard considering a separate EPC Contractor for the interconnection infrastructures. UL notes that the PV Project acceptance has been delayed compared to EPC Contract schedule and that CEOC certificate is still pending. The EPC Warranty Period started on February 2020 with the Final Acceptance Certificate.

2.1.5.4 O&M Services Agreement

UL reviewed the executed O&M Services Agreement by and between InterEnergy Holdins UK Limited together with the Annexes including the O&M Plan. UL notes that the Client is responsible for the operation, maintenance and management of the PV Project, having an O&M director for the operator supervision and personnel for the management. In addition, Tecnisol I (the Ikako 0 project SPV) has own permanent staff on site to perform preventive and corrective maintenance and SCADA monitoring.

The Client is also responsible for the subcontractor's management and supervision. UL notes that tasks such as annual maintenance of trackers and inverters, vegetation control, PV module cleaning or site surveillance are subcontracted.

The O&M Plan include supervision, preventive maintenance, and corrective maintenance for the Project as well as for the interconnection facilities together with the administrative and accounting management. UL considers the preventive maintenance plan to be aligned with UL's expectations including 20% of I-V curve string measurements and PV modules thermography. The response time specified for the corrective maintenance is considered to be aligned with industry standard, including 2 hours response for major issues.

The O&M Plan includes a list of spare parts to be available at project site that is considered to be appropriate. Maintenance reports including main KPIs are to be issued in monthly basis.

O&M warranties are explained in section below (Section 2.1.5.5).

The O&M estimated budget for the scope of services detailed in the O&M Plan is equivalent to 10.1 USD/kWp including asset management tasks and all subcontractors cost. UL considers the O&M

price to be aligned with industry standard based on the scope of services included and the project characteristics.

2.1.5.5 Tests and Warranties

The EPC Contract warranty period is for 2 years starting at the Final Acceptance certificate (01 February 2020) and includes equipment warranties above equipment manufacturer's warranties such as 10 years for the inverters and MV transformers and 20 years for trackers against corrosion.

A performance ratio warranty is included under the EPC Contract for the PAC testing project acceptance and also a PR warranty is assumed for the EPC Warranty period (to be checked in monthly reports). UL notes that the Guaranteed PR ("GPR") is in the low range compared to UL's independent estimated figures. The PR tests were successful for the PAC (December 2018 (Tecnisol I), January 2019 (Tecnisol IV) and March 2019 (Tecnisol II and Tecnisol III)), while the monthly PR Warranty started in February 2020 with the FAC. UL notes that the Client estimated PR is higher than the GPR for February 2020 – April 2020, while the PV Project PR is lower than the GPR for May 2020 – October 2020. In addition, UL notes that for May – October 2020 the actual PR is 10.5% lower than UL's independent temperature corrected PR estimation presented in Table 2.19. The information provided by the Sponsor concludes that the low PR is due to the low availability of the PV Project due to the DC cabling issue. UL notes that the DC cabling replacement works detailed in Section 2.2.6 were completed on 19 November 2020. UL analyzed the PR calculation provided by the Client for the reference testing period of 16 October to 22 November 2020 to evidence the PR improvement with the DC cabling replacement available in Table 2.4 of Section 2.2.6. UL considers that PR improved with completion of the DC cabling replacement works. UL recommends a follow up on the PR results for the coming months to verify that the PR results are aligned with UL's independent figures.

If the Project fails to achieve the GPR during the EPC Warranty Period, the Contractor shall pay LDs of 0.09 USD/kWh of the project's generation for each percentage shortfall between the actual PR and the GPR. The LDs are capped to a 15% of the EPC Price. UL considers that assuming the Guaranteed PR figures, the EPC Contractor has a considerable margin to avoid LDs, however, the reviewed O&M Service Agreement by and between the Client considers GPR LDs from expected monthly temperature corrected PR aligned with UL's figures.

Regarding the O&M Service Agreement warranties, a monthly availability warranty of 98% is assumed at inverter level with a time-based availability. In case of non-compliance LDs shall apply equivalent to 1% of the annual fee for each 1% drop. In addition, a monthly Performance Ratio warranty is assumed considering a temperature corrected calculation aligned with UL's estimation. In case of non-compliance LDs shall apply from the actual corrected temperature corrected value until the EPC Contract warranted value, an LD equivalent to 0.09 USD/kWh.

2.1.6 Permitting review

UL conducted a permitting review for the Ikakos Solar Project. Ikako Project is composed of 4 SPVs named Ikakos 0, Ikako I, Ikako II and Ikako III and a transmission line of 34.5 kV. The permits reviewed where the Definite Generator Licenses, Commercial Operation Registers, Authorization Letters to dispatch energy into the National Interconnexion System, the Environmental Impact Authorizations, the Construction Licenses from the Municipality of David, the Approval for land use and zoning by the Ministry of Housing and Territorial Planning and the Interconnexion Agreements.

UL reviewed the permits sent by the Sponsor and found that are in accordance with the Panamanian legislation.

2.1.7 Financial Model Inputs Review

UL reviewed the Client's inputs considered in the financial model ("Financial Model" or "FM") provided. UL has focused its review on OPEX assumption, generation and revenue. UL has not performed any check of the FM formulation or further considerations beyond the review of the mentioned inputs.

The COD considered in the Financial Model is in line with information reviewed for PV Project and the PPA's COD. The evaluation period assumed is 25 years and the PV Project capacity is consistent with information provided.

The OPEX costs for 2020 and 2021 are estimated to be USD 1,400,410 (equivalent to 30.7 USD/kWp), and USD 1,393,476 (equivalent to 30.5 USD/kWp), respectively. UL notes that considering the maintenance structure (several services subcontracted) and the scope of services (considered to be quite complete) is assumed to be aligned with industry standard. UL notes that the long term OPEX assumptions only considers the indexation but no additional costs are assumed for main equipment replacement. A spare parts cost is assumed from year 2021 of 30,000 USD/year. UL notes that the inverter warranty for the PV Project is for 10 years, therefore, no considerable spare part cost is expected during the inverter warranty period, therefore, UL is of the opinion that Spare Part cost is aligned with industry standard. In addition, a maintenance reserve account of 1 USD million will be considered to cover unexpected cost for the Wind Project and Ikakos PV Project. UL considers that having this additional MRA for both Projects (Penonome II + Ikakos) is reasonable, provided that this MRA (if used) is replenished each year.

Repowering costs is assumed every 5-year period equivalent to 0.36 USD/Wp at year 5 for the new 1.7 MWp installation (PV module and trackers plus BOS).

UL has only reviewed the production results according to the probabilistic scenario P50, P90 and P99 for the repowering scenario. UL performed a pre-constructive energy production report (EPR) on 19 August 2020 (see Appendix A) and an evaluation of the portfolio benefit analysis ("PBA") of the PV Project repowering scenario and the Wind Project OEPR on 01 October 2020. According to these studies the Ikakos P90 annual average production for a 15 year evaluation period was estimated to be 80.82 GWh/yr. UL notes that the FM energy production of the PV Project is aligned with UL's estimation of the PBA analysis for the repowering scenario

UL notes that the revenue assumption and the PPA capacity is aligned with the PPAs payment rate stated in the PPAs contracts reviewed.

2.1.8 Risk Summary Table for Ikakos PV Project

Below it is summarized the UL's main issues detected at the current stage of the Ikakos review.

Table 2.2: Summary List of Project Issues – PV Project

Section	Subject	Comment	Risk Appraisal
2.2	Project Site Assessment	Although no risk is identified in the pictures provided, UL did not conduct a site visit because of COVID situation to inspect in detail the actual status of the components. UL recommends reviewing monthly maintenance reports with detailed preventive and corrective maintenance track record.	L
2.3.1	Civil Design Review	Due to swelling and shrinking properties of the soil were detected in the additional geotechnical tests performed, UL recommends continuous monitoring of the soil conditions during the operation phase. UL was informed by the Client that annual monitoring is considered and in case any issue is detected, a correction plan will be applied. UL considers this maintenance scope appropriate for the Ikakos Project	L

Table 2.2: Summary List of Project Issues – PV Project

Section	Subject	Comment	Risk Appraisal
2.5.1	Energy Production Report	UL performed the energy production assessment for the repowering scenario based on the information provided by the Client including specification of adding 1.7 MWp every 5 years. UL notes that currently this implementation plan is under consideration but no detailed design is still available, therefore, a higher simulation uncertainty was assumed.	L
2.6.1 & 2.6.3	IA & EPC Contract	The commercial operation start certificate ("CEOC"), defined in the PV Project Acceptance Agreement, is still pending due to a pending requirement of the grid code compliance (response time requirement by the CND). UL was informed that the EPC Contractor solution has to be approved by the inverter manufacturer, which is going to provide a PSS simulation to verify the grid code compliance in the coming weeks. UL recommends a follow up on the EPC Contractor and the inverter manufacturer.	L
2.6.6	EPC Contract Tests	The monthly PR results provided by the Client are below UL's independent estimated figures for May – October 2020 (10.5% on average). The Client information states that this lower PR is due to the DC Cabling isolation issue detailed in Section 2.2.6 together with the replacement works currently being performed. UL was provided with evidence of available capacity of the PV Project for each month due to the DC cabling issue and a clear correlation was found between the affected capacity and the PR results. The repair of the DC Cabling was completed on 19 November 2020 for all sub-plants. A clear PR improvement has been demonstrated for reference testing period from 16 October to 22 November 2020 with the completion of DC cabling replacement. UL recommends performing a follow up on the PV Project PR on the coming months to verify that PR values are aligned with UL's independent estimates.	M
2.6.6	EPC Contract Tests	UL considers that guaranteed PR is below UL's independent figures. UL notes that the EPC Contractor has a considerable margin to avoid application of LDs in case of PR non-compliance. UL was provided with the Service Agreement by and between the Client, which considers the payment of LDs in case of non-compliance of the expected monthly PR.	L
2.6.4	O&M Services Agreement	An availability warranty of 98% is included under the Services Agreement, which is considered to be in the low range of industry standard (typically 99%).	L
2.6.4	O&M Services Agreement	UL notes that no guaranteed response time is included under the O&M Services Agreement. Availability and Performance warranty considers industry standard exclusions; however, a response time warranty or maximum period is recommended in order to ensure a maximum time to resolve any issue or otherwise LDs will apply. UL considers the estimated failure response procedure detailed in the Annex VII of the O&M Plan to be aligned with industry standard. details.	L

Risk evaluation code for the integrity, performance or profitability of the Project

L	Aspects of low/slight importance
M	Aspects of medium/moderate importance
H	Aspects of high or significant importance

2.2 PV Project Overview

2.2.1 Site Location

Ikakos project site is located in San José de David in the Chiriquí province of Panama. Ikakos area is located approximately 11.3 km southeast of David, which is the nearest city with an approximate population of 144,000, and approximately 4.5 km south Chiriquí.

PV Project site covers an area of approximately 96 hectares with a relatively flat terrain. The general area surrounding the PV Project site consist of agricultural and farmland including high vegetation presence in the east. The site is located approximately 15 km north of the sea; however, the surrounding area has a high presence of water streams to the sea. In addition, the Panama's central highlands are located approximately 35 km north to Project site.

2.2.2 Site Map

The site map in Figure 2.1 below shows the location of the PV Project site within the state.

Figure 2.1: Location of the Ikakos Site

The site map in Figure 2.2 below shows the location of the PV Project site in relation to the surrounding areas.

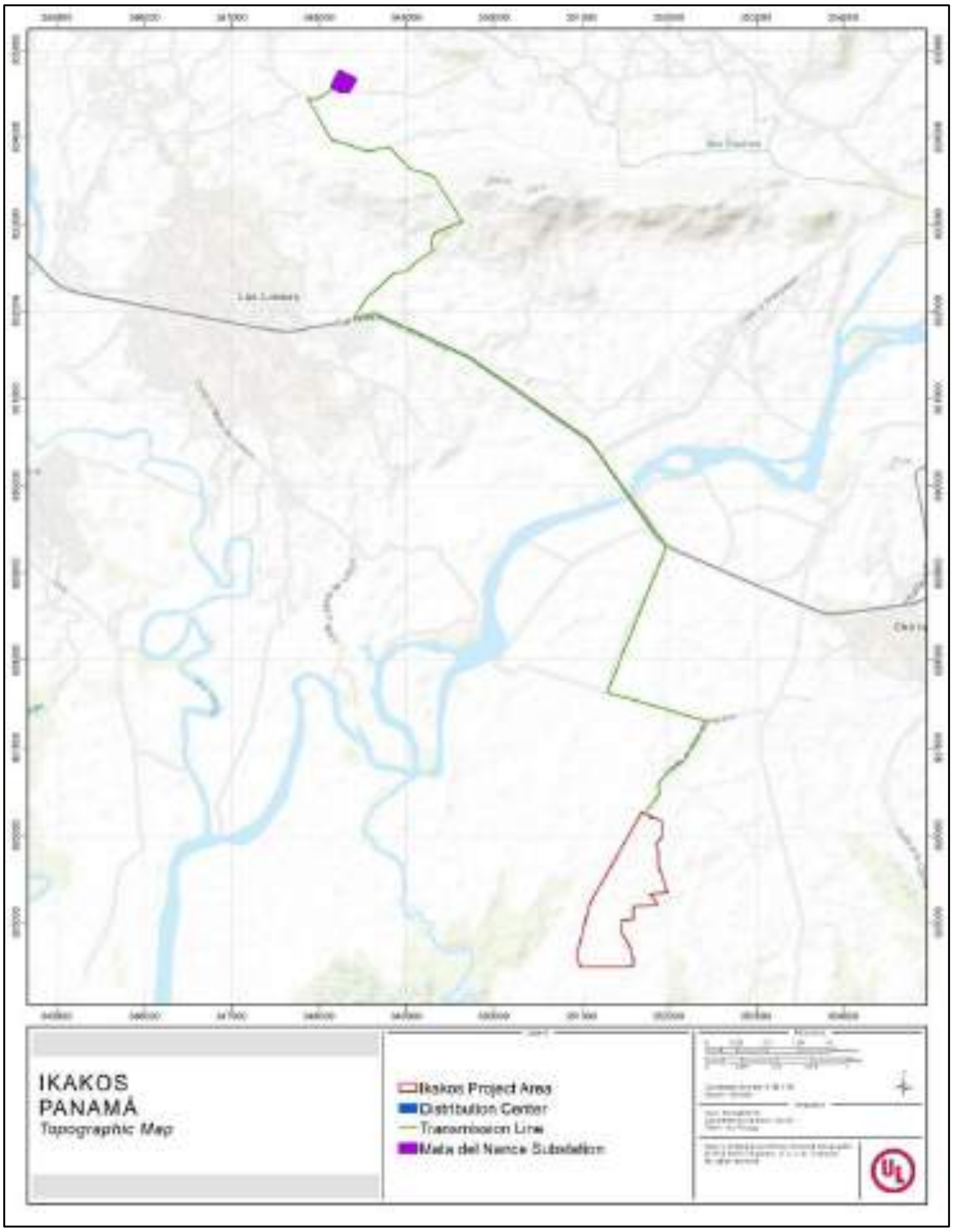

Figure 2.2: Ikakos Site Layout Map

2.2.3 Topography

The PV Project site is situated in a relatively flat terrain at an elevation of approximately 13 m above sea level. The PV Project area has a slight tilt of 1.4% on average from north to south.

PV Project site covers an area of approximately 96 hectares with a relatively flat terrain, having only a slight slope from north to south. PV Project is divided into 4 sub-plants of 10 MW each, therefore, the project area is divided into 4 adjacent project areas as presented below.

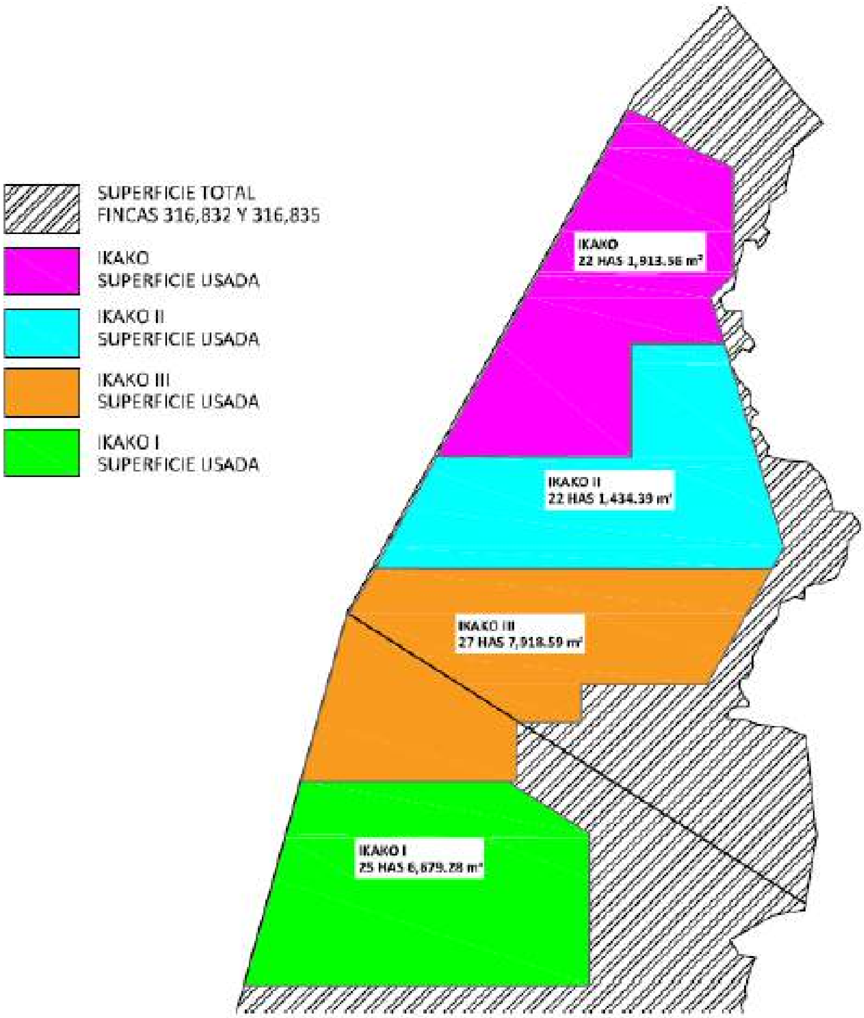

Figure 2.3: Ikakos sub plants area overview

UL did not conduct a site visit due to the COVID-19 situation; therefore, UL relied on satellite images to understand and evaluate the site conditions. The PV Project area is already constructed and as presented in the figures below, the terrain is properly prepared and maintenance activities are performed to prevent vegetation growth.

Figures below shows the general topography and vegetation of the Project site from the drone images provided by the Client:

Figure 2.4: Ikakos General View - 1

Figure 2.5: Ikakos General View - 2

Figure 2.6: Type of Soil during Construction

Figure 2.7: Type of Soil during Operation

2.2.4 Project Substation and Interconnection

The substation that serves as the point of interconnection is "Mata del Nance," which is located 13.5 km from the PV Project and belongs to the state capital company (ETESA). The distribution center is located north to project area (Ikako 0 sub-plant) to collect all sub-plants production at 34.5 kV. An overhead transmission line of 13.5 km with 2 independent circuits interconnects the project to Mata del Nance substation.

Figure 2.8: Power Block

Figure 2.9: Ikakos Transmission Line

2.2.5 Roads and Site Access

The principal access road to the site is the Panamericana road, exit road of Agronomy University at Chiriquí town. A dirt road of approximately 2 km interconnects the PV Project site with the Panamericana road. UL was informed that no specific works were required for the dirt road. UL considers the Ikakos site access to be appropriate.

Figure 2.10: Internal Road

Figure 2.11: External Perimeter Road

2.2.6 Operational Background

As per the information provided by the Client, the Project had several issues during the construction phase that were under the EPC Contractor responsibility. UL was informed that EPC Contractor delayed the repair of the issues detected, which affected the energy production from the commercial operation of the PV Project (August 2018). UL notes that the Final Acceptance certificate defined under the EPC Contract was issued on February 2020 when the EPC Contract and the Client reached an agreement on the PV Project status [2].

UL notes that the main issue detected during the construction phase of the PV Project was the isolating failure of the underground DC cabling between the strings and the combiner boxes, identified on May 2019. The underground DC cabling had isolating issues due to rainwater affection provoked by the rainy season of the area. As per the information provided, major part of the DC cabling was not installed with proper conduits to avoid direct affection from water or other soil exposures. After identification of the issue, the parties agreed to perform a surface installation of the DC cabling with specific trays for DC cabling placement as presented in figures below provided by the Client.

Figure 2.12: DC Cabling Tray - 1

Figure 2.13: DC Cabling Tray - 1

UL was provided with meeting minutes between the parties for the identification and the repair of the DC cabling installation [3]. The procedure of changing the installation from underground to surface tray included an isolation test of the cabling to ensure that was working properly. The DC cabling isolation tests resulted to be failed for an approximately 10% of the DC cabling for the PV Project, all cables affected was from Prysmian manufacturer, AD7 cabling suitable for partial flooding.

The Client and the EPC Contractor agreed to perform the replacement of the affected wirings, totaling 233 cables (10% of the total). The Prysmian AD7 cables were replaced for Prysmian AD8 cables (suitable for complete immersion). The EPC Contractor started the replacement in February 2020 and ended in June 2020 as record provided by the Client [4].

Having the 10% of the cabling replaced (those that were initially identified having issues), the Client performed random isolation tests on the remaining Prysmian AD7 DC cabling previously not identified as affected and already placed in aerial tray. Further isolation issues were detected (additional 14% DC cabling affected), all of them Prysmian AD7 cables, assuming that it might be related to a serial defect on DC cabling installed. UL was informed that only Prysmian AD7 cables are affected, which represents a 65% of the total DC cabling of the PV Project.

The Client confirmed that in order to completely solve this issue, the Client and the EPC Contractor agreed to change the Prysmian AD7 DC cabling of the whole Plant (65% of the total and with a 10% of the DC cabling initially replaced) in order to avoid future isolating problems with the same Prysmian AD7 cable installed.

UL was informed that the number of open circuits due to isolating problems on the DC cabling was considerably increased on June – September 2020 as presented in the table below based on the Sponsor information [5]. UL notes that the number of open circuits affects directly to the available capacity of each sub-projects. The reduction of the capacity available provokes a decrease of the PV Project PR since less circuits under operation reduce the production. The average number of open circuit values and average capacity available for the PV Project from the FAC is presented in the table below.

Table 2.3: Ikakos Operational Status

Month	Ikako 0		Ikako I		Ikako II		Ikako III	
	Avg Open Circuits	Avg Capacity Available	Avg Open Circuits	Avg Capacity Available	Avg Open Circuits	Avg Capacity Available	Avg Open Circuits	Avg Capacity Available
Feb 2020	13	97.8%	19	96.7%	20	96.5%	33	94.3%
Marr 2020	17	97.1%	13	97.8%	22	96.3%	20	96.6%
Apr 2020	48	97.1%	39	97.8%	58	96.3%	78	96.6%
May 2020	48	91.7%	39	93.3%	58	90.0%	88	86.5%
June 2020	71	87.8%	86	85.2%	95	83.5%	55	90.5%
July 2020	114	80.3%	69	88.1%	58	90.0%	53	90.9%
Aug 2020	126	78.3%	70	88.0%	61	89.5%	53	90.9%
Sept 2020	123	78.7%	70	87.9%	63	89.1%	53	90.9%
Oct 2020	13	97.7%	24	95.8%	53	90.8%	55	90.5%
Nov 2020	0	100%	0	100%	6	98.9%	20	96.5%

UL reviewed the updated DC cabling replacement status provided by the Client on 23 November 2020 [6]. UL notes that the DC cabling replacement was completed on 15 October 2020 (Ikako 0), 26 October 2020 (Ikako I), 16 November 2020 (Ikako II) and 19 November (Ikako III).

In addition to the DC cable replacement status overview, UL was provided by the Client with the daily PR calculation for the reference testing period from 16 October to 22 November 2020 with the results presented below for each sub-project.

Table 2.4: Ikakos Client PR Verification

Day	Ikako 0		Ikako I		Ikako II		Ikako III	
	Open Circuits	PR (%)	Open Circuits	PR (%)	Open Circuits	PR (%)	Open Circuits	PR (%)
16 Oct 2020	0	85.2%	11	77.9%	58	69.1%	48	73.9%
17 Oct 2020	0	81.2%	11	77.9%	58	72.9%	48	75.0%
18 Oct 2020	0	87.5%	11	83.6%	58	76.0%	48	79.4%
19 Oct 2020	0	84.2%	10	81.7%	71	67.7%	66	77.3%
20 Oct 2020	0	83.5%	6	81.4%	69	71.6%	66	75.1%
21 Oct 2020	0	89.3%	4	81.8%	62	74.8%	66	92.3%
22 Oct 2020	0	83.5%	3	83.7%	53	72.7%	66	74.5%
23 Oct 2020	0	82.5%	1	81.3%	38	67.5%	66	73.1%
24 Oct 2020	0	83.6%	1	83.9%	38	75.7%	66	74.5%
25 Oct 2020	0	82.4%	1	82.7%	38	72.7%	66	74.1%
26 Oct 2020	0	86.1%	1	82.1%	38	72.4%	66	68.8%
27 Oct 2020	0	84.7%	0	82.7%	33	75.1%	59	72.9%
28 Oct 2020	0	88.8%	0	84.7%	33	75.8%	48	74.2%
29 Oct 2020	0	79.4%	0	88.0%	26	79.7%	44	68.5%
30 Oct 2020	0	85.7%	0	85.0%	20	76.4%	47	58.5%
31 Oct 2020	0	84.5%	0	83.8%	17	74.5%	43	78.2%
01 Nov 2020	0	80.5%	0	83.6%	15	75.4%	43	77.5%
02 Nov 2020	0	84.5%	0	82.8%	11	76.9%	40	76.9%
03 Nov 2020	0	82.9%	0	82.3%	11	77.9%	40	76.2%
04 Nov 2020	0	88.3%	0	85.6%	11	82.4%	40	78.0%
05 Nov 2020	0	83.2%	0	85.1%	11	80.1%	32	78.5%
06 Nov 2020	0	86.1%	0	85.7%	11	81.7%	32	81.2%
07 Nov 2020	0	81.0%	0	84.5%	11	76.6%	32	78.1%
08 Nov 2020	0	89.0%	0	85.5%	11	84.5%	32	81.7%
09 Nov 2020	0	79.8%	0	82.2%	8	76.1%	28	78.4%
10 Nov 2020	0	81.8%	0	81.3%	8	77.5%	23	78.1%
11 Nov 2020	0	80.3%	0	80.2%	8	76.7%	20	78.3%
12 Nov 2020	0	85.1%	0	83.7%	8	78.9%	20	78.8%
13 Nov 2020	0	83.3%	0	81.9%	6	77.1%	16	82.1%
14 Nov 2020	0	84.1%	0	82.4%	4	77.4%	16	82.2%
15 Nov 2020	0	74.5%	0	83.5%	1	75.0%	16	79.9%
16 Nov 2020	0	79.8%	0	84.4%	0	81.7%	7	73.0%
17 Nov 2020	0	79.0%	0	81.6%	0	75.6%	3	94.6%
18 Nov 2020	0	80.5%	0	83.3%	0	78.8%	3	76.4%
19 Nov 2020	0	82.6%	0	85.4%	0	79.7%	0	79.9%
20 Nov 2020	0	93.7%	0	90.6%	0	90.5%	0	89.5%
21 Nov 2020	0	88.2%	0	87.9%	0	87.0%	0	88.9%
22 Nov 2020	0	90.5%	0	86.9%	0	87.7%	0	88.7%

UL notes that the PR calculation results presented above confirm the PV Project performance improvements with the DC cabling replacement considering the number of open circuits.

UL recommends performing a follow up on the PV Project PR on the coming months to verify that PR values are aligned with UL's independent estimates.

2.3 Balance of Plant Design

2.3.1 Civil Design Review

2.3.1.1 Geotechnical Review

UL was provided with a geotechnical investigation assessment performed by OP Ingenieros S.A ("OP" or "Geotechnical Engineer") [7] at the location of the PV Project in October 2014. The purpose of the investigation was to determine the basic characteristic of soil necessary to design the foundation for the PV projects Ikako 0, Ikako I, Ikako II and Ikako III and the soil aggressiveness against steel structures, among other objectives.

The geotechnical investigation was performed in the area of the PV Project and consisted of Standard Penetration Test ("SPT") and laboratory tests such as Atterberg limits and particle-size analysis. UL denoted that several tests normally required for a geotechnical investigation of a PV project were not included in the report such as test pits, geophysical survey and several laboratory tests such density, friction angle, cohesion parameters, chemical tests, among other. The chemical tests are required in order to determine soil aggressiveness against steel structures (corrosion) and geophysical survey provided information require for civil and electrical design.

A total of 6 SPT were performed up to maximum average depth of 5 m in order to determinate the soil characteristics underlain. According to the blow counts obtained during SPT, the soil bearing capacity can be determined and the results indicate that the values go from 3 to 13 ton/m^2 (depending of the location and the depth). The type of soil detected were classified according to the Unified Soil Classification System ("USCS") as silty with high plasticity (MH) and at some location (in the superficial layer), silty with low plasticity characteristics (ML).

According to the results obtained from the Atterberg Limits tests (liquid limits and plasticity index), the soil present high swelling and shrinking characteristics and the Geotechnical Engineer recommends further tests in order to determinate the expansion percentage of the soil. UL is not aware if further tests were performed according to the recommendation of the Geotechnical Engineer. UL was informed by the Sponsor that no further geotechnical investigation was performed; however, continuous monitoring has been performed in the Project site regarding this matter and no problems are being detected till date. UL was informed that the Sponsor is planning to perform additional investigations in order to determinate if the swelling and shrinking conditions of the soil could represent a future risk for the Project. UL agrees with this decision. UL was informed that a proposal has been requested to several companies to perform those additional tests. UL recommends a follow up on the additional tests results.

The groundwater level was detected at the location 3, 4 and 6 at different depth such as 2.6 m, 3.45 m and 1.60 m respectively. Soil with plasticity characteristics together with groundwater level can affect the stability of a civil structure with the time. For the specific Ikakos Project and based on the documentation available, it is not possible to determinate if the plastic soil (with swelling and shrinking characteristics) together with the groundwater level could affect the stability of the PV structure. It is important to mention that even though this information is not available, UL was informed that no problems have been detected during the 2 years of operation of the Project which is an indicative of a good performance of the soil till date; however, complementary studies are recommended.

Additional tests were performed by LCC Ingeniería S.A in order to qualitatively determine the swelling and shrinking properties of the soil. UL reviewed the report performed by LCC Ingenieria, dated on 22 October 2020 [8] and denoted that 6 tests pits were performed at the Project site until a maximum depth of 2.1 m. Soil samples were taken in order to perform laboratory tests to determinate the swelling and shrinking properties of the soil. The laboratory tests performed were soil classification, particle size analysis, Atterberg limits and Lambe test. UL observed that according to the conclusion of the report, 5 of the location studied indicate low swelling and shrinking conditions, while only 1 indicates medium to high swelling and shrinking conditions. Based on the results, UL recommends continuous monitoring of the soil conditions during the operation phase of the Ikakos Project in order to determinate any possible settlement or movement of the tracker foundations due to the swelling and shirking properties of the soil. It is important to mention that in the case of foundation issues due to the soil conditions, these issues appears in low pace which make the early detection easy to identify. UL was informed that currently, no issues have been detected during the 2 years of operation of Ikakos Project, which corroborate the results of the additional tests performed.

Also, UL was informed that the manufacturer Gonvarri performs an annual maintenance of the tracker system where the Sponsor will coordinate a topographic survey for tracker structure control in order perform a complete maintenance (stability and functionality evaluation) of the tracker structure every year. In the case that pile stability problems are detected due to the soil conditions, UL was informed that the possible repairing plan to be apply could be the same process followed during the construction (construction reinforcement of the piles); however, depending of the issue detected, an adequate solution will be studied. UL considers this maintenance scope appropriate for the Ikakos Project.

The Geotechnical Engineer indicated that a foundation depth of 1.5 m (common foundation depth for a PV structure), the bearing capacity of the soil at this depth vary from 3 to 5 ton/m^2 and presents soft to medium consistency; however, the Geotechnical Engineer does not provide a clear recommendation for the foundation depth neither regarding the type of foundation feasible for the PV Project.

According to the information reviewed, UL considers that the geotechnical report and the additional tests performed provided adequate information of the soil characteristics of the PV Project. Even though, low and high swelling and shrinking soil conditions were detected at the Ikakos Project site, UL considers that the monitoring proposed by the Sponsor during the operation phase is adequate and can detected any possible foundation issues due to the soil conditions. UL was informed that till date, no problems has been detected.

2.3.1.2 Tracker Structural Design Review

The tracker structural design was performed by the manufacturer, Solar Steel by Gonvarri on 03 October 2017 [9].

The configuration selected by the designer and manufacturer is as follow: each tracker is formed by one row that will support 60 solar modules placed in landscape position in columns of three solar modules, each panels column is supported by 2 secondary beams, which rest on the main beams. These elements turn on their axis making that the modules move following the sun movement, from East to West. The main beams are supported by seven piles driven into the soil. The modules are fixed to the secondary beams by mean of bolts. Each tracker will have a motor located in the central pile. The maximum height of the main beams axis is 1,700 mm and the distance between piles is 6,020 mm. The angle range of tracker is +/-55°, and the distance between trackers is 9,000 mm. The size of the solar photovoltaic panels for this installation is 1,956 mm long by 992 mm wide.

The designer proposed 2 types of trackers according to its position in the photovoltaic plant, one type named as exposed, that is formed by the trackers located in the external part of the plant, and other named as sheltered that corresponds with the tracker located in the plant internal part. The structure of the exposed trackers must support higher wind loads than the one of the sheltered trackers because the trackers located in the plant external part give protection against the wind load to the ones located in the internal part, which is in line with UL´s expectations.

The final structural solution is detail in the next two figures:

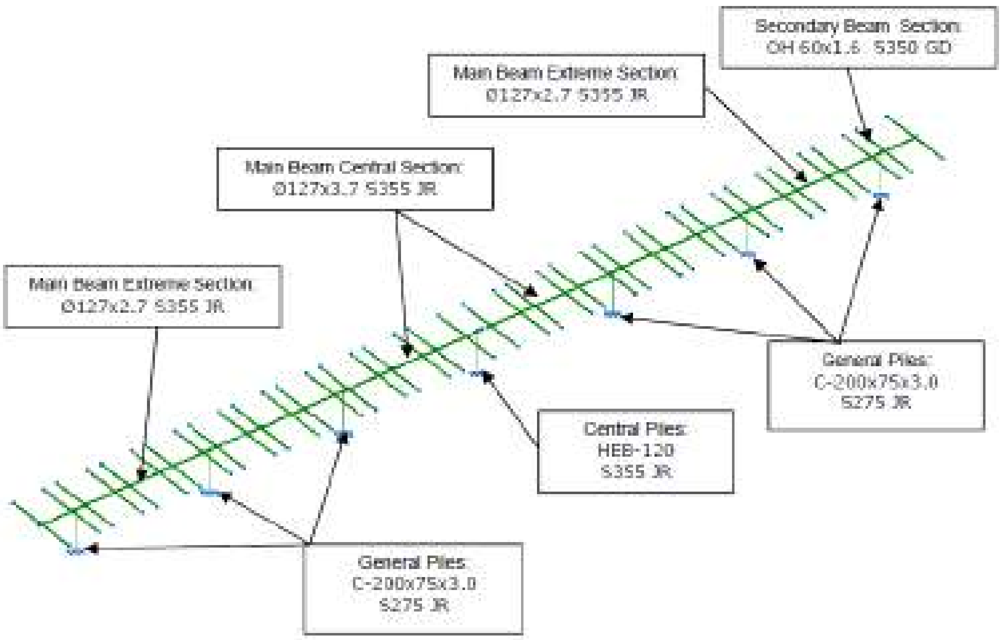

Figure 2.14: Exposed Tracker Configuration Proposed by Gonvarri for Ikakos project

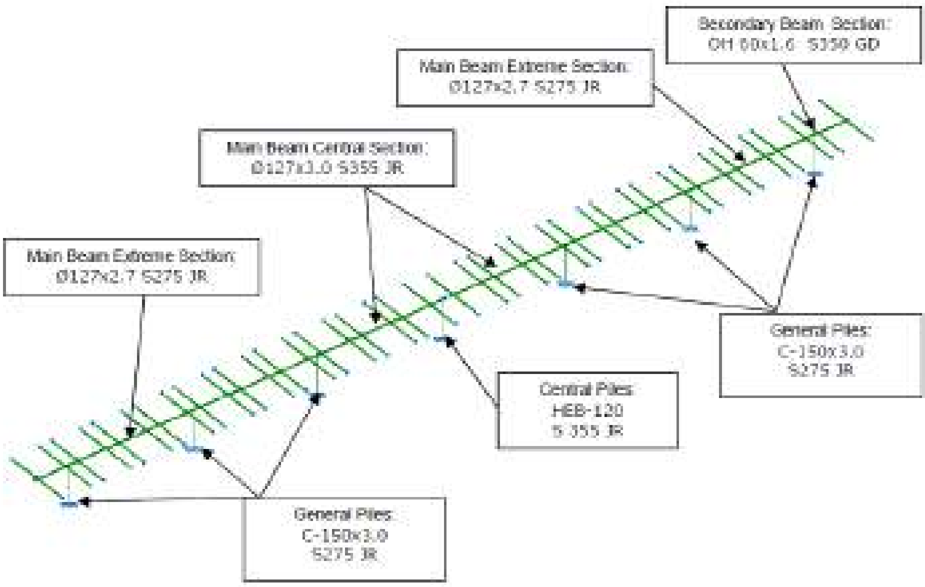

Figure 2.15: Sheltered Tracker Configuration Proposed by Gonvarri for Ikakos project

UL noted that tubular structural beams are usually used as main beams and the same for C and W shaped as steel columns. W shaped steel columns will give greater resistant against wind loads when used as central piles.

The selected material for the tracker was structural steel, S355, S275 and S350GD steel type specifically (classification according the European standard). The nominal thickness of the structural elements is around 40 mm to 80 mm.

All joints between elements are bolted. The quality of the screws used are 8.8 (according the Eurocode) in the whole structure except the bolts used for fixing the panels to the purlins that will be A2-70 stainless steel bolts.

The finishing treatment for the steel structures (except the ones made of S350GD steel) is hot-dip galvanized according to standard UNE-EN ISO 1461:2009. UL considers this according to the expectations.

The design criteria and reference standards for the structural calculations are:

Loads:

- REP-14 Reglamento para el Diseño Estructural en la República de Panamá 2014;
- ASCE – 7-05: Minimum Design Loads for Buildings and Other Structures; and
- Tracker Wind Tunnel Analysis, Wind Load CFD characterization by AST Engineering Combinations.

Load Combination:

- ASCE-7-05: Minimum Design Loads for Buildings and Other Structures.

Structural Element Review:

- ANSI/AISC 360-05 Specification for Structural Steel Buildings; and
- AISI S100-2007 North American Specification for the Design of Cold-Formed Steel Structural Members.

UL considers that design criteria and loads standards are within UL expectations. UL denoted that the tracker structural design calculation did not include information regarding if the calculation considered the parameter obtained in the geotechnical investigation of the PV Project; however, the Sponsor confirmed that the parameters used in the structural calculation considers the specific geotechnical conditions of the Project site. UL recommends that the conditions obtained in the complementary geotechnical investigation to be performed are compared to the geotechnical parameters used for the structural calculation design in order to confirm that the geotechnical conditions mentioned in the Section 2.3.1.1 are considered (swelling and shrinking conditions).

UL considers the use of a tracker wind tunnel analysis in order to obtain more accurate loads over the structures is highly beneficial for the structure stability; considering that structural design of the solar structures will always be ruled by wind loads.

To perform structural calculations, solicitations and sizing of the elements Gonvarri used CYPE 2018 structural software. Three major load cases were included in the design of the tracker, dead load, wind load and seismic load. The dead load was represented by the weight of the solar modules and the steel structures own weight. The wind load was calculated according to the U.S. standard ASCE 7-05 using the wind speed data indicated in the Panamanian Standard REP-2014 and the results obtained in the tracker wind analysis (Wind analysis was performed in two positions of the solar modules, 5° and 55°). The seismic load was calculated according to the international standard ASCE 7-05; a modal spectral analysis was performed over the whole structure. The structure design and calculation were carried out according to the US standards AISI S100 (LRFD) which is the main code used for steel structures.

In all the cases it has been considered a linear behavior for the materials, in consequence it has been carried out a first order calculation for the displacements and efforts on the elements obtained.

UL concludes that structural calculations performed by Gonvarri are very detailed and includes all major load cases using local data for the Project. The steel structures used are of hot dipped galvanized steel. UL was provided by the galvanized certificates of the steel elements and denoted that the elements have a coating thickness greater than 100 microns that is higher than the minimum fixed by the galvanizing reference standard. UL confirmed that the hot dipped galvanized coating was selected according to the expectations.

UL concludes that structural calculations performed by Gonvarri is detailed and includes all the considerations typically expected by UL.

2.3.1.3 Foundation Design Review

UL denotes that all design calculations were already reviewed and explained in the structural design section. UL will comment over the final foundation installation solution within this section.

Solar Steel by Gonvarri performed a ramming and pull out test campaign within the PV Project site in order to obtain the best foundation installation procedure, pile depth and final configuration to sustain the tracker loads. The tests were performed in May 2017 [10].

56 tests were performed all over the PV Project area using 46 CH-200x3 steel columns (C shaped) and 10 HEB-120 steel columns (H shaped). Two type of tests were performed; traction and shear. Tests were applied in all type of columns considering sheltered and exposed positions. UL considers that the ramming and pull out tests performed include all structural positions of the tracker and used equivalent structural elements compared with the ones used within the structural calculations.

The investigation concludes that direct ramming is the type of foundation feasible for the PV Project. According to the results, 31 tests performed at the piles CH-200x3 were satisfactory for a depth of 1.5 m and 15 piles were satisfactory for a depth of 2 m. Similar situation for the piles HEB-120 were 4 tests were satisfactory for 1.5 m depth and 6 tests were satisfactory for a depth of 2 m. Based on the results and the manufacturer experience, the PV Project area was defined as follow:

- 2 m depth for the 100% of the HEB-120 piles;
- 1.5 m depth for the 68% of the CH-200x3 piles; and
- 2 m depth of the 32% of the CH-200x3 piles.

UL denoted that the Structural Engineer calculated the loads for the pull out tests following the criteria of the same standards used for the tracker structural design calculation [11]. The three major load cases were included in the design of the tracker, dead load, wind load and seismic load. Following the AISI standard load cases were fixed for ultimate limit state and for service limit states.

In this case, the piles were classified per tracker type, such as: for exposed tracker the CH-200x3 was selected as a general piles and the HEB-120 was selected for central piles, while for sheltered trackers the CH-150x3 was selected as a general piles and the HEB-120 for central piles. However, only the CH-200x3 and HEB-120 were tested. The document explains how the forces shall be applied in the piles during tests both for traction and shear. UL considers that the procedure follow for the pull-out tests is in line with the good industry practices.

UL concurs with the results obtained after the investigation and concludes that properly evaluates the best procedures for foundation installation.

2.3.1.4 Hydrological Investigation

UL reviewed the hydrological investigation performed by E&R Construction Company and Fazilita Energías Renovables at the location of the Ikako 0 project on 17 April 2017 [12]. A representative Engineer of the companies named Ludgardo P. T. Escobar (license No 2012-006-033 in Panama) performed and signed the hydrological study. The purpose of the investigation was to determinate the hydrological conditions of the PV Project area and evaluate the limits of the maximum flood plains at the proposed PV locations.

The PV Project is located in the sector of Llano de Hicaco, in the “corregimiento” of Chiriquí, David District of the Chiriquí Province of Panama. In the hydrological region, the PV Project is located within the watershed #108 named Río Chiriquí with an area of approximately 1,905 km2. The weather is classified as humid tropical climate with average temperatures between 26°C and 29°C. The annual average precipitation of the watershed is 3,642 mm and most of the precipitation are from May to November.

Within the watershed Río Chiriquí, several weather stations are located. The weather station was operated by the institute of hydraulic resources and electrification (in Spanish “Instituto de Recursos Hidráulicos y Electrificación” or “IRHE”) and now by the Electric Transmission Company (in Spanish “Empresa de Transmision Eléctrica” or “ETESA”). 25 weather station were considered for the study and using the arithmetic mean method the average annual mean precipitation of the watershed was determined. According to the Thornthwaite method, the soil water balance was calculated and the results indicate that the evapotranspiration is low, therefore, the rainfall water is mostly present in the surface.

In order to calculate the design flow for the Project, the sub-watershed “Qda Las Pavas” was determined. The PV Project is located within this sub-watershed that has an area of 121.09 Ha. Using the information obtained from the ETESA study, where a regional analysis of maximum flood was performed in 1986, the maximum flow can be estimated at any location in Panama. Following this study, a regional map of flooding was determined and 2 different methods were applied in order to calculate the maximum flow of the sub-watershed such as Lavalin Method and Rational Method.

The return period selected for the calculation of the maximum flow was 50 years, which is in line with UL´s expectations. The Lavalin Method provided a maximum flow of 58.75 m^3/s and the Rational Method provided a maximum flow of 95.75 m^3/s. The average of these maximum flows was selected in order to define the design flow of the PV Project which is 77.25 m^3/s.

Based on the topography of the PV Project and the design flow determined, the software HEC-RAS (created by the US Army Engineer Corp.), was used for modeling the sub-watershed in order to analyze its runoff and flooding areas during maximum events for different return periods. Several cross sections of the PV Project were obtained indicating the maximum flood level, based on this, the safe level for embarkment was determined which is 1.5 m above the maximum flooding level.

UL denoted that only one flooding area was determined at Ikako 0 where a natural water channel is located. The report indicates that it is recommendable change the section of the water channel with a trapezoidal shape of 5 m base and 2.6 m height in order to lead the important design flow of 77.25 m^3/s of a return period of 50 years out of the Project site; however, UL was informed that the water channel lead the water properly and the trapezoidal section was not necessary. No further flooding areas were detected.

Figure 2.16: Drainage System Proposed for Ikako 0 project

UL was provided with the internal drainage system calculation of Ikakos performed by the Engineer Wilberto Andrade Guerra on 31 July 2017 [13]. The purpose of the calculation was to determinate the feasible rainfall drainage system for the Ikakos Project following the local standards.

UL denoted that the drainage system report includes the calculation method used, following the requirements of the Panamá ministries manuals (Ministerio de Obras Públicas or “MOP” in Spanish). UL observed that the manual indicates that for rainfall sewers, channels and spillways is recommended to consider for the design a return period of 10 years, for this reason, a return period of 10 years was selected for the Ikakos internal drainage system design. UL considers that this return period is low, however, considering that the drainage of the natural water channel at the east of the Project lead most of the water precipitation, 10 years of return period is acceptable.

The drainage system consists of internal concrete channels of trapezoidal section, natural channels of triangular sections and sewers in the intersections with the internal roads. The system was designed to conduct the maximum flow and velocity calculated per area of the Project. UL denoted that the software used for the drainage calculation and flow modeling were not included in the report. The internal drainage system is according to the figure below:

Zona de drenaje	Area (ha)
AREA 1	0.808
AREA 2	1.066
AREA 3	1.24
AREA 4	0.812
AREA 5	2.931
AREA 6	4.787
AREA 7	10.524
AREA 8	2.67
AREA 9	7.224
AREA 10	1.588
AREA 11	6.8
AREA 12	4.253
AREA 13	6.04
AREA 14	7.978

Figure 2.17: Internal Drainage System

From the review of the internal drainage system calculation report performed for Ikakos, UL opines that the calculation was performed according to the local standards for general civil structures of Panamá.

2.3.2 Electrical Design Review

The Project has a DC rating of 45.64 MW_{DC} peak and an AC rating of 40.8 MW_{AC}, limited to 40.00 MW_{AC} at the POI. The electrical balance of plant includes: a PV array broken into 4 10.2 MW_{AC} blocks, four 34.5 kV medium voltage collection systems, and a 13.5 km 34.5 kV transmission line. The transmission line interconnects the Project to Mata del Nance substation. The key parties associated with interconnection and electrical BOP include:

- Tecinsol — Project Company;
- Cobra — BoP Contractor;
- ETESA — Grid operator;
- Jema — Inverters O&M and Supplier;
- Gonvarri — Trackers O&M and Supplier ;
- FEMSA — Power Off-taker;
- Riba Smith.— Power Off-taker;
- Hilton — Power Off-taker; and
- Clinica Hospital San Fernando — Power Off-taker.

The Ikakos PV Project POI, Mata del Nance substation, is connected to the SIN at 34.5 kV and 115 kV transmission lines and therefore several lines would have to simultaneously fail to make the grid unavailable to export energy.

UL reviewed the design documents received to-date, including the Issued for Construction ("IFC") collection and substation drawings along with key electrical system design studies addressed in the corresponding sections herein.

UL considers the documentation sufficient for a high level design description of the Project, however UL recommends completing the documentation with operative reports regarding grounding resistance measurements, electrical losses follow up and latest final SCADA design.

2.3.2.1 DC Electrical Design

UL has reviewed the DC electrical design regarding wires selection, strings modules, array boxes and cables and notes the design as detailed for construction and performed according industry standards. In particular, UL notes that:

- The maximum expected DC voltage is calculated according good industry standards, using minimum site temperatures and ensuring that the system voltage does not exceed 1,500 V_{DC};
- The PV array is wired into series strings composed of 30 Modules each, and the nominal operating voltage is calculated to maximize MPPT range utilization;
- The plant project has 70% of 330 W modules and 30% of 325 W;
- The electrical balance of plant project is divided in 4 power blocks with 4 inverter each with a total of 16. Each power block consists of 1,158 string with a total of 34,740 modules; and
- The Project has a DC rating of 45.64 MW and an AC rating of 40.8 MW_{AC} at the output of the inverters and limited to 40.00 MW_{AC} at the POI. The electrical balance of plant includes: a PV array broken into four 10.2 MW blocks, a 34.5 kV medium voltage collection system, and a transmission line.

UL notes that the maximum and minimal voltage for each module are under the inverter limit and the maximum V_{OC}.

The DC configuration and wiring of the PV modules allows for maximum energy capture given the prevailing climate of the project site. The fusing, wire sizes and wire management appear to be appropriately specified but not yet designed for the intended conditions and electrical loads. The inverters and step up transformers appear appropriately sized for the expected power production and ambient conditions.

2.3.2.2 Medium-Voltage Collection System

The output voltage from the JEMA inverters are stepped up from 620 V to 34.5 kV_{AC} through 2.85 MVA transformers installed on the inverter skids. There are one transformer for each inverter. The 34.5 kV output from the transformers is connected in a daisy chain to bring the full power capacity to the switchyard substation in 4 medium voltage circuits.

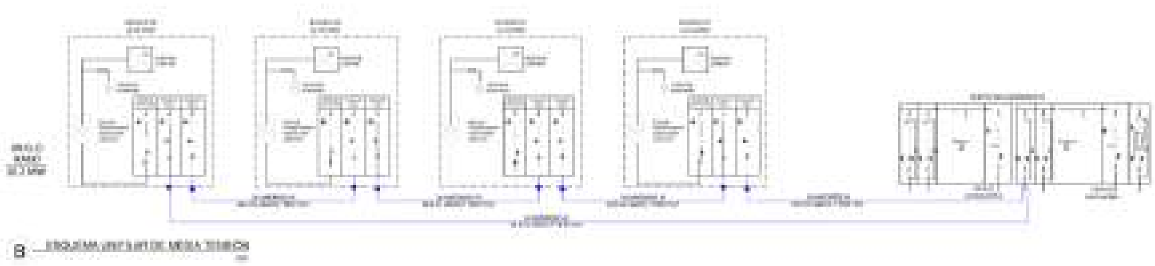

Figure 2.18: Medium Voltage Collection System

2.3.2.2.1 Grounding

A grounding system has to be designed for the site to provide protection for workers and equipment against inadvertent contact with energized components. The grounding system provides for bonding of all exposed metal parts and equipment, the safe discharge of static and lightning induced voltages, and a save return path for stray currents in the event of a ground fault.

UL reviewed the specific grounding design [14] and notes that it includes cables type and section, earthing resistivity, and considered that the design following IEC 60364-5-54 for personnel safety to assure that the step and touch potentials are limited.

The grounding system consist of a grid of conductors horizontally buried within trenches, supplemented in some cases by a series of vertical rods connected to the grid if necessary. All the structures and metal parts of the installation will be connected to the grounding system, as well as to the grounding rings of the inverter-transformer buildings and electrical boxes.

The PV plant ground is made of bare copper with 35 mm^2 section buried to a minimum depth of 0.5 m with some copper rods as required, along the MV and LV trenches. The Inverter-transformer building ground is made of bare copper with 95 mm^2. The soil resistance at the inverter is below 5 ohm for all inverter.

UL notes that there is not indicate values of soil resistivities, therefor the report take the most unfavorable value of most, that is silts. UL also notes that the calculation for the LV short-circuit current, the minimal conductor section, and minimal step and touch potential was performed.

UL considered that the project ground design is in compliance with the best standard.

2.3.2.2.2 Lightning Protection

Lightning protection has to be designed into the system through the grounding system and through surge protectors installed on both the DC and AC sides of the system.

The lightning protection and grounding systems conform to the suggested practices to minimize damage from nearby lightning strikes. UL considers the lightning protection system to be well defined with detailed specifications.

2.3.2.2.3 Underground Collection

The DC circuits are divided into the following sections:

- A 6 mm^2 Cu cable connecting the string end until the harness connector;
- A AWG6 (13.3 mm^2 Cu) cable connection the harness connector until the combiner box; and
- A 500 kcmil Al (253 mm^2) cable connection the combiner box until the inverter.

Cable ampacity calculations are performed to determine that the peak cable loading is below the maximum operating limit and that the fault current is below the withstand capability of the cable. Cable sizes are based on the short circuit capability, electrical losses, and thermal ampacity, which are a function of many site-specific variables including the PV module and inverter output, the soil thermal resistivity (“rho”), and the length of the cable run.

UL notes that the cables follow the typical design for a PV plant with the connection from modules until the array box been not underground and the cables between array box and inverter will be placed anchored to the follower structure or directly buried in trenches.

UL notes a basic calculation on each DC circuits and AC circuits. In general, the specified cable sizes are sufficient for the expected output.

2.3.2.3 Project Switching Station

The project collection substation or switching station consists of a medium voltage PV feeder, Hicaco IV substation, with 2 busbar A and B, connecting 4 inverters without a step-up transformer. A TL with two circuits leaves the sectioning center in underground cable for 50 m and continue their route overhead through the transmission line until the Mata de Nance substation.

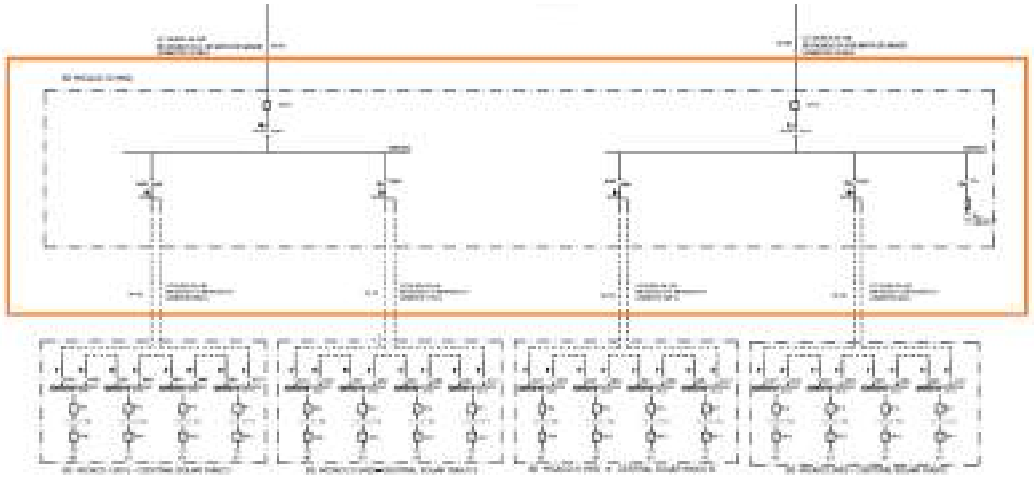

Figura 1-2: Diagrama Unifilar S.E. Mata de Nance 34.5 kV y S.E. Hicaco IV. [19]

Figure 2.19: Hicaco IV SE

The Figure 2.19 shows the Ikakos PV connecting to the SIN through the HICACO collection substation by two circuits: 34-139 and 34-140.

2.3.2.3.1 Substation Ground

UL notes that no grounding study is yet performed for the switching station design itself. However, switching station grounding study is embedded in the project grounding report and the EPC requires the Project to fulfil IEEE Std. 80 provides guidance and information pertinent to safe grounding practices in substation grounding design and in determining safe step and touch voltages. UL takes no exception on the design, however UL recommends completing the design with grounding resistance measurements as the plant is operative and the measurement of earth resistance is mandatory in an operating generation facility.

2.3.2.4 Transmission Line

UL has reviewed the IFC design of the transmission line composed by two circuits; 34-139 and 34-140. The transmission line design (“TL”) is typical and it is composed by 269 concrete and metallic towers for the 13.6 km length. The main conductors are ACSR 477 MCM Hawk wires that allows the interconnection of the Project to the SIN. The design includes ACSR 1/0 AWG Raven earth conductor.

UL notes the design according TSO specifications, local regulation and typical according industry practices. UL notes that the design does not represent an undue risk for the PV Project.

2.3.2.5 Design Studies

Below is a summary of the key design studies.

2.3.2.5.1 Short-Circuit Study

UL has reviewed the short circuit study for SE MATA DE NANCE and the PV plant notes no objection. Short-circuits analyzed are three-phase and single-phase and it was verified that the short-circuit power does not exceed the short-circuit current. UL notes that the PV plant study model a different inverter and electrical topology, however still with 40 MW of power production.

The purpose of the short circuit study is to determine the maximum fault current on the collection system and substation as well as the collection cable and major equipment withstand capability. The analysis model should include the complete electrical system from the generators to the POI. Maximum fault current at the POI should be provided by the utility. The study is commonly performed in SKM, ETAP or similar power system analysis software.

2.3.2.5.2 Load Flow Study

UL reviewed the reactive load flow results included in the interconnection studies. UL notes that the study does not require the installation of capacitor banks to compensate the Project power flow. The study considers the full range of operating voltages, in line with good industry practice.

The purpose of the load flow study is to determine the reactive capability of the Project, determine if additional reactive equipment is needed to comply with the interconnection requirement, and to verify that the voltage levels at the major equipment does not exceed the manufacturer’s specifications (0.9 to 1.1 p.u. V) for the range of nominal POI voltages (0.95 p.u. V to 1.05 p.u. V). The study is commonly performed in SKM, ETAP or similar power system analysis software.

2.3.2.5.3 Harmonics Study

The purpose of a harmonics study is to evaluate the harmonic distortion limits against those limits provided by IEC 61400 and IEEE 519. In the event the limits are exceeded at the POI, the project is required to identify mitigation solutions or other next step actions. This study is typically completed in the late stages of detailed design.

UL reviewed the harmonics study and notes that TDH for Ikakos circuits 34-139 and 34-140 are below 3%, and in addition voltage flicker measured is under appropriate value.

2.3.2.5.4 System Protection Studies

The purpose of a protection coordination study is to show that the protection equipment will respond to faults appropriately. The coordination is commonly depicted using time current coordination (“TCC”) curves. Additionally, a transient over-voltage (“TOV”) study assesses the maximum voltage rises and proper sizing of surge arrestors and insulation. These studies are commonly one of the last studies performed during detailed design

UL notes that the protection studies reviewed consider inverter transformer 0.23/34.5 kV and not 0.62/34.5 kV; UL considered that it is not an issue.

2.3.2.5.5 Electrical Loss Study

Electrical losses are experienced in all electrical components of the project, including the inverters, power block transformer, electrical collection system cable, substation transformer, and transmission line conductor. These losses are established in the electrical system design.

UL notes that cables losses are calculated to LV and MV cables and seem coherent to the electrical system. A complete Electrical Loss Study to the POI is missing, however the EPC´s specifications stablish a maximum 4.5% loss that is in line with the design (long transmission line at 34.5 kV).

2.3.2.6 Auxiliary Equipment

UL notes that the auxiliary equipment expected to supply the necessary auxiliary services, as data acquisition and monitoring, meteorological station, security CCTV, etc. is made in low voltage and AC current.

An auxiliary transformer is located on the MV Skid, rated for a load of 15 kVA at 620/208 V or 620/400 V. The connection group is Dny11, dry-type and IP54 code protection.

2.3.2.7 Electrical Design Conclusions

UL performed a high-level review of the partial documentation related to electrical design. UL considers the design consistent with industry practice for the on-site electrical system to the existing high voltage electrical infrastructure for the PV Project.

UL has not identified any issues that materially impact the successful operation of the electrical system based on the available documentation, however, UL recommends completing the documentation with a specific annual electrical losses report, that enable losses tracking during operation, and the substation grounding resistance measurement to ensure the substation is appropriately grounded according IEEE 80.

2.4 Technology Review

2.4.1 PV Modules

UL has reviewed the information about Jinko Solar modules, Eagle JKM325PP-72 and JKM330PP-72 provided by the Client and information about Jinko Solar that is publicly available. Ikakos project consist of JKM325PP (30%) and JKM330PP (70%) PV modules.

The modules are 72-cell utility scale PV modules with the specifications presented below.

Table 2.5: PV Module Specifications

Module Characteristics	JKM325PP-72	JKM330PP-72
Technology	Polycrystalline	Polycrystalline
Number of Cells	72	72
STC Power Rating	325 Wp	330 Wp
Peak Efficiency	16.75%	17.01%
Power Output Tolerance	-0/+3%	-0/+3%
Voltage at Max Power	37.6 V_{DC}	37.8 V_{DC}
Current at Max Power	8.66 A_{DC}	8.74 A_{DC}
Open Circuit Voltage	46.7 V_{DC}	46.9 V_{DC}
Short Circuit Current	9.10 A_{DC}	9.14 A_{DC}
Temp. Coeff. of Power	-0.40 %/°C	-0.40 %/°C
Temp. Coeff. of Voltage	-0.31 %/°C	-0.31 %/°C
Maximum System Voltage	1,500 V_{DC}	1,500 V_{DC}
Module Dimensions	1956x992x40 mm	1956x992x40 mm
Module Weight	26.5 kg	26.5 kg

2.4.1.1 Company Background

Jinko Solar began manufacturing solar ingots in 2007 and began producing solar modules in 2009. Jinko has been ranked in the top 10 module manufacturers since 2011 and in 2017 was the leading worldwide supplier of PV modules, shipping over 9.8 GW of PV modules. Jinko is ranked as a Tier 1 module supplier by Bloomberg New Energy Finance. Jinko is a vertically integrated manufacturer of PV modules; the company manufactures the ingots and wafers, fabricates the solar cells, and constructs the PV modules. Jinko states that they have the capacity to produce over 8 GW of PV modules annually with module assembly plants in China, Malaysia, Portugal, and South Africa. Jinko also has the capacity to produce 8 GW of solar ingots and 5 GW of PV cells annually.

2.4.1.2 Tests and Certificates

The Jinko Solar proposed series of PV modules have been tested and found to meet the requirements of IEC 61730, which tests the modules for safety against electrical shock, fire, and other. The modules have also been tested and certified against the IEC 61215, which governs the field performance of PV modules. The modules are tested and listed for use at 1,500 V_{DC}. UL considers the tests listed above to be industry standard certifications for safety. UL also notes that the IEC tests do not address module field performance or longevity of the modules.

The Jinko Solar modules analyzed have been tested according to the IEC 62804 Ed. 1.0 standard that evaluates the PV modules' resistance to Potential Induced Degradation ("PID"). PID is a concern for PV systems operating at high DC voltages since it reduces the power output of the PV modules over time due to the inability of PV module components to adequately provide electrical insulation at high system voltages. Different types of module construction (double glass modules), “ungrounded” PV arrays, and PV modules with high quality EVA back sheets and additional space between PV cells and module edge frames exhibit lower susceptibility to PID.

2.4.1.3 Warranties

Jinko Solar offers a 10-year warranty for defects in material and workmanship from the date of delivery of the modules to the project or 180 days following the module manufacturing date. In addition to the 10-year warranty, Jinko Solar offers a 25-year performance guarantee following date of purchase or installation. The degradation rate of 2.5% in the first year for polycrystalline is guaranteed, while a degradation rate of 0.7%/year is guaranteed after the initial year of service. The actual power output of the PV modules is guaranteed to be no less than 80.7% of the original nameplate rating at the end of twenty (25) years. UL considers the warranty offered by Jinko Solar to be an industry standard warranty for polycrystalline PV modules.

2.4.1.4 Technical Specifications

The modules have a nominal output rating of 325 Wp (JKM325PP) and 330 Wp (JKM330PP-72V) at Standard Test Conditions (“STC”), with and open circuit voltage of 46.7 V_{DC}, 46.9 V_{DC} for JKM325PP and JKM330PP, respectively. Maximum design system voltage is 1,500 V_{DC} (JKM325PP). Module open circuit voltage will allow to construct strings of 30 modules, remaining below the IEC system voltage limit of 1,500 V_{DC}, for all cell temperatures warmer than -2°C at 50 W/m^2, assuming a temperature coefficient of open circuit voltage of -0.31%/°C. UL reviewed the open circuit maximum voltage according to the Ikakos site conditions and UL notes that the 1,500 V_{DC} is not exceeded.

UL considers that the module specifications are typical for PV modules used in large scale utility power plants and compare well with those from suppliers for similar technologies.

2.4.1.5 Overall Evaluation

UL considers that the Jinko Solar PV modules to be appropriate and consistent with industry standard. Jinko Solar is a top tier module manufacturer with a background of quality and continuous innovation. UL notes that the modules have industry standard specifications and warranties and should perform as expected for the life of the PV Project.

2.4.2 Inverters

UL has reviewed the information about the Jema IFX6 inverters provided and information on the inverters and the information that is publicly available. The inverters proposed for this Project are manufactured by Jema Energy S.A (“Jema”) in Spain. The Ikakos project consist of 16 IFX6 inverters.

Table 2.6: Inverter Specifications

Manufacturer	Jema Energy
Model:	IFX6 2550
Inverter Type	Central
Max Input Voltage:	1,500 V_{DC}
Rated Output Power (25°C]	2,675 kVA
Rated Output Power (50°C)	2,550 kVA
Rated Altitude:	1,000 m*
Enclosure Rating:	IP-54
MPPT Voltage Window	890 – 1,250 V_{DC}

Table 2.6: Inverter Specifications

Manufacturer	Jema Energy
Number of Inputs	12
Output Voltage	420 V_{AC} – Three Phase
Efficiency (Max/CEC)	98.7%/98.4%
Operating Temperature	-20º to 50ºC*

*: Active temperature power derating from 50ºC

2.4.2.1 Company Background

Jema is a manufacturer of industrial power conversion components based in Gipuzkoa, Spain. The company was founded in 1953 to design and manufacture circuit boards and variable speed drives and started in the renewable energy business in 2002. Jema was acquired by Irizar Group, a Spanish transportation equipment conglomerate, in 2009. Jema's current number of employees is over 130, while Irizar Group has more than 3,500 employees. Jema Energy headquarters are located in Gipuzkoa, Spain, and the company has technical and sales offices in Pleasanton (US), Querétaro (Mexico), and Botucatu (Brazil).

Jema's renewable power system business line manufactures battery chargers for electric vehicles, reactive power compensation, and PV inverters. Jema PV inverters have a rated capacity from 3 kW for string inverters to 2,830 kW for central inverters. Jema produces the PV solar inverters in is central manufacturing facility in Spain. Jema has reported inverter shipments over 1 GW since 2007.

2.4.2.2 Tests and Certificates

Jema IFX6 inverters have been tested and found to comply with IEC 61000 for Electromagnetic Compatibility and EN 62109-1:2011 for Safety of PV inverters (general requirements and IEC 62109-2:2011 (particular requirements for inverters). Jema inverters meet the requirements and are tested to IEC 61683:1999 for measuring inverter efficiency. UL notes that these certifications are basic requirements for reliable, bankable inverters.

2.4.2.3 Warranties

The Jema IFX6 inverter comes with a 5-year warranty on materials and workmanship. Jema also offers an extended warranty package that extends the coverage for the inverters for up to a total of 25 years in five-year increments. According to the OMA contract and Jema's warranty letter provided [15], the inverter and power block components warranty has been extended for a 10-year period. This warranty assumes that the inverters are installed and maintained in a manner consistent with the manufacturer's recommendations. The warranty does not cover normal wear and tear, inverter faults due to environmental conditions, or the inverters being operated outside the design limits of the equipment. UL considers this warranty to be standard for the industry and also considers the fact that the warranty extension has been included to be positive for the Project since replacement and on-site assistance in case of failure is covered. In addition, UL was informed by the Sponsor that is planning to extend the warranty until year 25.

2.4.2.4 Technical Specifications

The solar inverter converts the direct current electricity produced by the PV module into alternating current that can be fed into the grid. The inverter is a crucial part of a grid-connected solar plant.

The inverter to be used at the Project is the Jema IFX6 rated to 2,675 kVA at 25ºC, while the nominal power at 50ºC is 2,550 kVA. The model is a modular, outdoor-rated inverter suitable for utility-scale applications in hot climates. The inverter features both passive and active cooling of the electronic components.

The inverter cabinet has an IP-54 rating, which is a typical rating for outdoor use and indicates that the inverter is protected from dust (limited dust ingress allowed) and protected from splashed water but not from water jets (i.e. pressure washing the inverter cabinets is not recommended).

The IFX6-3 inverters have a maximum DC input voltage of 1,500 V_{DC} and a Maximum Power Point Tracking voltage window of 890 – 1,250 V_{DC}. The inverters have a power output derating above 1,000 m that is not applied for Ikakos project since the project site has a 12 m mean elevation.

The inverter is configured as a “transformerless” design, meaning that the inverter is capable of interconnecting directly to the grid without the need for a step-up/isolation transformer on the output. As per Ikakos project design, a 34.5 kV transformer is installed in the Jema standard SKID configuration.

2.4.2.4.1 Reactive Power Capabilities

The inverter model is capable of delivering reactive power and has an adjustable power factor, specified at 1.0 in the Jema’s datasheet.

2.4.2.5 Power Plant Controller

A power plant controller (“PPC”) is included in the Project design to provide supervisory control to the Project and to regulate the output of the inverters used in the Project. The PPC is a software package that communicates with Jema inverters over a Power Line Communications protocol and allows the main controller to communicate with the individual inverters without the need to install extra cabling at the plant. The PPC provides data from the PV arrays, inverter power production, and status information and should include, if installed, a method to monitor the status and position of the single-axis trackers installed at the Project. The PPC has the capability to provide some level of power output control for the plant, including ramp rate control, active and reactive power control, and the ability to disconnect the PV plant from the grid, fulfilling the Panama grid code. UL was provided with Jema compliance letter to Panama grid code for both inverter and PPC installed in the Ikakos project [16].

2.4.2.6 Overall Evaluation

UL considers the Jema IFX6 central inverter to be an industry-standard inverter from a company with significant experience in the power electronics industry. UL notes that Jema provided the inverter’s together with the MV transformer in the standard skid configuration SIX6-2550. Based on the information provided, UL considers that the inverter is properly designed and comply with Panama grid code.

2.4.3 Trackers

UL has reviewed the information about the Tracsmart 3.0 single axis tracker provided and information about the trackers and Grupo Gonvarri / Solar Steel that is publicly available. Solar Steel is a brand of Gonvarri Steel services that provides contract manufacturing services for third party tracker and rack manufacturers as well as constructing the line of trackers and fixed tilt rack systems sold under the Solar Steel brand name.

Table 2.7: Tracker Characteristics

Property	Value
Model	TracSmart 3.0
Tracking	Single Axis

Table 2.7: Tracker Characteristics

Property	Value
Tracking Drive	Independent row drives
Tilt Angle Range	± 55°
Power Requirements	Self-Powered (DC power)
Max Modules per Row	3x20 modules in landscape
Max Wind Speed	Operation 20 m/s Stow 32 m/s
Array Azimuth	0º
Relevant Certifications	IEC 62817

2.4.3.1 Company Background

Grupo Gonvarri ("Gonvarri") was founded in 1958 with corporate offices located in Madrid Spain. Gonvarri currently has 36 factories in 17 countries and employs over 3,400 people. Gonvarri Steel Services manufacturers steel products for the automotive, road safety, mechanical installation and solar industries. Product lines include barrier systems for roadways, cable tray systems for industry, steel parts for manufacturers of domestic appliances and fixed tilt racks and tracking systems for the solar energy industry. Solar Steel indicates that it has produced over 6.6 GW of trackers and rack structures for the PV industry (over 5 GW as a contract manufacturer for third party developers and over 1.8 GW under the Solar Steel brand name).

Gonvarri manufactures the TracSmart solar tracker in ISO9001 & ISO14001 certified plants. All steel components used in the tracking system conform to the European EN-1090 standard that deals with the fabrication of supporting steel structures.

2.4.3.2 Technical Specs

The TracSmart 3.0 is a single axis tracker with self-driven rows, capable of supporting up to sixty 60 utility scale modules in 3 modules in landscape configuration. The trackers are separated by a pitch distance between 7.15 m (Ikako 0) and 8 m (Ikako I).

The steel is all formed and galvanized in house by Solar Steel and pre-fabricated into components that are ready for field installation and that require no cutting, welding and/or drilling operations be performed in the field. This is standard practice by structure manufacturers to minimize field construction time and the need for skilled labor in the installation process.

Each row of the TracSmart 3.0 trackers is driven by a dedicated drive motor that is mounted in the center of the row and drives torque tubes mounted to the north and south of the motor. The tracker motors are controlled by a dedicated control unit that calculates the position of the sun using the NOAA solar tracking algorithm. The NOAA sun tracking algorithm is used in most utility scale trackers. The tracker controller monitors the tracker position through an inclinometer mounted on the tracker and can track the sun to within 1° of accuracy, which is more than sufficient for flat plate photovoltaic panels. A tracking error of 1° for flat plate photovoltaic modules corresponds to a loss in theoretical energy capture of less than 0.02%. The trackers have defined a tracking range of ±55° to minimize inter row shading, this tracking limit will be configured in the tracker controller software.

Gonvarri tracker design considers two types of trackers according its position in the photovoltaic plant, external trackers located in the perimeter and internal trackers. The external trackers have to support higher wind loads and therefore, a reinforcement on those trackers is assumed.

The maximum height of the main beams axis is 1.7 m. The main beams shall be supported by 7 piles driven into the soil. The modules shall be fixed to the secondary beams by mean of 6 m.

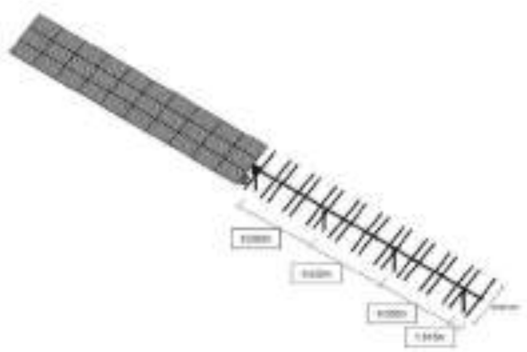

Figure 2.20: TracSmart overview

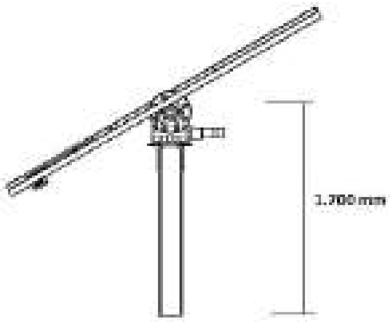

Figure 2.21: TracSmart Section View

The TracSmart 3.0 has a self-power configuration with a dedicate auxiliary PV module installed in each tracker as presented in Figure 2.22. The modules shall be fixed to the secondary beams by mean of bolts.

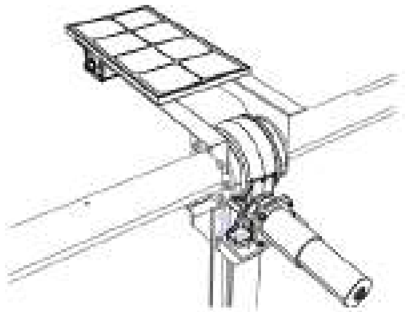

Figure 2.22: TracSmart Self-Power Module

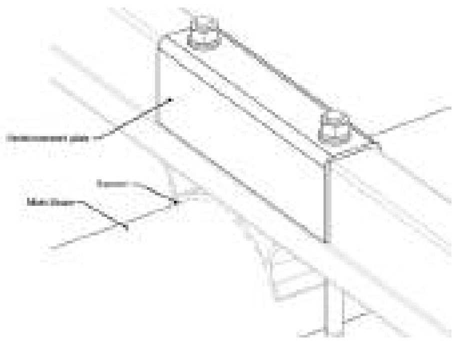

Figure 2.23: TracSmart Secondary Beam

UL notes that the TracSmart network configuration provides a master and slaves configuration. The typical configuration for the TracSmart is that the tracker control units ("TCUs") from individual trackers are controlled by several network control units ("NCU"). The NCU centralizes all TCUs data such as rotating angles or alarms. The wind speed sensors data is registered in the NCU and is the equipment in charge to provide the signal to rotate to stow position to the TCUs. The NCU connection can be through wired solution (TS485) or wireless solution (ZigBee). UL was informed that the Ikakos project has the ZigBee configuration. The Ikakos project configuration includes 3 NCUs for each of the 4 sub-plants.

The tracker structure steel components have a hot-dipped galvanized coating applied in accordance with accepted industry standards (ISO-1461 – "Hot Dip Galvanized Coatings on Fabricated Iron and

Steel Articles”). All steel components have a 20-year warranty for protection against corrosion as per the EPC Contract.

2.4.3.3 Tests and Certificates

The tracker has been designed according to all relevant design standards including ASCE 7-05, “Minimum Design Loads for Structures”, which governs structural designs in America and the European EUROCODE-1, “Action on Structures” which governs structural designs, and EUROCODE-3 “Design of Steel Structures” which covers general rules for roll forming of steel components and the general design of steel structures. The trackers are designed to return to a horizontal stow position when a wind gust over 20 m/s is detected. The trackers have a maximum wind speed in the stow position of 32 m/s. UL notes that documentation provided indicates that the TracSmart trackers have been certified to IEC 62817:2014 (PV tracker design qualification). UL considers the IEC 62817 as the best practice in the market.

2.4.3.4 Warranties

Solar Steel (Grupo Gonvarri) provides a 10-year warranty on tracker components, which are warrantied to be free from defects in design, materials and workmanship. Solar Steel provides a 5-year warranty on the motor, slew drive and control unit for the tracker. In addition, the EPC Contract provides a corrosion warranty of 20-year period as stated in Appendix 21.02 of the EPC Contract. UL notes that these are typical warranty periods for tracker components.

2.4.3.5 Overall Evaluation

The tracker design and specifications are consistent with industry standards. Based on the information provided, UL considers the TracSmart 3.0 tracker to be an industry-standard tracker with a solid, reliable design.

2.5 Pre-Constructive Energy Production Report

Although the PV Project is under operation since August 2018, UL could not perform a reliable operational energy estimate (“OEPE”) due to less than 1 year of operational data was available from the Final Acceptance (February 2020) and the lack of quantification of the DC cabling issue, detailed in Section 2.2.6, from the commercial operation start (August 2018) to Final Acceptance. Considering this, UL has performed a pre-constructive independent energy estimate (“EPE”) to evaluate the long-term solar resource and energy at the proposed PV Project site.

2.5.1 Introduction

UL has performed an independent resource and energy assessment based on review of provided equipment characteristics, Project documents, contracts, and design according to the level of provided design. UL evaluated two scenarios for the PV Project; standard scenario with the current PV Project configuration and a repowering scenario based on the information provided.

UL was provided with a repowering implementation plan from the Client for the PV Project [17]. The repowering strategy consist of installing an additional DC peak power capacity of 1.7 MWp every 5-year period. UL notes that no replacement of PV modules or any components is considered, only additional capacity to be added, therefore, extension of PV Project area will be required in order to place new trackers and PV modules.

The repowering strategy is considered to optimize the energy output of the PV Project, considering that PV modules degradation will progressively reduce the actual effective installed DC capacity. The inverter numbers will remain constant while the DC/AC capacity will be increased every 5-year period. UL notes that the DC/AC ratio of year 1 is 1.14, which is considered to be industry standard and this does not provoke a considerable inverter limitation loss. Although the new repowering capacity will increase the DC/AC ratio, the PV module degradation also will contribute to a reduction of the year-to-year DC/AC ratio.

UL was informed that no detailed documentation is still available regarding repowering capacity configuration for the PV Project. UL notes that additional new capacity should be added as complete strings addition (without mixing previously installed PV modules with new PV modules). Single line diagrams should be evaluated to divide new additional strings connections to already installed inverters. UL recommends performing an independent review on the detailed engineering before installing the new capacity at year 5.

UL performed a high-level energy assessment of the repowering scenario considering Client provided information and PV project energy assessment for standard scenario (without repowering). UL evaluated the energy increase of the 1.7 MWp new capacity to be added every 5 years based on the equivalent PV Project estimated energy yield (kWh/kWp). As the system degradation needs to be considered, UL assumed that year 5 annual energy production will be equal to year 5 production of standard scenario plus the new equivalent energy generation of 1.7 MWp (this is a simplification and rough estimation due to the fact that not specific design and detail calculation have been made at this moment). Then the system degradation was estimated for the additional capacity (considering that was installed at year 5). The process was repeated for each 5-year period where new additional 1.7 MWp blocks were considered (assuming specific system degradation for each period).

The uncertainty assessment was estimated for the repowering scenario considering a specific uncertainty for the repowering energy production. UL evaluated the uncertainty of the new installed capacity production based on the level of detail of the information provided by the Client. The new energy production of the repowering scenario was estimated to be 12%.

2.5.2 Typical Meteorological Year

A typical meteorological year (TMY) dataset is defined as a long-term annualized hourly time series of insolation and meteorological parameters. UL relied on the TMY derived from Solargis hourly long-term series, considering this dataset to provide the most appropriate data source to characterize the long-term solar resource for the project area given available data sources.

Solargis has developed a solar radiation data set as part of their high-resolution climate database through SolarGIS © v2.1, with primary layers including solar radiation, temperature and terrain data. The database was developed using a modified version of the Heliosat-2 method created from Meteosat Second Generation satellite and atmospheric data using in-house algorithms, including inputs and improvements suggested by Perez et al. (2002), Duerr and Zelenka (2009), Cebecauer et al. (2010 a,b) and others.

Table 2.8: Estimated Annual Irradiation and Meteorological Components for the TMY

Parameter	Value
Global Horizontal Irradiation ($kWh/m^2/yr$)	2,007
Diffuse Horizontal Irradiation ($kWh/m^2/yr$)	821
Mean Temperature (°C)	26.4
Mean Wind Speed (m/s)	1.29

Further available data sources analyzed at the project site together with the onsite site data made available in the proximity of the project site were also analyzed to assess their representativeness to characterize the project conditions. A review of the different available inputs and site-specific information available, UL considered SolarGIS data set the most confident data, and derived the TMY from the long-term annualized hourly time series.

2.5.3 Loss Assumptions – Gross Energy to Net Energy

After calculating the gross energy for the Project site, the following loss factors were applied to the net energy forecasted for the Project:

Table 2.9: Detailed Energy Production Loss Accounting

Detailed Loss Category	Standard Scenario	Repowering Scenario
	Percent Loss	Percent Loss
Effective Irradiation		
Horizon Shading	0.0%	0.0%
Near Shading	3.0%	3.0%
Incident Angle Modifier Factor (Reflection)	0.8%	0.8%
Soiling and Snow	0.6%	0.6%
Effective Irradiation Total	**4.3%**	**4.3%**
Photovoltaic Conversion		
Initial Light Induced Degradation	1.0%	1.0%
Non-STC Operation (Irradiance Level)	0.4%	0.4%
Non-STC Operation (Temperature)	8.4%	8.4%
Module Quality	-1.5%	-1.5%
Module Mismatch	0.8%	0.8%
Photovoltaic Conversion Total	**9.1%**	**9.1%**

Table 2.9: Detailed Energy Production Loss Accounting

Detailed Loss Category	Standard Scenario	Repowering Scenario
	Percent Loss	Percent Loss
Electrical		
DC Wiring	0.8%	0.8%
Inverter Limitation	0.3%	0.3%
Inverter Efficiency	1.4%	1.4%
Medium-Voltage Transformer Efficiency	0.9%	0.9%
AC Wiring - Collection System	0.7%	0.7%
High Voltage Transformer Efficiency	0.0%	0.0%
Transmission Line to Point of Interconnection Efficiency	2.5%	2.5%
Electrical Total	**6.5%**	**6.5%**
Operational		
Tracking System Performance	0.2%	0.2%
DC System Performance (Module/String Failures)	0.1%	0.1%
Availability of AC System (Inverters & MV Transformers)	0.8%	0.8%
Availability of Collection, HV Transformer, & Substation	0.2%	0.2%
Availability of Utility Grid	0.2%	0.2%
System Consumption (Inverters, HVAC)	0.3%	0.3%
POI Curtailment (40 MW)	0.0%	0.0%
Operational Total	**1.7%**	**1.7%**
*Annual Performance Degradation (Material/System Average)**	***0.51% / 0.7%***	**0.51% / 0.7%**
Total Losses	**19.6%**	**19.6%**

Note: Degradation loss is not included in combined loss and is applied mid-year

UL has assessed the energy results and loss factor assumptions according to site conditions and the provided project data, including Project design, technology, contracts, etc.

Gross energy

The energy simulation relied on the Perez-Ineichen transposition model to calculate a global plane-of-array ("POA") irradiation of 2,393 kWh/m^2 and a gross annual energy estimate of 109.22 GWh.

PV selected Equipment and Configuration

- **PV Modules** – The Energy Assessment assumes the use of the following PV modules for each PV plant of 11.41 MW$_{DC}$ and 10.20 MW$_{AC}$:
    - o 24,240 Jinko Solar JKM330PP-72-V and 10,500 Jinko Solar JKM325PP-72-V PV modules rated at 330 Wp and 325 Wp;
- **Inverters** – The Energy Assessment assumes that the Project will consist of 4 Jema IFX IFX6 -2550 TL.620 inverters supplied by Jema for each PV Plant. The inverter specifications rate these inverters as 2,550 kW at a temperature of 50°C;
- **Plant Configuration** – The energy assessment was evaluated for each plant configuration based on single-axis tracker (N-S) PV array with a ±55° range of motion and an orientation of 0° azimuth (True South).
    - o **Ikako 0:** The provided project design specifications include a pitch distance of 7.15 m;

- o **Ikako 1:** The provided project design specifications include a pitch distance of 8.00 m;
- o **Ikako 2:** The provided project design specifications include a pitch distance of 7.25 m;
- o **Ikako 3**: The provided project design specifications include a pitch distance of 7.95 m;

and a collector band width of 3.95 m for all PV Plants.

Effective Irradiation

- **Horizon Shading** –UL evaluated the site conditions according to satellite imagery review and using shading simulation tools, according to surrounding conditions;
- **Near Shading** – The near shading loss was simulated based on the site conditions, the provided project configuration, and the provided tracking system specifications, accounting for diffuse radiation impact from neighboring rows;
- **Incident Angle Modifier Factor IAM (Reflection) -** The incident angle modifier ("IAM") effect was modeled according to the module specific IAM parameterization; and
- **Soiling Losses -** Soiling impact was estimated on a monthly basis based on precipitation data from nearby available data sources. Per the Sponsors' agreement, there will be soiling control and cleaning activities throughout the year. The soiling loss was estimated assuming 1 cleaning is to be performed every year during the dry season; considering site conditions and maintenance.

Photovoltaic Conversion

- **Light Induced Degradation** – In order to evaluate expected power output after the initial degradation period, the loss was estimated according to the equipment specifications, PV module first year performance warranty and expected module behavior;
- **Non-STC Operation for Irradiance Level and Temperature** – These losses account for changes in performance due to irradiance and temperature. They are assessed in the energy simulation on an hourly timescale based on module specifications and the meteorological data in the TMY;
- **Module Quality** – Module quality is evaluated according to equipment technical specifications and positive power tolerance binning; and
- **Module Mismatch** – This loss is estimated considering the array configuration and the expected tolerances on module output (i.e., bin size). As the system ages, it is expected that mismatch loss will gradually increase annually due to system degradation (material degradation and component/wiring degradation). For the long term, the mismatch loss for year 25 was assumed to increase for a total of 1.1%.

Electrical

- **DC Wiring** – Low voltage wiring accounts for the distance between inverters and Medium voltage transformers, considered standard electrical efficiency loss references for the proposed design. Since the detailed site-specific electrical loss calculation was not available for review, UL relied on basic inputs to the simulation model that represent typical electrical design for utility-scale projects and provided plant design information;
- **Inverter Efficiency –**This loss accounts for the DC-to-AC conversion efficiency evaluated for the inverter equipment and site conditions;
- **Medium-Voltage Transformer Efficiency** – Since the detailed site-specific electrical loss calculation was not available for review, UL relied on a standard 1.0% electrical efficiency loss at STC;
- **AC Low Voltage Wiring - Collection System** – The Energy Assessment considered an AC LV wiring loss of 1.1% in STC; this value is considered standard reference for this electrical

efficiency loss. Since the detailed site-specific electrical loss calculation was not available for review, UL relied on basic inputs to the simulation model that represent typical electrical design for utility-scale projects and provided plant design information;

- **High Voltage Transformer Efficiency –** The project interconnects at 34.5 kV, therefore, no HV transformer is installed; and
- **Transmission Line to Point of Interconnection Efficiency** – UL evaluated this loss based on the transmission line information available including a transmission line length of 13.5 km at 34.5 kV. Neither a detailed site-specific electrical loss evaluation nor electrical designs with wire sizes were available for review.

Operational

- **Tracking System Performance:** This loss accounts for the possibility of tracker accuracy and downtime for motor failures and wind stow. While tracker availability should be high, wind stow events, backtracking algorithm accuracy, and tracker accuracy should also result in a loss factor of 0.2% for N-S axis tracking projects;
- **DC System Performance:** This loss accounts for undetected DC-system failures and underperformance related to maintenance routines. Some module failures, wiring failures, and underperforming modules may occur in the DC system. As the system ages, these failures will increase in frequency; thus, UL has modeled DC system performance loss in 0.1% for year 1, and gradually increase along the long term;
- **HVAC & Auxiliary System Consumption:** This loss accounts for the heating and cooling of the inverter enclosure (if any) and the power consumption of auxiliary components, including tracking motors, data acquisition, electronics, and lighting. According to manufacturer information, a consumption of 3 W/kW from an output power of 100 kW was considered for each inverter. Therefore, for this study the HVAC & Auxiliary components loss further than the inverter consumption is not included in the loss analysis;
- **Availability of Power Plant:** A value of 1.0% was assumed in the assessment. This value was adopted according to the Sponsor’s expectation that O&M services will result in 99.0% plant availability. UL attributes availability losses based on the typical contractual availability for utility-scale projects, and non-contractual availability, primarily due to force majeure events, scheduled maintenance, unscheduled maintenance, and repair delays;
- **Grid Availability of Utility Grid:** UL assumed a grid availability loss of 0.2%, which corresponds to four 6-hour events per year during daylight hours. This is a standard assumption for grid reliability and is consistent with typical local grid operation; and
- **POI Limitation Curtailment** – This loss accounts for lost production due to power purchase agreement curtailment or grid restrictions. A power plant limitation of 40.00 MW_{AC} at POI was considered according to Project available information, resulting in a value of 0.0% loss.

Material Degradation and Long-Term Calculation Approach

The material degradation rate represents degradation of the solar module material. The annual degradation in module output is estimated based on module specifications provided by the manufacturer, industry typical values, and UL’s experience with similar projects. The module supplier warrants that annual degradation will not exceed a certain amount in 25 years, resulting in a material degradation percentage per year. UL assumes that actual degradation will be less than this warranted amount. The project-specific material degradation rate is estimated based on the site-specific climate (e.g., plane-of-array irradiance).

- **Annual Performance Degradation** - This loss accounts for the annual degradation of system performance. The annual degradation in system output is estimated based on module specifications provided by the manufacturer, industry typical values, the local climate, and UL's experience with similar projects;

- **Material Degradation:** The material degradation rate represents degradation of the solar module material. The module supplier warrants that annual degradation will not exceed 80.7% in 25 years. UL assumes that actual degradation will be less than this warranted amount. The project-specific material degradation rate is estimated based on the site-specific climate (e.g., plane-of-array irradiance).

Energy System Output is estimated along the Long Term according to plant technology, industry typical values, the local climate, and UL's experience with similar projects. Together with impact of Material Degradation, the Long-Term Assessment accounts for additional adjustments of system factors that are expected to impact the long-term energy output of the project:

- **System Degradation:** The system degradation rate includes additional adjustments for system factors that are expected to impact the long-term energy output of the project:
  - **Inverter and Curtailment Loss Reclamation:** If relevant, inverter limitation loss and curtailment loss reclamation are assessed. As the DC array reduces in capacity, UL expects these loss factors to also gradually reduce;
  - **DC System Performance Loss Increase:** DC system performance loss is expected to increase by 0.04% per year, cumulating to 1.1% in 25 years due to component/wiring failures, underperforming and broken modules, and other array-level events that may not be identified or addressed immediately by O&M activities; and
  - **Mismatch Loss Increase:** As the DC array reduces in capacity, it is expected that mismatch losses will increase. An annual mismatch loss increase of 0.01% per year was assigned, cumulating to 1.21% additional mismatch loss by year 25.

Calculation Approach: Long term applicable loss balance is calculated from year zero and additional applicable adjustments to characterize year X. Material degradation loss is calculated from year zero and was applied subtractively to the partial net energy at the point of the module in the system's energy flow. UL considers the year-zero subtractive approach to be most appropriate when considering the physical realities of degradation and its impact on the system's energy. The system degradation rate is reported as the average year-to-year difference in net energy output over the evaluation period.

UL evaluated all loss categories based on the level of detail provided in Project contracts, the Project design, and the selected equipment.

2.5.4 Uncertainty Calculations and Exceedance Levels

2.5.4.1 Standard Scenario

A summary of the uncertainty elements for the Energy Assessment is presented below.

Table 2.10: Overview of Uncertainty Assumptions – First Year – Standard Scenario

Uncertainty Sources	Global Horizontal Irradiation		Energy Production	
	Percent	kWh/m²/yr	Percent	MWh/yr
Measurement Accuracy	5.0%	100	5.0%	4,383
Inter-annual Variability	2.8%	56	3.0%	2,646
Representativeness of Mon. Period	0.6%	12	0.6%	532
Spatial Variability	0.1%	2	0.1%	88

Table 2.10: Overview of Uncertainty Assumptions – First Year – Standard Scenario

Uncertainty Sources	Global Horizontal Irradiation		Energy Production	
	Percent	kWh/m²/yr	Percent	MWh/yr
Simulation & Plant Losses	-	-	2.6%	2,273
Annual Degradation	-	-	0.1/yr	-
Combined Uncertainty*	**5.8%**	**116**	**6.4%**	**5,628**

Note: First-year combined uncertainty does not account for degradation uncertainty, which only impacts future-year energy uncertainty.

Table 2.11: Overview of Uncertainty Assumptions – 25-Year Evaluation Period – Standard Scenario

Uncertainty Sources	Global Horizontal Irradiation		Energy Production	
	Percent	kWh/m²/yr	Percent	MWh/yr/yr
Measurement Accuracy	5.0%	100	5.0%	4,040
Inter-annual Variability	0.9%	18	0.9%	737
Representativeness of Mon. Period	0.6%	12	0.6%	490
Spatial Variability	0.1%	2	0.1%	81
Simulation & Plant Losses	-	-	2.6%	2,095
Annual Degradation	-	-	1.3%	1020
Combined Uncertainty*	**5.1%**	**103**	**5.9%**	**4,785**

Note: 25-year average energy uncertainty accounts for increasing degradation loss/uncertainty and increasing climate uncertainty.

The energy production uncertainty for the site was calculated to be 6.4% for the first year and 5.9% for a 25-year evaluation period. The table below presents the estimated net annual energy production and capacity factor at 5 confidence levels, assuming a 25-year evaluation period.

Table 2.12: Energy Production Exceedance Results – Standard Scenario

Probability of Exceedance	First-Year		Evaluation Period Average	
	Annual Energy Production (GWh)	AC Capacity Factor	Annual Energy Production (GWh)	AC Capacity Factor
P50	87.66	24.5%	80.80	22.6%
P75	83.87	23.5%	77.57	21.7%
P90	80.45	22.5%	74.67	20.9%
P95	78.41	21.9%	72.93	20.4%
P99	74.57	20.9%	69.67	19.5%

Note: *Annual average energy uncertainty accounts for degradation and climate uncertainty over the project's lifetime. Evaluation period uncertainty adjusts for the reduced effect of inter-annual variability over the project's lifetime

2.5.4.2 Repowering Scenario

A summary of the uncertainty elements for the Energy Assessment is presented below.

Table 2.13: Overview of Uncertainty Assumptions – First Year – Repowering Scenario

Uncertainty Sources	Global Horizontal Irradiation		Energy Production	
	Percent	kWh/m^2/yr	Percent	MWh/yr
Measurement Accuracy	5.0%	100	5.0%	4,383
Inter-annual Variability	2.8%	56	3.0%	2,646
Representativeness of Mon. Period	0.6%	12	0.6%	532
Spatial Variability	0.1%	2	0.1%	88
Simulation & Plant Losses	-	-	3.5%	3,062
Annual Degradation	-	-	0.1/yr	-
Combined Uncertainty*	5.8%	116	6.8%	5,990

Note: First-year combined uncertainty does not account for degradation uncertainty, which only impacts future-year energy uncertainty.

Table 2.14: Overview of Uncertainty Assumptions – 25-Year Evaluation Period – Repowering Scenario

Uncertainty Sources	Global Horizontal Irradiation		Energy Production	
	Percent	kWh/m^2/yr	Percent	MWh/yr/yr
Measurement Accuracy	5.0%	100	5.0%	4,376
Inter-annual Variability	0.9%	18	0.9%	809
Representativeness of Mon. Period	0.6%	12	0.6%	531
Spatial Variability	0.1%	2	0.1%	88
Simulation & Plant Losses	-	-	3.5%	3,056
Annual Degradation	-	-	*1.3%*	*1138*
Combined Uncertainty*	**5.1%**	**103**	**6.4%**	**5,581**

Note: 25-year average energy uncertainty accounts for increasing degradation loss/uncertainty and increasing climate uncertainty.

The energy production uncertainty for the site was calculated to be 6.4% for the first year and 5.9% for a 25-year evaluation period. The table below presents the estimated net annual energy production and capacity factor at 5 confidence levels, assuming a 25-year evaluation period.

Table 2.15: Energy Production Exceedance Results – Repowering Scenario

Probability of Exceedance	First-Year		Evaluation Period Average	
	Annual Energy Production (GWh)	AC Capacity Factor	Annual Energy Production (GWh)	AC Capacity Factor
P50	87.66	24.5%	87.51	24.5%
P75	83.62	23.4%	83.36	23.3%
P90	79.99	22.4%	79.63	22.3%
P95	77.81	21.8%	77.39	21.7%
P99	73.73	20.6%	73.20	20.5%

Note: *Annual average energy uncertainty accounts for degradation and climate uncertainty over the project's lifetime. Evaluation period uncertainty adjusts for the reduced effect of inter-annual variability over the project's lifetime

2.5.5 Conclusions

UL considered available datasets within the region to determine their appropriateness for estimating the long-term solar resource. In absence of suitable ground measurement data, UL used satellite modeled TMY from Solargis database extracted at the Project location to estimate the long-term solar resource. The long-term GHI and the long-term POA at the project site was estimated to be 2,007 kWh/m^2/year and 2,393 kWh/m^2/year, respectively.

Based on the insolation and meteorological parameters defined previously and the selected PV plant specifications provided by the Sponsor, the electrical energy output of the project was modeled using UL's energy simulation model that includes PVsyst 6.86.

UL evaluated the energy production for the PV Project for two scenarios; standard scenario with the current configuration and a repowering scenario based on the information provided (1.7 MWp to be added every 5 years).

The table below provides an overview of the Energy Assessment results evaluated for the Project's first year of operation and for the evaluation period. The long-term energy production assessment considers how some loss factors may change along the evaluation period, including module and system degradation, mismatch losses, and the inverter limitation losses, which is reduced in the long-term as modules degrade.

Table 2.16: Summary of Energy Assessment Results

Item	Standard Scenario		Repowering Scenario	
	First Year	Long Term	First Year	Long Term
Global Horizontal Irradiation (kWh/m^2/yr)	2,007	2,007	2007	2007
Plane-of-Array Irradiation (kWh/m^2/yr)	2,393	2,393	2393	2393
Gross Energy (GWh/yr)	109.22	109.22	109.22	113.29
Net Energy (GWh/yr)	87.66	80.80	87.66	87.51
Performance Ratio (%)	80.3	74.0	80.3	74.3
AC Capacity Factor (%)	24.5	22.6	24.5	24.5
Energy Yield Ratio (kWh/kW$_{DC}$)	1,920	1,770	1920	1910
Total 25 -Year Evaluation Period Energy Production (GWh)	-	2,019.94	-	2187.78

2.6 Contracts Review

2.6.1 Interconnection Agreement

UL reviewed four executed interconnection agreement ("IA") dated 16 April 2012 between the ETESA ("TSO" or "Transmission Provider") and Tecnisol I, II, II and IV SA ("Interconnection Customer" or the "Project") for Ikako 0, I, II and III respectively.

Table 2.17: Ikakos IA Key Points

IA number	GG-144-2015, GG-143-2015, GG-142-2015 and GG-141-2015 for Tecnisol I, II III and IV respectively
Date	28 September 2015
Expected COD	Original date September 2018
Effective COD Date	Pending
Term	15 years from commercial operation (16 November 2017)
Contract Capacity	10 MW_{AC} per plant, total of 40 MW
POI	Mata del Nance substation (34.5 kV)

UL has reviewed the IA and concludes that they are standard agreements used for renewable energy projects in Panama with ETESA.

The Point of Interconnection is the Mata del Nance substation (34.5 kV) where two new transmission lines bays were built by the Project and is in the process to been transferred to ETESA. The specific change of property is located at the Mata del Nance Project bays disconnector switch arranged in breaker and a half configuration.

UL considers that the conditions of force majeure and termination are typical.

The term of the agreement is 15 years from the COD acceptance letter that is still pending. According the IA the Projects achieve COD when grid code compliance testing is successfully completed. As noted in the Grid Control Center ("*Centro de Despacho Nacional*" in Spanish or "CND") letter [1] the Project has not fulfilled response times on following reactive changes requirements. The Sponsor is working together with the EPC Contractor to modify the PPC and achieve the dynamic response times required and plan to repeat and pass the testing in October-November 2020. UL notes that these issues are not uncommon in the industry and expects a resolution as it is technically achievable.

UL notes that the term will be valid until June 2035, according the plan and can be extended if both parties agree.

2.6.1.1 POI Interconnection Substation

The 34.5 kV POI station, Mata del Nance, is configured in a breaker and a half arrangement connecting to the 34.5 kV and 115 kV Panama grid. The direct costumer are Ikako 0 and Ikako II that shares the POI with Ikako I and Ikako III respectively., as the sub plants are connected as follows:

- Ikako 0 and Ikako I share the 34-139 circuit and the left side bay at Mata del Nance substation; and
- Ikako II and Ikako III shares the 34-140 circuit and the right-side bay at Mata del Nance substation.

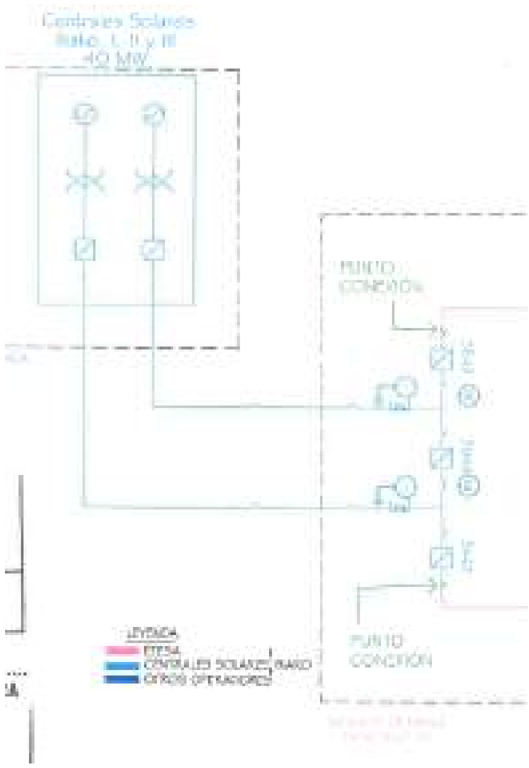

Figure 2.24: Mata Del Nance SLD Extract

UL considers the POI station design not an undue risk. A cursory review finds the station design to be typical of Utility-owned switchyards and UL notes that it uses an enhanced arrangement that other 34.5 kV substations in SIN. The Project was required to build to ETESA's utility standards, which are generally more robust than standard wind industry practices in UL experience.

2.6.2 Power Purchase Agreement

UL performed a high-level review of the executed power purchase agreements ("PPAs") for the sale of the PV Project energy. UL review was limited to amount of energy agreed in the PPAs and the Project capacity. The table below summarizes key terms of the off-take agreement as per the scope agreed with the Client:

Table 2.18: Ikakos PPA Key Terms

Buyer	Coca Cola FEMSA de Panamá, S.A.	Ventas y Mercadeo S.A.	Industrias Lácteas S.A	Clínica Hospital San Fernando	Ice Gaming Corporation	Iron Tower Corp.	Riba Smith, S.A	Petrolera Nacional, S.A.
Seller	Tecnisol I, S.A.	Tecnisol I, S.A.	Tecnisol I, S.A.	Tecnisol I, S.A.	Tecnisol III, S.A.	Tecnisol III, S.A.	Tecnisol III, S.A.	Tecnisol I, S.A.
Execution Date	Mar-17	Mar-17	Mar-17	Mar-17	Feb-18	Feb-18	Feb-18	Dec-19
COD	April 2018	March 2019	July 2018	July 2018	April 2019	April 2019	July 2018	May 2020
Term	15 years (April 2033)	15 years (March 2034)	15 years (July 2033)	15 years (July 2033)	15 years (April 2034)	15 years (April 2034)	15 years (July 2033)	10 years (May 2030)
PPA Capacity	40 MW	40 MW	40 MW	40 MW	40 MW	40 MW	40 MW	40 MW

Table 2.18: Ikakos PPA Key Terms

Buyer	Coca Cola FEMSA de Panamá, S.A.	Ventas y Mercadeo S.A.	Industrias Lácteas S.A	Clínica Hospital San Fernando	Ice Gaming Corporation	Iron Tower Corp.	Riba Smith, S.A	Petrolera Nacional, S.A.
Payment Rate								
Base (USD/MWh)	90	90	90	91.88	89.74	89.74	90.00	81.5
Price Adjustments	Minimum Base Price adjustment: 83 USD/MWh Maximum Base Price adjustment: 125 USD/MWh					Minimum Base Price adjustment: 83 USD/MWh Maximum Base Price adjustment: 135 USD/MWh		Minimum Base Price adjustment: 80 USD/MWh Maximum Base Price adjustment: 100 USD/MWh
Last PPA Price 2020: (USD/MWh)	83.00	83.00	83.00	85.72	89.39	89.33	84.11	NA

As per UL's review, the executed PPAs covers all the PV Project capacity; 40 MW of the PV Project and in addition, part of the Wind Project capacity (117.5 MW) is assumed as back up generation and for some of them hydrological plants are also assumed as back up generation to compensate production.

The PPAs COD ranges from April 2018 (Coca Cola FEMSA de Panamá, S.A.) to May 2020 (Petrolera Nacional, S.A.). Although the PV Project was energized on August 2018, UL was informed that no Liquidated Damages were applied for lack of demand. UL notes that PPAs have back up projects to provide generation.

UL notes that no specific amount of energy is defined under the PPAs since the PPA structure considers the scheme to cover all Buyers demand, considering the PV Project or the backup generation from Wind Project, hydrological plants or spot market in this order of priority.

2.6.3 EPC Contract

UL reviewed the executed engineering, procurement, and construction agreement ("EPC Contract") dated 23 August 2017 [18].

The EPC Contract of Ikakos project is formed by and between each sub-project SPV; Tecnisol I S.A ("Tecnisol I"), Tecnisol II S.A ("Tecnisol II"), Tecnisol III S.A. ("Tecnisol III") and Tecnisol IV S.A. ("Tecnisol IV"), together referred as (the "Owner") and the consortium formed by Gran Solar Panamá S.A. ("Gran Solar") and Cobra Instalaciones y Servicios ("Cobra") together referred as (the "EPC Contractor" or the "Contractor"). The EPC Contract is for four plants of 10 MW, one for each SPV and together referred as ("Ikakos") project.

In addition, UL reviewed the PV Project Acceptance Agreement between the Owner and the EPC Contractor dated 01 February 2020 [2], which updated the acceptance requirements for Final Acceptance and COD certificates for all sub-projects.

The EPC Contract states the EPC Contractor provided all material and labor for the design, engineering, procurement, manufacturing, construction, testing and commissioning of the PV plant, including the provision of all equipment and the rectification of Defects, on a "turnkey" basis.

At this stage, UL notes that the Ikakos project is under operation since August 2018. Ikakos reached the Provisional Acceptance Certificate ("PAC") on December 2018 for Tecnisol I (Ikako 0), January 2019 for Tecnisol IV (Ikako III) and March 2019 for Tecnisol II and Tecnisol III (Ikako I and Ikako II). All sub-plants reached the Final Acceptance Certificate ("FAC") on February 2020, while the COD certificate was issued on 02 October 2020.

For the interconnection infrastructure, UL notes that a separate EPC Contract was executed for the transmission line ("TL") (the "TL EPC Contract") between Tecnisol I S.A and Instalaciones y Servicios Inserpa S.A (the "TL Contractor"). The executed TL EPC Contract is dated 24 August 2017 and the scope is for the transmission line and interconnection works to connect the transmission line.

The table below provides a summary of EPC Contract terms.

Table 2.19: Ikakos EPC Contract Overview

Commercial Terms	
Contract Name	Solar Project Engineering, Procurement and Construction Agreement
Amendment	PV Project Acceptance Agreement, dated 01 February 2020
Effective Date	23 August 2017
Final Acceptance	01 February 2020
COD Certificate	02 October 2020
CEOC Certificate	Pending
EPC Contractor	Consortium formed by Gran Solar Panamá S.A. and Cobra Instalaciones y Servicios S.A.
Transmission Line EPC Contractor	Instalaciones y Servicios Inserpa S.A.
Owner	Tecnisol I S.A.; Tecnisol II S.A.; Tecnisol III S.A.; and Tecnisol IV S.A.
Scope and Completion	
Project Capacity	40.8 MW_{AC}, 45.64 MWp
Contractor's Scope	The EPC Contractor is responsible for: design and engineering, including studies and surveys; procurement of all materials and equipment for the PV plant; the construction of civil, mechanical, electrical and interconnection works; and all applicable permits necessary in order for it to carry out and complete the works. A separate EPC Contract was considered for the interconnection infrastructures works.
Milestones	Provisional Acceptance – December 2018 (Tecnisol I), January 2019 (Tecnisol IV) and March 2019 (Tecnisol II and Tecnisol III); Final Acceptance – 01 February 2020; COD Certificate - 02 October 2020; and CEOC Certificate – Pending.
Equipment Suppliers	Modules – Jinko Solar JKM325PP-72; Inverters – Jema IFX6 2550 central inverters; and Trackers - TracSmart 3.0 Gonvarri.
EPC Contract Price	
Contract Price	USD 36,849,000, equivalent to 0.81 USD/Wp (Ikakos projects) USD 2,859,635, equivalent to 0.06 USD/Wp (Interconnection infrastructures)
Security	Down payment guarantee: for an amount of 12.5% of the Contract Price; Construction bank guarantee: for an amount of 15% of the Contract Price; and Operation bank warranty: for an amount of 10% of the Contract Price.
Default and Termination	
Force Majeure	Force majeure events are typical.
Events of Default	UL finds them to aligned with industry standard practices including events of default from the Contractor and termination by the Contractor in case the Owner fails to perform any payment milestones to the Contractor
Termination	Termination rights are given for both parties in the event of Force Majeure for a 120 days period

Table 2.19: Ikakos EPC Contract Overview

Key Warranties and Provisions	
Performance Guarantee	Guaranteed Performance Ratio is described under Appendix 12.01 of the EPC Contract. The GPR for the PAC is defined in monthly basis with an annual reference value of 78.7%-78.9% depending on the sub-plant. The Contractor shall pay performance LDs in case • PAC: The measured PR is below 98% of the Guaranteed PR, in case of lower than 98%, the PR test must be repeated; and • Operation PR: A 0.09 USD/kWh of the project's generation for each percentage shortfall between the actual PR and the GPR.
Warranty Period	From the FAC certificate and in place until the latter of 2nd anniversary from 01 February 2020. In case of any defect, the Contractor shall perform the repair or replacement. The manufacturer´s warranties are described in Appendix 21.02 of the EPC Contract.
LDs CAP	The combined Contractor's delay and performance liability damages to the Owner is capped at 15% of the EPC Price
Limit of Liability	Contractor Aggregate Limit of Liability: 100% of the Contact Price

UL has reviewed the executed version of the EPC Contract provided by the Client. UL considers the provisions within to be reasonable and representative of common industry practices for the engineering, procurement, and construction of a solar project.

2.6.3.1 Milestones and Delay Liquidated Damages

The EPC Contract was signed in 23 August 2017 (the "Effective Date") and Ikakos project reached the Provisional Acceptance Certificate ("PAC") on December 2018 (Tecnisol I), January 2019 (Tecnisol IV) and March 2019 (Tecnisol II and Tecnisol III).

UL notes that the PAC requirements are defined in the Appendix 12.01 of the EPC Contract and include the following milestones among others:

- All works have been completed except the Punch List;
- Punch List has been agreed between the parties;
- Civil, mechanical and electrical works completion certificates have been obtained;
- The projects can operate properly and the Energization certificates have been issued;
- Commissioning tests and operation has been accepted by CND and ETESA;
- All licenses and permits under Contractor's responsibility have been obtained; and
- Commissioning test have been successfully finished including performance ratio.

An amendment to the EPC Contract was executed on 01 February 2020 as PV Project Acceptance Agreement to update the requirements for acceptance certificates (FAC and COD).

All sub-plants reached the Final Acceptance Certificate ("FAC") on 01 February 2020. The FAC requirements are defined under the Clause 2.03 of the PV Project Acceptance Agreement and, among others, include the following milestones:

- All as built documentation and each sub-project documents have been delivered; and
- Bank warranty (10% of EPC price) for a 2-year period from 01 February 2020.

UL notes that the COD certificate was issued on 02 October 2020 for all sub-plants. The COD requirements stated under the Clause of 2.04 of the PV Project Acceptance Agreement include, among others, the following milestones:

- Project site cleaning and waste removal; and
- Certificate delivery of works payment of subcontractors, suppliers or any third party related.

According to the Clause 3.03 of the PV Project Acceptance Agreement, the commercial operation start certificate ("CEOC") is responsibility of the EPC Contractor. UL notes that the CEOC is defined by the NIS 2.6 of the Operating Regulations of Panama (document to be issued by the CND to determine that the PV Project is in technical conditions to be operated by this entity). The requirements listed under the agreement include among others:

- CND approval of the PSS modelling and compliance with Panama electrical grid code;
- Delivery of support documentation of CEOC;
- Transmission Line contractor coordination;
- CND and ETESA coordination; and
- CEOC certification approval from CND.

UL was informed by the Sponsor that there is still a pending item to be approved by the CND related to approved interconnection requirements (power plant control response time) as per CND letter [1].

Delay penalties are described in the Clause 12.05 and Appendix 12.05 of the EPC Contract. The delay LDs are referred to key milestones such as civil, mechanical and electrical works completion date, energization certificate, Final Acceptance certificate achievement and correction of the works. Each key milestone has a start LDs date and in general, an amount of 0.025% of the EPC Price shall be applied for each business day of delay.

UL notes that the FAC certificate achievement was specified to be at 25 May 2018 and the actual execution date of the FAC was on 01 February 2020. However, no LDs were applied as per the PV Project Acceptance Agreement.

Delay and performance penalties are subject to the limit of 15% of the EPC Price that is aligned with industry standard (low range).

2.6.3.2 EPC Contract Price and Payment

EPC Contract price ("EPC Price") is detailed in the Clause 9.01 of the EPC Contract. The EPC Price for the scope of work under the EPC Contract including materials and installation was USD 36,849,000, which is equivalent to 0.81 USD/Wp. As specified above, there is a specific EPC Contract for the transmission line (LT EPC Contract). The LT EPC Contract price was USD 2,859,635, which is equivalent to 0.06 USD/Wp. Therefore, the overall EPC price for the Ikakos project is equivalent to 0.87 USD/Wp that is considered to be aligned with UL's expectation for the project site and the date of signature of the EPC Contracts.

UL reviewed the milestone payment included in the Clause 8.05 of the EPC Contract for the Milestones defined in the Appendix 8.05 and detailed below.

Table 2.20: EPC Contract Milestone Payment Schedule

Milestone EPC Contract	Percentage
Initial Disbursement	12.5%
3- Construction Certificate	72.5%
4- PAC	7.5%
5- FAC	5%
6- COD	2.5%(1)
Total	**100%**

Note: (1) As per EPC Contract and updated on the Amendment of the Project Acceptance executed on 01 February 2020

UL considers the payment structure to be aligned to industry standard, including a 15% for PV Project acceptance. UL notes that the PV Project Acceptance Agreement, updated the COD certificate payment amount as per the Clause 3.03 of the agreement, detailed in the table below. UL was provided with COD payment evidence dated 02 October 2020.

Table 2.21: Acceptance Agreement COD Payment Amount

Sub-Project	Amount (USD)
Tecnisol I, S.A.	142,122
Tecnisol II, S.A.	280,306
Tecnisol III, S.A.	556,674
Tecnisol IV, S.A.	142,122

With the purpose of securing the EPC Contractor obligations under the agreement, a bank warranty for an amount equal to 10% of the EPC Price (Clause 9.04) is to be in place prior the Final Acceptance Certificate and for a 2-year period. UL finds the structure and amount of the bank guarantees to be provided typical and within industry standards.

2.6.3.3 Default, Termination and Liability

UL reviewed the terms and conditions for Termination in the EPC Contract and finds them to be typical of industry standard practices including events of default from the Contractor and termination by the Contractor in case the Owner fails to perform any payment milestones to the Contractor. In case of an event of default, the Owner might terminate the EPC Contract immediately and the bank warranty might be executed.

Termination rights are given for both parties in the event of Force Majeure for a 120 days period. UL considers this termination condition to be aligned with industry standard.

The combined Contractor's delay and performance liability damages to the Owner is capped at 15% of the EPC Price that is according to industry standard (low range).

The EPC Contractor's overall liability is capped at 100% of the EPC Price, which is according to industry standards.

2.6.3.4 EPC Contract Conclusions

UL reviewed the executed version of the EPC Contract 23 August 2017 for the PV projects and considers the general structure of the contract to be in line with industry standards. In addition, UL reviewed the executed PV Project Acceptance Agreement dated 01 February 2020.

The EPC Contractor was responsible, on a fixed price and turnkey basis, for all the works required for the design, execution, and completion of the works consisting on the construction, operation and maintenance of 4 sub-plans of 10.2 MW_{AC} (11.3 MWp) each. It also comprises all the civil works and electrical works. An additional EPC Contract was executed for the interconnection infrastructure including the transmission line with Instalaciones y Servicios Inserpa S.A.

UL notes that the Project is under operation since August 2018 with Provisional Acceptance achieved on December 2018 (Tecnisol I) - March 2019 (Tecnisol II and III), Final Acceptance on 01 February 2020 and COD certificate dated 02 October 2020. UL notes that the Final Acceptance certificate and COD milestone were delayed from the EPC Contract schedule; however, no LDs were applied as per the PV Project Acceptance Agreement. UL notes that the commercial operation start certificate ("CEOC"), defined in the PV Project Acceptance Agreement, is still pending (EPC Contractor responsibility) due to a pending requirement of the grid code compliance (response time). UL was informed that the EPC Contractor solution is still pending to be approved by the inverter manufacturer. UL recommends a follow up on the EPC Contractor and the inverter manufacturer solution.

The EPC Price for the scope of work including materials and installation is USD 36,849,000 (VAT excluded), equivalent to 0.81 USD/Wp for a Project Capacity of 45.64 MWp, while the interconnection infrastructure cost is equivalent to 0.06 USD/Wp. UL considers the EPC Price to be within UL's expectation based on the PV Project characteristics.

The EPC Contract warranty period is for 2 years starting at the Final Acceptance certificate achievement (01 February 2020). UL notes that the EPC Contract includes equipment warranties above equipment manufacturer's warranties such as 10 years for the inverters and MV transformers and 20 years for trackers against corrosion. UL considers these equipment warranties to be benefit for the PV Project.

A performance ratio warranty is included for the PAC testing project acceptance and also a monthly PR warranty is assumed for the EPC Warranty period, however, UL considers the Guaranteed PR figures to be in the low range compared to UL's independent estimation. If the PV Project fails to achieve the PR Warranty during the EPC Warranty Period, the EPC Contractor shall pay LDs of 0.09 USD/kWh of the project's generation for each percentage shortfall between the actual PR and the GPR. The LDs are capped to a 15% of the EPC Price.

2.6.4 O&M Services Agreement

The Operation and Maintenance ("O&M") of the PV Project is managed directly by the Client that is in charge of the management, operation and management of the PV Project. Ikakos consist of 4 sub-project SPVs. An executed Service Agreement for the O&M was provided for review dated 01 February 2020 [19] by and between InterEnergy Holdins UK Limited (the "Operator") with limited liability to each sub-project; Tecnisol I S.A ("Tecnisol I"), Tecnisol II S.A ("Tecnisol II"), Tecnisol III S.A. ("Tecnisol III") and Tecnisol IV S.A. ("Tecnisol IV") (together to be the "Owner").

The Client has dedicated staff on-site to perform operation and maintenance and some of the work is subcontracted third parties such as annual maintenance for trackers and inverters, PV module cleaning, vegetation control or transmission line maintenance.

UL has reviewed the executed Service Agreement for the O&M together with the detailed O&M plan included as Annex 3 of the Service Agreement (the "O&M Plan") dated April 2020 [20]. In addition, specific annexes of monthly reports, equipment manuals, spare parts list or PR calculation were provided for UL's review.

The O&M Plan includes supervision, preventive maintenance, and corrective maintenance for the Project as well as for the interconnection facilities. The table below provides a summary of the O&M Plan main aspects:

Table 2.22: Key Terms of the O&M Services Agreement

Commercial Terms	
O&M Reference Document	Services Agreement O&M
Additional Document	O&M Plan Annexes
Owner	Tecnisol I S.A.; Tecnisol II S.A.; Tecnisol III S.A.; and Tecnisol IV S.A.
Operator Responsible	InterEnergy

Table 2.22: Key Terms of the O&M Services Agreement

Operator Subcontract	Gonvarri (tracker inspection); Jema (inverter inspection); PV Hardware (SCADA service); Local subcontractor (PV module cleaning and vegetation control); Mantenimiento de Sistemas Eléctricos de Chiriquí S.A. (“Selchi”) (transmission line); and Local subcontractor (site surveillance)
Scope of Work	
Scope of Services	Administrative management, accounting, Project’s operation, preventive, corrective, and routine maintenance and repairs for the Project, including interconnection infrastructure as well as spare parts replacement. The Client will submit monthly reports including main KPIs and main events performed at the project.
Remote Monitoring	Project monitoring 7 days a week 24 hours per day through the SCADA system
Client Responsibilities	Monitoring and project supervision, preventive and corrective maintenance, spare parts replenishment, administrative and accounting management, security and surveillance of the project and subcontractor’s management.
Communication and Reporting	Monthly reports that summarize the main KPIs and relevant parameters of the PV Plant operation and maintenance reports for corrective maintenance.
Price and Term	
Term	The Client is the responsible for the operation and management during project lifetime
OMA Budget	The O&M budget is equivalent to 10.1 USD/kWp per year including subcontractor’s costs.
Default and Termination	
Force Majeure	Force Majeure events are typical.
Key Performance Parameters	
Equipment Warranties	10-year for workmanship warranty for PV modules, 10-year for inverters, 10-year for structural tracker elements and 20-year against corrosion, 2-year for all other equipment.
Availability	A monthly availability warranty of 98% is assumed at inverter level with a time-based availability. In case of non-compliance LDs shall apply equivalent to 1% of the annual fee for each 1% drop.
Performance Ratio	A monthly Performance Ratio warranty is assumed considering a temperature corrected calculation aligned with UL’s estimation. In case of non-compliance LDs shall apply from the actual corrected temperature corrected value until the EPC Contract warranted value, an LD equivalent to 0.09 USD/kWh.

UL has reviewed the O&M Services Agreement together with the Annexes provided by the Client. In general terms, UL considers the provisions within to be reasonable and representative of common industry practices for the operation and maintenance services of a PV project. UL’s opinions and conclusions are provided below along with additional details of the O&M Plan.

2.6.4.1 Organizational Chart

The O&M of the PV Project is managed directly by the Client for the engineering and management of the project including dedicated staff for the operation and maintenance of the PV Project. In addition, the Client subcontracts specific tasks detailed in the table below.

Table 2.23: O&M Organizational Chart

Dedicated Staff	Function	Frequency
1 - O&M director (InterEnergy)	O&M responsible for all plants in Panama. Remote assistance and control.	Permanent
1 - Site manager (Tecnisol)	In charge of O&M management for Ikakos	Permanent
1 - SCADA operator (Tecnisol)	SCADA monitoring responsible to control operation remotely	Permanent
3 - Technicians for electromechanical works (Tecnisol)	Responsible of the preventive and corrective maintenance. Permanent presence on-site.	Permanent
Subcontractors		
PV modules cleaning (Local contractor)	Manual cleaning and water tank truck	2 per year
Vegetation control (Local contractor)	Including required equipment, personnel and cleaning of the site	6 per year
Inverter maintenance (Jema)	Annual site visit for preventive maintenance	1 per year
Tracker maintenance (Gonvarri)	Permanent monitoring with monthly reporting and annual site visit for preventive maintenance	1 per year
Transmission line and interconnection infrastructures maintenance (Selchi)	Earthing system verification, visual inspection and vegetation control in monthly basis	12 per year
SCADA service (PV Hardware)	SCADA service annual fee	1 per year
Project surveillance (Urracá)	Project site security and surveillance	24/7

UL considers the organizational chart to be appropriate for the operation considering the PV Project characteristics. UL is of the opinion that having tracker and inverter manufacturers performing annual preventive maintenance is positive for the PV Project.

2.6.4.2 Scope of Services

The Client is in charge of the management, operation and maintenance of the PV Project including the interconnection facilities (the "Services"). As stated in the O&M Plan, the Client operation and maintenance responsibilities include the following:

- Monitoring of the project 7 days a week 24 hours per day through the SCADA system and personnel on-site;
- Preventive maintenance, routine inspections and verification of civil, mechanical and electrical works;
- Corrective maintenance;
- Spare parts stock control and replenishment;
- Administrative and accounting management;
- Security of the project during 24 hours per day; and
- Subcontractors management and coordination.

As stated in Section 5.1 of the O&M Plan, the Client must perform the Services in accordance with applicable permits, interconnection requirements and Panamá grid code.

2.6.4.2.1 Preventive Maintenance

UL notes that the preventive maintenance activities of the PV Project are referred in section 7.1.2 and in the Annex V of the O&M Plan. UL notes that the realization of the preventive and predictive maintenance includes, among others, the following aspects:

- PV modules cleaning (bi-annual);

- Thermographic inspection of the 25% of the PV modules (quarterly);
- Thermographic inspection of the 100% of the combiner boxes (annual);
- 100% String I-V curve review from the SCADA (monthly);
- 20% String I-V curve on-site measurement (annual);
- Tracker components visual inspection (quarterly);
- Tracker tilt verification (bi-annual);
- Tracker network control unit verification (annual);
- Tracker inspections and complete preventive maintenance to be performed by the tracker manufacturer (annual);
- Inverter inspections and complete preventive maintenance to be performed by the inverter manufacturer (annual);
- Power block parameters monitoring verification (monthly)
- Power blocks air filters cleaning (bi-annual);
- Power block inspection (monthly);
- SCADA components supervision and alarms verification (annual);
- CCTV cameras inspection (annual);
- Electrical connections inspection (bi-annual);
- Meteorological sensors cleaning (weekly);
- Grounding system verification (bi-annual);
- General project inspection (monthly);
- Vegetation control (bi-monthly);
- Maintenance and inspections of access and internal roads, and surrounding areas of the Project (annual, if required);
- Drainage system inspection (quarterly); and
- Transmission line earthing system verification, visual inspection and vegetation control (monthly).

UL considers the scope described under the Annex V to be detailed including all components of the PV plant and to be aligned with UL´s expectations. In addition, UL considers that the annual site visit to perform preventive maintenance from the tracker and inverter manufacturer to be positive for the project. However, UL recommends including the following:

- Recalibration of pyranometers (annual).

2.6.4.2.2 Corrective Maintenance

The corrective maintenance for the PV Project is performed when a failure or issue is detected as detailed in Clause 7.1.2 of the O&M Plan. The Client shall respond promptly and provide corrective maintenance for the resolution of incidents or failures of all PV Project components, including but not limited to those failures that resulted from wear and tear and/or malfunction, deterioration, and/or breakage thereof, whatever the origin.

According to section 5.1 of the O&M Plant the corrective maintenance is to be performed with the following response time:

- 24 hours response time for minor event, which does not affect the production;
- 12-hour response time for major events, which affects the production by less than 50%; and
- 2 hours response time for emergency event that affects the production by more than 50% or the security, health of any employee or protection of the project.

UL considers the response time established by the O&M Plan to be consistent with industry standard.

2.6.4.3 Communication and Reporting

The O&M Plan lists the reporting details under section 7.2 and consist of the following:

- Maintenance Report: After any corrective maintenance performed a report is submitted detailing the staff involved, incident description, summary of works performed and equipment used for the corrective maintenance; and
- Monthly Report: Each calendar month, an operation report shall be submitted summarizing the Project operation according to the Annex II of the O&M Plan. UL notes that the monthly reports include generated energy, comparative from predicted energy, contractual PR, contractual availability. UL recommends specifying generated energy in hourly and daily basis.

UL considers the report parameters to be industry standard.

2.6.4.4 Spare Parts

The list of the spare parts available on site assumed by the Client is detailed in the Annex IV of the O&M Plan. UL notes that the list of spare parts include a 0.9% of the PV modules, cabling, tracker components including 8 sets of the TracSmart 3.0, power block components, distribution center spares and CCTV among others. UL considers the spare part list to be appropriate and complete; however, UL recommends including meteorological sensors and SCADA equipment. UL was informed that the client has already requested proposals to the manufacturers to include those spares parts.

UL notes that the spare parts are located in the warehouse presented below:

Figure 2.25: Spare Parts Warehouse

Figure 2.26: PV Modules Spare Parts

2.6.4.5 O&M Budget

According to the Section 11 of the O&M Plan provided, the O&M budget for the O&M Plan fulfillment corresponds to a total amount of USD 403,871 (VAT excluded), which is equivalent to 10.1 USD/kWp per year including all subcontractor's fees. UL notes that the Client O&M Plan also includes the administrative and accounting management of the project that normally is considered under a separate contract (asset management agreement). UL considers the O&M budget to be aligned with industry standard considering the scope of services and the subcontractors costs assumed.

2.6.4.6 Force Majeure

UL notes that according to Clause 7.1.3 of the O&M Plan provided, an extraordinary maintenance is to be considered for unexpected events including force majeure event. UL notes that listed force majeure events are typical including natural disasters, drought, flood, earthquake, storm, fire, explosion, lightening, epidemic, war, riot, civil disturbance, sabotage, terrorism or threat of terrorism, and strikes.

2.6.4.7 O&M Services Agreement Conclusions

The Client is responsible for the administrative and accounting management, operation and maintenance of the PV Project. UL was provided with a Services Agreement for the O&M including a detailed O&M Plan corresponding to the Annex 3 of the Services Agreement. The Client is in charge of the O&M of the project and subcontractor's management. The O&M Services Agreement include supervision, preventive maintenance, and corrective maintenance for the Project as well as for the interconnection facilities together with the administrative and accounting management.

UL notes that the scope of services is detailed and complete all preventive tasks to be performed and the frequency. Most of the tasks are to be performed by subcontractors such as the PV module cleaning, vegetation control, tracker and inverter annual inspections, transmission line maintenance and project surveillance.

The O&M Plan includes a list of spare parts to be available at project site that is considered to be appropriate. Maintenance reports including main KPIs are to be issued in monthly basis.

An availability guarantee is included under the O&M Services Agreement of 98%. UL considers the availability warranty to be in the middle low range of industry standard (typically 99%). In case of non-compliance, LDs shall be applied (1% of the total annual Fee for every 1% of availability drop).

The O&M estimated budget for the scope of services detailed in the O&M Plan is equivalent to 10.1 USD/kWp including asset management tasks and all subcontractors cost. UL considers the O&M price to be aligned with industry standard based on the scope of services included and the project size.

2.6.5 Tests and Warranties

2.6.5.1 EPC Contract Warranties

2.6.5.1.1 Warranty period

The EPC Contract provides a 24 months period of warranty ("EPC Warranty Period") on all works and equipment from the Final Acceptance certificate and until the 2nd anniversary of the Final Acceptance. In case any defect is detected during the EPC Warranty Period the Contractor shall repair or replace the defect as per the Clause 5.08. UL considers the warranty period to be aligned with industry standard.

2.6.5.1.2 Serial Defects

UL notes that Defects are defined under the EPC Contract as per any service, work or equipment that is not working properly due to design error, construction cause, equipment used by the EPC Contractor or any works performed by the EPC Contractor. UL notes that no specific definition of serial defects is included under the EPC Contract. UL considers that typically the serial defect is defined in order to specify an obligation for the EPC Contractor to perform a root cause analysis and provide a report to the Owner once serial defects occurs. In any case, UL notes that the EPC Contractor shall repair any Defect during the warranty period.

2.6.5.1.3 Manufacturer's Warranty

The EPC Contract provides the following warranties for the main equipment:

- 10-year warranty on modules and 25-year warranty on module power degradation;
- 10-year warranty on inverters and power block components;

- 10-year warranty on tracker's mechanical materials, 5-year warranty on tracker's electrical materials, and 20-year warranty on piles and trackers corrosion protection; and
- 2-year warranty other main equipment's, components and services.

UL is of the opinion the warranties for the EPC Contract are within industry standards and are adequate to support the PV Project. UL considers the inverter and power block warranty extension to a 10-year period (5-year period is standard) to be positive for the Ikakos project.

2.6.5.1.4 Initial Guaranteed Performance Ratio

The initial Guaranteed Performance Ratio ("GPR"), (referred in the EPC Contract as "Valor Garantizado de Desempeño" in Spanish) is defined under the Appendix 12.01 for the PAC testing requirements. The initial GPR for the PAC was specified in a monthly basis with annual values as presented below.

Table 2.24: Ikakos EPC Contract Guaranteed Performance Ratio

Month	Ikako 0	Ikako I	Ikako II	Ikako III
1	78.82%	79.01%	78.94%	79.05%
2	77.56%	77.72%	77.69%	77.76%
3	76.92%	77.04%	77.04%	77.09%
4	77.18%	77.35%	77.32%	77.39%
5	78.92%	79.10%	79.07%	79.14%
6	79.43%	79.64%	79.60%	79.68%
7	79.23%	79.41%	79.37%	79.45%
8	79.19%	79.38%	79.33%	79.42%
9	79.61%	79.84%	79.79%	79.88%
10	79.46%	79.72%	79.64%	79.75%
11	79.89%	80.11%	80.03%	80.14%
12	79.58%	79.80%	79.73%	79.83%
Annual - PAC	**78.70%**	**78.89%**	**78.85%**	**78.93%**
Annual GPR*				
1st Year	**77.66%**	**77.85%**	**77.80%**	**77.88%**
2nd Year	**77.11%**	**77.30%**	**77.25%**	**77.33%**

Note: EPC Warranty Period PR include a 99% project availability and a 0.7% annual degradation
Note 2: Annual GPR was considered to be starting from August 2018

The initial PR commissioning testing calculation methodology is detailed under the Appendix 1.01(a) of the EPC Contract. The PR calculation methodology defines testing period of 10 days with a calculation time interval of 10-minutes, a required PV plant availability of 100% (understanding that no failure or issue is detected on the PV Project). UL considers the PV plant availability to be aligned with industry standard; however, UL notes that in that the global availability is lower than 98% due to grid availability, UL considers that the PR testing period should be extended in order to properly address the PR during the 10 days required.

The minimum irradiation threshold is specified as 100 W/m^2 that is considered to be aligned with UL's expectations for the Ikakos meteorological conditions.

The PR shall be estimated as per the following formula:

$$PR_{cor} = \frac{G_{ref}}{P_0} \times \frac{\sum_i E_i}{\sum_i \{H_i \times [1 + T_{coeff} \times (T_{cell,i} - T_{stc})]\}}$$

Where,

- PR_{cor}: PR weather temperature corrected
- G_{ref}: Reference Irradiation (1,000 W/m^2)
- P_o: Installed capacity at STC as per PV modules datasheet nameplate capacity (kWp);
- H_i: Irradiation at PV module plane of array (Wh/m^2). Minimum 2 pyranometer shall be considered with a maximum measurement uncertainty of ±5%;
- E_i: Output energy at metering level;
- T_{coeff}: PV module temperatura coefficient (%/ºC);
- T_{celli}: Measured cell temperature (°C). A temperature sensor as minimum shall be considered with a maximum uncertainty of ±1%; and
- T_{STC}: Reference temperature at STC (25°C).

UL considers the temperature corrected PR calculation to be aligned with industry standard; however, UL notes that best industry practice defines the installed capacity as per PV modules flash tests in order to evaluate the actual installed capacity instead of the PV modules nameplate capacity.

UL notes that the monthly GPR is considered to be in the low range compared to expectations for the formula of calculation (temperature corrected PR). UL considers that the GPR presented in Table 2.24 corresponds to the standard PR calculation assuming temperature loss. UL notes that the EPC Contract initial GPR is consistent with a non-temperature corrected PR, while the formula of calculation is a temperature corrected PR.

As reference, UL estimated the temperature corrected GPR based on the EPC Contract methodology and the information provided by the Client [21] in order to compare GPR values (Table 2.24) to EPC Contract formula results (temperature corrected, Table 2.25). UL considers that the GRP is in the low range compared to UL's independent PR estimation considering a temperature corrected PR.

Table 2.25: UL estimated temperature corrected Guaranteed Performance Ratio (PAC)

Month	Ikako 0	Ikako I	Ikako II	Ikako III
1	85.22%	85.49%	85.37%	85.53%
2	84.55%	84.79%	84.70%	84.83%
3	83.59%	83.77%	83.74%	83.81%
4	82.73%	82.96%	82.89%	83.00%
5	83.74%	83.97%	83.90%	84.01%
6	84.03%	84.30%	84.22%	84.34%
7	83.73%	83.95%	83.88%	83.99%
8	83.85%	84.08%	84.00%	84.12%
9	84.35%	84.64%	84.55%	84.68%
10	84.00%	84.32%	84.20%	84.36%
11	84.29%	84.57%	84.45%	84.60%
12	84.84%	85.11%	85.01%	85.14%

The PV Project reached the PAC on December 2018 and the PR results for the PAC testing period of each sub project were higher than the PR presented in Table 2.24, therefore, no LDs were applied. UL notes that the PR tests results were calculated based on a temperature corrected formula, hence the PR results were above GPR results.

In case of non-compliance of the initial GPR, the EPC Contractor shall pay LDs to the Owner in case the PR is lower than the GPR but higher than the 98% of the GPR. In case the is lower than 98% the PR testing shall be repeated.

2.6.5.1.5 Operation Guaranteed Performance Ratio

According to the Clause 13.02, the GPR is guaranteed during the EPC Warranty period as long as the Ikakos project is operated based on EPC Contractor's operation and manual delivered to the Owner as per Clause 12.02. During the EPC Warranty Period the EPC Contractor shall provide to the Owner monthly reports including equipment warranty claim (if any), monthly operation performance, subcontractors' details including PR calculation and comparison to GPR. The GPR for the operating year is also presented in Table 2.24 for annual values, while monthly values together with the PR calculation methodology are detailed under the Appendix 11.01 of the EPC Contract.

The PR calculation for the Operation GPR is equal to the initial PR commissioning testing for the PAC described under Section 2.6.5.1.4. The Operation PR shall be calculated in monthly basis.

UL notes that the PV Project reached the Final Acceptance on 01 February 2020 as detailed in Section 2.6.5.3.2, therefore the EPC Warranty Period started including the Operational GPR.

UL considers that the performance of the PV Project can be checked through the actual PR calculation. UL was provided with maintenance operational reports from the Client for February to November 2020 including PR results as detailed in the following table:

Table 2.26: Client Temperature Corrected PR Calculation

Month	Ikako 0	Ikako I	Ikako II	Ikako III
February 2020	80.3%	78.0%	77.8%	80.3%
March 2020	83.4%	82.1%	78.6%	81.7%
April 2020	81.3%	82.0%	79.5%	80.3%
May 2020	76.2%	77.7%	77.3%	76.4%
June 2020	72.9%	73.7%	71.8%	79.2%
July 2020	66.4%	72.1%	75.5%	77.8%
August 2020	65.1%	70.1%	75.5%	78.0%
September 2020	64.9%	71.4%	71.2%	76.4%
October 2020	76.3%	78.0%	70.4%	75.4%
November 2020	82.6%	83.5%	78.5%	79.9%

Note: September and October PRs are pending to be validated by the Client.
Note 2: November monthly data includes until 22 November 2020.

UL notes that the Client calculated PR is higher than the GPR for February 2020 – April 2020, while the PV Project PR is lower than the GPR for May 2020 – October 2020. In addition, UL notes that for May – October 2020 the actual PR is 10.5% lower than UL's independent temperature corrected PR estimation presented in Table 2.19. As stated in Section 2.2.6 and according to information provided from the Sponsor, DC cabling issue affected considerably the PV Project available capacity affecting the PR results. The monthly maintenance reports provided from the Client stated that the low PR is provoked by the low availability of the PV Project provoked by the DC cabling issue as presented in the table above. UL considers the PR results from May 2020 to September 2020 to be below expectations due to the DC cabling issue. UL analyzed the PR calculation provided by the Client for the reference testing period of 16 October to 22 November 2020 to evidence the PR improvement with the DC cabling replacement available in Table 2.4 of Section 2.2.6. UL considers that PR improved with completion of the DC cabling replacement works. UL recommends a follow up on the PR results for the coming months to verify that the PR results are aligned with UL's independent figures.

UL notes that the Operating GPR will be evaluated in the monthly reports, therefore, the LDs may apply in those monthly values. In case of non-compliance of the GPR during the EPC Warranty Period, the Contractor shall pay LDs to the Owner, a 0.09 USD/kWh of the project's generation for each percentage shortfall between the actual PR and the GPR. The LDs are capped to a 15% of the EPC Price. UL notes that considering the low values of the GPR compared to the formula of calculating the actual PR (temperature corrected PR), the EPC Contractor has a considerable margin to comply with the GPR and therefore to not apply LDs. UL was informed by the Client that this risk is to be mitigated by the O&M Contract, which is to be signed between the PV Project SPV and the Client. UL reviewed the executed Service Agreement by and between InterEnergy Holdins UK Limited, which include a Performance Ratio Guarantee reviewed under section 2.6.5.1.5 and aligned with UL's expectations. UL notes that the EPC Contractor might have a margin for LDs application considering the low GPR but with the Service Agreement, the Client is considering paying LDs in case the PR is below expected temperature corrected PR aligned with UL's figures.

2.6.5.1.6 Warranty of Design

According to the Clause 13.07, in case of the Owner detects any failure, error or design, defect of the works performed by the EPC Contractor that was not detected during the EPC Warranty Period, The EPC Contractor shall repair or replace the detected defect if the notification is performed to the EPC Contractor within a 8-year period from the 01 February 2020.

2.6.5.2 O&M Services Agreement Warranties

2.6.5.2.1 Availability Warranty

The availability warranty is defined under the Annex 2 of the O&M Services Agreement. The Guaranteed Availability Value is a monthly value of 98%. The availability formula considered is to be measured at inverter level and it is a time-based availability, which is consistent with industry standard although the energy-based availability is assumed to be best industry practice. The availability will be calculated as per the hours of non-operation of each inverter with a minimum threshold of 100 W/m^2 at 15-minute time interval.

The availability calculation considers industry standard exclusions such as grid outages, force majeure and events not attributable to the operator among others, however, UL notes that the exclusion assumed for time intervals with shadows caused by any objects outside the PV Project including horizon shading to not be consistent with industry standard. UL was informed that this exclusion was referred to temporary shadows provoked by punctual external objects such as machinery, temporary works or temporary buildings but the Sponsor clarified that no exclusion will be considered for near mountain horizon shading provoked to PV Project.

In case of non-compliance of the Guaranteed Availability, the Operator shall pay to the Owner LDs for each 1% drop from the Guaranteed Value of 98% in monthly value. A 10% cap of the total annual Fee is assumed. UL considers the LDs to be in the low-middle range of industry standard assuming that a full 1% of drop is to be recognized without any penalty if a 0.9% drop is calculated.

2.6.5.2.2 Guaranteed Performance Ratio Corrected Value

Considering the difference between the GPR of the EPC Contract compared to the expected PR values for corrected temperature PR calculation detailed in Section 2.6.5.1.4, the O&M Services Agreement also includes the Guaranteed Performance Ratio Corrected Value ("GPRCV") to consider the actual temperature corrected PR. Guarantee. The GPRCV assumes a temperature-corrected calculation aligned with industry standard, while the GPRCV values are aligned to UL's estimation presented in Table 2.25.

The GPRCV calculation assumes a 10-minutes time interval calculation. The minimum plane of array irradiance threshold is 100 W/m^2 aligned to availability warranty threshold.

The GPRCV estimation considers industry standard exclusions such as grid outages, force majeure and events not attributable to the operator among others, however, UL notes that the exclusion assumed for time intervals with shadows caused by any objects outside the PV Project including horizon shading to not be consistent with industry standard. UL was informed that this exclusion was referred to temporary shadows provoked by punctual external objects such as machinery, temporary works or temporary buildings but the Sponsor clarified that no exclusion will be considered for near mountain horizon shading provoked to PV Project.

UL notes that no O&M warranty is in place since the Client is the direct responsible of the operation and maintenance of the PV project.

In case of non-compliance LDs shall apply from the actual corrected temperature corrected value until the EPC Contract warranted value, an LD equivalent to 0.09 USD/kWh.

2.6.5.3 EPC Contract Tests

2.6.5.3.1 Provisional Acceptance Certificate

The PAC was achieved on December 2018 (Tecnisol I), January 2019 (Tecnisol IV) and March 2019 (Tecnisol II and Tecnisol III) with the fulfillment of the requirements specified in Section 2.6.3.2. In addition, UL was provided with the following tests for the PAC:

- FAT&SAT testing:
  - Electric switchboard verification report by Chemik;
  - Power blocks, including inverters and MV transformers, testing procedures and operation manuals;
  - PV modules QA performed by PI Berlin including visual inspection, insulation tests, I-V curve determination, STC results compilation, electroluminescence analysis and overview of the PV modules abnormalities for EPC Contract specified sampling for the 8 batches delivered;
  - SAT procedure for the SCADA performed by PV Hardware (“PVH”); and
  - Fiber Optic and Instrumentation & control cables test reports by SUMCAB.
- Pre-Commissioning testing:
  - Tracker structural elements verification;
  - PV modules visual inspection;
  - Installed capacity verification;
  - String polarity;
  - DC wiring islanding;
  - String wiring verification;
  - Combiner boxes verification;
  - Electrical works inspection;
  - Civil woks inspection;
  - Auxiliary services inspection; and
  - Buildings inspection.
- Commissioning testing:
  - I-V curve string measurement;
  - Voltage drop measurement;
  - Auxiliary services verification;
  - PV modules thermography inspection;
  - Monitoring system testing;

- CCTV system inspection;
- Meteorological stations verification; and
- Performance ratio verification.

UL performed a high-level review on the testing and verification results for the tests provided and UL notes that the PAC testing and verification was performed according to Appendix 1.01 of the EPC Contract.

In regard to the PR commissioning test, UL notes that the test was performed before each sub-plant as requirement for PAC certificate achievement. The EPC Contractor PR results were as follows:

- Ikako 0: Testing period from 26 November 2019 to 05 December 2019. PR resulted to be 91.92% for temperature corrected PR, which is higher than the temperature corrected GPR;
- Ikako I: Testing period from 27 February 2019 to 08 March 2019. PR resulted to be 86.49% for temperature corrected PR, which is higher than the temperature corrected GPR. UL notes that the Client excluded the 07 March data due to a low grid availability;
- Ikako II: Testing period from 28 February 2019 to 09 March 2019. PR resulted to be 83.12%, which is lower than the temperature corrected GPR for March (83.59%). UL notes that the Client excluded the 07 March data due to a low grid availability; and
- Ikako III: Testing period from 17 January 2019 to 26 January 2019. PR resulted to be 84.51% for the temperature corrected PR, which is lower than the temperature corrected GPR for January (85.53%). UL notes that the Client excluded the 20 January data due to a low grid availability.

According to the information provided including EPC Contract PR testing results for the PAC and Client's PR review [22], some days were excluded due to low grid availability. UL considers that if any day is excluded from the 10-day testing period, the testing period should be extended until 10-valid days can be considered. In addition, UL notes that the GPR is defined at STC and that to be compared with the testing results, the temperature corrected GPR should be considered (estimated by UL at Table 2.25). Considering this, UL notes that the GPR was not met for Ikako II and Ikako III as detailed above.

2.6.5.3.2 Final Acceptance Certificate

The FAC was issued on 01 February 2020. As stated in Section 2.6.3.1, the EPC Contract schedule included a FAC date of 25 May 2018, therefore the Ikakos project Final Acceptance has been delayed. The parties agreed the issuance of the FAC as per the condition of the executed agreement [2]. UL was provided with evidence of the FAC documentation requirement including:

- String wiring inspection;
- String polarity inspection;
- Performance ratio testing results;
- Project site area cleaning; and
- As-built documentation delivery.

According to the Appendix IV of the FAC agreement, the GPR for the first and second year of the EPC Warranty Period has been updated considering the PV module degradation from the PV Project operation initial date (August 2018) for a total drop of 1.05% of the EPC Contract GPR. UL considers the reduction of the GPR to be consistent with the PV module manufacturer performance warranty.

The EPC Contractor measured PR is presented in the table below. UL notes that the EPC Contract guaranteed performance ratio ("GPR") is in the low range compared to UL's independent figures. UL considers that the EPC Contract is comparing the temperature corrected PR (without temperature loss) versus the GPR (with temperature loss). In this case, the temperature corrected PR will be lower than the temperature corrected GPR as presented below.

Table 2.27: Ikakos February 2020 Performance Ratio Test

February 2020	Ikako 0	Ikako I	Ikako II	Ikako III
EPC Contractor Measured PR	80.26%	77.99%	77.80%	77.27%
EPC Contractor GPR	75.86%	75.95%	75.89%	76.01%
Estimated Temperature Corrected GPR	83.50%	83.74%	83.65%	83.78%

According to the EPC Contractor February 2020 report, the PV project is producing a -13.8% lower than the predicted energy, while the irradiation for the testing period was -9.8% lower than the predicted irradiation. Although the EPC Contractor Measured PR was greater than the EPC Contractor GPR, UL notes that the EPC Contractor Measured PR is below UL's independent estimated PR.

2.6.5.3.3 COD Certificate

UL notes that the amendment to the EPC Contract of the PV Project Acceptance Agreement defines the requirements for the COD certificate. The COD certificate was issued on 02 October 2020 for all sub-projects.

2.6.5.3.4 CEOC Certificate

UL notes that the CEOC defined under the PV Project Acceptance Agreement, defined under Section 2.6.3.1, is still pending. UL was informed by the Sponsor that there is still a pending item to be approved by the CND related to interconnection requirements (power plant control response time) as per CND letter [1]. The CEOC approval is under the EPC Contractor responsibility. UL recommends a follow up on the CEOC certificate status.

2.7 Permitting review

UL performed a review of the permitting needed for the construction and operation of the PV Project. The relevant permits, authorizations and studies to comply with the legislation of the host country in the construction and the operational phases of the Project are summarized below. Table 2.28 describes details of each permit, authorization and study with the obligations or recommendations written in the table.

Table 2.28: Summary of Permits and Authorizations for the PV Project

Permit/Authorization	Description	Obligations and Recommendations	Status
Definitive Generation License for Ikako Solar Project in favor for Tecnisol I, S.A., by the National Public Services Authority (ASEP)	Resolution AN No. 8545 and register certificate No. 257-15 for the construction, exploitation, maintenance, generation and sale of energy, issued on 06 May 2015. Valid for 40 years. License modification Resolution AN No. 11239 in the EIA and construction schedule issued on 12 May 2017. Another modification to the construction and operation schedule was authorized in 14 December 2017 Resolution AN No. 11914	Compliance with the terms and obligations established in the license	Valid

Table 2.28: Summary of Permits and Authorizations for the PV Project

Permit/Authorization	Description	Obligations and Recommendations	Status
Definitive Generation License for Ikako I Solar Project in favor for Tecnisol II, S.A., by the National Public Services Authority (ASEP)	Resolution AN No. 8546 and register certificate No. 258-15 for the construction, exploitation, maintenance, generation and sale of energy, issued on 06 May 2015. Valid for 40 years. License modification Resolution AN No. 11240 in the EIA and construction schedule issued on 12 May 2017.	Compliance with the terms and obligations established in the license	Valid
Definitive Generation License for Ikako II Solar Project in favor for Tecnisol III, S.A., by the National Public Services Authority (ASEP)	Resolution AN No. 8547 and register certificate No. 259-15 for the construction, exploitation, maintenance, generation and sale of energy, issued on 06 May 2015. Valid for 40 years. License modification Resolution AN No. 11241 in the EIA and construction schedule issued on 12 May 2017. Another modification to the construction and operation schedule was authorized in 14 December 2017 Resolution AN No. 11915	Compliance with the terms and obligations established in the license	Valid
Definitive Generation License for Ikako III Solar Project in favor for Tecnisol IV, S.A., by the National Public Services Authority (ASEP)	Resolution AN No. 8548 and register certificate No. 260-15 for the construction, exploitation, maintenance, generation and sale of energy, issued on 06 May 2015. Valid for 40 years. License modification Resolution AN No. 11242 in the EIA and construction schedule issued on 12 May 2017.	Compliance with the terms and obligations established in the license	Valid
Interconnexion Agreement between Tecnisol I, S.A., and the Electric Transmission Company (ETESA)	Supervision Agreement No. GG-139-2015 issued on 28 September 2015.	Compliance with the terms and conditions established in the agreement	Valid
Interconnexion Agreement between Tecnisol III, S.A., and the Electric Transmission Company (ETESA)	Supervision Agreement No. GG-140-2015 issued on 28 September 2015.	Compliance with the terms and conditions established in the agreement	Valid
Contract for the access to the transmission system between Tecnisol I, S.A., and the Electric Transmission Company (ETESA)	Contract No. GG-144-2015 issued on 28 September 2015. Valid for 15 years since the point of interconnexion is in commercial operation.	Compliance with the clauses established in the contract	Valid
Contract for the access to the transmission system between Tecnisol II, S.A., and the Electric Transmission Company (ETESA)	Contract No. GG-143-2015 issued on 28 September 2015. Valid for 15 years since the point of interconnexion is in commercial operation.	Compliance with the clauses established in the contract	Valid
Contract for the access to the transmission system between Tecnisol III, S.A., and the Electric Transmission Company (ETESA)	Contract No. GG-142-2015 issued on 28 September 2015. Valid for 15 years since the point of interconnexion is in commercial operation.	Compliance with the clauses established in the contract	Valid
Contract for the access to the transmission system between Tecnisol IV, S.A., and the Electric Transmission Company (ETESA)	Contract No. GG-141-2015 issued on 28 September 2015. Valid for 15 years since the point of interconnexion is in commercial operation.	Compliance with the clauses established in the contract	Valid
Commercial operation register for Tecnisol I, S.A., by the Ministry of Industries and Commerce	Operation notice No. 2555018-1-826820-2015-452493	No conditions or terms established in the document	Valid

Table 2.28: Summary of Permits and Authorizations for the PV Project

Permit/Authorization	Description	Obligations and Recommendations	Status
Commercial operation register for Tecnisol II, S.A., by the Ministry of Industries and Commerce	Operation notice No. 2555049-1-826825-2015-452702	No conditions or terms established in the document	Valid
Commercial operation register for Tecnisol III, S.A., by the Ministry of Industries and Commerce	Operation notice No. 2554947-1-826814-2015-452707	No conditions or terms established in the document	Valid
Commercial operation register for Tecnisol IV, S.A., by the Ministry of Industries and Commerce	Operation notice No. 2555030-1-826823-2015-452717	No conditions or terms established in the document	Valid
O&M Contract for the Mata de Nance Substation between Tecnisol I and the Electric Transmission Company (ETESA)	Contract No. GG-061-2018 issued on 16 July 2018.	Compliance with the terms and obligations established in the contract	Valid
Authorization letter for Tecnisol I, S.A. dispatch to the National Interconnected System (SIN) by the National Dispatch Center (CND)	Letter No. ETE-DCND-GOP-PMP-188-2019 issued on 08 April 2019. Letter indicating that from 29 March 2019 Ikako Solar Project is available to dispatch to the SIN.	Request the list of pending items and date of resolution in order to grant the commercial operation to the central.	Valid
Authorization letter for Tecnisol II, S.A. dispatch to the National Interconnected System (SIN) by the National Dispatch Center (CND)	Letter No. ETE-DCND-GOP-PMP-189-2019 issued on 08 April 2019. Letter indicating that from 29 March 2019 Ikako I Solar Project is available to dispatch to the SIN.	Request the list of pending items and date of resolution in order to grant the commercial operation to the central.	Valid
Authorization letter for Tecnisol III, S.A. dispatch to the National Interconnected System (SIN) by the National Dispatch Center (CND)	Letter No. ETE-DCND-GOP-PMP-190-2019 issued on 08 April 2019. Letter indicating that from 29 March 2019 Ikako II Solar Project is available to dispatch to the SIN.	Request the list of pending items and date of resolution in order to grant the commercial operation to the central.	Valid
Authorization letter for Tecnisol IV, S.A. dispatch to the National Interconnected System (SIN) by the National Dispatch Center (CND)	Letter No. ETE-DCND-GOP-PMP-301-2019 issued on 05 June 2019. Letter indicating that from 10 May 2019 Ikako III Solar Project is available to dispatch to the SIN.	No conditions or terms established in the document	Valid
Environmental Impact Study Approval for the Transmission Line of 34.5 kV for Ikako, I, II, III Solar Project and Mata del Nance Substation by the National Environmental Authority	Resolution ARACH IA-062-2016 issued on 24 May 2016. It will take effect since it starts execution and will be valid for two years.	Compliance with the conditions established in the resolution ARACH IA-062-2016.	Valid
Environmental Impact Study Approval for Ikako Solar Project by the National Environmental Authority	Resolution ARACH IA-157-2014 issued on 21 October 2014. A modification was issued on 6 January 2016, Resolution ARACH-IAM-004-16. Another modification due to an error was made on 28 March 2017, Resolution DRCH-IA CORREC 03-2017. It will take effect since it starts execution and will be valid for two years.	Compliance with the conditions established in the resolution ARACH IA-157-2014.	Valid

Table 2.28: Summary of Permits and Authorizations for the PV Project

Permit/Authorization	Description	Obligations and Recommendations	Status
Environmental Impact Study Approval for Ikako I Solar Project by the National Environmental Authority	Resolution ARACH IA-046-2016 issued on 08 April 2016. A modification was issued on 14 July 2017, Resolution ARACH-IAM-009-17. It will take effect since it starts execution and will be valid for two years.	Compliance with the conditions established in the resolution ARACH IA-046-2016.	Valid
Environmental Impact Study Approval for Ikako II Solar Project by the National Environmental Authority	Resolution ARACH IA-155-2014 issued on 21 October 2014. A modification was issued on 17 March 2016, Resolution ARACH-IAM-008-16. Another modification due to an error was made on 30 March 2017, Resolution DRCH-IA CORREC 05-2017. It will take effect since it starts execution and will be valid for two years.	Compliance with the conditions established in the resolution ARACH IA-155-2014.	Valid
Environmental Impact Study Approval for Ikako III Solar Project by the National Environmental Authority	Resolution ARACH IA-154-2014 issued on 21 October 2014. A modification was issued on 23 March 2016, Resolution ARACH-IAM-010-16. Another modification due to an error was made on 28 March 2017, Resolution DRCH-IA CORREC 004-2017. It will take effect since it starts execution and will be valid for two years.	Compliance with the conditions established in the resolution ARACH IA-154-2014.	Valid
Construction License for Ikako Solar Project by the Municipality of David	License No. 42698 issued on 27 September 2017. Completion date of the work was 04 April 2018.	No conditions or terms established in the document	Valid
Construction License for Ikako I Solar Project by the Municipality of David	License No. 42699 issued on 27 September 2017. Completion date of the work was 27 April 2018.	No conditions or terms established in the document	Valid
Construction License for Ikako II Solar Project by the Municipality of David	License No. 42696 issued on 27 September 2017. Completion date of the work was 04 April 2018.	No conditions or terms established in the document	Valid
Construction License for Ikako III Solar Project by the Municipality of David	License No. 42697 issued on 27 September 2017. Completion date of the work was 27 April 2018.	No conditions or terms established in the document	Valid
Approval for land use and zoning for Ikako Solar Project by the Ministry of Housing and Territorial Planning	Resolution No. 564-2017 issued on 06 December 2017.	Compliance with the clauses established in the resolution	Valid

UL denotes that the Project is divided into 4 SPVs and the transmission line. Each SPV and the transmission lines has its own Environmental Impact Authorization. Only the 4 SPVs has the Definitive Generation License, Commercial Operation Register, Authorization Letter to dispatch energy into the National Interconnexion System and the Construction License from the Municipality of David. UL reviewed all the permits sent by the Sponsor and found no inconsistencies that could cause future problems in terms of legitimacy under the Panamanian legislation.

UL also reviewed the environmental reports sent by the Sponsor and points that the Project was built aligned with the IFC Performance Standards.

3. PENONOMÉ II WIND FARM

3.1 Executive Summary

3.1.1 Project Overview

Penonomé II is located in Penonomé, which is part of the Cocle Province of the Republic of Panama. The Project is about 10 km away form of the Penonomé town. The site is also located approximately 15 km north of the coast.

The Project consists of 86 WTG Goldwind 2.5 MW which total 215 MW.

The Project site is approximately 8,500 hectares with predominantly flat terrain. The Project site consist of privately-owned agricultural and farmland including scattered forestry.

Penonomé II is divided into 4 wind farms named: Nuevo Chagres 2, Portobelo, Marañon, and Rosa de los Vientos (phase 1 and phase 2).

The Wind Project has several neighbor wind farms including Penonomé I (operational) and Penonomé IV (under development that according to the Sponsor is owned by UEP III) projects that are part of the Penonomé portfolio, and they have a wake effect agreement between all of them.

The project is characterized by the connection through 2 transmission lines in 34.5 kV. It is interconnected in the Substation El Coco at 230 kV. The 230 kV POI station, El Coco, is configured in a breaker and a half arrangement connecting to the 230 kV Panama grid.

The main access to the site is located right next to the Hector Conte Bermudez street and dirt roads built by the Wind Project provide access to the Wind Project substation, O&M building and all WTG locations.

3.1.2 Operational Assessment

3.1.2.1 Operational Energy Production Report

UL performed an Operational Energy Production Report (OEPR) for the Project and issued the report on 05 October 2020 (Ref. No.: UL-ES-AA20-13321645-04.07), which is included in Appendix B.

The analysis relied on revenue meter production data to estimate long-term (LT) plant performance over an evaluation period of 20 years from COD. The data were first quality screened and evaluated. Monthly gross energy production values were then calculated from the reported monthly energy production data by assuming 100% availability. These gross energy values were then normalized to 30-day standard months to provide a consistent baseline. Suitable LT reference datasets were then identified by analyzing r-squared coefficients between the density-adjusted monthly reference wind speeds and the normalized monthly gross energy production over the operational period of record (POR). Regression relationships between selected LT reference wind speed datasets and normalized gross energy production were used to calculate long-term gross energy production on a monthly and annual basis. MERRA-2 data source has not been used due to the differences between the POR and the LT wind speed, so an ERA5 long-term data source since 1997 has been used. Finally, estimates of future project availability, blade degradation and electrical losses were applied to the gross energy to estimate the LT net energy production potential for the project.

A summary of the Project energy results is presented in the following table:

Table 3.1: Project Energy Results Summary

Project Name	Penonome II
Operational POR	January 2016 – July 2020
Projected Future Operational Gross Energy Production	554.1 GWh/year
Availability	5.4% loss (94.6% eff)
Curtailment Loss	0.2% loss (99.8% eff)
Electrical Loss	4.5% loss (95.5% eff)
Blade Degradation losses	0.2% loss (99.8% eff)
P50 Average Annual Net Production	498.7 GWh/year
P50 Net Capacity Factor	26.5%
P90 Average Annual Net Production – Evaluation Period	471.4 GWh/year
P90 Net Capacity Factor	25.0%
P99 Average Annual Net Production – 1 Year	368.3 GWh/year
P99 Net Capacity Factor – 1 Year	19.5%

3.1.2.2 Wind Turbine Inspection and Blades Strategy Plan

UL performed wind turbine inspections and blades strategy plan evaluation for the Penonomé II project and issued the report on 15 September 2020 (Ref. No.: UL-ES-AM20-1101772929-01.06), which is included in Appendix C. Main conclusions of this report were the following:

Table 3.2: Wind Turbine Inspections Summary

Section	Status	UL Comment
General Wind Turbine Inspection	Completed	No turbine was found with severe defects after the inspections.
Blades and Hub Inspection	External Completed in 72 Turbines Internal not Performed	External Inspection, 2 turbines with recommendation of limitate actions (T39 & T41). New potential risk identified. Internal inspection was not performed due to specific blade´s brake system design

No turbine was found with severe defects during general wind turbine inspections and all discrepancies have been noted on a punch list provided to the Client, by means of summary results per each specific inspection. Discrepancies on the punch list are expected to be addressed by OEM, during the claim process, or by the Client during the next maintenance cycle. According to the Blades external inspections, it was recommended limitated actions in 2 wind turbines (T39 and T41) that were finally stopped.

According to the information provided by the Sponsor (email 30 July 2020), the Blades Strategy Plan contemplates yearly inspections in all the Blades and a repair plan during all the lifetime of the Blades (until 2040 according to LTE results). These costs are included in the OPEX assumptions in order to consider and prevent future potential risks relate to this issue (see Section 5.2.1). Sponsor informed that, in 2020, as part of the Blades Strategy Plan, all the turbines are going to be repaired according to the level of damage suggested by UL.

The Sponsor defined a blades strategy plan issue on 18 September 2020 [23] with the objective to define a complete plan for the blade's strategy. The executive summary of this report executed by the Sponsor is the following:

- The Arbitration process was initiated because a disagreement on the compliance of the TSA contract in relation to some Change Orders. During the process, some internal correspondence of Goldwind, raised a potential quality-related issue in the blades. On 28 June 2017, UEP II filed a complaint against Goldwind USA, Inc in the American Arbitration Association (AAA) and entered an arbitration process for allegedly failing to disclose alleged quality issues in wind turbine Blades. The major problem was the material used for manufacturing the blade Tips which was not in consistence with the technical specifications provided by Sinoma, as mentioned Goldwind in its Overseas Regulatory Announcement;

- The arbitration process was favorable to the Owner and resulted in a considerable amount paid by the turbine manufacturer as a compensation in response to the claim presented by UEP II;
- Due to the process, it was discovered that the blades have a quality-related issue that affect three main aspects: root bushings, aluminum tip and overall, quality control during manufacturing. In the market, there are several manufacturers who suffer of similar issues; the difference is that UEP II managed to prove it in an arbitration and got compensated for it;
- In summary, the design and implementation of the strategy plan for replacement has two main drivers: technical and financial;
- The objective of the blade strategy plant report is to define a complete plan for the blade replacement strategy that meets the following:
  - Maintain or improve the operational functions of the Wind Farm; and
  - Analyze the condition of the blades and its lifetime extension and define strategies to guarantee their correct operation and performance.
- The blade strategy plan is divided in the following different sections, where the different parts that make up the strategy are defined, as well as the traceability followed until the full definition of the plan:
  - **1. Blades damage history.** Summarizes all the featured events, from a legal and operational point of view, that affected the blades life between the arbitration process and the Independent Engineer selection process. It also includes major repairs carried out in the blades until December 2019;
  - **2. Blades strategy plan design.** Includes all the necessary tests performed to analyze the current condition of the blades and altogether with the results, they will define the Blades Strategy Plan;
  - **3. Blades strategy plan.** This section includes detail of all the action lines to be carried out to ensure the optimal operation and performance during the lifetime of the blades. The definition of this chapter has been done according to the results obtained from the previous tests; and
  - **4. Schedule and financial assessment.** Capital and Operational expenses for the Blades Strategy Plan execution are explained. Furthermore, a detailed scheduled for all the planned works is attached in the blade strategy plan.
- The subsections of the blade strategy plan include explanations of the historical process since the blade issues were detected until an advisor is hired to help IE to design an action plan including some repair works on the blades;
- After the arbitration result, the objective was to design a complete strategy to mitigate any possible risk derived from the condition of the blades while operating the Wind Farm in optimum conditions;
- Some additional type of tests, not carried out until the date, were performed whose purpose was to assess the real condition of the blades (externally and internally), to detect any factor that could influence in the blade's operability. The testing stage was composed of four phases (Phase 1A, Phase 1B, Phase 2 and Phase 3);
- Based on the results obtained in the Blades Strategy Plan Design, the Blades Strategy Plan has been defined; in which possible actions are evaluated and analyzed to manage future potential risks. The definition process considers technical and economic viability, and feasibility of the proposed plan;

- According to the blades external categorization established and the tests carried out so far in the Root Issue, the Blades Strategy is defined. The inspections done in the Phase 1A allowed to establish an external repair schedule according to a 5-level categorization of the damages;
- In the case of the blade root issue, the strategy contemplates the implementation of a monitoring system (Control Risk System) and the purchase of some brand-new sets to be available in the Wind Farm as Spare Parts in case of replacement. This control risk system in conjunction with the purchase of 7 new sets of blades is considered an effective solution to reduce response time in case of blade replacement thus reducing the unavailability. Therefore, production losses are minimized;
- In the final chapters, it is analyzed the economic and scheduling impact of the above-mentioned works of repair and replacement in the finance of the project. It is assumed an increase of costs in OPEX and CAPEX, and a reduction of production as the turbines will not be online during the works since it is necessary to stop them for safety reasons; and
- The analysis produces different outputs which serves as inputs for the financial model. For this task, the financial and engineering departments worked together to define the parameters.

UL considers the blades strategy plan report consistent and traceable in all faces with supporting evidence in each section. The conclusions and UL comments after the review of the blade's strategy plan are summarized in the following main section (based on the UL Report Review letter issued on 21 September 2020):

- **Section 1. Blades damage history.** Summarizes all the featured events, from a legal and operational point of view, that affected the blades life between the arbitration process and the Independent Engineer selection process. It also includes major repairs carried out in the blades until December 2019. UL has reviewed this section and agree with the content.
- **Section 2. Blades strategy plan design.** Includes all the necessary tests performed to analyze the current condition of the blades and serve as basis to define the Blades Strategy Plan. UL has reviewed this section and agree with the content.
- **Section 3. Blades strategy plan.** This section includes detail of all the action lines to be carried out to ensure the optimal operation and performance during the lifetime of the blades. UL has reviewed this section and agree with the content, with the following comments.
  - Monitoring System: To identify the need of replacement, a monitoring system will be installed in the blade roots to control in real-time the condition of it and manage the risks identified in the related report. UL have been appointed to perform this works.
  - Quality Control Plan: UL will verify that the requirements identified during the design evaluation with respect to critical Components and critical manufacturing processes were observed and implemented in production and assembly. UL have no received evidence of any documentation of new blades as per the date of the present report.
  - Quality Control Assurance: UL as the Independent Engineer of this Project, will be responsible of the supervision of all the works that make up the Blades Strategy, including inspection and repair works. In that sense, UL will validate the inspection and repair works carried out by the contractor. UL have been appointed to perform this works.
  - Shipping of new blades: The intention of UEP II is to purchase 7 sets of blades to be delivered by the end of the low-wind season, which is around end of November. Considering the shipping, the blade should leave the factory around September. UL have no received evidence of any shipment as per today and is aware of the possible impact due to actual pandemic situation.
- **Section 4. Schedule and financial assessment.** Describes Capital and Operational expenses for the Blades Strategy Plan execution. UL has reviewed this section and agree with the content, with the following comments:

- UL has reviewed and confirms that Plan Schedule includes detail planning of all the phases to have in consideration and the associated costs until the year 2020. In addition, the scheduled lifetime including Aging Management actions is described as well as costs related to them.
- UL have reviewed the Blades inspection reports and repair works schedule. In addition, UL have received first reports for WTG02 and WTG03. Blades Inspections started on 11 September 2020.
- UL verify that condition monitoring system have been considered to manage risk and use to determine when a blade start to have an operational risk and follow up actions will be needed. Seven full sets of blades will be available on site.
- UL verify that a reserve account of 1 USD million have been considered. This is to be used for several purposes related to replacement and/or repair works. In case the reserve account is used, Sponsor indicates that it will be replenished to 1 USD million next year.
- UL verified the Blades Strategy Plan Cost and founds it reasonable as indicated and reviewed that all concepts describe in the document are considered.

- It is UL opinion that all sections of the Blade Strategy Plan are successfully completed and in an ongoing process. In addition, UL note that main actions are considered:
  - A global external blades repair plan
  - A monitoring system consisting to manage risk
  - Seven (7) new blades sets to be available on site
  - A reserve account of 1 Million USD.

3.1.2.3 Performance Assessment Report

UL performed a Performance Assessment (PA) for the Project and issued the report on 20 August 2020 (Ref. No.: UL-ES-AA20-13321645-05.02), which is included in Appendix D.

The operational performance analysis includes a comparison with the pre-construction Energy Yield Assessment ("EYA") provided by the Client [24]. The energy production during 2019 was 546.5 GWh according to the revenue meter, while 511.7 GWh were expected according to the results of the EYA provided by the Client. Therefore, a relative difference of -6.8% has been found.

In the PA analysis, the losses have been evaluated by means of classification of the production variance sources in several categories. These categories have been defined crossing the categories of energy losses in the EYA and the available operational information. Taking into consideration the losses obtained in the operational data analysis, comparing them with the EYA ones, and considering the EYA P50 (in revenue meter) value as reference, the next relative differences on each analyzed category were obtained translated to net energy:

- 7.49% positive variance on wind and wakes modelling: 38.31 GWh.
- 8.36% positive wind anomaly (2019) vs LT reference: 42.76 GWh.
- 1.93% positive variance on availability losses: 9.86 GWh.
- 0.82% negative variance on electrical losses: 4.2 GWh.
- 9.23% negative variance on operational under-performance of the wind turbines: 47.24 GWh.
- 1.42% negative variance on density: 7.28 GWh.
- 0.50% as remaining variance this analysis: 2.55 GWh.

The presented variances are obtained as a percentage of the EYA P50 energy results. Additionally, the Client requested the comparison per category in order to review the assumptions on the pre-constructive analysis. This requires evaluation of the losses as a percentage of the gross energy before wakes. The comparison is presented in next figures:

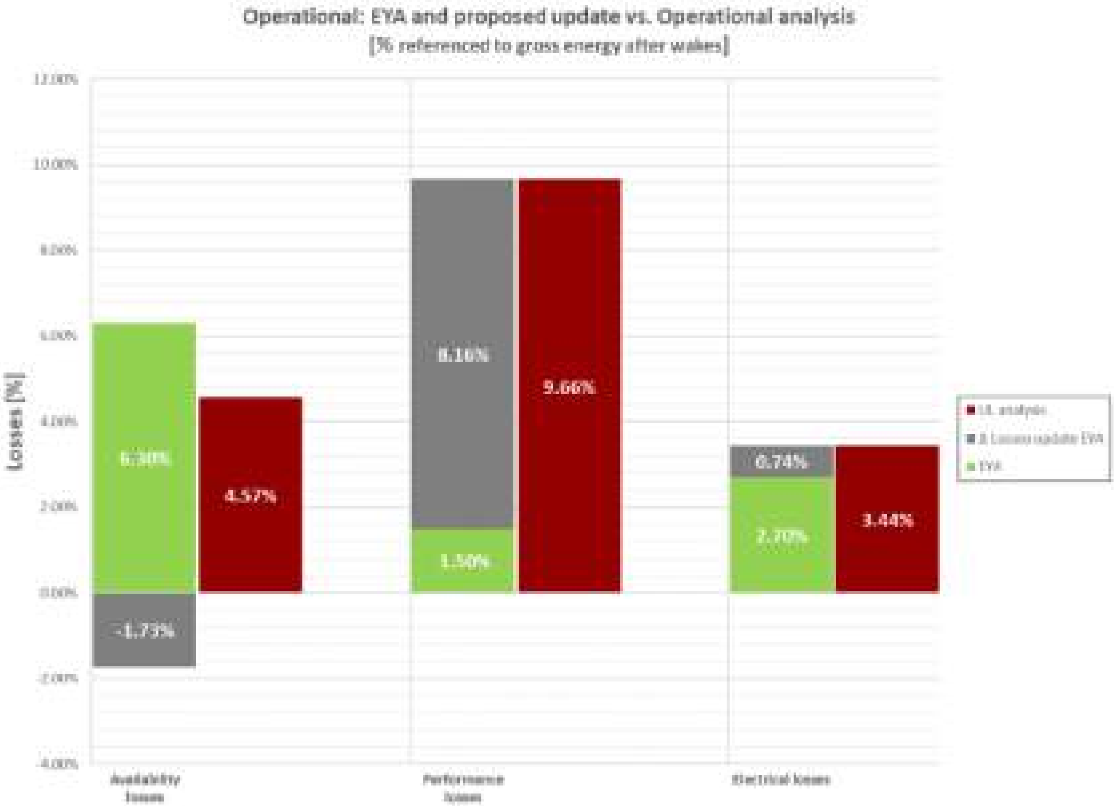

Figure 3.1: Differences on Availability, Performance and Electrical losses

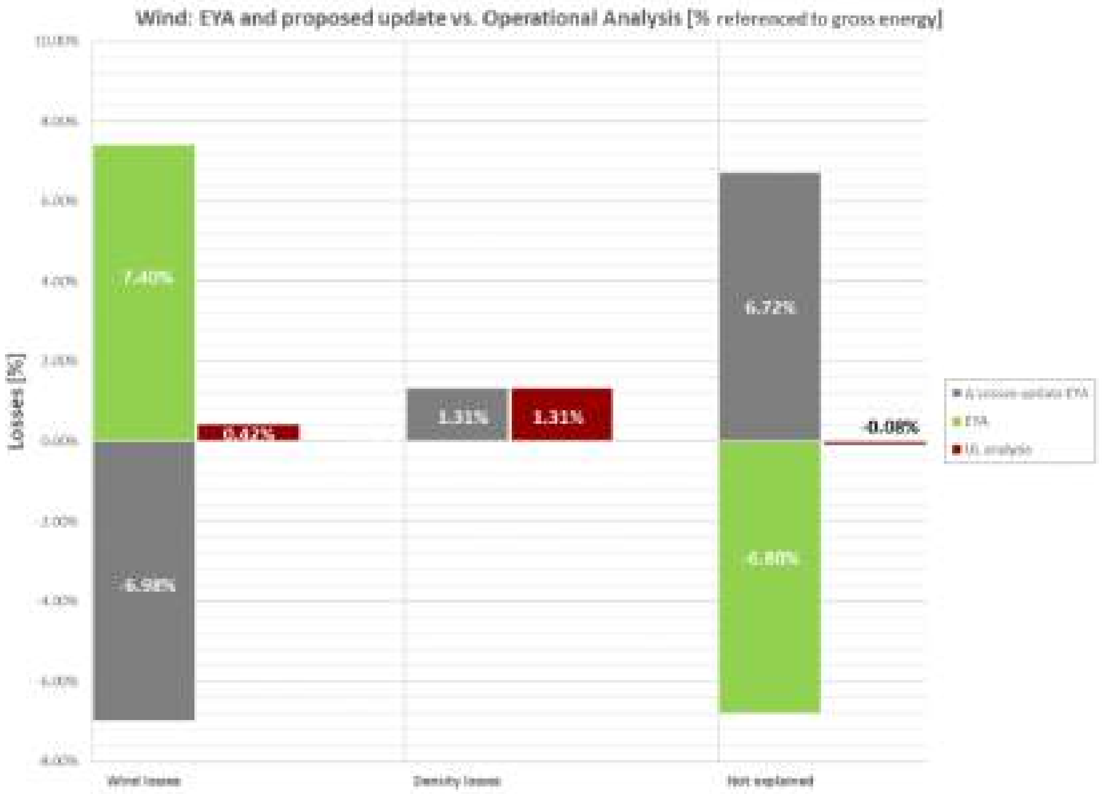

Figure 3.2: Wind related discrepancy, air density discrepancy and not explained losses

Finally, and after the PA analysis, UL recommends the following:

- Review the nacelle anemometer calibration in order to avoid too early or too late de-rating strategies close to the cut-out wind speed. Too early application lead to underperformance and too late application implies additional risk on the structural integrity;
- Record in a proper log the curtailment strategies in order to enable an analysis with proper differentiation of performance and curtailments. Additionally, non-expected curtailments could be found in this kind of analysis;
- When several sources of information are involved, proper synchronization of the sources enables a more reliable analysis. Uncertainty related with the synchronization is drastically reduced and the synchronization effort will decrease drastically; and
- Having into consideration the alarm reports could enable a more accurate availability analysis.

3.1.2.4 Life Time Extension Analysist

Lifetime extension (LTE) analysis has been performed for the Project according to the methodology described in the ANSI/UL 4143 Guideline and Appendix E of this report includes the full lifetime extension analysis report issued by UL on 18 June 2020 (Ref. No.: UL-ES-AA20-13321645-02.01 and UL-ES-AA20-13321645-03.01).

Lifetime extension factors have been calculated through a comparison between the certification damage equivalent loads (DELs) and site-specific DELs. Multiplying the certified lifetime (20 years) by this factor results in the estimate of useful life that is available. The foundations and electrical equipment are outside of this review.

Nowadays, the installed wind turbines in the Project are GW106 (107.5 m rotor diameter with blade Sinoma 52.5. However, after several issues with the blades and other components, there is the option to change the blades to LM53.2, which corresponds with one version of the GW 2.5 MW model. The resulting wind turbine is a GW109 (109 m rotor diameter).

When considering LTE P50 and P90 values in years per component and wind turbine the following table summarized the results regarding lifetime extension that can be expected for the Project.

Table 3.3: Average LTE estimation summary for the WTGs of the Project including P50 and P90 load exceedance probabilities

Item	Rotor 106		Rotor 109 (Blade LM)	
	P50	P90	P50	P90
Blade Root. Composite	>30.0(1)	24.9	>30.0	25.8
Blade Root. Joint	>30.0	28.5	29.2	25.9
Hub	>30.0	27.8	>30.0	24.8
Hub-Shaft Joint	>30.0	>30.0	>30.0	>30.0
Low-Speed Shaft	>30.0	>30.0	>30.0	>30.0
Main Frame. Casting	>30.0	>30.0	>30.0	>30.0
Main Frame. Welded	>30.0	>30.0	>30.0	>30.0
Main Frame. Tower Joint	>30.0	>30.0	>30.0	>30.0
Tower Top	>30.0	>30.0	>30.0	>30.0
Tower Bottom	>30.0	>30.0	>30.0	>30.0

Note: (1) Considering that the blade quality is according to the design specification. The blade root bushing issue is not considered in this figure.

Table 3.4: LTE management plan costs per year

Item	Rotor 106		Rotor 109 (Blade LM)	
	P50	P90	P50	P90
Years 1–5 Cost (kUSD/year)	0.0	0.0	0.0	0.0
Years 6–10 Cost (kUSD/year)	67.2	67.2	0.0	0.0
Years 11–15 Cost (kUSD/year)	67.2	71.0	0.0	0.4
Years 16–20 Cost (kUSD/year)	67.2	115.4	0.0	27.2
Years 21–25 Cost (kUSD/year)	67.2	221.8	0.0	119.6
Years 26–30 Cost (kUSD/year)	67.2	300.0	1.5	248.3

Note: Assuming an exchange rate of 1.12 USD/EUR.

As shown in previous tables lifetime expectations can be increased to 30 years in almost all the components provided that periodical inspections and a proper maintenance plan is executed according to UL's recommendations in order to avoid further problems. The inspection plan proposed by UL is based on P90 estimation and aims to detect failure in the incipient state when the retrofit of the component requires a low cost. In the event of doubt regarding the severity of a finding, further inspection techniques to define this severity or its reparation are recommended. The initial global budget for inspections through the lifetime of the assets (assuming P90 results) will be:

- Rotor 106: USD 4.15 million for the Project (this budget includes the blade tip review regarding corrosion issues but excludes the blade root bushing specific inspection and the monitoring system); and
- Rotor 109: USD 2.12 million for the Project.

Special remarks must be considered due to corrosion findings and bolted joints maintenance. The lack of action in order to achieve these improvements implies loss of validity of the lifetime analysis here reported.

3.1.3 Technology Review

The blade of GW109-2.5 MW could be supplied by LM Wind Power (53.2 m) or Sinoma (52.5 m). Both companies produce the blades in China. UL considers it good practice to have at least 2 sources for major components because single-sourced components typically constitute some supply and cost risks.

GW109-2.5 MW has 2 Type Certificate, one of them with Sinoma blade and certificates by China General Certification ("CGC") and the other with LM blades and certificates by DNV. The project turbine has installed the Sinoma blade and, therefore, certified by CGC.

Both blades are made from glass fiber reinforced polymer ("GFRP") and equipped with typical lightning protection systems ("LPS") commonly used in the wind industry. UL understands that the blades differ in aerofoil shape, length, max. cord distance, materials, construction techniques and weight.

LM Wind Power has more than 30 years of experience and leading global supplier of wind turbine blades, with market share of approximately 28% and four factories operating in China: Tianjin, Xinjiang, Qinhuangdao, and Jiangsu. LM also has factories in Canada, USA, India, Denmark, Spain and Poland. LM supply to most major WTG manufacturers. The blade LM design is well understood and has significant experience in the industry.

Sinomatech Wind Power Blade Company was founded in 2007 and is based in Beijing, China and with 7 factories across China, with annual total production capacity reaching 4,000 blade sets, although with a short amount aimed to the international market. Sinoma is one of the top three domestic suppliers in China.

Data of the 2.5 MW fleet indicates a consistently technical availability of more than 98% on global market. According to Goldwind, the availability formula is based on IEC 61400-26-1, time-based availability. UL notes that the operational energy-based availability of Penonome, 94% from 2016 to 2019 is due a blade issues that UL considers mitigated by including preventive actions within the Blades Strategy Plan and retrofits carried out in the pitch bearings.

UL notes that the defect of the Light Protection System ("LPS") located in the blade tip is mitigated according to the tip repair plant considered in the Sponsor's Blade Strategy Plan which includes annual tip inspection in all the WTGs of the Project thorough a high-definition camera and the tip reinforcement that will be progressively applied to a 20 WTGs each year. Therefore, all blade tips will be reinforced every 5 years.

3.1.4 Balance of Plant Design

3.1.4.1 Civil Review

UL was provided with a set of civil documentation of Penonome II Project which includes geotechnical investigation, WTG foundation design calculations, hydrological study and drainage system designed for the Project.

UL noted that geotechnical investigation was performed for the Penonome II Project; however, the tests and information collected during the investigation were not presented in a single report, instead, the geotechnical information of the Project was included in the foundation design documentation. UL found the geotechnical information of the Project in several Annexes of the Penonomé Wind Farm Foundation Project performed by CEMOSA between May 2013 and January 2014. UL denoted that 88 WTG locations were studied, which means that the total of the 86 WTG final locations were investigated in order to know the geotechnical parameters and soil conditions of each WTG location.

The geotechnical investigation consisted on boring logs performed at each WTG locations until maximum depths of 32 m. During boring logs, Standard Penetration test were performed and samples were taken to carry out mechanical a physical laboratory tests. Dynamic Penetration tests were performed at the locations were layers with low resistance were detected. According to the laboratory tests results, the soil was classified as not aggressive against the concrete. Also geophysical survey was performed.

The type of soil encountered are classified as clay, sand, silts and combinations of them, depending of the location and the depth studied. Groundwater was detected during boring logs. The analysis performed by CEMOSA consist on verify if a WTG foundation of 10 m of radius is feasible for the soil condition encountered at a depth of 2.5 m (at the foundation footprint) and if the soil encountered in the deepest layers met with the minimum resistance requirements for cohesive and granular materials estimated in the admissible load calculation methodology previously performed. If the foundation is not feasible at some location, a greater radius is selected (12 m) or the foundation is placed in a deeper level (3 m). According to the results, the majority of the locations are feasible for the foundation of 10 m radius and 2.5 m depth. However, foundations of 12 m radius and also depth foundation are recommended for several locations. These foundations are recommendation from the Geotechnical Engineer; however, final dimensions of the foundation are defined during foundation design calculation.

According to the documentation reviewed by UL, there are at least 3 foundation types for the 86 WTGs installed for Penonomé II Project. The foundations were designed for WTG model Goldwind GW 109-2.5 MW and, based on the information collected by the Sponsor, consist of 47 shallow spread footing of 10 m radius, 32 shallow spread footing of 12 m radius and 7 depth foundations, no as built drawings were available for UL's review. UL performed the review of the available documentation of the 3 foundation types.

UL reviewed the structural design documentation performed for Penonomé II wind farm issued by CEMOSA on 05 April 2013 for the foundation type 1 (10 m radius), the structural verification performed on 24 September 2014 for the foundation type 1 and type 2 and the structural calculation performed on 15 May 2014 for foundation type 3 (pile foundation). UL observed that parameters obtained from the geotechnical campaign, load combinations, material characteristics and safety factors selected were evaluated in the calculation of the design.

The foundations were analyzed by finite element model using the software Vettones. The internal moment and shear forces are obtained from the results of the finite element analysis and were used for the flexural and shear capacity evaluation. UL considers that the international and local standards used for the foundation calculation are in line in the expectations. UL reviewed the verifications performed for the foundation design such as geotechnical and structural aspects evaluation, interface aspects and fatigue analysis performed by the Structural Engineer and UL finds them acceptable for the design.

UL also reviewed the hydrological investigation and drainage system calculation performed for the Project by performed by Dicoinlay S.A. in March 2013, the precipitation data was analyzed and the dimensionless water flow for several return period were obtained based on the ETESA methodology. Based on the hydrological investigation, a drainage system was designed and consist of 3 concrete box culverts under road 6 and road 8 of the Project, using a return period of 20 years. Even though the return period of 20 years is according to the local standards, UL always recommends selecting a higher return period for this type of projects. UL observed that the drainage system calculation does not include information regarding the superficial drainage system used for the Project site, such as ditches at the sides of the roads or any other designed required; however, UL was informed by the Sponsor that the drainage system were performed according to the Ministry of Public Works of Panamá.

3.1.4.2 Electrical Design Review

The Project utilizes 86 Goldwing G109-2.5 MW turbines for a total nameplate generating capacity of 215 MW. The electrical BOP includes a 34.5 kV medium-voltage collection system and a 34.5/230 kV collection substation. The Wind Project Point of Interconnection ("POI"), ETESA El Coco substation is located beside the Project substation and connected to the SIN through sectioning two main 230 kV transmission lines.

UL has reviewed the design documents, which include IFC and as built collection, substation, and transmission line drawings along with key electrical system design studies.

UL notes that the underground collection design does not detail concrete ducts for reinforcement and protection of the MV collection system in roads crossings and platforms. The no existence of ducts reinforcement should be noted as a small risk for the cable's durability and installation reliability.

The design of the PMT foundation does not include a collecting deposit for oil spillages. UL notes it as an environmental risk and recommends a concrete perimeter to avoid oil spillages to the ground.

UL considers the design as typical. The electrical losses study and the collection system cable calculations while being partial and inform that the circuit of Penonome II reaches 3% of electrical losses but the losses documentation is not conclusive.

UL notes that according to images provided, underground splices do follow a good standard, their specific location is not provided, and no concrete ducts reinforcement. According to the Sponsor, the location of splices is planned to be performed during this 2020 by O&M team in conjunction with the technical team.

UL is reported that the different SPVs achieved a shared facilities agreement, that is beneficial for the transaction, according the noted property of electrical equipment and billing it is a must in order to simplify and clarify actuations, billing and shared cost for the asset.

3.1.5 Contracts Review

3.1.5.1 Interconnection Agreement

UL reviewed the executed interconnection agreement ("IA") dated 16 April 2012 for the Wind Project and concludes that it is a standard agreement used for renewable energy projects in Panama with ETESA.

The Point of Interconnection is the El Coco substation (230 kV) that was built by the Penonome I and is in the process to be transferred to ETESA. The POI is one of the Penonome II Project bays arranged in breaker and a half configuration.

The IA is valid until 17 April 2027 and can be extended if both parties agree and UL considers that the conditions of force majeure and termination are typical.

3.1.5.2 Power Purchase Agreement

UL performed a high-level review of the amount of energy agreed and the Project capacity of the executed power purchase agreements ("PPAs") for the sale of the Wind energy. There are several PPAs executed with distribution companies (EDEMET, EDECHI and ENSA) for each division of the Wind Project (4 sub-projects; Nuevo Chagres, Rosa de los Vientos, Marañon and Portobelo).

The term of the PPAs are for 15 years. The executed PPAs covers a total Wind Project capacity of 165 MW. The remaining Wind Project capacity (50 MW of Rosa de los Vientos II) are considered for backup generation for the PV Project and for spot market, in that order of preference. UL notes that the committed energy under the PPAs are referred to specific turbines generation for each contract, assuming specific capacity for each PPA (defined as sub projects). All energy production from each sub project will be purchased by each Buyer

The PPAs have a base price that range from 95 USD/MWh to 110 USD/MWh, while the price adjustment to be performed is defined by a specific formula under the PPAs in a monthly basis in function of the Panamanian CPI, only the 25% of the price is adjusted. The average PPAs price for 2020 ranged from 98 USD/MWh to 113.42 USD/MWh.

UL notes that the committed energy under the PPAs are referred to specific turbines generation for each contract, assuming specific capacity for each PPA (defined as sub projects). All energy production from each sub project will be purchased by each Buyer.

3.1.5.3 Turbine O&M Contract

UL performed a review of the WTG service and maintenance agreement ("SMA") between Goldwind International Holdings (HK) Limited ("Service Company") and UEP Penonome II, S.A. ("Buyer") dated on 23 April 2014. Under the agreement, the Service Company is responsible for performing preventive and corrective maintenance of the WTGs. The term of the agreement is initially for 5 years and may be extended for an additional 5 years. UL has also been provided with a First Amendment to the SMA signed on 01 October 2020 where several aspects were modified from the initial SMA (definitions, scope, Price, Term, availability warranty provisions) and the Service Company has been replaced by Goldwind Service Company Panama S de RL.

UL notes that the specific Term of the new First Amendment are not explicitly set in the contract, but the Term seems to start (and Sponsor confirmed) in 01 November 2020 and will last until 31 December 2023.

UL finds the Service Company services provisions in terms of predictive, preventive and corrective works to be suitable for the Project. However, the First Amendment excludes the Claims Relating to

Blades and this is a critical aspect for the Project that should be properly considered in the OPEX estimations (see Section 3.1.7 Financial Model Inputs Review).

For each calendar year during the term during which services are performed, the Buyer will pay the Service Company a fee of 45,000 USD/WTG/yr to be adjusted annually (from 2013 and according to the Republic of Pamana's index) as per the customer price index of Panama. The annual fee per WTG for the term extension is USD 80,000. UL considers that the price for initial term of 5 years to be reasonable; however, prices for the extensions term and above UL's expectations. According to the draft of the First Amendment to the SMA, the SMA Price is set to 48,500 USD/WTG/yr (annual indexed from 2020 according to the US index). In addition, Buyer will be responsible for the all main crane expenses up to 50,000 USD/month.

A time-based availability is guaranteed within the SMA which is 97% annually. UL notes that the current availability guaranteed for the Project within market standards. However, and based on the draft of the First Amendment of the SMA, the time-based availability warranty will be changed to a seasonality availability based on time (96% for the non-windy season and 97% for the windy season). UL notes that this approach is untypical and below UL's expectations where a minimum of 97% is expected for the whole year especially when considering that the Claims Relating to Blades are considered an exclusion.

Events of default are typical and within expectations. However, UL recommends having a performance related event of default definition to encourage the Service Company to provide its best service.

All in all and considering that the blades are excluded from the First Amendment of SMA, UL considers the scope of services provided under the SMA to be comprehensive and suitable for the Project.

3.1.5.4 BOP O&M Contract

All civil BOP O&M activities are executed directly by the Project at its own expense and on a needed basis.

UL reviewed an O&M contract for the operation and maintenance of the wind farm's MV infrastructure signed between UEP Penonome II, S.A., and Ingeniería y Productos Electromecánicos S.A. (IPELSA or MV O&M Contractor) The scope of MV O&M Contract includes the preventive and corrective maintenance of the Wind Project's MV lines.

The MV O&M Strategy details the requirements and works to be performed by the MV O&M Contractor with respect to the MV installation of the Wind Project:

- Testing of underground lines and aerial lines with the aim of finding any potential failure;
- Verification of all equipment in order to point out improvement in the performance of such equipment;
- Carrying out isolation measurements to the equipment; and
- Failure detection with non-intrusive equipment.

The equipment covered under the scope of work of the MV O&M Strategy is 40.3 km of aerial lines, and 69.2 km of underground lines.

The different SPVs of Penonomé and Penonomé II executed a shared facilities agreement that covers electrical infrastructure. Works of O&M at El Coco substation are under the MV O&M Contract.

UL notes that the term of the contract is 1 year with the possibility to renew it. As per the Sponsor's information this contract will be renegotiated covering the UL's recommendations.

The MV O&M Contract Price is 7,900 USD/month and group of work that is to be on an on-call basis.

Sponsor provided the new renegotiated contract conditions with a costs reduction 7,900 to 6,600 USD/month that will be included in the future IPELSA Amendment.

3.1.5.5 Wake Effect Agreement

There is a Wake Effect Agreement by which future project UEPIII (which hold an assignment agreement with UEP), affecting the Project (owned by UEPII) should compensate UEPII derived to the caused wake losses until 25 years after the Commercial Operation Date. UL usually considers such agreement as positive for the projects; however, UL recommends clarifying the definition of liable wind turbines. UL highlights the existence of a former wake effect agreement between UEPII and UEP, by which project UEPII, affecting UEP should compensate UEP, derived to the caused wake losses until 25 years after the Commercial Operation Date. Furthermore, there is not any mention to possible effects on WTG loads and limitation in lifetime extension.

3.1.6 Permitting review

UL conducted a permitting review for the Penonomé Wind Project. The Project is formed of 4 wind projects named Marañón, Nuevo Chagres, Portobelo and Rosa de los Vientos. The four projects have their own Environmental Impact Authorization and Definitive Generator Licenses.

As the Panamanian legislation requires, an independent Environmental Impact Assessment is required for the transmission line and the roads to access to the Project. UL also reviewed three Environmental Impact Authorizations for the transmission line and the Penonomé roads phase II and Penonomé roads phase III.

Other permits were reviewed, such as the Commercial Operation Register, the Interconnexion Agreement and the construction license from the Municipality of Penonomé. UL denotes that is missing the official response form the National Authority of Civil Aviation regarding a construction expansion or structure modification for 20 wind turbines. Sponsor informed UL that they have requested a copy of this document to the official organism (AACP).

3.1.6.1 IFC Performance Standards Review

UL reviewed the information and evidence delivered by the Sponsor in order to assess the full compliance with the 8 IFC Performance Standards. The provided information includes environmental and health and safety plans and developed reports executed during the operational phase of the Project.

UL denotes that the Project has developed an Environmental and Social Management System, in which is described the policy, the identification of risks and impacts, management programs, organizational capacity, the emergency preparedness and response plan, the stakeholder engagement plan, and a monitoring and review methodology for them. UL also reviewed the health and safety plan and evidence of its execution, the biosafety protocol regarding the sanitary contingency of SARS-CoV-2, the legal land tenure of the Project and the archeological findings plan for the operational phase of the Project.

In UL’s view the evidence delivered by the Sponsor is complete to assess the fulfillment of the requirements stated in each IFC Performance Standard.

3.1.7 Financial Model Inputs Review

UL reviewed the Client’s inputs considered in the financial model (“Financial Model” or “FM”) provided. UL has focused its review on OPEX assumption, generation and revenue. UL has not performed any check of the FM formulation or further considerations beyond the review of the mentioned inputs.

The COD considered in the Financial Model is in line with information reviewed for Wind Project and the PPA’s COD. The term of the PPAs is properly addresses under the FM, considering spot market once the PPAs term is expired.

The total OPEX costs for operation of the Project for 2021 are estimated to be USD 9,831,273 (equivalent to 114,317 USD/WTG or 19.7 USD/MWh) with WTG direct costs of 59,472 USD/WTG during 2021 and with an increase in future 5-years period due to inspections plan and blade repairs.

Due to the fact that the SMA of the WTGs excludes blades repairs, the Sponsor performed a specific blade strategy plan that includes a specific plan for monitoring and inspecting the WTGs during the lifetime of the Project (initially 4.8 USD million for 2020 and 640-783 USD/yr thereafter), the acquisition of a set of 7 rotor-blades in 2020 in order to ensure a short time period for blades replacement (4.55 USD million). UL considers that this blade strategy plan is adequate and considers that the related costs have been properly captured in the inputs of the FM according to the following:

UL considers that the total OPEX assumed for the inputs for the FM is aligned with industry standard for the region and Project size and characteristics (middle low range).

In addition, UL positively evaluated the assumption of a maintenance reserve account of 1 USD million (to be replenished each year if used) that will be constituted as annual letter of credit for the exclusive use of the Projects (Penonome II + Ikakos). UL considers that this MRA amount is reasonable and provides comfort to the Projects for facing non-scheduled and unexpected corrective O&M costs that are excluded from the O&M contracts and UL does not expect considering further contingencies or additional maintenance reserves.

UL has reviewed the production results according to the probabilistic scenario P50 (498.7 GWh/yr), P90(1 year) (432.5 GWh/yr) and P99(1 year) (378.4 GWh/yr). The production estimation considered in the Financial Model matched with the UL’s estimations.

UL notes that the revenue assumption and the PPA capacity is aligned with the PPAs payment rate stated in the PPAs contracts reviewed.

3.1.8 Risk Summary Table for Penonome II Project

Below it is summarized the UL's main issues detected at the current stage of the Penonomé review.

Table 3.5: Summary List of Project Issues

Section	Subject	Comment	Risk Appraisal
3.3	Operational Assessment	UL identified 5 WTGs (T7, T16, T25, T39, and T41) with critical issues that could be repaired without blades replacement. T39 and T41 are currently stooped due to this issue. According to the Blades Strategy Plan review report, inspection and repair works started on 11 September 2020 and this risk will be mitigated or reduced when all the repair works are completed within 2020. Sponsor informed UL that they are currently working on the repair works as rope-access inspection works have already been finished. Related reports are currently being analyzed by UL.	**M**
3.5.2	Electrical Review	UL notes that the underground collection design does not detail concrete ducts for reinforcement and protection of the MV collection system in roads crossings and platforms. The no existence of ducts reinforcement should be noted as a risk for the cable's durability and installation reliability. The design of the PMT foundation does not include a collecting deposit for oil spillages. UL notes it as an environmental risk and recommends a concrete perimeter to avoid oil spillages to the ground.	**L**
3.6.3	Turbine O&M Contract	The First Amendment of the SMA excludes blades defects and provides an availability guarantee slightly below market standards. There is a quote for the 7 new brand sets of LM blades and the Sponsor is currently negotiating the Blades Supply Agreement. In UL's opinion, having 7 new sets of blades as spare parts in the Project site will significantly reduce the response time and mitigates the risk of having the blades excluded from the SMA Amendment.	**L**
3.6.4	BOP O&M Contract	Overall UL considers the MV O&M Contract to lack detail which may pose a risk if critical maintenance is to be carried out. The price seems to be high and there are not associated guarantees. Sponsor provided the new renegotiated contract conditions including a reduction in the costs and confirming that associated guarantee are set to 1 year. These new conditions will be considered and included in the next contract renew planned for December 2020.	**L**
3.7	Permitting	UL denotes that is missing the official response from the National Authority of Civil Aviation regarding a construction expansion or structure modification for 20 wind turbines. Sponsor informed that a copy of this document has been requested to AACP. In case that the AACP is granted without any restriction, this risk will be closed form a technical standpoint.	**M**

Risk evaluation code for the integrity, performance or profitability of the Project

L	Aspects of low/slight importance
M	Aspects of medium/moderate importance
H	Aspects of high or significant importance

3.2 Wind Project Overview

3.2.1 Site Location

Penonomé II project site is located in Penonomé, in the Cocle Province of the Republic of Panama. The center of the Wind Project is located approximately 10 km southeast of the Penonomé town, which is the nearest populated area with an approximate population of 22,000 people.

The Project counts with 86 WTG Goldwind 2.5 MW which total 215 MW.

Project site covers an area of approximately 8,500 hectares with a relatively flat terrain. The general area surrounding the Project site consist of privately-owned agricultural and farmland including scattered forestry. The site is located approximately 15 km north of the coast.

3.2.2 Site Map

The site map in Figure 2.1 below shows the location of the Project site within the state.

Figure 3.3: Location of the Penonomé II Site

The site map in Figure 2.2 below shows the location of the Project site in relation to the surrounding areas.

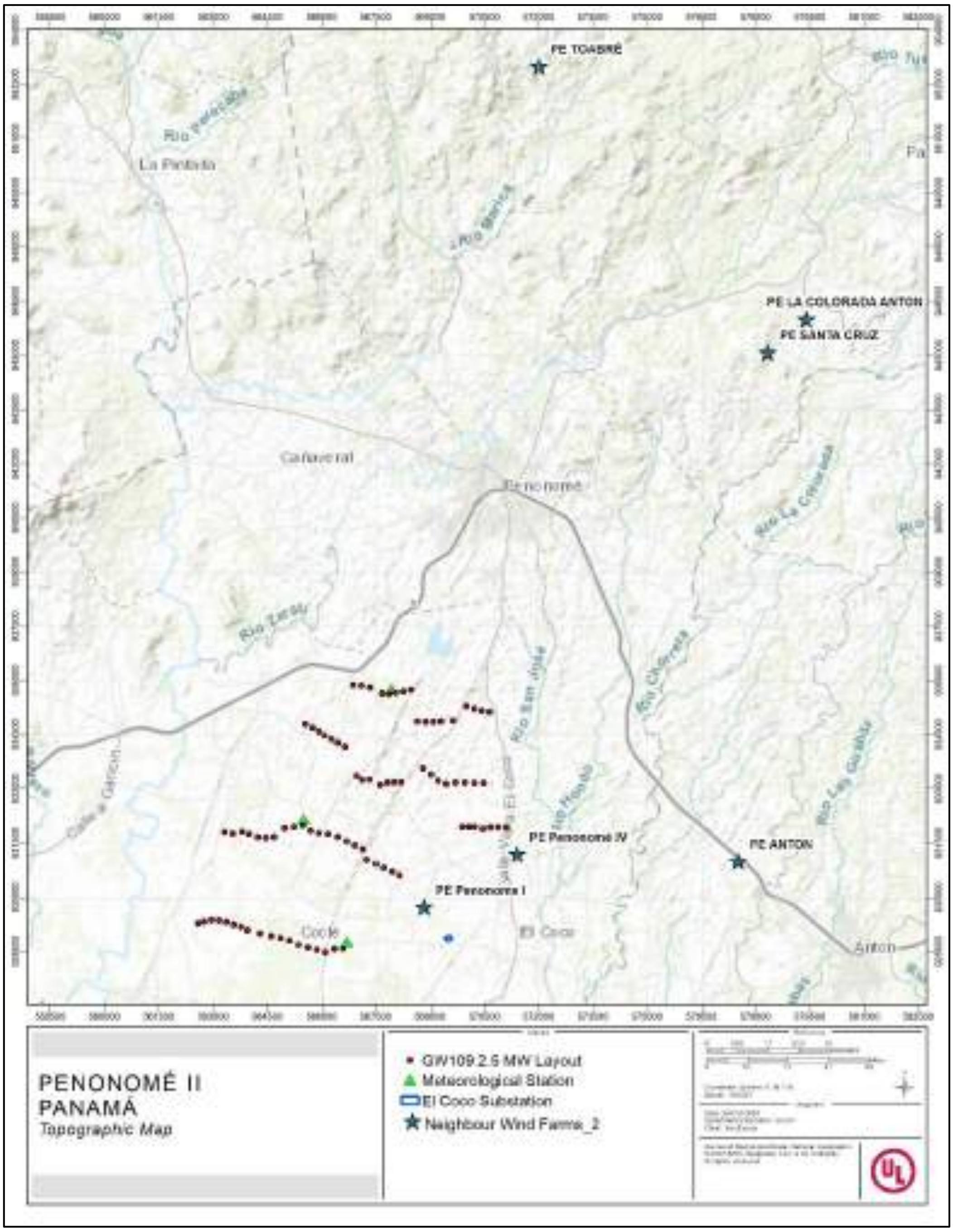

Figure 3.4: Penonomé II Site Layout Map

3.2.3 Topography

The site is situated in a relatively flat terrain at an elevation of approximately 25 m above sea level and covers an area of approximately 8,500 hectares. Penonomé II is divided into 4 wind farms named: Nuevo Chagres 2, Portobelo, Marañon, and Rosa de los Vientos (phase 1 and phase 2) The different areas are shown below.

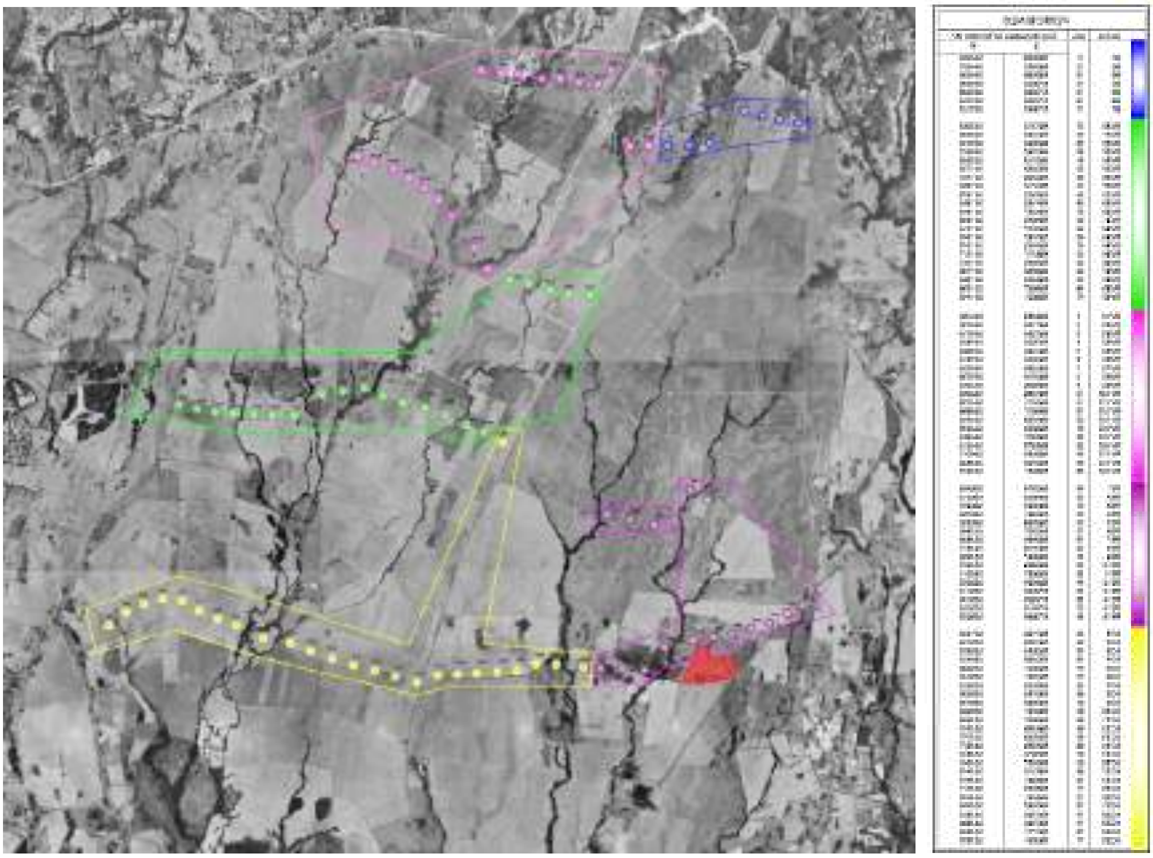

Figure 3.5: Penonome II Areas

UL relied on satellite images and the provided documentation to understand and evaluate the site conditions. The Project area is already built, however, no pictures of the Wind Project were made available to UL. Figures below show the general topography of the site through access roads images provided:

Figure 3.6: Penonomé II General View Through Access Road- 1

Figure 3.7: Penonomé II General View Through Access Road - 2

Minor differences in the elevation are noticeable through the google earth elevation profile tool. UL has not performed a specific visit to the site, mainly due to COVID situation; however, from previous experience in the area it can be pointed out that the material found in the top layer is homogeneous and apparently with low content of clayey sand, the characteristics of stone aggregates and compaction conditions suggest a good quality of base material.

3.2.4 Project Substation and Interconnection

The project is characterized by the connection through 2 transmission lines in 34.5 kV. It is interconnected in the Substation El Coco at 230 kV. The 230 kV POI station, El Coco, is configured in a breaker and a half arrangement connecting to the 230 kV Panama grid and the POI is shared with the other phases of the Project The substation is connected to the SIN (Panama electrical grid) through two 230 kV transmission lines in in/out configuration. The El Coco substation intersect Llano Sanchez – Panama II 12 & 13 230 kV transmission lines.

Figure 3.8: Interconnection Substation

3.2.5 Roads and Site Access

The access to the site is shared with Penonomé I, hence, the main access to the site is located right next to the Hector Conte Bermudez street and dirt roads built by the Wind Project provide access to the Wind Project substation, O&M building and all WTG locations.

Figure 3.9: Main access road

Figure 3.10: Road to Wind Project substation

3.2.6 Neighbor Wind Farms

As presented in Figure 3.4 there are several neighbor wind farms to the Wind Farm including different phases of the Penonomé Porftolio such as Penonomé I (in operation) and Penonomé IV (under development). UL notes that there is a wake effect agreement for the Penonomé portfolio to establish wake effect conditions. In order to avoid misunderstandings, Sponsor confirmed (email 15 October 2020) that the project called Penonome IV is owned by the entity UEP III (see Section 3.6.5 for more information regarding wake effect agreement).

Additionally, UL was informed by the Client that there are several wind farms both in operation and under development such as PE Anton (7 km), PE Santa Cruz (13 km), PE La Colorada (14 km) and PE Toabré (19 km). UL notes that there is a Wake Effect Agreement between UEPI and UEPII and the Sponsor informed that it is expected that a Wake Effect Agreement between UEPII and future UEPIII will be executed in case this phase is built. For the rest of under development projects defined above it seems that they will not affect (in terms of turbulence) the Project. To date and according to the information provided by the Client, there is not any other wind farm near to the Project that has required wind generation license.

3.3 Operational Assessment

3.3.1 Operational Energy Production Report

UL performed an Operational Energy Production Report (OEPR) for the Project and issued the report on 05 October 2020 (Ref. No.: UL-ES-AA20-13321645-04.07), which is included in Appendix B.

3.3.2 Wind Turbine Inspection and Blade Strategy Plan

UL performed wind turbine inspections (WTI) and issued a report consisting on the blades categorization according to the external level of damage for the Penonomé II project and issued the report on 23 March 2020 (Ref. No.: UL-ES-AM20-1101772929-01.05), which is included in Appendix C.

In addition, UL reviewed the blades strategy plan [23] assumed by the Sponsor. The conclusions and UL comments after the review of the blades strategy plan is included in the UL's Report Review letter issued on 21 September 2020.

3.3.3 Performance Assessment

UL performed a Performance Assessment (PA) for the Penonomé II project and issued the report on 20 August 2020 (Ref. No.: UL-ES-AA20-13321645-05.02), which is included in Appendix D.

3.3.4 Life Time Extension Analysist

UL performed the Life Time Extension Analysis of the 2 blades configuration described in the report (Rotor 106 and Rotor 109) for the Project and issued the reports on 18 June 2020 (Ref. No.: UL-ES-AA20-13321645-02.01 and UL-ES-AA20-13321645-03.01), which are included in Appendix E.

3.4 Technology Review

Table 3.6 below shows the specifications for the 2 types of blades available for the GW109-2.5 MW. Blades may be supplied by LM Wind Power (53.2 m) or Sinoma (52.5 m). Both companies produce the blades in China.

UL considers good practice to have at least 2 sources for major components because single-sourced components typically constitute some supply and cost risks. Goldwind has 2 Type Certificate for the GW109-2.5 MW, one of them with Sinoma blades and certificated by China General Certification and the turbine with LM blades certificated by DNV. UL understands that the blades differ in aerofoil shape, length, max. cord distance, materials, construction techniques and weight. UL has not been provided with additional information about the blades installed in the Project (blade material, layout showing blade structure construction and/or a cross-section view through the blade) in order to perform a detail analysis on that topic.

Both blades are made from glass fiber reinforced polymer ("GFRP") and equipped with typical lightning protection systems commonly used in the wind industry. In addition, the blades may be supplied with vortex generators and trailing edge serrations (noise suppression devices) depending on project requirements [25].

Table 3.6: GW109-2.5 MW Blade Specifications

Parameter	SI52.5B	LM53.2P
Manufacturer	Sinomatech Wind Power Blade Co., Ltd.	LM Wind Power Blades
Length (m)	52.5	53.2
Material	GFRP	GFRP
Swept area (m^2)	9,059	9,331

Sinomatech and LM have chosen to use all-glass blades for the 52.5B and 53.2P versions only, the challenge of blade weight rising as a function of increased rotor diameter. UL considers that was mitigated, in part, through structural design innovation. The benefits and disadvantages of each material are detailed in Table 3.7.

Table 3.7: Blade Material Comparison

Blade Material	Benefits	Disadvantages
Fiberglass with an epoxy or polyester resin	**Industry proven, fault tolerance, and cost** Fiber-glass reinforced epoxy is a well proven material for wind turbine blade applications. It is relatively fault tolerant, has reasonable strength to stiffness characteristics, and a lower cost.	**Weight and resulting loads** As fiberglass blades are made larger, the weight of the blades can increase significantly. Heavy blades result in more expensive wind turbines, since higher loads need to be absorbed.
Carbon Fiber	**Stiffness, weight, and loading** Carbon is significantly stiffer than fiberglass. A stiffer material allows for lighter blades without compromising strength. A lighter blade has lower fatigue loads due to gravity.	**Defects and lightning** Carbon fiber blades are less tolerant of manufacturing defects, most notably fiber alignment errors, which can significantly reduce the blade strength with only a few degrees of misalignment. Also, operational experience has shown that when carbon blades are struck by lightning, the damage tends to be more expensive to repair than fiberglass blades.

The Sinoma 52.5B blades are made by vacuum injection molding and a gel coat is dispensed to the bottom substrate to increase adhesion force. The blade is reinforced with a glass fiber spar that is prefabricated and cured for additional stiffness. To avoid steps or gaps on shells unions, mirror surface molds are used to increase the blade surface finish, improving the aerodynamic efficiency. Sinomatech use special structural patent adhesive to join the glass cloth and the fiber.

Main beams of blades are manufactured applying vacuum infusion method, thus eliminating possible manufacturing defects and improving the stiffness of blades. Positioning tools are used to ensure the positional accuracy of bolt holes.

3.4.1 Blade Suppliers

3.4.1.1 LM Blades

LM Wind Power has more than 30 years of experience and leading global supplier of wind turbine blades, with market share of approximately 28% and four factories operating in China: Tianjin, Xinjiang, Qinhuangdao, and Jiangsu. LM also has factories in Canada, USA, India, Denmark, Spain and Poland. LM supply to most major WTG manufacturers including GE and Vestas. In October 2016, GE announced the pending purchase of LM Wind Power; LM is expected to continue to supply blades to other OEMs. The blade LM design is well understood and has significant experience in the industry.

3.4.1.2 Sinoma Blade

Sinomatech Wind Power Blade Company designs, develops, and manufactures wind turbine blades including the SI52.5B model. It also provides after-sales services, including installation, protection, maintenance, and repair services to customers and owners of wind farms especially in China, the United States, Canada, India, and Germany. The company was founded in 2007 and is based in Beijing, China and with 7 factories in Jiuquan of Gansu, Funing of Jiangsu, Baicheng of Jiin Province, Xilin of Inner Mongolia, Pingxiang of Jiangxi Province, Handan of Hebei Province and Dali of Yunnan, with annual total production capacity reaching 4,000 blade sets with a short amount aimed to the international market. Sinoma is one of the top three domestic suppliers in China. Sinoma blade took the lead to adopt the advanced vacuum infusion technology in China, and equipped with equipment to secure the stability of the infusion forming [26]. UL has not been provided with additional information about the blade suppliers for the G109 model (including name and location of manufacturing) in order to perform a detail analysis on that topic.

Sinomatech began designing rotor blades for a 1.5 MW turbine with vacuum injection molding process and fiberglass material. Carbon has been recognized as an enabler of longer blades and is being used in Goldwind 6 MW that weighs 28.8 tonnes and has a swept area of 20,106 square meters [27]. It is made of a mix of carbon fiber and high-modulus glass fiber. Sinoma has chosen to only use all-glass blades for the SI52.5B version, the challenge of blade weight rising as a function of increased rotor diameter.

3.4.2 Blade Testing

Figure 3.11 shows a blade undergoing test at a LM blade test facility. Blades are subjected to static strength, rigidity, and vibration frequency testing. Fatigue testing is also conducted in accordance with the GL2010 standard. The tests are designed to verify that the blades will have a design service life of no less than 20 years.

In general, LM performs static and fatigue tests on all their blade variants and Goldwind blades, as far as UL is aware, performs static load testing, with fatigue calculation.

Figure 3.11: LM Glass Fiber

3.4.3 Blade Lightning Protection System

The blade lightning protection system is designed in accordance with IEC 61400-24 Wind Turbines-Part 24: Lightning Protection. A metal air termination system is installed at blade tip. An 82 mm^2 copper conductor is used to connect the air termination system to the hub.

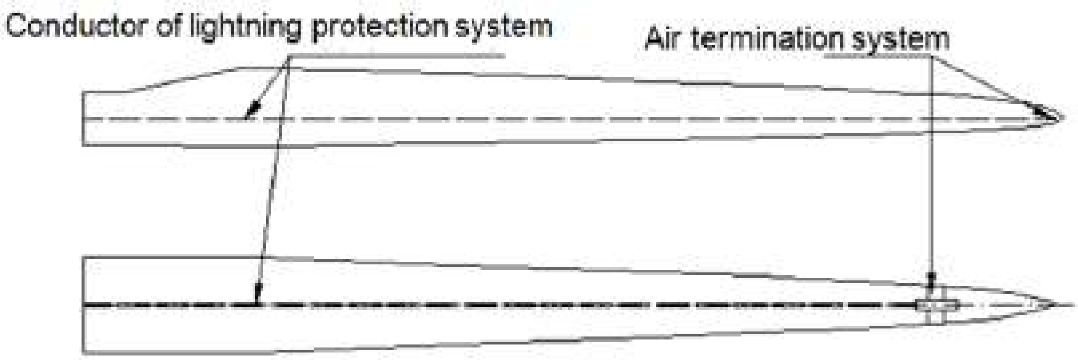

Figure 3.12: Schematic of Lightning Receptors

All modern megawatt wind turbines must be able to conduct current from the blade lightning receptors to ground through 3 rotating junctions: the blade bearing, rotor bearings, and yaw bearing. Goldwind accomplishes this using a down-conductor cable that is connected on one end to the blade's air receptors and terminated on the flange at the blade root which is connected to the nacelle via the hub. The nacelle is connected to ground through a lightning arrestor located in the nacelle which is attached to a cable running to the foundation grounding system through the tower.

According to the available documentation, Goldwind has used the IEC 61400-24 standard to guide the design and verification of the blade lightning protection system. Adherence to this standard means that the ability of the air-termination system and down-conductor system to intercept lightning flashes and conduct lightning currents has been verified by one of the following methods:

- High-voltage and high-current tests;
- Demonstration of similarity of the blade type (design) with a previously verified blade type or a blade type with documented successful lightning protection; or
- Use of analysis tools previously verified by comparison with test results or with blade protection designs that have had successful service experience.

3.4.4 Vortex Generator

Goldwind offers optional aerodynamic add-ons known as vortex generators ("VG") that help maintain the attachment of the air flow around the airfoil to benefit energy output. The VGs typically run span-wise across the inboard part of the blade. The VGs are applied to the surface of the blade and may be applied at the factory or in the field. Each VG unit consists of 2 fins that are attached individually to the blade surface that start near the root and spaced along the inner span from the leading edge towards the suction side.

3.4.5 Tip Speed and Leading Edge Protection

The GW109-2.5 MW operates at a nominal rotor speed of 10.2 m/s with an estimated maximum tip speed as high as 77 m/s. UL notes that 80 m/s that is often used as a "rule of thumb" within the industry to indicate caution. Research by leading OEMs and coating manufacturers has shown that blade tip speeds exceeding 80 m/s will lead to excessive erosion and possible structural failure without an additional leading edge protection ("LEP"). As rotor diameters increase, leading wind turbine OEMs are including LEP as a standard part of the blade design, where it was once considered optional. Several environmental variables can affect the life of LEP coatings at a given project, which in turn, may influence long term operating costs.

3.4.6 Availability Track Record

Data of the 2.5 MW fleet indicates a consistently availability of more than 98% on global market. According to Goldwind, the availability formula is based on IEC 61400-26-1, time-based availability. UL considers an average annual availability of ≥ 97% to be within expectations but notes that this number may be influenced by a number of variables including local power purchase agreements, local grid congestion, environmental conditions, contractual obligations, and O&M budget.

Table 3.8: Availability 2.5 MW Platform outside Chinese market

Year	2016	2017	2018	2019
2.5 MW Platform	98.2	97.9	98.2	99.6

UL requested the deployment numbers and locations of the turbines with Sinoma 52.5 blade model and LM 53.2 blade model and the respective annual availability. This information has not been provided and, therefore, UL could not compare the performance of both configurations and the possibility of ruling whether the low availability is due to the Sinoma configuration from a global fleet perspective.

3.5 Balance of Plant Design

3.5.1 Civil Review

3.5.1.1 Geotechnical Investigation Review

UL noted that geotechnical investigation was performed for the Penonome II Project, however, the tests and information collected during the investigation was not presented in a single report, instead, the geotechnical information of the Project was included in the foundation design documentation. UL found the geotechnical information of the Penonomé II Project in several Annexes (in Spanish “Anejos”) of the Penonomé Wind Farm Foundation Project performed by CEMOSA between May 2013 and January 2014.

The documentation that provide geotechnical information of the Project are the following:

- Anejo 4 [28]: includes the geotechnical investigation performed for 18 WTG locations, from the AE 72 to the AE 86, AE 88, AE 49 and AE 52;
- Adenda of the Anejo 4 [29]: includes the geotechnical investigation for 4 WTG, such as AE 50, AE 51, AE 53 and AE 87;
- Anejo 5 [30]: includes the geotechnical investigation performed for 13 WTG locations, from the AE 01 to the AE 13;
- Anejo 6 [31]: includes the geotechnical investigation performed for 18 WTG locations, from the AE 54 to the AE 71;
- Anejo 7 [32]: includes the geotechnical investigation performed for 5 WTG locations, such as AE 25, AE 26, AE 27, AE 30 and AE 31;
- Anejo 8 [33]: includes the geotechnical investigation performed for 17 WTG locations, from the AE 32 to the AE 48; and
- Anejo 9 [34]: includes the geotechnical investigation performed for 13 WTG locations, from the AE 14 to the AE 24, AE 28 and AE 29.

UL denoted that the Penonomé II Project consists of 86 WTGs and 88 WTG locations were studied according to the geotechnical information provided, which means that the total of the 86 WTG final locations were investigated in order to know the geotechnical parameters and soil conditions of each WTG location. However, UL did not confirm this information by comparing the coordinates of the boreholes performed during the geotechnical investigation with the coordinates of the WTG final locations.

According to the geotechnical information provided in the reports mentioned above, the geotechnical investigation consisted on boring logs performed at each WTG locations until depths that vary between 16, 20, 29, 30 and 32 m. During boring logs, Standard Penetration test (“SPT”) were performed and samples were taken to carry out mechanical a physical laboratory tests. UL also denoted that Dynamic Penetration tests were performed at the locations were layers with low resistance were detected and more detailed information was required.

The geotechnical investigation includes a laboratory testing program on the collected soil samples to obtain soil properties with the following tests: grain-size distribution, Atterberg limits, moisture content, density, unconfined compressive strength and chemical tests such as sulfates and chloride content, soil and water aggressiveness against the concrete, and Bauman Gully acidity level. According to the chemical tests results, the soil was classified as not aggressive against the concrete.

UL denoted that geological risks analysis was not included. Groundwater was detected at different levels depending of the location studied. Groundwater level was considered in the foundation design calculation.

UL was provided with a geophysical surveys reports performed by INGE Solum ("INGE Solum") at the Penonomé II Project site [35] and verified by Geofísica Consultores [36]. UL denoted that the geophysical survey consisted on seismic refraction and refraction microtremor ("ReMi") performed at 20 WTG locations of the Project. Electrical resistivity tests or thermal resistivity tests were not included in the reports.

According to the SPT and dynamic penetration tests performed, the different soil layers found have variable depth and thickness depending on the location. The type of soil encountered are classified as clay, sand, silts and combinations of them, depending of the location and the depth studied. The analysis performed by CEMOSA consist on verify if a WTG foundation of 10 m of radius is feasible for the soil condition encountered at a depth of 2.5 m (where the foundation was planned to be placed) and if the soil encountered in the deepest layers met with the minimum resistance requirements for cohesive and granular materials estimated in the admissible load calculation methodology previously performed. According to the results, the type of foundations recommended consist of shallow spread footing, with the following characteristics:

- 49 locations are feasible for the WTG foundation of 10 m radius and 2.5 m depth;
- 19 locations are feasible for a WTG foundation of 12 m of radius and 2.5 m depth;
- 6 locations are feasible for a WTG foundation of 10 m of radius and 3 m depth;
- 4 locations are feasible for a WTG foundation of 12 m of radius and 3 m depth; and
- 10 location were recommended to perform further investigations due to the conditions did not met the conditions needed for the type of foundation proposed.

These foundations are recommendation from the Geotechnical Engineer, however, final dimensions of the foundation are defined during foundation design calculation. UL also denoted that complementary geotechnical investigations were performed at 7 WTG locations [37] [38] [39]. The reports indicate that for the AE-03, AE-04 and AE-05 depth foundations are recommended.

3.5.1.2 Foundation Design Review

According to the information provided, UL denoted that there are 3 type of foundations designed for the 86 WTGs model Goldwind GW 109-2.5 MW installed for the Project. The types of foundation consist of 2 shallow spread footing (one of 10 m of radius and the second one of 12 m of radius) and 1 depth foundation designed with piles. Based on the information provided by the Sponsor, 47 are shallow spread footing of 10 m radius, 32 are shallow spread footing of 12 m radius and 7 are depth foundations. UL denoted that the type of foundations per location were determined based on the geotechnical studies and change orders issued during the construction of the Project; however, the As Built drawings of the Project are not available for UL's review. Additional to this, UL was provided with the documentation related to a reinforcement designed for one of the shallow spread footing performed during construction.

UL reviewed the structural calculation report performed for the foundation of 10 m radius of Penonomé wind farm [40] issued by CEMOSA (or the "Structural Engineer") on 05 April 2013, the structural verification of the foundations of 10 and 12 m radius performed by CEMOSA on 24 September 2014 [41], and the structural calculation for the pile foundation (or foundation type 3) performed for the wind turbines locations AE 3, AE 4 and AE 5 by CEMOSA on 15 May 2014 [42] [43].

UL denoted that based on the geotechnical and geophysical investigation, the groundwater level is expected very close to the surface, therefore, the foundations selected for Penonomé II considers the most unfavorable conditions which is that the groundwater level will always be present. The type 1 and type 2 foundation designs consider groundwater level at the ground surface level (natural terrain level), therefore, buoyance effect was considered for the foundation design. For the location where the foundation type 1 and type 2 were not valid due to the soil conditions, the depth foundation type 3 was designed. According to the information provided for UL review, the pile foundation type 3 was designed for the locations AE 3, AE 4 and AE 5; however, based on the information collected by the Sponsor, at least 6 pile foundations were built in the Project. UL could not verify this information with the documentation provided.

The foundation type 1 has base width of 20 m and a base thickness of 3.05 m in the pedestal section, tapering to 1 m at the edges. The foundation type 2 has a base width of 24 m and a base thickness of 3.05 m in the pedestal section, tapering to 1 m at the edges. The reinforcing steel for both foundations is specified in two main orthogonal directions for bottom and top steel. The foundations pedestal is a 5.40 m diameter cylinder with a height of 0.55 m, protruding 0.10 m from the finished ground level. The foundation considers groundwater level at the ground surface level. The foundation type 3 has a base width of 20 m and a base thickness of 3.05 m in the pedestal section, tapering to 1 m at the edges, also, has 18 piles of 1.2 m of diameter and 28.5 m length, distributed symmetrically in 2 lines, one line on the perimeter of the circumference base (12 piles) and other line closest to the center of the foundation base (6 piles).

UL denotes that the 3 foundations types backfill described in the foundation design calculation and drawings do not indicates the recommended slope of 1% or 2% away from the center of the foundation to facilitate drainage. The concrete for the foundations is specified as C40000 for slab, pedestal and piles, backfill material should have a minimum density of 18 KN/m^3, reinforcement steel shall be of grade 60000 and for the anchor cage 150 Kpsi. The turbine anchorage consists of a conventional embedment ring and anchor bolts. The embedment ring is located below the bottom flexural reinforcement. The anchor bolts are unbonded, however, drawings of the anchor cage were not provided. The tower base flange is supported on a high strength grout bed.

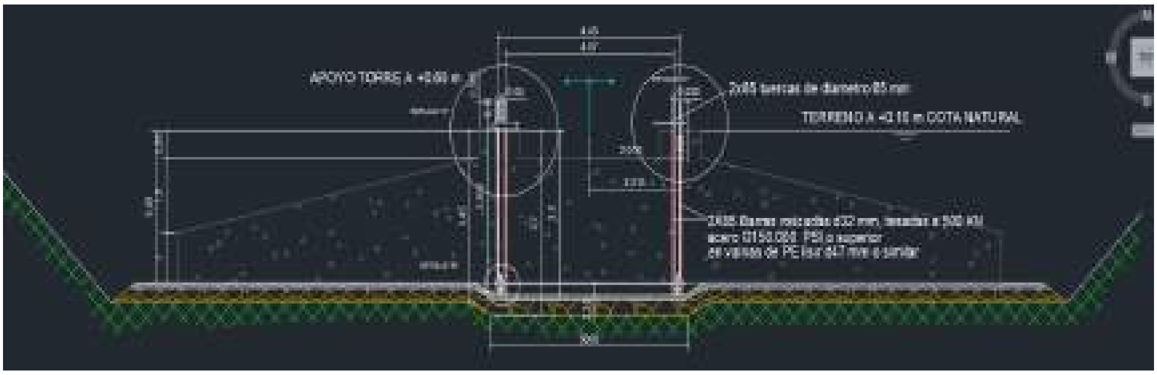

Figure 3.13: WTG Foundation Section (Type 1)

UL observed that parameters obtained from the geotechnical campaign, load combinations, material characteristics and safety factors selected were evaluated in the calculation of the design. Safety factors were determined for loads and material. According to the foundation design report of the foundation type 1, loads were taken from the Goldwind load document GW2.5-109 Foundation Loads Report issued on 23 August 2011. UL denoted that and additional structural verification of the foundation type 1 and type 2 was performed where an updated loads document of Goldwind “GW-07SS.0029 Specification for Foundation of GW 109/2500 IES IIIA, Sinoma 52.5 Blade, 90m hub height” was considered, and according to the results, both foundations are feasible for the loads analyzed. For the foundation type 3, loads were taken from the Goldwind load document GW2.5-109 Foundation Loads Report (90m HH, IECIIA)-A0- (1).

The foundations were analyzed by finite element analysis model (“FEM”) using the software Vettones. The foundation-soil interaction was modeled using vertical springs working only by compression. For foundation type 3, pile-soil interactions were modeled as beam elements, using vertical and horizontal springs with the soil characteristics at the perimeter of the piles. The weight of the soil backfill directly above the footprint was modelled as area pressure applied at top of the foundation.

The internal moment and shear forces are obtained from the results of the finite element analysis and were used for the flexural and shear capacity evaluation. International codes and guidelines as well as local codes were used in the design of the foundations design. UL reviewed the geotechnical aspects evaluation performed by the Structural Engineer with respect to overturning stability, sliding resistance, bearing capacity, settlement and deformation, foundation gapping and rotational stiffness and UL finds them adequate for the design.

The evaluation of structural aspects was considered for the foundation design. Foundation base internal moments were obtained from the finite element analysis. Top and bottom flexural reinforcing were checked using upper bound and lower bound vertical loads (weight of soil, concrete, and superstructure) respectively to capture the most severe utilization of flexural capacity. The foundation base internal one-way shear forces were also obtained from finite element analysis. The one-way shear capacity was checked according to the standard ACI 318-2011. UL find the top and bottom flexural reinforcement and the one-way shear capacity of the foundation design acceptable. Reinforcement steel calculation for the piles of the foundation type 3 were also included in the report and UL considers it adequate.

The evaluation of the interface aspects was performed for the foundation designs. The interface between the foundation and the turbine structure is through an anchor cage with specified anchor bolts. The Structural Engineer checked the interface aspects such as: cracking and bursting control according to the ACI 318-2011, pulling out and concrete compression strength. UL finds the evaluation of the interface aspects adequate for the design.

Fatigue analysis for the 3 foundation types was performed on the foundation concrete and steel (the flexure and shear reinforcement) using 10^7 cycles of the loads provided by the manufacturer using a return period of 20 years according to the IEC-61400. Fatigue has also verified on the post-tensioned bolts. UL denoted that fatigue evaluation for the grout (compression under the plate), concrete (compression under the grout and under the embedment plate) or piles were included. UL recommends performing the fatigue analysis of the foundations for all loads conditions of the Markov matrices provided by the manufacturer, according to the standards DNV-OC-502.

UL also denoted that during construction phase, some foundation design was modified, specifically the foundation AE 12 due to the concrete strength obtained after laboratory tests performed to the poured concrete samples, was below required and modifications on the design were necessary. UL reviewed the calculation report performed by CEMOSA on 20 September 2014 [44] that consist on verify that the foundation type 1 is feasible for the Project if the concrete strength is below as expected. According to the results, the foundation AE 12 presented compression failures in the pedestal and an alternative solution was designed. The solution selected was to increase the section of the pedestal at two sides of the pedestal, according to the figure below:

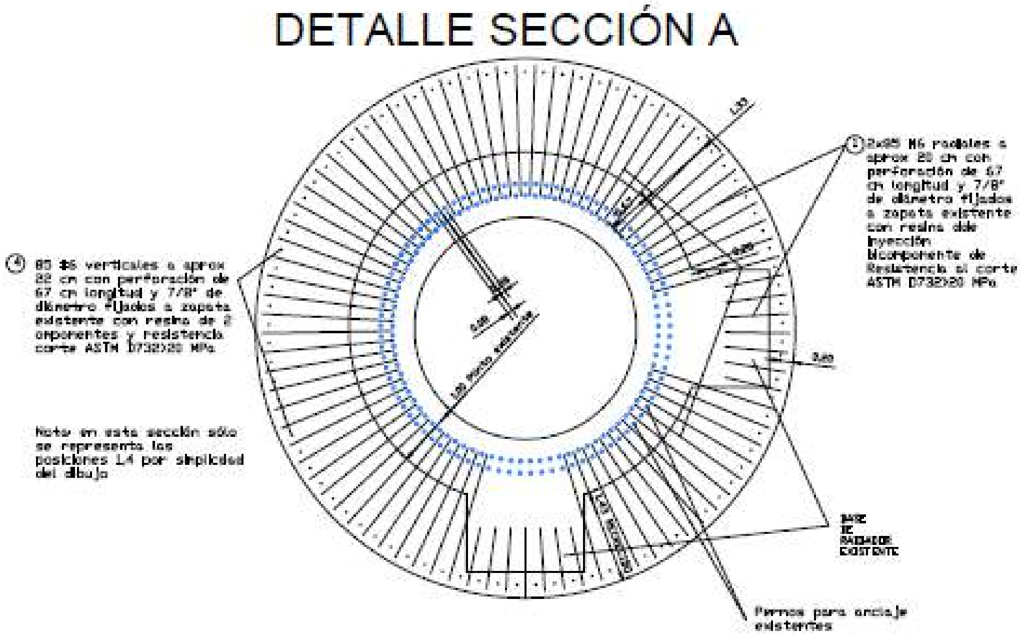

Figure 3.14: Reinforcement of the Foundation AE 12

UL considers that the solution of increase the section is the proper solution in these cases; however, UL considers that the section should have been increased for all the sides of the foundation, due to the loads can affect at foundations for different directions. No other evidences were encountered by the Sponsor regarding design modifications of any other foundations built for Penonome II Project.

After the review of the designer computation and design procedure, UL takes no exception to the design procedure. Even though the as built drawings of the WTG foundation are not available, UL was provided with a list of the WTG locations and the type of foundation per location performed by the Sponsor after the review of the Project documentation available (change orders and studies performed during the construction) and confirms the type of foundation at each of the 86 WTG location.

3.5.1.3 Hydrological Investigation Review

UL denoted that there was a hydrological investigation [45] performed by Dicoinlay S.A. ("Dicoinlay") at the location of the Project in March 2013. The purpose of the investigation was to explore and evaluate the limits of the maximum flood plains at the proposed PV locations and evaluate the maximum water flow to be used for the drainage system design.

The area of the Project is located approximately 13 km south of Penonomé and belongs to the watershed of Río Grande of approximately 177 km^2, which is the watershed N° 134 according to the study performed by "Proyecto Hidrometeorológico Centroamericano" ("PHCA"). The watershed was divided into 2 sub-watersheds for the study, these areas are used for agriculture purpose.

The precipitation data analyzed for the study was provided by the electric transmission company of Panamá (in Spanish "Empresa de Transmisión Eléctrica, S.A." or "ETESA"), where the weather station selected was Antón, the nearest one to the Project. The methodology followed to calculate the maximum flow was according to the Maximum Flood Analysis Study performed by ETESA, which provide hydrometeorological information of the whole country, UL denoted that the report does not clearly explain the how many years were used for the precipitation data analysis; however, the report indicates that a frequency curve was calculated for all the weather stations, taking more into consideration, the ones with more data registered and closer to the Project area. The dimensionless water flow for several return period was obtained based on the ETESA methodology, using the Weibull probability formula. UL denoted that the hydrological investigation does not include flood modeling of the Project area during extreme events. UL denoted that even though a flood modeling was not performed, the Sponsor informed that the Project area does not present flooding areas during rainy events due to the presence of natural water channels that drain most of the rainfall water of the Project site.

UL denoted that the drainage system designed for the Project consist of 3 concrete box culverts, one under the road 6 (camino 6) and two under road 8 (camino 8) of the Project. The section of the concrete boxes is between 2 to 3 m wide and approximately 2 m height (vary depends of the location). UL observed that for the design of the concrete boxes, a return period of 20 years was considered, UL opines that a higher return period should have been selected. UL recommends a return period of 50 years or more.

UL also denoted that for one of the concrete box of the road 8, the maximum design flow is slightly lower than the water flow capacity of the channel designed, UL considers that the design of this concrete box is tight; however, due to the design always considers safety factors, UL considers that the concrete box designed for a return period of 20 years should not represent a problem for the Project. UL observed that the drainage system calculation does not include information regarding the superficial drainage system used for the Project site, such as ditches at the sides of the roads or any other designed required; however, UL was informed by the Sponsor that even though this information is not included in the report reviewed, a superficial drainage system was designed for Penonomé according to the local standards of the Ministry of Public Works (MOP), such as “Manual de Requisiros y Normas Generales actualizadas para la Revisión de Planos” in Spanish.

From a review of the hydrological investigation of the Project, UL is of the opinion that it properly evaluates the technical aspects relative to Project; however, UL considers that even though the return period of 20 years is greater than the one recommended in the local standards, a higher return period for the drainage system is always recommended considering the type of Project. Also, UL denoted that no information regarding superficial drainage system was included in the report neither how the Project plant is affected by the rainfall water.

3.5.2 Electrical Design Review

The Wind Project utilizes 86 Goldwind GW109-2.5 MW turbines for a total nameplate generating capacity of 215 MW. The electrical BOP includes a 34.5 kV medium-voltage collection system and a 34.5/230 kV collection substation. The key parties associated with interconnection and electrical BOP include the following:

- UEP Penonome II — Project Company;
- Goldwind — WTG O&M and Supplier;
- Cobra— BoP Contractor;
- ETESA — Grid operator;
- IPELSA — O&M BOP Electrical contractor;
- Empresa de distribución Eléctrica Chiriqui, S.A. — Power Off-taker;
- Empresa de distribución Eléctrica Metro-Oeste, S.A.— Power Off-taker; and
- Elektra Noreste, S.A. — Power Off-taker.

The Wind Project POI, El Coco substation, is connected to the SIN via two 230 kV transmission lines and therefore both lines would have to simultaneously fail to make the grid unavailable to export energy.

UL reviewed the design documents received to-date, including the Issued for Construction ("IFC") collection and substation drawings along with key electrical system design studies addressed in the corresponding sections herein.

UL notes that according to the Sponsor, the location of splices is planned to be performed during this 2020 by the O&M team.

UL notes no documentation related to that details concrete ducts for reinforcement and protection of the MV collection system in road crossings and platforms and that these bring a small risk for the cables durability and installation reliability.

UL notes no collecting deposit for oil spillages at PMT foundation is included in the design. UL notes it as an environmental risk and recommends a concrete perimeter to avoid oil spillages to the ground.

A typical electrical loss study take into account MV and HV losses until POI and consider the energy production variability. UL notes that the electrical loss study presented by the Sponsor and reviewed at Section 3.5.2.4.5 does not consider all these elements. UL recommends performing an independent losses study completed with a measurement campaign to identify weak circuit to replace, particularly the cable that groups Penonome II to the common switchgear.

3.5.2.1 Medium Voltage Collection System

The Project collection system consists of 9 main 34.5 kV feeder circuits. The circuits consist of underground and overhead cable that terminates to indoor type 36 kV rated switchgear connected within the substation. Pad Mount Transformers ("PMT") used to step up WTG voltage and connect the WTG to the main feeder circuits, which is common practice. According to the information provided, the WTG's MV switchgears are integrated in the PMT. The interconnection between WTGs sharing the same array is developed by means of aluminum single core type underground cable.

Two overhead transmission lines have been designed to transport the energy of the wind turbines furthest to the substation.

No branch circuit exceeds 540 A, and the WTG switchgears, inside the padmount tank, are rated 630 A. UL notes that there are no fault indicators installed in the collection circuit due to the simple design used.

Underground splices are used generally for connecting distances greater than the cable real length, which is typical. UL notes that the "PLANO GENERAL DE CONEXIONADO MT,OPW Y CU" [46] report the cables and fiber MV interconnection, however as shown below, a detail about the underground splices are missing. According to the Sponsor, the location of splices is planned to be performed during this 2020 by O&M team in conjunction with the technical team.

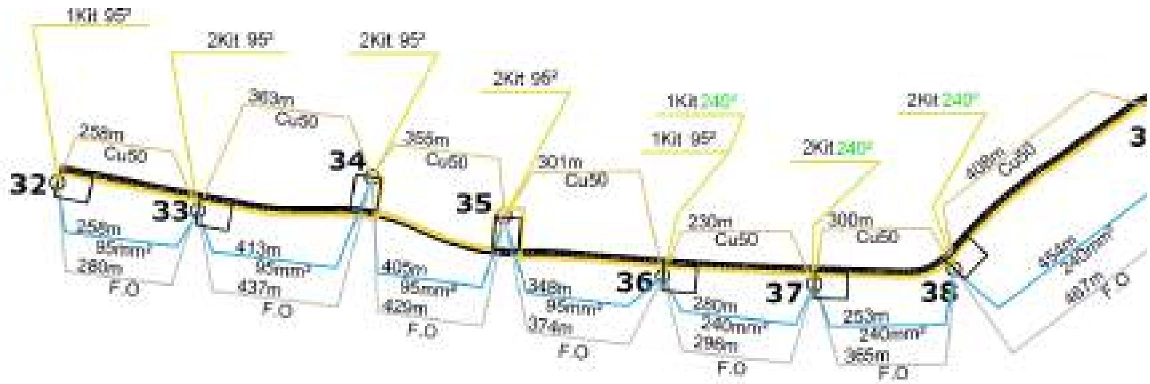

Figure 3.15: Underground Splices Detail

The underground feeder cables are aluminum conductor with screen of copper wires and copper tape and high module ethylene propylene rubber ("HEPR") insulation. The collection cable sizes indicated on the preliminary single-line diagrams are 95, 240 and 400 mm², which are generally in line with typical industry practice. The turbines are connected in radial and loop-feed (daisy chain) configurations with surge arresters at each feeder end, in line with common wind industry practice.

UL notes that the design does not detail concrete ducts for reinforcement and protection of the MV collection system in roads crossings and platforms. The no existence of ducts reinforcements is a small risk for the cables durability and installation reliability.

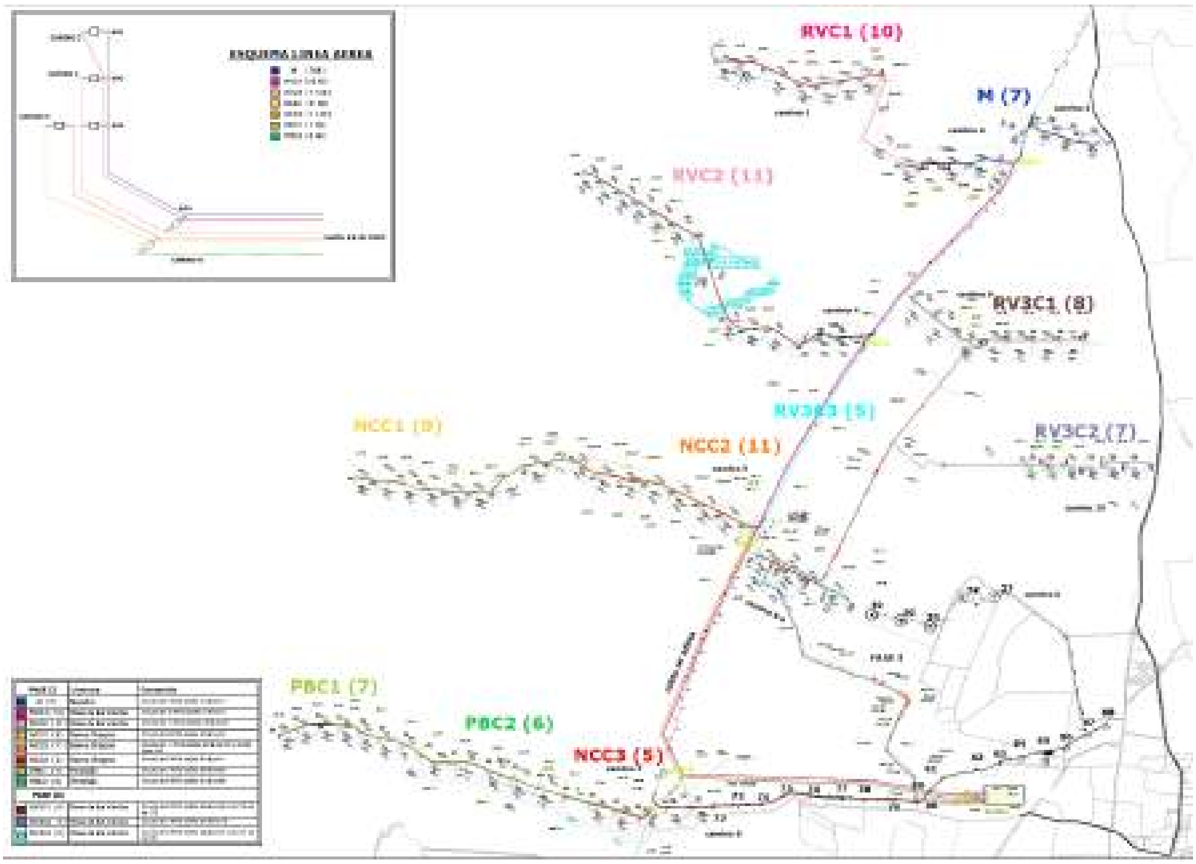

Figure 3.16: Penonome II Collection System Cables

3.5.2.1.1 Generator Step-Up Transformer

Each turbine generates power at 690 V and requires an external Pad Mount Transformer ("PMT" or "GSU") to connect the turbine to the 34.5 kV collection system located at the side of the wind turbine tower base. The PMT is rated for continuous load of 2.75 MVA at 0.69/34.5 kV.

UL has received and reviewed yearly transformer oil testing reports and notes the equipment in good condition.

UL has received the design of the PMT foundation and notes that no collecting deposit for oil spillages is included in the design. UL notes it as an environmental risk and recommends a concrete perimeter to avoid oil spillages to the ground. Sponsor informed UL that they are analyzing this point for considering future actions.

3.5.2.1.2 Underground Collection

The 34.5 kV feeder cables exit the PMT in conduits to the underground collection system, direct buried to a depth of 1.35 m and width of 0.175 m for single circuit and in two layers for double circuit. The conduit burial trench design illustrates the cables in a plane configuration only. Fiber optic cable, in duct, is included in the collection system trenches with a minimal separation from the feeder cables, and ground wire is included.

The design specifies a 0.4 m (center to center) vertical separation between all circuits to minimize inductive heating. The above design specifications are in line with common wind industry practices.

Cable sizes are based on the short-circuit capability, electrical losses, and thermal ampacity, which are a function of many variables, including the turbine output, the soil thermal resistivity (rho), and the length of the cable run. The purpose of the cable study is to properly size the medium-voltage underground cable for the load and site-specific conditions.

UL notes that the EPC contractor, CODEPA, includes no documentation on the cable ampacity study. UL notes that the Project design includes the premises of maintaining electrical losses below 3% according typical industry practices and notes that the power flow calculation includes a short circuit capability, but not derating due to trench details and soil thermal resistivity. Therefore, UL considers the cable sizing as sufficient but not optimal.

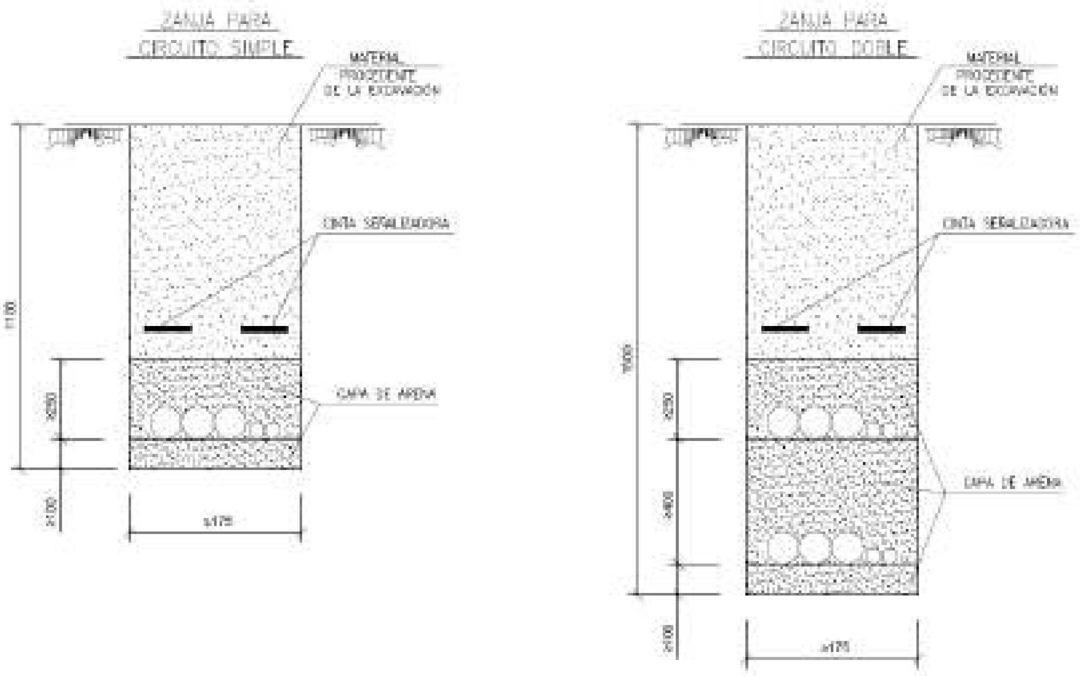

Figure 3.17: Concrete Ducts

3.5.2.1.3 Grounding

UL was not provided with the turbine foundation ground grid designs or the grounding system design report for review. UL confirm that the client provides test earthing [47] values and notes that the values are below 5 ohm for all WTG.

UL considered the documentation provided not enough to analyze with the Project following IEEE 80-200 for personal safety to assure that the step and touch potentials are limited.

3.5.2.2 Project Collection Substation

The 34.5/230 kV collection substation includes total of 12 34.5 kV 1250 A 34.5 kA feeder circuit breakers and particularly 8 Penonome II feeder circuits, 3 switchgears for capacitor banks/harmonics filter connection, 2 switchgears for auxiliary services connection, 2 interconnection switchgears and 2 34.5 kV 2,500 A switchgear connected to two Main Power Transformers ("MPT") for 230 kV. The substation is connected to the SIN (Panama electrical grid) through two 230 kV transmission lines in in/out configuration. The El Coco substation intersect Llano Sanchez – Panama II 12 & 13 230 kV transmission lines.

UL notes there are three capacitor banks/harmonics filters at 34.5 kV level as shown on the substation design drawings. UL reviewed the Power Flow and Reactive Capability Study in below. The Study indicates that equipment already installed, together with the turbines are sufficient.

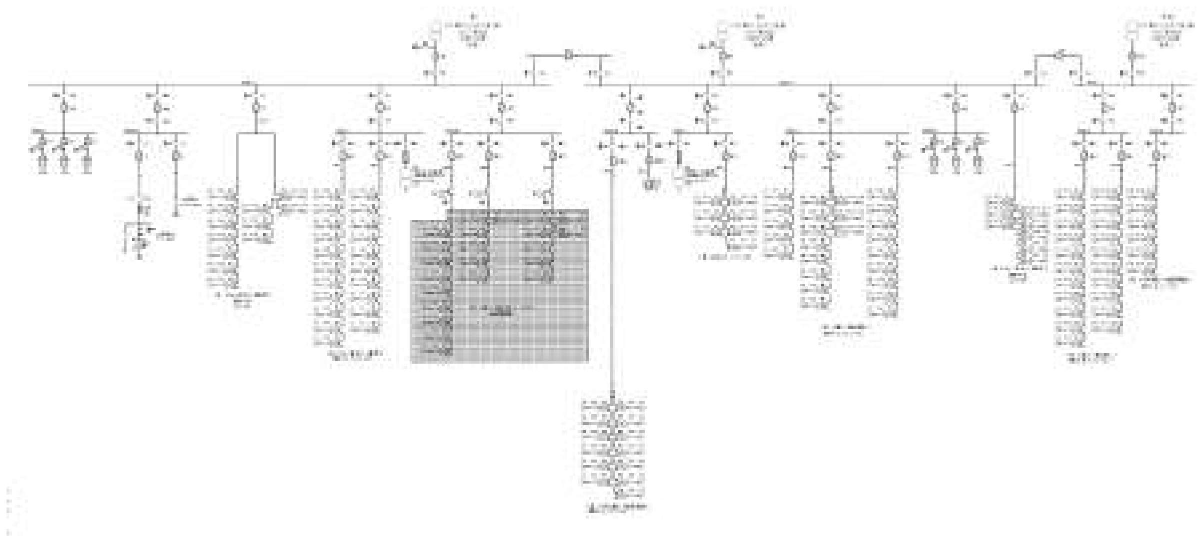

Figure 3.18: Collection Substation On-Line Switching Diagram

3.5.2.2.1 Main Power Transformer ("MPT")

The substation contains three MPTs rated 120/140 MVA (T91, T92, T140), 230/34.5 kV with a ±8 step ±10% On-Load Tap Changer ("OLTC") on the HV side. The connection group is Ynd11 and there are two Zig-zag Ground Reactors ("ZGR"), one per each MPT, to provide grounding fault current limitation of 1000 A. UL notes that the MPTs is sufficiently sized for the Project to operate at full load (215 MW) at 0.95 power factor and 0.95 p.u voltage (238 MVA) leaving 181 MVA of spare capacity for the rest of Penonome phases. UL notes that the full approved capacity for Penonome II, phase II and III, under the IA is 168.8 MW far above maximum MPT capacity.

UL notes that phase II consisted in four wind farms connected with two MPTs: T91 and T92. Phase III is also with the same MPTs. Both phases are integrated with T140. The Figure 3.18 shows how the three projects phases are integrated in Busbar A, B and J, using the same Collection Substation.

3.5.2.2.2 Substation Grounding

UL was not provided with the substation grounding design and test earthing measurement for review.

UL considered the documentation provided not enough to analyze with the Project following IEEE 80-200 for personal safety to assure that the step and touch potentials are limited.

Sponsor informed UL that they are currently looking for additional information in the above topics.

3.5.2.3 Transmission Interconnection Facilities

The Wind Project POI is located beside the Project substation, El Coco 230 kV. The substation is connected to the SIN (Panama electrical grid) through two 230 kV transmission lines in in/out configuration. The Figure 3.19 below shows that El Coco substation intersect Llano Sanchez – Panama II 12 & 13 230 kV transmission lines.

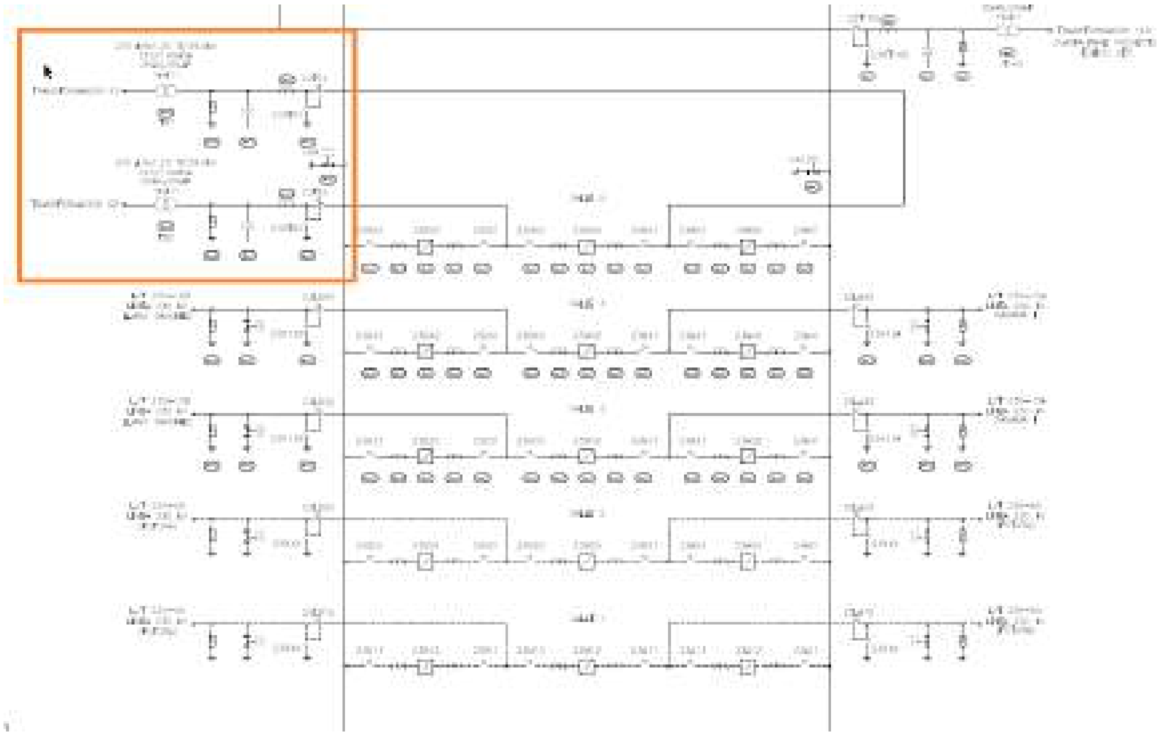

Figure 3.19: El Coco 230 kV Substation

The 230 kV POI station, El Coco, is configured in a breaker and a half arrangement connecting to the 230 kV Panama grid and the POI is shared with the other phases of the Project, that are Penonome I. UL notes that the bay is shared as well as the interconnection infrastructure with these other phases, including 34.5 kV bus bars. UL notes that Penonome I built the POI and the two 230 kV transmission line modifications and actually the substation is in the process to be transferred to ETESA.

UL is reported that the different SPVs achieved a shared facilities agreement, that is beneficial for the transaction, according the noted property of electrical equipment and billing it is a must in order to simplify and clarify actuations, billing and shared cost for the asset. For a visual explanation see next figures where the no colored equipment is owned by the other Penonome Phases and the green is owned by Penonome II.

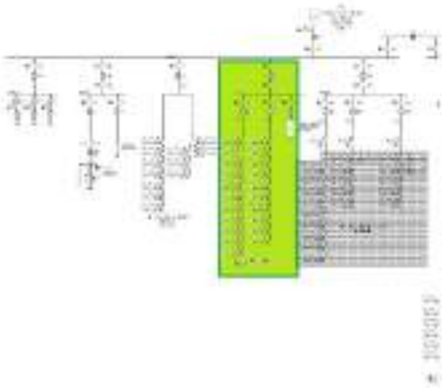

Figure 3.20: El Coco 34.5 kV SLD Left

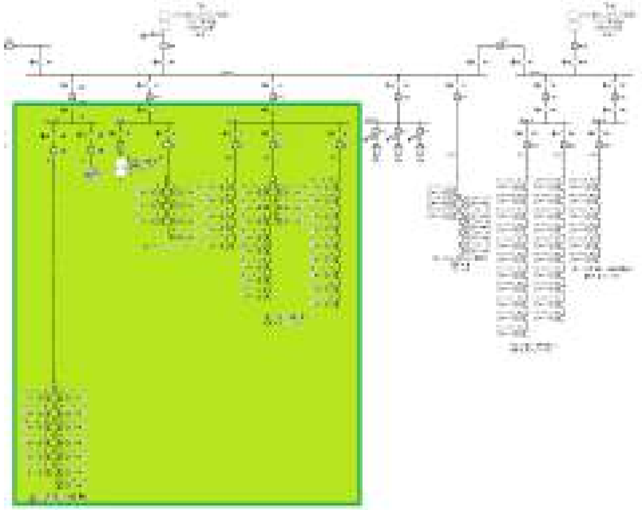

Figure 3.21: El Coco 34.5 kV SLD Right

A cursory review finds the station design to be typical of Utility-owned switchyards and UL notes that it uses the same arrangement as the other 230 kV substation in SIN. The Project was required to build to ETESA's utility standards, which are generally more robust than standard wind industry practices in UL experience.

3.5.2.4 Design Studies

Below is a summary of the key design studies.

3.5.2.4.1 Short-Circuit Study

The purpose of the short circuit study is to determine the maximum fault current on the collection system and substation as well as the collection cable and major equipment withstand capability. The analysis model should include the complete electrical system from the generators to the POI. Maximum fault current at the POI should be provided by the utility. The study is commonly performed in SKM, ETAP or similar power system analysis software.

SINEC performed an as built short-circuit/protection coordination analysis [48] to determine the maximum fault current on the collection system and the collection cables withstand capability. The analysis modeled the complete electrical system from the turbine to the POI, in line with good industry practice. ETESA provided the maximum fault current at the POI.

The Study determined the 3-phase ("3LG"), line-to-line ("LL"), line-to-line-to-ground ("LLG"), and single-line-to-ground ("SLG") faults for system busses from the POI to the turbine LV nacelle bus. The short circuit levels calculated are 21 kA at 34.5 kV level and 7.1 kA at 230 kV level. The resulting maximum fault current is also less than the withstand capability of the main substation equipment.

UL notes that the short circuit analysis did not evaluate the short circuit ratio ("SCR") at the MV connections at the turbines. An SCR greater than 3 is recommended for nominal operation of the turbine; for values below 3, the WTG default parameter settings may require modification.

UL considers the short-circuit analysis assumptions, methodology, and results to be sufficient. The maximum estimated fault current is below the withstand capability of the collection cable and major substation equipment.

3.5.2.4.2 Power Flow Study

The purpose of the power flow study is to determine the reactive capability of the Project, determine if additional reactive equipment is needed to comply with the interconnection requirement, and to verify that the voltage levels at the major equipment does not exceed the manufacturer's specifications (0.9 to 1.1 pu V) for the range of nominal POI voltages (0.95 pu V to 1.05 pu V) in Panama Código de Redes 2012). The study is performed in PSS/E version 33, power system analysis software.

In the power flow study review conducted, Sinec concluded that for all the extreme situations simulated, the requirements for the "Grid Code" are met. The key elements to maintain an appropriate performance under every operation condition are the power transformer 230/34.5 kV tap changers, since its manipulation allows keeping wind generator terminal voltages inside its reactive power generation or absorption condition. In the power flow study review conducted, Sinec concluded that for all the extreme situations simulated, the requirements for the "Grid Code" are met.

The study evaluated the Project capability and bus voltages. UL notes that the Project was design to a reactive compensation of 52.5 MVAr at 34.5 kV level for 230 kV connection achieved with two capacitor banks, one per 34.5 kV busbar, of 3 steps of 9 MVAr for Penonome Phases I.

The study notes that with or without Penonome II the Panama electrical system operate with 10 MVar reactive margin.

The study assessed zero wind conditions, which UL considers to be good practice. The study concluded that the Project is capable of operation at 100% of rated capacity without exceeding the voltage limits of the substation equipment, collection system, or turbine generator busbars. UL considers that the Project is compliant with the requirements of the IA.

3.5.2.4.3 System Protection Studies

The purpose of a protection coordination study is to show that the protection equipment will respond to faults appropriately. The coordination is commonly depicted using time current coordination ("TCC") curves. The substation protection single line diagrams include typical protection equipment, such as GE-L90, SEL-311, SEL-351, SEL-487, SEL-587, and SEL-751 relays, which are used for transmission line, feeder circuit, transformer, and bus protection.

SEL performed a system protection coordination study as part of the as-built short-circuit/protection coordination analysis [49] and that study describes the protection relaying philosophy and coordination. The TCC curves show sufficient protection coordination between the protective devices in line with industry practice. The Study also includes set points of typical functions, such as ground, voltage, and frequency protection, all of which appear to be reasonable. SEL presented some concerns on the final current transformer ratio selected by ETESA for standardization of their equipment. UL notes no risk, but the equipment is not optimized for the Penonome portfolio.

UL notes that the protection study is updated for as-built conditions and reflect any new equipment data and final short circuit and load flow study results, in-line with common practice.

UL considers that the protection system design and engineering are in accordance with the IA and meets expectations for a wind power plant.

3.5.2.4.4 Harmonics Study

The purpose of a harmonics study is to evaluate the harmonic distortion limits against those limits provided by IEC 61400 and IEEE 519. In the event the limits are exceeded at the POI, the project is required to identify mitigation solutions or other next step actions. This study is typically completed in the late stages of detailed design.

Leyden performed a monitoring campaign of the voltage harmonic distortion measurement [50] taking into consideration El Coco substation as Point of Common Coupling (PCC). This study described the results of harmonic voltage measurements, no simultaneous, in the HV power transformers (T91 and T92) and MV measurements at various points at El Coco SE wind farm. The result was compared with the simulations carried out in previous study from 2014.

From the measurement study is possible to concluded that harmonic level in HV 230 kV are in accordance with item C01 “Niveles de harmonicas” from network code 2012. And that the MV measurement presented THDU lower than the IEC 61000-3-6 limit.

UL notes that the comparation between the simulation from 2014 study and the measurement from 2017 show that the values of voltage harmonic distortion are similar.

3.5.2.4.5 Electrical Loss Study

Electrical losses are experienced in all electrical components of the wind project, including the turbine step-up transformers, electrical collection system cable, substation transformer, and transmission line conductor. These losses are established in the electrical system design.

The Project’s General Engineering Specification specifies that the annual energy losses of the entire Project must not exceed 3.0%. UL has reviewed partial documentation related to MV collection system calculations but not a typical annual electrical losses study. The partial “kW loss study” performed by VYE [51] notes that the circuit of Penonome II reaches over 3% of electrical losses at MV WTG’s circuits, that is above UL’s expectations for a typical project considering that this is only covering the MV collection system (excluding other electrical losses like transformers).

A typical Electrical Loss Study should consider MV and HV losses until the POI and considers the energy production variability inside loss calculation. UL notes that the presented electrical losses study [51] does not consider all elements above.

UL notes that no as-built or operational losses study is performed for comparison.

UL recommends performing an independent losses study completed with a measurement campaign to identify weak circuit to replace, particularly the cable that groups Penonome II to the common switchgear.

3.5.2.5 SCADA and Controls

Typical industry practices and ETESA operation standards requires that wind plants install SCADA systems capable of transmitting data to and receiving instructions from the Transmission Provider. The Order further requires that the Transmission Provider and the Interconnection Customer determine what SCADA information is essential for the wind plant, and the Order gives the parties discretion to account for the plant size and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

UL has reviewed the Project SCADA equipment and system design, including the turbine control and SCADA systems supplied by the turbine manufacturer, and the substation communications block diagram.

3.5.2.5.1 Turbine Controls

Each Goldwing turbine utilizes a microprocessor-based control system, with settings that are either preprogrammed or refined during turbine tuning and commissioning. The turbine control system operates in conjunction with the Goldwing SCADA and Power Plant Controller (discussed in Section 3.2.1.5.2 below). The capabilities and functionality of onboard turbine controls are described in the Turbine Supply Agreement.

UL notes that the onboard turbine control system maintains turbine generator output within programmed envelopes, or windows of operation, such as the generator capability curve and over- and low-voltage ride through envelope. UL considers the onboard control system of the Goldwing turbines to be sufficient and in line with industry standard practice.

3.5.2.5.2 Substation SCADA and Controls

The Project utilizes Goldwing Central Control Platform SCADA, in conjunction with Goldwing Power Plant Controller ("PPC"), for turbine SCADA and turbine plant control. The SCADA and PPC are installed in the Project substation.

UL notes that the PPC turbine control functions include the following:

- Reactive power control;
- Voltage control;
- Power factor control;
- Active power control;
- Frequency control;
- Voltage Ride Through (low and high) coordination; and
- Line droop compensation.

All wind farm substation SCADA communication is handled by two BSI RMS575 UCS controllers. One SEL2407 GPS clock provides the clock signal for all substation and wind farm equipment that have event time-stamping functions, such as the protection relays, meteorological stations, and control systems. The clock signal ensures that all equipment and devices maintain time synchronism with each other. UL considers this to be good practice as it facilitates investigation of abnormal events, system faults, trips, etc.

UL considers the Project SCADA and PPC equipment and system design to be in line with industry standard practices and expects the system to meet requirements of the IA and Panama regulation.

3.5.2.6 Electrical Design Review Conclusion

UL has reviewed the design documents, which include IFC and as built collection, substation, and transmission line drawings along with key electrical system design studies. The design is in line with common industry practices, is comprehensive.

UL has not discovered any issues that materially impact the successful operation of the electrical system and considers the Wind Project to be compliant with the technical requirements of the IA.

Besides that, UL notes some documentation is missing. These documents are listed at the Section 3.5.2 and Risk Summary Table.

UL notes the BOP electrical design is not optimized for splitting the different Penonome phases between different owners and it is a technical/contractual concern the actual status of the electrical BOP. UL confirms that the client is aware of this issue and do not see this as impact to the electrical system operation.

3.6 Contracts Review

3.6.1 Interconnection Agreement

UL reviewed the executed interconnection agreement ("IA") dated 16 April 2012 between the ETESA ("TSO" or "Transmission Provider") and Union Eolica Panameña SA ("Interconnection Customer" or the "Project").

Table 3.9: Summary List of Project Issues

IA Parameters	
Expected COD	Original date November 2013
Effective Date	16 April 2012
Term	30 years from generation permit signature date 16 November 2017
Contract Capacity	336.8 MW_{AC} assigned 220.0 MW to Penonome II
Point of Interconnection (POI)	El Coco substation (230 kV)

UL has reviewed the IA and concludes that it is a standard agreement used for renewable energy projects in Panama with ETESA, noting this agreement as the first of its kind in Panama.

The Point of Interconnection is the El Coco substation (230 kV) that was built by Penonome I and is in the process to been transferred to ETESA. UL notes by the document that ETESA pretends to acquire only the 230 kV level of the El Coco substation. The POI is shared with Penonome I partially at the initial operating life of the Wind Project. UL has been provided with updated documentation and agreements with ETESA on transferring el Coco substation to ETESA, including the MPT, so the POI is now split at 34.5 kV for the Wind Project feeders and not shared with Penonome I.

The term of the agreement is 15 years from the signature date, valid until 17 April 2027, and can be extended if both parties agree.

UL notes that the up to date capacity for Penonome II is 215 MW being accepted in the IA 336.8 MW.

UL considers that the conditions of force majeure and termination are typical.

3.6.1.1 POI Interconnection Substation

The 230 kV POI station, El Coco, is configured in a breaker and a half arrangement connecting to the 230 kV Panama grid and the POI is shared with the other phases of the Project, that are Penonome I. UL notes that the bay is shared as well as the interconnection infrastructure with these other phases, including 34.5 kV bus bars. UL notes that Penonome I built the POI and the two 230 kV transmission line modifications and actually the substation is in the process to be transferred to ETESA.

UL is reported that the different SPVs achieved a shared facilities agreement, that is beneficial for Penonome I and Penonome II, according the noted property of electrical equipment and billing it is a must in order to simplify and clarify actuations, billing and shared cost for the asset. For a visual explanation see next figures where the no colored equipment is owned by the other Penonome Phases and the green is owned by Penonome II.

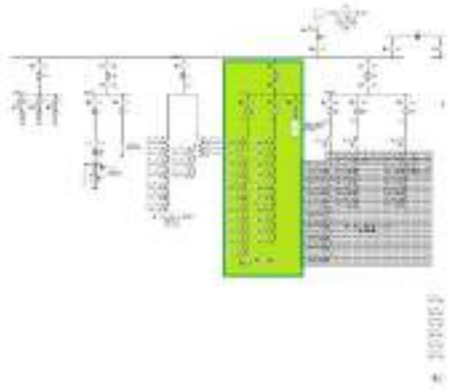

Figure 3.22: El Coco 34.5 kV SLD Left

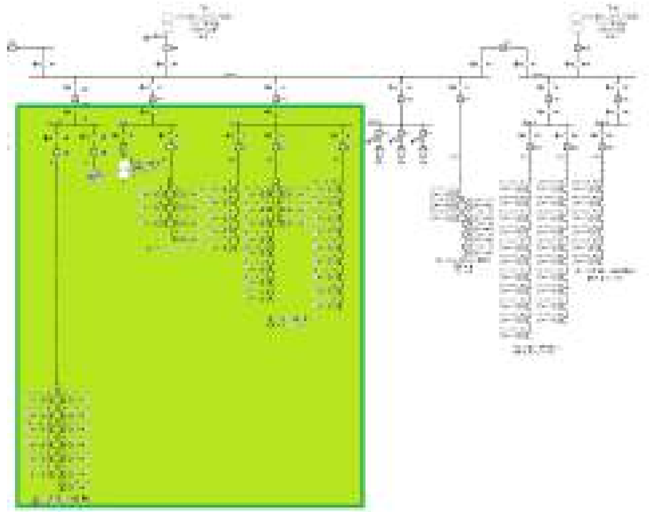

Figure 3.23: El Coco 34.5 kV SLD Right

UL considers the POI station design not an undue risk. A cursory review finds the station design to be typical of Utility-owned switchyards and UL notes that it uses the same arrangement as the other 230 kV substation in SIN. The Project was required to build to ETESA's utility standards, which are generally more robust than standard wind industry practices in UL experience.

3.6.2 Power Purchase Agreement

UL performed a high level review of the executed power purchase agreements ("PPAs") for the sale of the Wind Project energy. UL review was limited to amount of energy agreed in the PPAs and the Project capacity. The table below summarizes key terms of the off-take agreement as per the scope agreed with the Client:

Table 3.10: Penonomé II PPA Key Terms

Sub Project	Nuevo Chagres	Rosa de los Vientos I	Marañon	Portobelo
Buyer	EDEMET, EDECHI, ENSA	EDEMET, EDECHI, ENSA	EDEMET, EDECHI, ENSA	EDEMET, EDECHI, ENSA
Seller	UEP Penonome II S.A.	UEP Penonome II S.A.	UEP Penonome II S.A.	UEP Penonome II S.A.
PPA Starting Date	01-Jul-14	01-Jul-14	01-Jul-14	01-Jul-14
Term	15 years	15 years	15 years	15 years
Payment Rate				
Base (USD/MWh)	95	98	110	108
Price Adjustments	As per PPA formula			
Last PPA price 2020 (USD/MWh)	97.79	100.88	113.24	111.18

As per UL's review, the PPAs were executed between UEP Penonomé II, S.A (the Seller") and the distribution companies; Empresa de Distribución Eléctrica Chiriquí, S.A (EDECHI), Empresa de Distribución Eléctrica Metro-Oeste, S.A. (EDEMET) and Elektra Noroesta, S.A. (ENSA), all of them through the management of Empresa de Transmisión Eléctrica, S.A. (ETESA). The executed PPAs covers a total Wind Project capacity of 165 MW and have a PPA starting date of July 2014. The remaining Wind Project capacity (50 MW of Rosa de los Vientos II) are considered for backup generation for the PV Project and for spot market, in that order of preference. UL was provided with several amendments for each PPA and different PPAs for each distribution companies (EDECHI, EDEMET and ENSA) with different execution dates and COD dates.

The term of the PPAs is for 15 years and might be extended if the parties reach an agreement. 2 years before the termination of the PPA, the parties shall agree new terms for the extension of the PPAs. In case of no extension has been agreed, the previous PPA will be extended in monthly basis until any party terminate the PPA. UL was informed that Marañon and Portobelo have a 4.5-year extension of the PPA term.

UL notes that the committed energy under the PPAs are referred to specific turbines' generation for each contract, assuming specific capacity for each PPA (defined as sub projects). All energy production from each sub project will be purchased by each Buyer.

3.6.3 Turbine O&M Agreement

UL reviewed the Service and Maintenance Agreement ("SMA") for the Project dated as of 23 April 2014 and signed between Goldwind International Holdings (HK) Limited ("Service Company") and UEP Penonome II, S.A. ("Buyer") [52].

Additionally, UL has also reviewed the First Amendment of the SMA ("First Amendment") signed on 01 October 2020 [53] where the Service Company has been replaced by Goldwind Service Company Panama S de RL. This First Amendment includes amendments on several topics like definitions, scope, Price, Term and availability warranty provisions from the initial SMA.

This report includes, apart from the review of the SMA version, the review of the First Amendment.

UL notes that the First Amendment sets that the SMA (version signed on 23 April 2014) is expiring on 31 October 2020.

The SMA outlines the operation and maintenance obligations of the Service Company, the original equipment manufacturer of the turbines for the Project, who will be providing operation and maintenance of the turbines for an expected period of 5 years (the "Term") with 5 years extension option from Service Commencement Date. The First Amendment will extend the Term until 31 December 2023.

The table below provides a summary of the SMA and First Amendment terms.

Table 3.11: Key Terms of the Service and Maintenance Agreement

Commercial Terms	
Contract Name	Service and Maintenance Agreement
Effective Date	23 April 2014
Contract Amendments	First Amendment, signed on 01 October 2020
Service Company	Goldwind International Holdings Limited to be moved to Goldwind Service Company Panama S de RL in the First Amendment
Buyer	UEP Penonome II, S.A.
Scope of Work	
Remote Monitoring and Resets	There is no reference with respect to the remote monitoring and resets in the SMA.

Table 3.11: Key Terms of the Service and Maintenance Agreement

Preventive Maintenance	The Service Company is to perform all routine maintenance consistent with the Operations Manual, including provision of all materials, equipment, tools, and labor.
Corrective Maintenance	The Service Company is to perform all corrective maintenance inclusive of troubleshooting, repair, and replacement of minor and major defective work. The First Amendment excludes Claims Relating to Blades.
Buyer Responsibilities	The Buyer is responsible for providing the WTG Operator with access to the site, O&M facilities, access to the SCADA system, maintaining Project BOP, operating and managing the Project, handling hazardous substances and maintaining permits and approvals.
Price	
Term	The term of the SMA is for a period of 5 years, commencing on the Service Commencement Date of the Project. 5 years of extension option has been included within the SMA with the same scope of work, but with different commercial conditions. The First Amendment extend the Term from 01 November 2020 to 31 December 2023.
SMA Price	The annual fee (VAT excluded and to be annually adjusted based on Panama Consumer Price Index from year 2013 onwards) is equivalent to 45,000 USD/WTG/yr (years 3 to 5); 80,000 USD/WTG/yr (years 6 to 10). The First Amendment sets the annual fee (VAT excluded and to be annually adjusted based on US Consumer Price Index from year 2020 onwards) to be modified to 48,500 USD/WTG/yr.
Security	Not provided.
Default and Termination	
Events of Default	Events of default are typical for both Service Company and Buyer.
Termination	In the event of an uncured default, the non-defaulting party can terminate the agreement.
Force Majeure	Events considered to be Force Majeure are reasonable.
Warranties	
General Repair	Market standards (12 months for repair and replacements).
Availability	First Amendment: Time-based availability of 96% for the Non-Windy season and 97% for the windy season. LDs for availability below 97% and bonus from 97% (50% of additional revenues) for each Production Period.

UL has reviewed the executed SMA and its First Amendment and considers the majority of the provisions within to be reasonable and representative of standard requirements for the operation and maintenance of the wind farms. However, there are some points that UL recommends being considered as per described below.

The SMA is considered a full-service contract that covers all scheduled and unscheduled maintenance of all components of the WTG (however First Amendment excludes the blades). UL considers that the preventive and corrective maintenance services to be provided by the Service Company are according to market standards. That being said, UL would consider to be for the Project benefits the remote monitoring of the Project as well as remote resets and manual resets when required and technically applicable explicitly included in the SMA.

UL notes that the First Amendment sets that the Scheduled Maintenance shall be scheduled to occur outside of the Windy Season Production Period and 6 months meetings will be performed between

Buyer and Service Company to approve the next 6 months preventive calendar dates that is positive for the Project. First Amendment of the SMA defined the following seasons:

- "Non-Windy Season Production Period" means each of the following periods during the Term:
  - (1) From 01 May 2021 to 30 November 2021;
  - (2) From 01 May 2022 to 30 November 2022; and
  - (3) From 01 May 2023 to 31 December 2023.
- "Windy Season Production Period" means each of the following periods during the Term:
  - (1) From 01 November 2020 to 30 April 2021;
  - (2) From 01 December 2021 to 31 April 2022; and
  - (3) From 01 December 2022 to 31 April 2023.

The First Amendment excludes the Claims Relating to Blades and this is a relevant variation from the initial SMA as the risk of these corrective works or blades reparation will be on the Buyer's side. In order to cover that risk additional costs and an appropriate maintenance reserve account are considered in the Financial Model to cover the blades repairs in the future (see Section 5.2).

UL notes that response times for corrective actions in the case of WTG are not stated in the SMA, but the corrective maintenance will be executed without any unjustified delay according to the nature and complexity of the works needed to perform the maintenance once the damage is reported and identified. Despite the fact the Service Company is already incentivized by the Availability Guarantee, UL would ideally recommend including a detailed response time schedule.

During the Term of the SMA, the Buyer's responsibilities are typical including providing the Service Company with access to and from the Project, O&M facilities, fulfilling safety rules and regulations, maintaining all required Project permits, providing to the Service Company a warehouse and access respectfully, providing to the Service Company access to the SCADA system, waste management for the hazardous substances that are resulting from the operations of the BOP other than the operations of the Service Company. UL considers the Buyer's responsibilities to be standard and suitable for the Project.

The Service Company is to provide monthly reports of which content is not explicitly written. According to the First Amendment, 15 Business Days after the end of each month, monthly reports should be provided by the Service Company including the Average Availability and the Availability of each WTG and a copy of the Availability Bonus and Liquidated Damages Tracker updated to include the Average Availability for such month. In addition, UL also recommends including the real or operational availability numbers of WTGs. As per the First Amendment, the Buyer, within 15 days after reception of the Average Availability calculation, shall review and approve or reject these calculations, otherwise these calculations will be deemed accepted by the Buyer. UL considers that the Average Availability calculations should not be deemed accepted by the Buyer who should have the right to review these calculations afterwards, at least for the corresponding specific Annual Production Period.

During the Term, the Service Company will employ or make available sufficient numbers of qualified personnel during operating hours. The Service Company to provide with its service personnel with such tools, spare parts, and equipment as required for the performance of the services. UL notes that the provision of the consumables required for the preventive or corrective maintenance is not explicitly written in the SMA. The Service Company will make the spare parts available until 31 December 2035 and the costs for acquiring Spare Parts during that period will be at the Service Company's cost plus 15%. UL considers the provision of labor spare parts, tools, and equipment to be typical.

The Term of the initial SMA is for a period of 5 years, commencing on the Service Commencement Date of the first WTG of the Project and ending on the date that the Warranty Period expires (according to the First Amendment ends on 01 November 2020). Despite 5 years of extension option is provided within the SMA, the First Amendment considers a new Term and a SMA Warranty Period from 01

November 2020 to 31 December 2023. UL recommends that new Clause 5.1 of the First Amendment explicitly considers that the Term will be from 01 November 2020 in order to avoid misinterpretations.

The initial SMA price is defined as an Annual Base Price (fixed) to be payable by the Owner to the WTG Operator from the Commissioning Completion of the last WTG as given in the table below (plus VAT).

Table 3.12: SMA Price (2013)

Years	Annual Base Price (USD/WTG/yr)
1 - 2	-
3 - 5	45,000
6 - 10	80,000

The SMA price shall be updated from 2013 according to the Price Index for the Republic of Panama annually. UL considers that the price for initial term of 5 years to be reasonable; however, prices for the term extension are above UL's expectations. That being said, UL notes that the First Amendment sets that the new SMA Price will be 48,500 USD/WTG/yr (Price for 2020 subject to annual indexation according to the US index) commencing in the Amendment Effective Date. First Amendment states that the quarterly installment for the fourth quarter of 2020 shall be invoiced by Service Company on or promptly after the Amendment Effective Date. In any case and in order to avoid misunderstandings, UL recommends that the SMA Price of the First Amendment will be applicable when the new clauses and scope of the First Amendment comes into force that are expected to be on 01 November 2020. In addition, Buyer will be responsible for the all main crane expenses up to 50,000 USD/month. All in all, UL considers that the SMA Price for the First Amendment is in the medium-high end of UL's expectations considering the exclusions of blades and main crane costs.

In addition, the hourly rates for the extra works provided within the Exhibit B2 of the SMA are found to be in the medium-high range of market standards and UL notes that there is no breakdown for such hourly rates which might lead to confusion. UL recommends clarifying the level of the person to be employed and its corresponding hourly rate for the avoidance of doubt. UL notes that the material, equipment, travel and subcontracted works' costs will be charged as actual incurring costs plus 15%. UL recommends having a certain cap in US Dollars in the case of major expenditures within the course of this item is to be done in order to avoid unexpected costs.

The Parties do not have an obligation to provide a Parent Company Guarantee under the SMA. According to the First Amendment of the SMA "Goldwind International Holdings Limited" will assign its rights and obligations under the SMA to "Panama S de RL" as the Service Company. Therefore, UL recommends that the new Service Company provides a parent company guarantee.

Force Majeure definition and related consequences are reasonable and market standards. For the crane works, the wind speeds greater than 10 m/s is considered as a Force Majeure event which UL finds typical. Nevertheless, UL recommends clarifying where (crane or met mast) and how (height and equipment (anemometer calibrated)) will be measured the wind speeds for such conditions . In addition, and as per the First Amendment, UL notes that COVID-19 pandemic is explicitly included as a Force Majeure Event and UL recommends follow-up of this topic with the legal and insurance consultant.

Event of default clauses are typical and within expectations. However, UL recommends adding a default clause such as "not fulfilling the warranted performance criteria for the consecutive 2 years" (or similar) to encourage the Service Company for providing its best service so as not to be the defaulting party.

In the event of an uncured default, the non-defaulting party can terminate the O&M Contract and the total liability will be equivalent to the Annual Fees for the specific year.

The Service Company shall dismount, repair or replace, and reinstall any defective part of the Equipment and/or execute any work for solving defects that are covered by this guarantee, without any cost or expenses to the Buyer with 12 months of warranty for the replaced or repaired material.

The Service Company, at its sole discretion, has the right to implement improvements to the WTGs and the Licensed Technology. However, UL recommends that the Buyer's written consent should be essential to obtain before implementing such improvement, and such improvement should not invalidate the type certificate of the WTG and should not negatively impact the future lifetime of the Project.

The time-based availability warranty provided within the SMA is 95% for the initial six months of the warranty period and 97% for the remaining months of the warranty period during the Term. UL notes that the availability warranty is to be typical and within low-end market standards. In addition, and as per the First Amendment, the Guaranteed Availability provisions are modified according to the following:

- Average Availability warranty at 97% for a Windy Season Production Period. This will be coincident with windy season periods and will allow to maximize production for the site; and
- Average Availability warranty at 96% for a Non-Windy Season Production Period.

UL notes that the new proposed time-based availability warranty values in the First Amendment are below markets standards and below UL's expectations especially when considering that the Claims Relating to Blades are excluded. A mitigation aspect in this case, that is to be implemented according to the First Amendment, is that the preventive works to be executed by Goldwind should be done during the Non-Windy Season Production Period.

UL reviewed the calculation formula of the time-based availability and found the calculation reasonable. Also, the new availability calculation defined in Exhibit G of the First Amendment is reasonable with the following comments or exceptions:

- It is pending to be clarified the meaning of subclause (h) "Intentionally Removed". As per the Client indications this refers to "blade icing";
- The Scheduled Maintenance (until 50h), cranes availability and compliance with Wind Sector Management Requirements are not considered as unavailable.

In any case, UL recommends as best industry standard that such calculation to be based on IEC time-based availability formula (IEC 61400-26-1) in order to obtain normalized results.

LDs calculation formula is typical and within expectations and UL considers the formula for the availability bonus application to be correct and to be according to markets standards. Payment will be based on the Annual Production Period basis, that means that the LDs or bonus payables during the Non-Windy Season Production Period and the immediately preceding Windy Season Production Period could be compensated.

UL notes that the First Amendment includes a modification in the Availability Bonus application that will be considered only in the event that the Average Availability is above 97%, regardless of the season of the year. UL notes that the availability bonus application will consider 50% of Project generation additional revenues which is a commercial aspect but classified in the high range of market standards. In addition, UL notes that there is not an availability gap between Availability LDs and bonus application for the Windy Season Production Period; therefore, for each Windy Season Production Period, the Project will be subject to receive Availability LDs or to pay the bonus. UL would positively evaluate the inclusion of a gap (0.5–1%) between warranted availability value and bonus application that will trigger the availability bonus (like in the case of the for the Non-Windy Season Production Period), which gap will be positive for the Project and will demonstrate the Service Company's intention to provide the best and most efficient maintenance services. Alternatively, and with the aim to avoid that the Project should pay Availability Bonus in years where the production and therefore the revenues are below expectations, it could be considered to apply Availability Bonus only above a pre-defined production.

The First Amendment includes the LDs and Bonus availability payments in a Production Period basis; however, they are payable in an annual basis and considering a net amount. UL considers that hypothetic availability bonus should not compensate hypothetic LDs in case that the annual availability is below the warranted annual value.

All in all, UL finds the Service Company services provisions in terms of predictive, preventive and corrective works to be suitable for the Project. However, the First Amendment excludes the Claims Relating to Blades and this is a critical aspect for the Project that should be properly considered in the OPEX estimations of the Financial Model (see Section 5.2 for further information).

3.6.4 BOP O&M Contract

UL notes that the Client has acknowledged to perform all civil BOP O&M activities at its own expense, hence UL recommends to properly reflect such costs in the Wind Project's FM.

The electrical BOP O&M activities reviewed in this section only contemplate the MV electric lines. As detailed in Section 3.6.1.1, the different SPVs of Penonomé and Penonomé II performed a shared facilities agreement that covers electrical infrastructure. Works of O&M at El Coco substation are under the MV O&M Contract.

UL notes that there are some inconsistencies in the documentation provided in regards of the MV O&M work on the step-up substation. Two additional documents have been provided in support of the MV O&M Contract. Both documents include a scope of work but only one of them includes the O&M of the step-up substation. The client has confirmed that the BOP O&M Contract includes the maintenance of the step-up substation up to the 34.5 kV transformer point. Sponsor provided the new renegotiated contract conditions that will be included in the future IPELSA Amendment.

UL reviewed an O&M contract for the operation and maintenance of the wind farm's MV infrastructure (the "MV O&M Contract") [54] signed in 01 December 2019 between UEP Penonome II, S.A. ("the Owner"), and Ingeniería y Productos Electromecánicos S.A. ("the MV O&M Contractor" or "IPELSA").

The scope of MV O&M Contract includes the preventive and corrective maintenance of the Wind Project's MV lines. The table below summarizes key terms of the MV O&M Contract.

Table 3.13: MV O&M Contract Key Parameters

General Contract Parameters	
Contract Name	MV lines O&M Contract
Effective Date	01 December 2019
Contract Amendments	To be executed on December 2020
MV O&M Contractor	IPELSA
Owner	UEP Penonome II S.A.
Technical Contract Parameters	
Term	1 years
Extension	On demand but no details are provided.
Key Scope Parameters	
Scope of Service	Please see below
Default and Termination	Typical in UL's view
Price	
Contract Price	7,900 USD/month (currency is not provided, but Sponsor confirmed that are USD) Future Amendment 6,600 USD/month as per the renegotiated conditions.
Key Warranty Parameters	
Warranties	Future amendment sets 1 year from reparation date.

UL notes that the Client provided a document that details the O&M strategy of the MV system "MV O&M Strategy" dated July 2019 [55]. UL recommends that such document makes reference to the actual MV O&M Contract and make it clear that the provisions detailed in such document apply to the actual MV O&M strategy.

The MV O&M Strategy details the following requirements and works to be performed by the MV O&M Contractor with respect to the MV installation of the Wind Project:

- Testing of underground lines and aerial lines with the aim of finding any potential failure;
- Verification of all equipment in order to point out improvement in the performance of such equipment;
- Carrying out isolation measurements to the equipment; and
- Failure detection with non-intrusive equipment.

The equipment covered under the scope of work of the MV O&M Strategy is:

- 40.3 km of aerial lines; and
- 69.2 km of underground lines.

UL notes that the MV O&M Contractor's required experience under the MV O&M Strategy is in line with UL expectations for the kind of work required and the Wind Project's characteristics.

The MV O&M Contractor is required to the following:

- Provide proof of at least 5 years of experience in similar works;
- Meet all the requirements under the MV O&M Strategy;
- Provide all the necessary equipment to carry out the works described in the MV O&M Strategy;
- The works are to be carried out the El Coco substation in coordination with UEP Penonomé II;
- The MV O&M Contractor shall clearly state the methodology and tools used to carry out the works; and
- The MV O&M Contractor will hand over to the owner a final report with all the tasks carried out once the task is finalized. UL note that this is not consistent with what the main body of the MV O&M Contract states when it notes that the reporting is to be done also on a monthly basis.

UL positively evaluates that the reporting of each O&M activity is to be submitted to the client within one week of the actual O&M action. However, it is acknowledged that no O&M form is attached to the contract. It is recommended to agree the way in which the O&M activities are to be reported.

UL notes that the term of the contract is 1 year with the possibility to renew it. Sponsor provided the new renegotiated contract conditions that will be included in the future IPELSA Amendment [56].

UL notes that the MV O&M Strategy states that the repairs will be carried out with rapidity (maximum of 2 hours to attend the fault) but does not provide any detail on timings for fault resolution.

UL notes that another document was provided as an annex including the MV O&M Contract Price. UL notes that this document makes no reference to the actual MV O&M Contract, however it does detail similar tasks to the scope of work under the MV O&M Contract and also, such work is to be carried out by IPELSA too. According to this document, the MV O&M Contract Price is 7,900 USD/month and group of work that is to be on an on-call basis. In addition, and according to the new renegotiated contract conditions a costs reduction 7,900 to 6,600 USD/month will be included in the future Amendment.

The conditions for termination of the MV O&M Contract are detailed in Clause 10 of the MV O&M Contract, and are typical in UL's view; however, UL notes that the actions to be taken after termination are not specified.

UL notes that no form of guarantee is considered under the MV O&M Contract and recommends considering this aspect in order to ensure the quality of work of the MV O&M Contractor. According to the information provided by the Sponsor they are currently negotiating this contract in order to update scope, price and guarantees and IPELSA confirmed that 1 year guarantee will be provided.

3.6.5 Wake Effect Agreement

UL has reviewed, only from a merely technical standpoint, a Wake Effect Agreement signed on 09 February 2017 between UEP Penonome II S.A. (“UEPII”) [57], and Unión Eólica Panameña S.A. (“UEP”). Further, UEP assigns all its rights and obligation of the Wake Effect Agreement to UEP Penonome III S.A. (“UEPIII”) by means of the Wake Effect Assignment Agreement signed on 15 June 2018 [58] between UEP, UEPII, UEP III, and UEP Penonome I S.A. (“UEPI”).

UL notes that some definitions refer to the “Existing Wake Effect Agreement” signed on 10 December 2014 between Goldwind International Holdings (HK) Limited (“Goldwind”), Unión Eólica Panameña S.A. (“UEP”), and UEP Penonome II S.A. (“UEPII”). UL recommends legal advisor opinion regarding this aspect. UL further highlights that this “Existing Wake Effect Agreement” entitles UEP to receive compensation from UEPII.

According to the Wake Effect Agreement, each of the UEP Penonome parties holds the following projects and assigned capacities:

- UEPII: Penonome Phase II (“Phase II Project”) located in Cocle with a capacity of 215 MW;
- UEPI: one wind farm near Phase II Project (“Phase I Project”) located in Cocle with a capacity of 55 MW; and
- UEPIII: one or more wind farms near Phase II (“Phase III Project”). UL notes that the capacity of UEPIII is not defined; however, the Existing Wake Effect Agreement sets an additional 66.8 MW design capacity licensed beyond Phase I Project and Phase II Project (the “Remainder”) that may adversely impact the Phase II Project.

The “Wake Effect Project” is defined as in the Existing Wake Effect Project and will be any wind energy project (excluding Phase I Project) to be installed within 6 km and in the direction ranging from 270 to 90 degrees or within 1,635 meters and in the direction ranging from 90 to 270 degrees from any Phase I Project wind turbine. UL notes the definition refers to Phase I Project and not Phase II Project, which does not consider the relative position of UEPIII to UEPII and could lead to omission of liable wind turbines. UL highly recommends including a revised definition of Wake Effect Project in the Wake Effect Agreement and clarify possible issue regarding excluded projects. UL advises that a clear statement exclude UEPII from liability toward the Remainder.

According to this agreement, any future Wake Effect Project will require the Independent Wind Consultant to determine the related wake effect affecting Phase II Project that will be considered for compensating wake losses (“Monthly Make Whole Payments”) and will be calculated according to the Exhibit A of this agreement during the Term (25 years from Commercial Operation Date). UL understands the definition of the Term refers to the Commercial Operation Date of UEPII but notes that is not clearly specified. As per the Sponsor’s information (email of 30 July 2020), the COD of the Wake Effect Agreement is February 2018.

UL has reviewed the Monthly Make Whole Payments calculation method and finds that lost MWh based on the calculation of the Independent Wind Consultant shall be compensated at:

- The PPA Price for any share of the hourly lost MWh that does not exceed hourly contracted energy under the PPA; and
- The Hourly Spot Price for any share of the hourly lost MWh that exceeds hourly contracted energy under the PPA.

Additionally, the lost MWh shall be entirely compensated to the Green Attribute Price, if such contract exists.

Sponsor provided (email 07 august 2020) the Monthly Make Whole Payment executed up to June 2020 that achieved a total amount of USD 1,148,121 from the period starting July 2018 to June 2020.

UL notes that the hourly contracted energy under the PPA is not defined, it should be noted that in the Existing Wake Effect Agreement, this value is set to 28 MWh, a lower value could lead to unbalanced agreements.

UL usually considers such agreement as positive for the projects; however, UL highly recommends basing the definition of the Wake Effect Project on UEPII and not UEPI in order to consider the relative position of UEPIII to UEPII. Sponsor informed UL (email 30 July 2020) that the Wake Effect Agreement reviewed here only relates to UEPI and UEPII and the future affectation of UEPIII to UEPII will be reflected in an independent wake effect agreement that was not currently available for UL's review. Additionally, UL notes that UEPII shall pay Make Whole Payment to UEP under the "Existing Wake Effect Agreement". Furthermore, there is not any mention to possible effects on WTG loads and limitation in lifetime extension.

UL recommends specific legal advisor opinion regarding transfer rights and their implications in the selling process transference of UEPI to UEPIII and their implications derived to this Wake Effect Agreement.

3.7 Permitting review

UL performed a review of the permitting needed for the construction and operation of the Wind Project. The relevant permits, authorizations and studies to comply with the legislation of the host country in the construction and the operational phases of the Wind Project are summarized below. Table 3.14 describes details of each permit, authorization and study with the obligations or recommendations written in the table.

Table 3.14: Summary of Permits and Authorizations for the Penonomé II Wind Farm

Permit/Authorization	Description	Obligations and Recommendations	Status
Definitive Generation License for Marañón Wind Project in favor of UEP Penonomé II,S.A., by the National Public Services Authority (ASEP)	Resolution AN No. 4075 for the construction, exploitation, maintenance, generation and sale of energy, issued on 10 December 2010. Valid for 40 years. The license had several modifications over time but the last one is a modification Resolution AN No. 7275 issued on 11 April 2014.	Compliance with the terms and obligations established in the license	Valid
Definitive Generation License for Nuevo Chagres Wind Project in favor of UEP Penonomé II,S.A., by the National Public Services Authority (ASEP)	Resolution AN No. 4094 for the construction, exploitation, maintenance, generation and sale of energy, issued on 15 December 2010. Valid for 40 years. The license had several modifications over time but the last one is a modification Resolution AN No. 7326 issued on 02 May 2014.	Compliance with the terms and obligations established in the license	Valid
Definitive Generation License for Portobelo Wind Project in favor of UEP Penonomé II,S.A., by the National Public Services Authority (ASEP)	Resolution AN No. 4092 for the construction, exploitation, maintenance, generation and sale of energy, issued on 15 December 2010. Valid for 40 years. The license had several modifications over time but the last one is a modification Resolution AN No. 7278 issued on 14 April 2014.	Compliance with the terms and obligations established in the license	Valid

Table 3.14: Summary of Permits and Authorizations for the Penonomé II Wind Farm

Permit/Authorization	Description	Obligations and Recommendations	Status
Definitive Generation License for Rosa de los Vientos Wind Project in favor for UEP Penonomé II,S.A., by the National Public Services Authority (ASEP)	Resolution AN No. 5379 for the construction, exploitation, maintenance, generation and sale of energy, issued on 13 June 2012. Valid for 40 years. The license had several modifications over time but the last one is a modification Resolution AN No. 7274 issued on 11 April 2014.	Compliance with the terms and obligations established in the license	Valid
Interconnexion Agreement between UEP Penonomé II, S.A., and the Electric Transmission Company (ETESA)	Contract to access the transmission system No. GG-019-2012 issued on 16 April 2012. The first amendment was issued on 16 September 2014.	Compliance with the terms and conditions established in the agreement	Valid
Commercial operation registers for UEP Penonomé II, S.A., by the Ministry of Industries and Commerce	Operation notice No. 2318210-1-792556-2014-409723	No conditions or terms established in the document	Valid
Environmental Impact Study Approval for Marañón Wind Project by the National Environmental Authority	Resolution IA-352-10 issued on 31 May 2010. It will take effect since it starts execution and will be valid for two years. A modification was issued on 28 June 2010, Resolution AG-0599-2010 regarding the percentage of funds from carbon emission reduction certificate to create a fund for the communities. A change of promoter was approved in 17 December 2013 in favor of UEP Penonomé II, S.A.	Compliance with the conditions established in the resolution IA-352-10 issued on 31 May 2010.	Valid
Environmental Impact Study Approval for Nuevo Chagres Wind Project by the National Environmental Authority	Resolution IA-353-10 issued on 31 May 2010. The Project had several modifications, being the last issued on 21 April 2014, Resolution IAM-037-2014 regarding a change of promoter in favor of UEP Penonomé II, S.A. The environmental resolution will take effect since it starts execution and will be valid for two years.	Compliance with the conditions established in the resolution IA-353-10 issued on 31 May 2010.	Valid
Environmental Impact Study Approval for Portobelo Wind Project by the National Environmental Authority	Resolution IA-354-10 issued on 31 May 2010. It will take effect since it starts execution and will be valid for two years. The Project had several modifications, being the last issued on 16 January 2013, Resolution IAM-002-2013	Compliance with the conditions established in the resolution IA-354-10 issued on 31 May 2010.	Valid
Environmental Impact Study Approval for Rosa de los Vientos Wind Project by the National Environmental Authority	Resolution IA-355-10 issued on 31 May 2010. It will take effect since it starts execution and will be valid for two years. The Project had several modifications, being the last issued on 16 December 2013 for a change of promoter w in favor of UEP Penonomé II, S.A. Resolution IAM-002-2013	Compliance with the conditions established in the resolution IA-355-10 issued on 31 May 2010.	Valid
Environmental Impact Study Approval for the construction of roads for the Penonomé Wind Project by the National Environmental Authority	Resolution ARAC-IA-068 issued on 10 September 2012. It will take effect since it starts execution and will be valid for two years.	Compliance with the conditions established in the resolution ARAC-IA-068.	Valid
Environmental Impact Study Approval for the Transmission Line of the Penonomé Wind Project by the National Environmental Authority	Resolution ARAC-IA-087-13 issued on 09 August 2013. It will take effect since it starts execution and will be valid for two years.	Compliance with the conditions established in the resolution ARAC-IA-087-13.	Valid

Table 3.14: Summary of Permits and Authorizations for the Penonomé II Wind Farm

Permit/Authorization	Description	Obligations and Recommendations	Status
Environmental Impact Study Approval for the construction of roads for the Penonomé Wind Project phase III by the National Environmental Authority	Resolution ARAC-IA-075-14 issued on 31 July 2014. It will take effect since it starts execution and will be valid for two years.	Compliance with the conditions established in the resolution ARAC-IA-075-14.	Valid
Construction License by the Municipality of Penonomé	Permit No. 376 issued on 12 August 2016.	No conditions or terms established in the document	Valid
Approval for land use and zoning for Penonomé Wind Project by the Ministry of Housing and Territorial Planning	Resolution No. 366-2013 issued on 14 June 2013	Compliance with the conditions established in the resolution No. 366-2013	Valid
Wind turbine and transmission tower location and height approval by the National Authority of Civil Aviation	First Resolution No. 117-DJ-DG-AAC issued on 10 July 2013. A modification to the resolution was issued on 16 July 2013 for the use of red flash obstruction lights, Resolution No. 144-DJ-DG-ACC. A request for expansion in the construction evaluation or structure modification for 20 wind turbines that were initially part of Phase 3 but will become part of Phase 2 was issued on 13 March 2014.	Compliance with the conditions established in the resolution No. 117-DJ-DG-AAC and compliance with the signage and lighting established in the resolution No. 144-DJ-DG-ACC.	Pending supply of official response for the construction expansion or structure evaluation

UL denotes that the Penonomé II Wind Farm is formed by 4 wind projects, the transmission line and roads for the access to the Project. Each wind project, roads and the transmission line have its own Environmental Impact Authorization. Also, the 4 wind projects that form the Project have each their own Definitive Generation License. The Commercial Operation Register, the Interconnexion Agreement and the construction license from the Municipality of Penonomé is one for the whole Project.

UL reviewed the permits sent by the Sponsor and found out that all are in accordance to the Panamanian legislation. Nevertheless, UL denotes that there is missing the official response of the National Authority of Civil Aviation regarding a construction expansion or structure modification for 20 wind turbines. As per the Sponsor's information this document should be available but a copy of it has been requested to the AACP. **<UL will review the official response regarding the construction expansion or structure modification for 20 wind turbines from Civil Aviation when provided.>**

3.7.1 IFC Performance Standards Review

On January 2012, the IFC's Sustainability Framework articulates the Corporation's strategic commitment to sustainable development and is an integral part of IFC's approach to risk management. The Sustainability Framework comprises IFC's Policy and Performance Standards on Environmental and Social Sustainability, and IFC's Access to Information Policy. The Policy on Environmental and Social Sustainability describes IFC's commitments, roles, and responsibilities related to environmental and social sustainability. The Performance Standards aim to manage environmental and social risks and impacts so that development opportunities are enhanced. There are eight Performance Standards, which will be described along with the evidence of the Project´s compliance with them in the following table.

Table 3.15: IFC Performance Standards Review for Penonomé Project

IFC Performance Standard	Fulfillment	Compliance
Performance Standard 1: Assessment and Management of Environmental and Social Risks and Impacts	**Description:** Conduct a process of environmental and social assessment and establish and maintain an Environmental and Social Management System (“ESMS”) appropriate to the nature and scale of the project and commensurate with the level of its environmental and social risks and impacts. The ESMS will incorporate the following elements: (i) policy; (ii) identification of risks and impacts; (iii) management programs; (iv) organizational capacity and competency; (v) emergency preparedness and response; (vi) stakeholder engagement; and (vii) monitoring and review.	✓
	Project´s Response: UL reviewed the evidence regarding the ESMS and its execution during the operational phase of the Project. UL found that it is in accordance with the requirements to fulfill this Performance Standard.	
Performance Standard 2: Labor and Working Conditions	**Description:** Recognizes that the pursuit of economic growth through employment creation and income generation should be accompanied by protection of the fundamental rights of workers.	✓
	Project´s Response: UL reviewed evidence regarding the PPE, trainings and certifications to the personnel, the biosafety protocol, evidence on the execution of the health and safety protocols and a labor contract. UL also reviewed the evidence regarding the internal grievance mechanism plan and the health and safety plan during the operational phase. UL founds the evidence and the plans in accordance with the requirements needed to fulfill this Performance Standard.	
Performance Standard 3: Resource Efficiency and Pollution Prevention	**Description:** During the project life cycle, the Sponsor will consider ambient conditions and apply technically and financially feasible resource efficiency and pollution prevention principles and techniques that are best suited to avoid, or where avoidance is not possible, minimize adverse impacts on human health and the environment.	✓
	Project´s Response: UL has evidence regarding the execution of the resource efficiency plan and the pollution prevention during the operational phase of the Project.	
Performance Standard 4: Community Health, Safety, and Security	**Description:** The Sponsor will evaluate the risks and impacts to the health and safety of the affected communities during the project lifecycle and will establish preventive and control measures consistent GIIP, such as in the EHS Guidelines or other internationally recognized sources. The Sponsor will identify risks and impacts and propose mitigation measures that commensurate with their nature and magnitude. These measures will favor the avoidance of risks and impacts over minimization.	✓
	Project´s Response: UL reviewed evidence regarding water sampling in the community, traffic control plan, Waste Management Plan and safety measures taken for the communities.	
Performance Standard 5: Land Acquisition and Involuntary Resettlement	**Description:** The client will consider feasible alternative project designs to avoid or minimize physical and/or economic displacement, while balancing environmental, social, and financial costs and benefits, paying particular attention to impacts on the poor and vulnerable	✓
	Project´s Response: UL has evidence regarding the easement contracts and the leasing contracts where the Project was developed. The contracts were duly registered in the Public Notary of Coclé in Panamá.	
Performance Standard 6: Biodiversity Conservation and Sustainable Management of Living Natural Resources	**Description:** Consider relevant threats to biodiversity and ecosystem services, especially focusing on habitat loss, degradation and fragmentation, invasive alien species, overexploitation, hydrological changes, nutrient loading, and pollution. It will also consider the differing values attached to biodiversity and ecosystem services by affected communities and, where appropriate, other stakeholders. As a matter of priority, the Sponsor should seek to avoid impacts on biodiversity and ecosystem services. When avoidance of impacts is not possible, measures to minimize impacts and restore biodiversity and ecosystem services should be implemented.	✓
	Project´s Response: UL reviewed the environmental mitigation impacts reports during operation. UL found that the mitigation measures adopted are in accordance with this Performance Standard. The Sponsor sent information regarding the company that will be developing and executing the monitoring of the biodiversity in the area where the Project is located.	

Table 3.15: IFC Performance Standards Review for Penonomé Project

IFC Performance Standard	Fulfillment	Compliance
Performance Standard 7: Indigenous Peoples	**Description:** The Sponsor will identify, through an environmental and social risks and impacts assessment process, all communities of Indigenous Peoples within the project area of influence who may be affected by the project, as well as the nature and degree of the expected direct and indirect economic, social, cultural (including cultural heritage), and environmental impacts on them.	✓
	Project´s Response: UL points that the Sponsor sent information regarding the no presence of indigenous people in the area of influence of the Project. According to the indigenous bibliography of Panamá, there is no indigenous people where the Project is located.	
Performance Standard 8: Cultural Heritage	**Description:** In addition to complying with applicable law on the protection of cultural heritage, including national law implementing the host country's obligations under the Convention Concerning the Protection of the World Cultural and Natural Heritage, the client will identify and protect cultural heritage by ensuring that internationally recognized practices for the protection, field based study, and documentation of cultural heritage are implemented.	✓
	Project´s Response: UL reviewed the archeological prospection held during construction of the Project, where it stated that there was not found any archeological vestiges during the works. Besides, UL also reviewed the Archeological Findings Plan developed for the operational phase.	

UL reviewed the evidence sent by the Sponsor in order to fulfill compliance with the IFC Performance Standards. These evidences include plans developed and executed during the operational phase of the Project and environmental, social and health and safety reports and logs. UL finds that the information and evidence given is enough to assess the complete compliance of the 8 IFC Performance Standards.

4. PORTFOLIO BENEFIT ANALYSIS

UL performed an evaluation of the portfolio benefit analysis (“PBA”) of the PV Project standard scenario (without considering repowering strategy) and the Wind Project. The PBA report was issued by UL on 01 October 2020 and is included in Appendix F (Ref. No.: PR-006385 Issue E). The PBA considers an evaluation period of 15-year consistent with the evaluation period of the Wind Project OEPR.

The portfolio has a combined capacity AC capacity of 255 MW. Portfolio benefit results when changes in annual energy output from one or more assets in a portfolio are to some extent offset by changes in annual energy output from other assets. The amount of benefit depends on the extent to which uncertainties associated with the energy output estimate for each asset are correlated. In general, accounting for these correlations results in a reduction in the overall uncertainty of the aggregate energy output of the portfolio, and therefore a reduction in investor risk.

It is understood that the uncertainty is reduced for the portfolio as a whole, and not for any individual wind plant. It is the investor in the portfolio that benefits from this reduction, not the investor in an individual asset that is held in a portfolio. Some financial models may not be structured to account for financial impacts at the portfolio level, however, and so it may be necessary to allocate estimates of portfolio benefit to the individual assets.

UL evaluated in the PBA two different scenarios; a standard scenario considering PV Project and Wind Project as the configuration reviewed in the TA report and an additional PV Project repowering scenario considering Client information about a repowering plan of the PV Project.

The annual and evaluation period probabilities of exceedance for annual energy output for the assets, with and without portfolio benefit, are summarized in next tables for the Ikakos repowering. For a given probability of exceedance, the portfolio benefit is calculated as the difference in the exceedance value when the portfolio benefit is considered and when it is not.

Table 4.1: Annual Portfolio Benefit Summary – Ikakos Repowering Scenario

Probability of Exceedance	Without Portfolio Benefit		With Portfolio Benefit		Total Benefit	
	Net Energy (GWh/yr)	NCF (%)	Net Energy (GWh/yr)	NCF (%)	(%)	(GWh)
P50	586	26.2%	586	26.2%	0.0%	0.0
P75	544	24.4%	548	24.5%	0.6%	3.5
P90	507	22.7%	513	23.0%	1.3%	6.7
P95	484	21.7%	493	22.0%	1.8%	8.6
P99	442	19.8%	454	20.3%	2.7%	12.1

Table 4.2: Evaluation Period[1] (15-year) Portfolio Benefit Summary – Ikakos Repowering Scenario

Probability of Exceedance	Without Portfolio Benefit		With Portfolio Benefit		Total Benefit	
	Net Energy (GWh/yr)	NCF (%)	Net Energy (GWh/yr)	NCF (%)	(%)	(GWh)
P50	586	26.2%	586	26.2%	0.0%	0.0
P75	568	25.4%	571	25.6%	0.5%	3.1
P90	552	24.7%	558	25.0%	1.1%	5.9
P95	542	24.3%	550	24.6%	1.4%	7.6
P99	524	23.4%	535	23.9%	2.1%	10.8

The portfolio benefit associated with this portfolio equated to 12.1 GWh (2.7%) at the annual P99 level. The overall portfolio uncertainties when considering no portfolio benefit were 10.6% and 4.6% for annual and 15-year evaluation periods respectively. These uncertainties were reduced to 9.7% and 3.8% when considering the portfolio benefit.

The relative allocations can be applied to the portfolio benefit at each probability of exceedance, and the benefit distributed among the assets to aid in financial modeling. UL emphasizes that the benefit is only actually realized at the aggregate portfolio level.

Table 4.3: Asset Probabilities of Exceedance with Portfolio Benefit, annual Estimates, Yearly Breakdown - Penonomé+Ikakos - Ikakos Repowering Scenario

Asset	P75 (GWh/year)		P90 (GWh/year)		P95 (GWh/year)		P99 (GWh/year)	
	Without Benefit	With Benefit	Without Benefit	With Benefit	Without Benefit	With Benefit	Without Benefit	With Benefit
Ikakos PV Ann Avg	83.4	84.0	79.8	80.8	77.6	78.9	73.5	75.5
PENONOME II	460.9	463.9	426.9	432.5	406.5	413.7	368.3	378.4
Annual Results – Ikakos&Penonome								
PENONOME II+Ikakos PV Yr 1	544.5	548.0	506.9	513.5	484.3	492.9	442.0	454.2
PENONOME II+Ikakos PV Yr 2	544.1	547.6	506.4	513.1	483.9	492.5	441.6	453.7
PENONOME II+Ikakos PV Yr 3	543.5	547.0	505.9	512.6	483.4	491.9	441.1	453.2
PENONOME II+Ikakos PV Yr 4	542.9	546.5	505.3	512.0	482.8	491.4	440.6	452.7
PENONOME II+Ikakos PV Yr 5	545.5	549.0	507.8	514.5	485.2	493.8	442.9	455.0
PENONOME II+Ikakos PV Yr 6	544.9	548.4	507.2	513.9	484.7	493.2	442.3	454.5
PENONOME II+Ikakos PV Yr 7	544.3	547.9	506.7	513.3	484.1	492.7	441.8	453.9

[1] Solar preconstruction EPR evaluation period is 25 years, however, UL adopted the analysis for the PBA to 15-year evaluation period. Wind operational assessment is for 15 years from now, 20 from COD in 2015. The effective evaluation period is based on the shorter of the two studies, or 15 years.

Table 4.3: Asset Probabilities of Exceedance with Portfolio Benefit, annual Estimates, Yearly Breakdown - Penonomé+Ikakos - Ikakos Repowering Scenario

Asset	P75 (GWh/year)		P90 (GWh/year)		P95 (GWh/year)		P99 (GWh/year)	
	Without Benefit	With Benefit	Without Benefit	With Benefit	Without Benefit	With Benefit	Without Benefit	With Benefit
PENONOME II+Ikakos PV Yr 8	543.8	547.3	506.1	512.8	483.6	492.1	441.3	453.4
PENONOME II+Ikakos PV Yr 9	543.2	546.7	505.5	512.2	483.0	491.6	440.7	452.9
PENONOME II+Ikakos PV Yr 10	545.7	549.2	507.9	514.6	485.3	493.9	442.9	455.1
PENONOME II+Ikakos PV Yr 11	545.1	548.6	507.4	514.0	484.8	493.3	442.4	454.5
PENONOME II+Ikakos PV Yr 12	544.5	548.0	506.8	513.4	484.2	492.8	441.8	453.9
PENONOME II+Ikakos PV Yr 13	543.9	547.4	506.2	512.9	483.6	492.2	441.2	453.4
PENONOME II+Ikakos PV Yr 14	543.3	546.8	505.6	512.3	483.0	491.6	440.7	452.8
PENONOME II+Ikakos PV Yr 15	545.8	549.3	508.0	514.6	485.3	493.9	442.8	455.0
Annual Average	**544.3**	**547.9**	**506.6**	**513.3**	**484.1**	**492.7**	**441.7**	**453.9**

Note* Annual average estimation for Penonome II corresponds to the annual average for a 15-evaluation period, not for a specific year over the evaluation period.
Note** Annual average benefit is to be assumed only considering the Portfolio project (not individually)

Table 4.4: Asset Probabilities of Exceedance with Portfolio Benefit, Evaluation Period Estimates - Ikakos Repowering Scenario

Asset	P75 (GWh/year)		P90 (GWh/year)		P95 (GWh/year)		P99 (GWh/year)	
	Without Benefit	With Benefit	Without Benefit	With Benefit	Without Benefit	With Benefit	Without Benefit	With Benefit
Ikakos PV Ann Avg	83.8	86.8	80.5	81.5	78.5	79.8	74.8	76.7
PENONOME II	484.3	487.3	471.4	477.0	463.6	470.9	449.1	459.3

5. FINANCIAL MODEL INPUTS REVIEW

UL has reviewed the Client's inputs to be considered in the financial model ("Financial Model" or "FM") [59] and the related document regarding OPEX costs [60] both delivered on 18 November 2020. The Financial Model includes the assumptions of the PV Project and the Wind Project as single FM. The FM includes a forecast of the long-term costs for the Project operations ("OPEX"), an estimate of Project revenues and the both Projects production. UL has focused its review on the following aspects:

- Operating Expenses (OPEX) provided in the separate spreadsheet that considers the fixed costs to be added to the Financial Model; and
- Generation and Revenue inputs values to be used for the financial model cash flow.

It is important to highlight that UL's review focused on the inputs (OPEX, generation and revenue) of the financial model, but UL has not performed any check of the FM formulation or further considerations beyond the review of the mentioned inputs. UL did not perform an audit of the Financial Model.

The inputs assumptions for the PV Project and the Wind Project are reviewed in the following sections.

5.1 Ikakos PV Project

A summary of the details of the Financial Model OPEX assumptions for Ikakos Project are provided in the table below.

Table 5.1: Project OPEX Assumptions – Ikakos PV Project

Item	Value
PV Project Energization	August 2018
Beginning of Operations (Flag COD)	01 January 2020
PPA Beginning	Depending on PPA (from 30 April 2018 to 31 January 2021)
PPA Structure	All consumption required from the Buyers shall be covered by the PV Project. Back up generation from Wind Project, hydrological projects or spot market will cover the production in that order in case the PV Project has a lack of generation.
Evaluation period	25 years

The PV Project energization was in August 2018 as per the information provided and is consistent with the FM model assumption.

The FM assumes an evaluation period of 25 years, which is considered to be industry standard. UL notes that the executed PPAs have a 15-year term with possible extension to be negotiated between the parties as detailed in Section 2.6.2. UL notes that the PPA term is consistent with the FM term assumed for the energy sales, assuming selling energy at spot price once the PPAs are expired.

5.1.1 Capital Expenditure (CAPEX)

UL notes that the PV Project is already under operation, however, several minor tasks for finishing construction are still pending to be performed due to the COVID-19 situation along the year 2020. UL notes that the FM considers the pending finishing works to be performed during 2021 as per the table below:

Table 5.2: Project CAPEX Assumptions – Ikakos PV Project

Item	Estimated Cost in 2021 (kUSD)
Transmission Line easement UNACHI	472.00
Bridge construction	213.36
Adaptation works over the Road El Corro	21.00
Transmission Line other costs	53.00
O&M office (upgrade)	56.42
Security plan (car)	23.00
TOTAL	**838.78**

UL did not review any information related to additional costs of the CAPEX, however, the Sponsor provided clarification about each item.

5.1.2 Operating Expenses (OPEX)

The overall operating costs estimated by the Financial Model (excluding taxes and exchange rates) are summarized in the table and figure below.

Table 5.3: Project Annual OPEX Cost Estimates in USD (2020) – PV Project

Item	2019			2020			2021		
	Total Cost (kUSD)	Equivalent Cost (USD/kWp)	Percentage over total OPEX (%)	Total Cost (kUSD)	Equivalent Cost (USD/kWp)	Percentage over total OPEX (%)	Total Cost (kUSD)	Equivalent Cost (USD/kWp)	Percentage over total OPEX (%)
Plant operation & maintenance	513.05	11.2	49.2%	714.51	15.7	51.0%	668.33	14.6	48.0%
O&M Plan	82.87	1.8	7.9%	465.68	10.2	33.3%	469.90	10.3	33.7%
Others	430.2	9.4	41.2%	248.83	5.5	17.8%	198.43	4.3	14.2%
Security and Environmental supervision	-	-	0.0%	81.51	1.8	5.8%	111.51	2.4	8.0%
EHS	86.38	1.9	8.3%	27.50	0.6	2.0%	27.75	0.6	2.0%
G&A	366.22	8.0	35.1%	285.01	6.2	20.4%	285.42	6.3	20.5%
Insurance	57.53	1.3	5.5%	124.38	2.7	8.9%	131.98	2.9	9.5%
Labor	-	-	0.0%	107.50	2.4	7.7%	108.48	2.4	7.8%
Fee to IEH	20.52	0.4	2.0%	60.00	1.3	4.3%	60.00	1.3	4.3%
TOTAL	**1,043.71**	**22.9**	**100.0%**	**1,400.41**	**30.7**	**100.0%**	**1,393.48**	**30.5**	**100.0%**

Note: 1. Based on a total Peak Power of 45.65 MWp.
Note: 2 Repowering cost is to be added every 5 years with an equivalent cost of 0.36 USD/Wp at year 5

UL has reviewed the operating expenses cost assumptions included in the FM that are for 2020 and 2021 together with the historical expenses of 2019. UL notes that for 2019 the project was already under operation but still finishing works were performed, therefore, the 2020 and 2021 values are the reference figures for the operation of the PV Project. The OPEX cost assumed for the Evaluation Period considers the ones presented in the table above and to be corrected by the Panama forecast CPI.

A graphical representation of overall OPEX costs is provided in Figure 5.1 below.

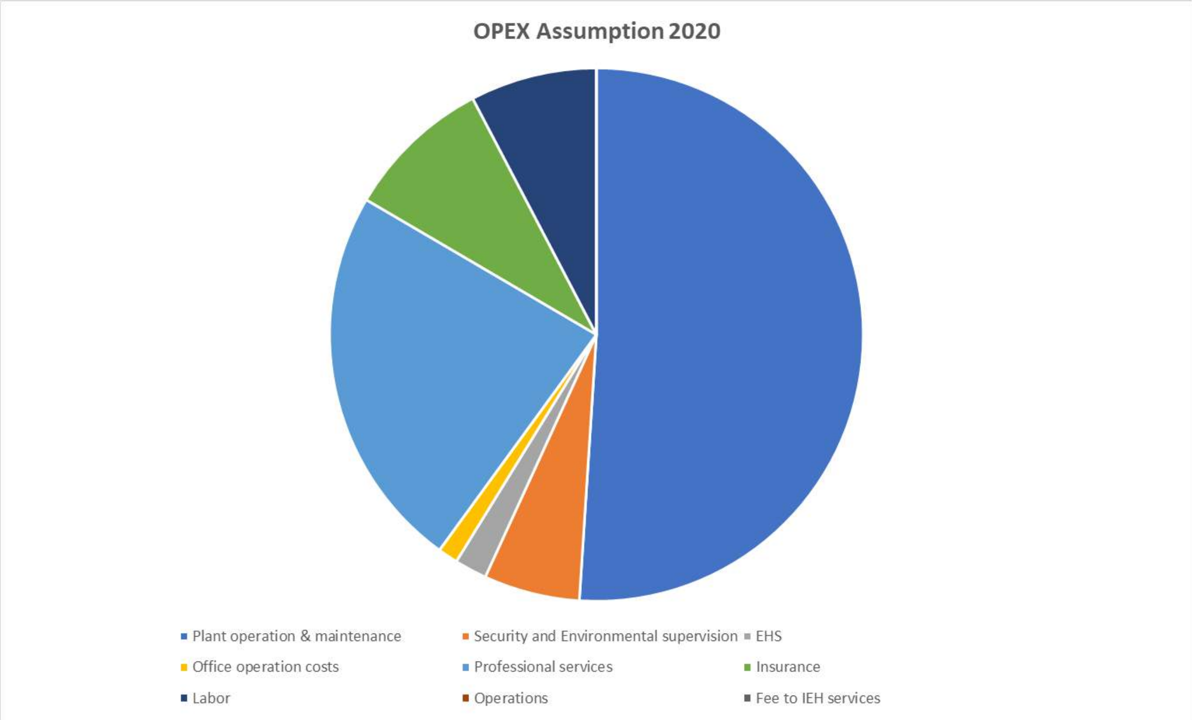

Figure 5.1: Project OPEX Assumptions (Taxes and Current Exchange Rate Excluded) – PV Project

UL reviewed the O&M costs assumptions of the Project for comparison to industry-wide OPEX expectations, for accuracy with contractual arrangements, for reasonableness in estimation of costs from non-contractual items (i.e. utilities) or atypical requirements (i.e. special permitting requirements), and for comparison for loan sizing.

UL comments are provided below (✓ = Adequate in UL's opinion; × = More information or updates needed):

✓ **Plant Operation and Maintenance**— The FM considers USD 714,509 and USD 668,330 as plant operation and maintenance for 2020 and 2021 respectively, which is equivalent to 15.6 USD/kWp and 14.6 USD/kWp, respectively. UL notes that 2020 figure is higher than 2021 due to additional spare parts were considered in 2020 where the Sponsor started the Operation of the PV Project. The Plant Operation and Maintenance includes the O&M Plan cost reviewed under Section 2.6.4 and Others item (cleaning services, electricity and water, land expenses, spare parts, office supply…). UL notes that the O&M Plan cost is equivalent to 10.2 USD/kWp for 2020 that is considered to be in the middle range compared to industry standard, however, as detailed in Section 2.6.4, the Client considers permanent own-staff on-site and additional, subcontract services such as inverter and tracker manufacturers annual maintenance, vegetation control, transmission line and interconnection infrastructure maintenance and a complete preventive maintenance plan. UL considers the O&M costs to be aligned with industry standard assuming several subcontractors and taking into account the scope of services.

UL notes that the Other items includes a Spare parts cost for the main component replacement over the lifetime of the PV Project, mainly inverter replacements. The Spare Parts cost was assumed to be USD 30,000 per year. UL notes that the inverter warranty for the PV Project is for 10 years, therefore, no considerable spare part cost is expected during the inverter warranty period. UL was informed that in addition, some other cost reduction will be used for spare part cost coverage. Considering this, UL is of the opinion that Spare Part cost is aligned with industry standard. In addition, UL was informed by the Sponsor on 06 October 2020, that a maintenance reserve account ("MRA") is considered to cover unexpected cost for the Wind Project and Ikakos PV Project (See Section 5.2.1). UL considers that having this additional MRA for both Projects (Penonome II + Ikakos) is reasonable, provided that this MRA (if used) is replenished each year;

✓ **Repowering cost**—The PV Project repowering scenarios considers the installation of 1.7 MWp every 5 years (only PV modules, trackers, and DC cablings). The FM assumes the repowering cost at each 5-year interval from PV Project operation start date. The repowering cost assumed is equivalent to 0.36 USD/Wp at year 5, which is increased until 0.38 USD/Wp at year 20. UL considers the repowering cost to be consistent with industry standard assuming that even a 1.7 MWp will be installed every 5 years, framework contracts can be set with suppliers to get utility scale prices.

Other additional costs considered in the FM are the following (listed for 2020):

- **Security and Environmental Supervision**—The equivalent costs assumed in the FM is 1.8 USD/kWp for the security and environmental for 2020 and 2.4 USD/kWp for 2021 (considering environmental costs);
- **Environment, Health and Safety**—The FM assumes an equivalent cost to 0.6 USD/kWp. This cost includes health and safety, environmental activities, social responsibility, waste management and donations;
- **General&Administration**—The equivalent costs assumed in the FM is 6.2 USD/kWp and include municipal tax and professional services (audits, bank fees and operation license). UL notes that the 84% of this item correspond to operational license, therefore, no technical opinion applies;
- **Insurance**—The FM considers an operational insurance costs equivalent to 2.7 USD/kWp, which represents a 7.9% of the total OPEX. Although a permanent surveillance is considered, UL notes that this equivalent cost is in the middle-high range of industry standard, however, UL did not review the scope of services for the surveillance;
- **Labor**—The equivalent costs assumed in the FM is 2.4 USD/kWp for labor; and
- **Fee to IEH Services**— The equivalent costs assumed in the FM is 1.3 USD/kWp for fees to InterEnergy Holdings ("IEH").

The total OPEX costs for operation of the Project for 2020 and 2021 are estimated to be USD 1,400,413 (equivalent to 30.7 USD/kWp) and USD 1,393,476 (equivalent to 30.5 USD/kWp), respectively. UL notes that the Professional Services fee includes also the Asset Management of the PV Project, therefore, UL is of the opinion that the total OPEX assumed is aligned with industry standard for the region and Project size and characteristics (middle high range).

UL notes that no taxes have been provided within the spreadsheet of fixed costs provided by the Sponsor.

In addition, UL notes that the long term OPEX assumptions only considers the indexation since the main equipment replacement is assumed to be constant as per the spare parts cost considered. Repowering additional cost is assumed every 5-year as per the repowering scenario assumed by the Client.

Furthermore, UL notes that no additional cost is considered under the FM for the DC cabling replacement detailed under Section 2.2.6. UL was informed that DC cabling replacement costs are to be covered by the EPC Contractor as per the Warranty Period of the EPC Contract.

5.1.3 Generation and Revenue

5.1.3.1 Generation (Energy Production)

As per the Client requirements, UL has only reviewed the production results according to the probabilistic scenario P50, P90 and P99 for the repowering scenario.

In addition, it should be remarked that UL performed a pre-constructive energy production report (EPR) on 19 August 2020 (see Appendix A) and an evaluation of the portfolio benefit analysis (“PBA”) of the PV Project repowering scenario and the Wind Project OEPR on 01 October 2020. According to these studies the Ikakos P90 annual average production for a 15 year evaluation period was estimated to be 80.82 GWh/yr. UL notes that the FM energy production of the PV Project is aligned with UL’s estimation of the PBA analysis for the repowering scenario.

The FM considers the hourly matrix of generation in order to properly estimate the PPA revenue depending on the Buyers demand profile. UL notes that the hourly generation profile assumed in the FM is consistent with the hourly matrix calculated by UL’s EPR.

5.1.3.2 Revenue

UL reviewed the PPA assumption considered in the Financial Model provided. UL notes that the total PPA capacity assumed is 40 MW_{AC} that is consistent with the information provided by the Client for the PPA contracts. As stated in Section 2.6.2, the PPAs considers that all generation produced by the PV Project will be purchased by the Buyers. In addition to the PV Project capacity, the PPAs considers the Wind Project and hydrological projects as back up project to compensate production.

UL notes that the PV Project was energized on August 2018 and that the FM PPAs start dates is aligned with the PPAs reviewed.

The FM revenues are calculated based on each PPA price, estimated as per the formulas of the PPAs that depends on the regulated electricity tariff price. The FM estimates the PPA expected price in the IEH Scenario and the results are presented in the table below for each Buyer.

UL notes that the FM considers a total of 15 Buyers, while the PPAs reviewed for the PV Project in Section 2.6.2 are only 8 Buyers, therefore, not all PPAs included under the FM corresponds to PV Project. The FM revenues assumed are from the following PPAs; Cocacola FEMSA (corresponds to Ventas y Mercadeo S.A. reviewed under section 2.1.5.2), Estrella Azul (corresponds to Industrias Lacteas SA reviewed under section 2.1.5.2), San Fernando, Riba Smith and Hilton (corresponds to Ice Gaming and Iron Tower reviewed under section 2.1.5.2) from the PPA Flag COD and additionally, Terpel (corresponds to Petrolera Nacional reviewed under section 2.1.5.2) from January 2021. All PPAs require a total consumption, assuming all the Buyers, of 110.0 GWh/year.

Considering that the estimated energy production generation for the first year was 87.18 GWh/year in P50 percentile, therefore, the backup generation will be needed to cover the Buyer consumption.

Table 5.4: FM Revenue Assumption – PV Project

PPA Buyer	PPA Start Date	Buyer Estimated Consumption (GWh)	Base Price 2020 (USD/MWh)
Coca Cola FEMSA (Ventas y Mercadeo) (Ikakos FM)	30-Apr-18	14.2	90.6
Estrella Azul (Industrias Lacteas SA) (Ikakos FM)	31-Jul-18	30.5	90.0
Clínica Hospital San Fernando (Ikakos FM)	31-Jul-18	6.1	91.9
Riba Smith (Ikakos FM)	31-Jul-18	45.2	90.0
Hilton (Gaming and Iron Tower) (Ikakos FM)	31-Dec-18	9.5	88.0
Cliente 22GWh	31-Jan-21	22.0	80.0
Cliente 7	31-Jan-21	40.0	90.0
Heineken	31-Dec-20	6.0	87.0
Terpel (Petrolera Nacional) (Ikakos FM)	31-Jan-21	4.6	81.5
Cliente 10	31-Jan-21	40.0	90.0
PPC	31-Jan-20	74.4	85.0
Cliente 12	31-Aug-20	12.0	88.0
Cliente 13	31-Jan-20	0.0	83.0
Cliente 14	31-Dec-20	0.0	83.0
TOTAL (Ikakos FM)	**-**	**110.0**	**-**
TOTAL	**-**	**304.4**	**-**

The FM provides visibility on the whole PPAs demand coverage from each project as presented in the figure below. The PV Project has priority to dispatch the energy production, covering the solar non-generation hours with Wind Project, hydrological plants from the Client or spot market in that order of preference.

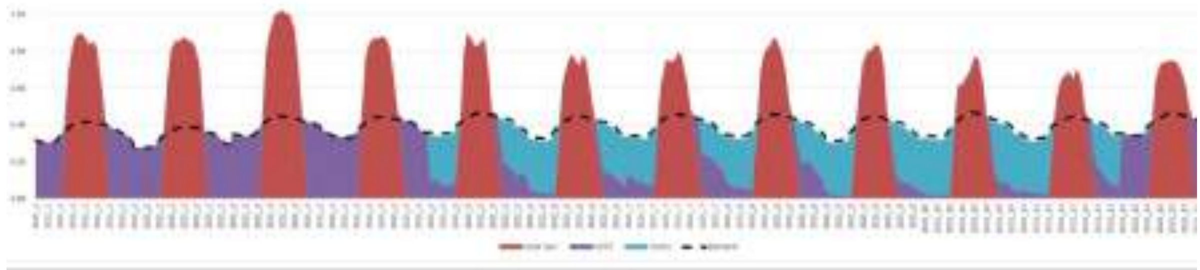

Figure 5.2: FM Demand Coverage

The PPAs have a term of 15 years (except for Terpel that is for 10 years), therefore, the FM assumes that from the end of the term of each PPA the PV Project revenues will be from the spot market.

UL did not review the indexation of the FM but recommends that the financial advisor confirms that all the indexations and adjustment of the FM have been considered according to the contract's specifications or according to the assumption of the market advisor.

UL considers the FM consideration for the PPA to be aligned from UL's high level review of the PPAs, however, considering the complex structure of assuming back up generation from other projects, UL recommends the legal and market advisor review the FM consideration.

5.2 Penonome II Wind Project

A summary of the details of the Financial Model OPEX for Penonome II Project assumptions are provided in the table below.

Table 5.5: Project OPEX Assumptions – Penonome II Wind Project

Item	Value
Wind Project Energization	July 2015
PPA Starting Date	July 2014
PPA Structure	All energy production from each sub project will be purchased by each Buyer
Evaluation period	25 years

The initial Wind Project energization was in July 2015 as per the information provided and is consistent with the FM model assumption.

The FM assumes an evaluation period of 25 years, which is considered to be industry standard. UL notes that the executed PPAs have a 15-year term with possible extension to be negotiated between the parties as detailed in Section 3.6.2. UL notes that the PPA term is consistent with the FM term assumed for the energy sales, assuming selling energy at spot price once the PPAs are expired.

5.2.1 Operating Expenses (OPEX)

The overall operating costs estimated by the Financial Model (excluding taxes, exchange rates and indexation) are summarized in the table and figure below according to the information provided by the Sponsor by means of the fixed costs spreadsheet [60].

Table 5.6: Project Annual OPEX Cost Estimates in USD/WTG/yr – Penonome II Wind Project

Item	2019 4th Operational year	2020 5th Operational year	2021 6th Operational year
WTG maintenance	50,341	46,830	52,032
Blade repairs	12,200	55,650	7,440
Plant operation & maintenance	19,719	19,786	14,959
Land Expenses	8,392	8,725	8,900
Electric Substation Rent&Cost	7,069	5,558	276
BOP maintenance	2,633	4,419	4,459
Shared assets maintenance	909	209	211
Others	716	875	1,113
Transmission costs	13,020	10,403	4,798
Labor	15,961	8,288	8,363
Total head office G&A	12,049	4,757	4,800
Security and Environmental supervision	8,674	5,663	4,727
Insurance	7,702	8,973	9,285
Wake Effect	7,934	6,822	4,162
Management fee and OER	0	3,750	3,750

Table 5.6: Project Annual OPEX Cost Estimates in USD/WTG/yr – Penonome II Wind Project

Item	2019 4th Operational year	2020 5th Operational year	2021 6th Operational year
Total (USD/WTG/year)	**147,600**	**170,921**	**114,317**
Total (USD/year)	**12,693,610**	**14,699,242**	**9,831,273**
Total (USD/MW/year)	**59,040**	**68,369**	**45,727**
Total (USD/MWh/year)(1)	**25.5**	**29.5**	**19.7**

Note: 1. Based on an estimated P50 production of 498.7 GWh/yr.

UL has reviewed the operating expenses cost assumptions for 2019 and 2020. UL notes that during 2019 and 2020 the Project experienced some relevant investigations in terms of blades strategy plant and the majority of the costs (1/3) invested during 2020 were due to this aspect. Therefore, and even the OPEX costs assumed and to be assumed by the Project are very relevant as explained below. UL has considered that the OPEX estimations for 2021 are more representative for the future long-term operation of the Project.

A graphical representation of overall OPEX (year 2021 not indexed) costs for the Project is provided in next figure.

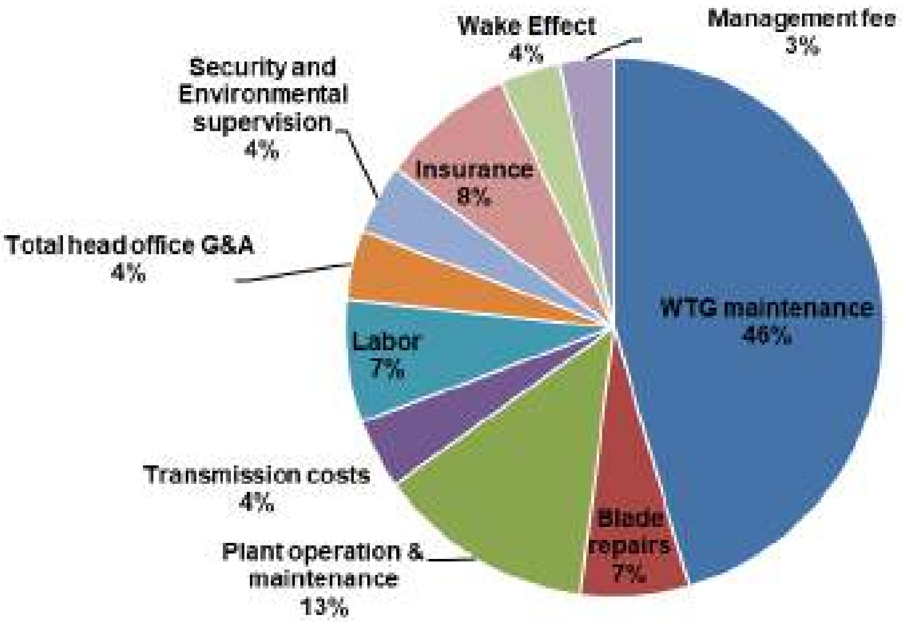

Figure 5.3: OPEX 2021 Assumptions (Taxes and Current Exchange Rate Excluded) – Penonome II Wind Project

UL reviewed the O&M costs assumptions of the Project for comparison to industry-wide OPEX expectations, for accuracy with contractual arrangements, for reasonableness in estimation of costs from non-contractual items (i.e. utilities) or atypical requirements (i.e. special permitting requirements), and for comparison for loan sizing.

UL comments are provided below (✓ = Adequate in UL's opinion; × = More information or updates needed):

- ✓ **WTG Maintenance**—The inputs for the FM considers 4,475 kUSD as WTG O&M contractual costs for 2021, which is equivalent to 52,032 USD/WTG. These costs are aligned with the costs payable under the Service and Maintenance Agreement (SMA) of the WTGs (see Section 3.6.3 for additional information). UL notes that the SMA term expires ending 2023 and therefore there is a high uncertainty about future scope and price of a renew of the SMA. The inputs of the financial model considered that the SMA price will be renewed in the same scope conditions and assuming an increase of 10% in year 2024 and an additional increase of 10% in year 2030 that is considered to be reasonable. In addition, Sponsor shared with UL an email exchanged with Goldwind (dated on 24 September 2020) where Goldwind provided an estimate for future SMA costs beyond year 2023. According to this email, and for going beyond 10-years, the Service Company should have to do a deeper dive and assess if they would offer a warranty for that period and if so, if additional items need to be excluded. In any case and for general modeling purposes, Goldwind performed a preliminary analysis (which is subject to a full analysis), and they determined that the future SMA costs that may be appropriate will be in a range between 55,000 and 60,000 USD/WTG. UL considers that the WTG contractual costs under the SMA are appropriately considered for the SMA term (until ending 2023) and properly estimated for the future years; however, UL remarks that the uncertainty from year 2024 onwards is relatively high and subject to future commercial discussions;

- ✓ **Blade repairs**—It is relevant to say that the previous “WTG Maintenance” item only refers to the SMA which excludes the blades repairs. In addition, and as previously commented, this Project has some relevant issues with blades (see Section 3.1.2.2 for further information). Therefore the Sponsor performed a specific blade strategy plan (issued on 18 September 2020 [23]), that apart from including a specific plan for monitoring and inspecting the WTGs, includes the acquisition of a set of 7 rotor-blades in order to ensure a short time period for blades replacement (if any). UL considers that this blade strategy plan is adequate and considers that the related costs have been properly captured in the inputs of the FM according to the following:

  - o During the Q4 2020, the Sponsor will be doing some inspections, blade’s repairs and monitoring system implementation in all the WTGs of the Project that will have a total estimated cost of 4,786 kUSD. In addition, the inputs for the FM considers an amount of USD 123,000 at beginning 2021 for security plan;
  - o By the end of 2020, the Sponsor will acquire 7 set of blades that, considering logistics and quality control plant will have a total estimated cost of 4.55 USD millions;
  - o For year 2021 onwards the Sponsor will be doing some specific WTG inspections and blades repairs in order to ensure a proper monitoring and WTG life extension to at least 25 years lifetime. The costs of these inspections will increase as the Project ages according to the following initial estimation:
    - ▪ 2021-2024: Estimated costs of 639.8 kUSD/yr;
    - ▪ 2025-2029: Estimated costs of 643.6 kUSD/yr;
    - ▪ 2030-2034: Estimated costs of 688.0 kUSD/yr;
    - ▪ 2035-2039: Estimated costs of 794.4 kUSD/yr; and
    - ▪ 2040: Estimated costs of 872.7 kUSD/yr.

  UL considers that the previous approach considered by the Sponsor is reasonable and UL confirmed that all the 3 previous costs allocation where already appropriately considered by the Sponsor in the inputs for the FM.

- ✓ **Maintenance Reserve Account**—According to the blade’s strategy plan defined by the Sponsor, it has been considered a maintenance reserve account (“MRA”) that will be constituted as annual letter of credit for the exclusive use of the following aspects:

- Replacement works. Based on visual inspections and specific alarms from the root monitoring system, the need for replacement of one or more blade sets will be evaluated annually;
- Root repair expenses. In case a root repair solution is defined and certified in a future;
- Crane rental costs. Crane rental expenses for the replacement works; and
- Additional blade sets purchase. Include: purchase, FAT, Logistics and Quality Control process costs.

It is important to consider that, under the SMA, the Project will be responsible for the all main crane expenses up to 50,000 USD/month and in case crane is necessary, its cost will be borne by the reserve account.

According to the Sponsor, and as it has been considered in FM tab “Debt Model (Q)” (row 170), the MRA will be available from 2021 and will a have a value of 1 USD million. If used partially or totally, the MRA will be fully replenished by the Sponsor for the next year. UL considers that this MRA amount is reasonable and provides comfort to the Project for facing non-scheduled and unexpected corrective cost of the WTGs that are excluded from the SMA. Based on the comments provided above and assuming that this MRA will be exclusively considered for unexpected and non-predictable costs of the Penonome II Project, UL does not expect considering further contingencies or additional maintenance reserves.

On 06 October 2020, UL was informed by the Sponsor, that this MRA should be also considered to cover unexpected cost for the Ikakos PV Project. Considering that the Ikakos PV Project has estimated a reasonable O&M costs (see Section 5.1.2), UL considers that having this MRA for both Projects (Penonome II + Ikakos) is reasonable, provided that this MRA (if used) is replenished each year.

Other additional costs considered in the FM for 2021 (indexation excluded) are the following:

- **Plant Operation & Maintenance**. According to the FM this item is formed by the following aspects:
  - Land Expenses: It is estimated a total amount of 765 kUSD/yr that is equivalent to 8,900 USD/WTG and represents 7.8% of total OPEX costs;
  - Electric Substation Rent&Cost: The cost related to the substation will significantly decrease on 2021 to a total amount of 24 kUSD/yr that represents a 0.2% of total OPEX costs. UL notes that the costs during 2019 and 2020 are related to shares access agreement and rent costs. However as previously commented, it is planned that the substation will be transferred to ETESA ending 2020, therefore the O&M costs will be assumed by ETESA and the Project will just need to pay the substation rent that will be around 2 kUSD/month. Based on these specific circumstances, UL considers that these costs are reasonable;
  - BOP Maintenance: This item, apart from the BOP works covered by the BOP O&M Contract with IPELSA (see Section 3.6.4) also includes other related maintenance works like roads, optic fiber, met mast, etc. It is estimated a total amount of 383 kUSD/yr that is equivalent to 4,459 USD/WTG and represents 3.9% of total OPEX costs that is considered reasonable;
  - Shared Assets Maintenance: It is estimated a total amount of 18 kUSD/yr that is in the low margin of UL’s expectations for this type of Project. However, as per the Sponsor information, this item only includes preventive maintenance T92 (or 34.5 kV maintenance after ETESA transfer) and bank capacitors maintenance;
  - Others. It is estimated a total amount of 96 kUSD/yr that is equivalent to 1,113 USD/WTG and represents 1.0% of total OPEX costs. This chapter include other aspects for a wind farm operation like Cleaning Services, Maintenance and fuel, transmission data, electricity

and water, internet&phone, travels, conference and visit accommodation, wind forecast services, materials and tools, office supply, other rent, food and entertainment and fees transport services.

- **Transmission Costs.** Includes the costs derived from connection toll, integrated operation CND and ASEP fees. It is estimated a total amount of 413 kUSD/yr that is equivalent to 4,798 USD/WTG and represents 4.2% of total OPEX costs;
- **Labor.** It is estimated a total amount of 719 kUSD/yr that is equivalent to 8,363 USD/WTG and represents 7.3% of total OPEX costs;
- **G&A.** General and Administrative expenses includes office operation costs and professional services. For this item it is estimated a total amount of 413 kUSD/yr that is equivalent to 4,800 USD/WTG and represents 4.2% of total OPEX costs;
- **Security and Environmental Supervision**—This item represents 407 kUSD/yr and he equivalent costs assumed in the FM is 4,727 USD/WTG/yr (4.1% of total OPEX) for the security and environmental. These costs are mainly associated to local environmental advisors and security services;
- **Insurance**—The FM considers an operational insurance costs of 799 kUSD/yr equivalent to 9,285 USD/WTG/yr, which represents an 8.1% of the total OPEX;
- **Wake Effect**—Wake effect costs vary from year to year depending mainly on the level of production. For 2021 it has been estimated to have a wake effect compensation payment of 358 kUSD/yr equivalent to 4,162 USD/WTG/yr, which represents an 3.6% of the total OPEX; and
- **Management Fee and OER**—It is estimated a total amount of 323 kUSD/yr that is equivalent to 3,750 USD/WTG and represents 3.3% of total OPEX costs. This cost is not indexed with local CPI, as according to the Sponsor, the Services Agreement price is fixed with no indexation. The OER (*Oficina de Electrificación Rural*) is not considered in years 2020-2025 and from 2026 onwards have a variable cost that even is not a big value, significantly changes from year to year (26-328 kUSD/yr assuming indexation).

The total OPEX costs for operation of the Project for 2021 (not indexed) are estimated to be USD 9,831,273 (equivalent to 114,317 USD/WTG or 19.7 USD/MWh) with WTG direct costs of 59,472 USD/WTG during 2021 and with an increase in future 5-years period due to inspections plan and blade repairs. UL notes that this value is not considering taxes, which have not been provided to UL within the spreadsheet of fixed costs delivered by the Sponsor. UL considers that the total OPEX assumed for the inputs for the FM is aligned with industry standards for the region and Project size and characteristics (middle low range).

5.2.2 Generation and Revenue

5.2.2.1 Generation (Energy Production)

UL has only reviewed the production results according to the probabilistic scenario P50, P90 and 1 year (or P90(1)) and P99 and 1 year (or P99(1)) that are included in the FM tabs: "P50(1)_UL Data" "P90(1)_UL Data"; and "P99(1)_UL Data" respectively. These data have been compared with the PBA results estimated by UL (see Section 4) according to the following table where it is shown that the inputs for the FM are aligned with UL's estimations:

Table 5.7: Energy Production Comparison between FM and UL's Estimations. For Penonome II

Probabilistic Production Scenario	Inputs FM (GWh/yr)	UL's Estimations (GWh/yr)
P50	498.7	498.7
P90 (year 1)	432.5	432.5
P99 (year 1)	378.4	378.4

5.2.2.2 Revenue

According to the FM tab "Control Panel_UEP2" (rows 8 to 19) and tab "Inputs_UEP2" (rows 107-112 and 125-130)) the PPA inputs are the following:

Table 5.8: PPA Inputs Considered in the FM for Penonome II

PPA Contract	Termination		PPA Capacity (MW)	PPA Price[(1)] (USD/MWh)
	PPA I	PPA II		
Marañon (PPA I & PPA II)	30 June 2029	31 December 2033	17.5	110.00
Portobelo (PPA I & PPA II)	30 June 2029	31 December 2033	32.5	108.00
Rosa de los Vientos (PPA I)	30 June 2029	-	52.5	98.00
Nuevo Chagres (PPA I)	30 June 2029	-	62.5	95.00

Note: (1) All 4 PPAs were signed on July 2014 and the economic values are given for that year, therefore annual indexation according to a portion of Panama's CPI forecast is applied from July 2015 onwards.

All PPAs have a term of 15 years (PPA I); however, it is assumed that PPAs for Marañon and Portobelo will be extended for an additional period of 4.5 years (PPA II). The UL's scope of work excluded a complete review of the PPAs and it is recommended that financial advisor confirms that the below comments are reasonable or not.

UL did not review the indexation of the FM but recommends that the financial advisor confirms that all the indexations and adjustment of the FM have been considered according to the contract's specifications or according to the assumption of the market advisor.

5.3 Financial Model Projections

As per the Client's specific request, UL has included in the figures below the financial model projections shared by the Client by email on 25 November 2020 ("IEG_Model Output_11.25.2020.pdf").

It should be noted and remarked that UL has not checked and reviewed the following figures, which do not reflect conclusions drawn by UL and have been added to this report solely for informational purposes. UL's review of the inputs for the financial model has been discussed in the sections above. Therefore, the figures below come from the Client and are the exclusive responsibility of the Client, and UL is not responsible for any of the conclusions that could be extracted from the below figures

P50 Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Macro Assumptions (%)																		
Panama CPI	1.0%	1.3%	1.4%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
US CPI	1.7%	1.9%	2.2%	1.9%	1.8%	1.8%	1.8%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%	2.0%	1.9%	1.9%	1.9%	1.9%
Performance (MWh)																		
UEP II Gross Generation	431,646	497,841	497,837	497,831	497,823	497,815	497,808	497,803	497,797	497,789	497,803	497,803	497,852	498,635	498,717	498,717	498,717	498,430
Tecnisol Gross Generation	70,820	86,151	88,099	88,242	87,642	87,040	86,439	88,365	88,486	87,864	87,241	86,618	88,523	88,623	87,979	87,335	86,690	88,346
Tecnisol - UEP II Backup PPA Generation	30,391	37,488	37,674	37,951	38,279	38,624	38,974	39,151	39,451	39,803	39,119	39,186	36,994	3,139	0	0	0	0
Tecnisol - Other Backup PPA Generation	17,850	24,690	25,043	25,449	25,892	26,335	26,784	27,165	27,603	28,074	27,269	27,226	17,077	0	0	0	0	0
Total Tecnisol Generation	**119,061**	**148,329**	**150,816**	**151,642**	**151,812**	**152,000**	**152,196**	**154,681**	**155,540**	**155,741**	**153,630**	**153,030**	**142,593**	**91,762**	**87,979**	**87,335**	**86,690**	**88,346**
End User Demand (MWh) (A)																		
DisCo PPA Demand	336,918	388,182	388,182	388,182	388,182	388,182	388,182	388,182	363,940	118,689	118,689	118,689	118,689	22,864	0	0	0	0
Tecnisol - UEP II Backup PPA	30,391	37,488	37,674	37,951	38,279	38,624	38,974	39,151	39,451	39,803	39,119	39,186	36,994	3,139	0	0	0	0
Merchant Energy Sales	55,858	61,885	61,699	61,422	61,094	60,749	60,399	60,222	84,163	329,063	329,747	329,680	331,873	461,552	487,555	487,555	487,555	487,278
Reimbursed Transmission Losses	8,479	10,286	10,282	10,276	10,268	10,260	10,252	10,248	10,242	10,234	10,248	10,248	10,297	11,080	11,162	11,162	11,162	11,153
Total UEP II End Uses	**431,646**	**497,841**	**497,837**	**497,831**	**497,823**	**497,815**	**497,808**	**497,803**	**497,797**	**497,789**	**497,803**	**497,803**	**497,852**	**498,635**	**498,717**	**498,717**	**498,717**	**498,430**
Large Client PPA Demand	88,889	113,584	114,724	115,875	117,042	118,216	119,403	120,601	121,811	123,033	120,397	120,308	99,210	6,155	0	0	0	0
Merchant Energy Sales	27,892	31,390	32,678	32,331	31,358	30,394	29,428	30,656	30,284	29,286	29,835	29,349	39,953	82,156	84,553	83,934	83,314	84,931
Reimbursed Transmission Losses	2,280	3,355	3,413	3,436	3,413	3,389	3,366	3,424	3,446	3,421	3,397	3,373	3,430	3,451	3,426	3,401	3,376	3,415
Total Tecnisol End Uses	**119,061**	**148,329**	**150,816**	**151,642**	**151,812**	**152,000**	**152,196**	**154,681**	**155,540**	**155,741**	**153,630**	**153,030**	**142,593**	**91,762**	**87,979**	**87,335**	**86,690**	**88,346**
Average Implied Prices ($/MWh) (B)																		
UEP II DisCo PPA	102.93	103.20	103.57	103.97	104.43	104.89	105.37	105.85	106.60	115.91	116.46	117.02	117.58	118.01	0.00	0.00	0.00	0.00
Tecnisol Large Client PPA	86.76	85.45	86.03	91.50	95.07	97.72	100.51	102.32	102.46	103.07	103.37	104.55	105.79	104.13	0.00	0.00	0.00	0.00
Tecnisol - UEP II Backup PPA	65.30	65.30	65.30	65.30	64.05	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	0.00	0.00	0.00	0.00
UEP II Merchant	52.13	47.71	53.70	53.95	57.98	61.03	66.27	69.30	72.41	76.27	78.19	84.79	93.41	98.15	100.65	102.79	104.94	107.49
Tecnisol Merchant	54.71	53.68	56.56	57.54	60.76	63.29	67.15	69.96	73.34	76.96	79.36	86.42	91.97	97.16	98.99	102.33	103.75	105.14
UEP II - Transmission Reimbursement	102.93	103.20	103.56	103.96	104.42	104.89	105.36	105.85	106.34	106.84	107.34	107.86	108.38	108.92	109.50	110.07	110.63	111.19
Tecnisol - Transmission Reimbursement	92.97	92.49	92.65	92.79	92.94	93.10	93.25	93.42	93.56	93.72	93.78	93.78	93.79	93.78	93.78	93.78	93.78	93.82
Average Implied Backup Costs ($/MWh)																		
Tecnisol - UEP II Backup PPA	65.30	65.30	65.30	65.30	64.05	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	0.00	0.00	0.00	0.00
Tecnisol - Other Backup PPA	67.15	53.48	48.11	46.07	47.59	48.40	49.29	49.80	50.73	51.72	52.34	53.46	56.57	0.00	0.00	0.00	0.00	0.00
Consolidated Revenues ($'000) (AxB=C)																		
UEP II DisCo PPA	34,677	40,062	40,204	40,358	40,536	40,718	40,903	41,090	38,794	13,757	13,822	13,888	13,956	2,698	0	0	0	0
Tecnisol Large Client PPA	7,712	9,706	9,870	10,603	11,127	11,552	12,001	12,340	12,481	12,681	12,446	12,578	10,496	641	0	0	0	0
UEP II Backup PPA	1,985	2,448	2,460	2,478	2,452	2,317	2,338	2,349	2,367	2,388	2,347	2,351	2,220	188	0	0	0	0
UEP II Merchant	2,912	2,953	3,313	3,314	3,542	3,707	4,003	4,174	6,094	25,098	25,782	27,953	31,002	45,302	49,074	50,116	51,162	52,376
Tecnisol Merchant	1,526	1,685	1,848	1,860	1,905	1,924	1,976	2,145	2,221	2,254	2,368	2,536	3,674	7,983	8,370	8,589	8,644	8,929
UEP II Transmission Reimbursement	873	1,062	1,065	1,068	1,072	1,076	1,080	1,085	1,089	1,093	1,100	1,105	1,116	1,207	1,222	1,229	1,235	1,240
Tecnisol Transmission Reimbursement	212	310	316	319	317	316	314	320	322	321	319	316	322	324	321	319	317	320
Total Consolidated Revenues	**49,897**	**58,225**	**59,076**	**60,000**	**60,952**	**61,611**	**62,615**	**63,502**	**63,369**	**57,592**	**58,183**	**60,729**	**62,785**	**58,343**	**58,987**	**60,252**	**61,358**	**62,866**
Consolidated Expenses ($'000)																		
Turbine Operations & Maintenance	3,546	4,532	4,614	4,967	5,155	5,249	5,343	5,440	5,542	6,073	6,330	6,450	6,573	6,698	6,830	6,961	7,093	7,208
Blade Operations & Maintenance	560	646	655	668	679	690	701	713	724	780	799	812	825	838	967	999	1,015	1,027
Module Operations & Maintenance	269	341	345	350	356	361	367	373	379	385	391	397	404	410	417	423	430	436
Land & Other Plant Maintenance	2,718	2,300	2,743	2,259	2,297	2,335	2,478	2,941	2,453	2,492	2,533	2,681	3,158	2,662	2,704	2,748	2,901	3,380
Total Operations & Maintenance	**7,093**	**7,819**	**8,357**	**8,245**	**8,486**	**8,635**	**8,890**	**9,466**	**9,097**	**9,730**	**10,052**	**10,341**	**10,959**	**10,608**	**10,918**	**11,132**	**11,440**	**12,050**
Consolidated G&A, Labor	2,010	2,478	2,511	2,547	2,588	2,629	2,671	2,714	2,757	2,801	2,846	2,892	2,938	2,985	3,033	3,081	3,131	3,173
Tecnisol - UEP II Backup PPA Purchases	1,985	2,448	2,460	2,478	2,452	2,317	2,338	2,349	2,367	2,388	2,347	2,351	2,220	188	0	0	0	0
Tecnisol - Other Backup PPA Purchases	1,199	1,320	1,205	1,173	1,232	1,275	1,320	1,353	1,400	1,452	1,427	1,455	966	0	0	0	0	0
Consolidated Transmission & Regulatory Fees	1,137	1,428	1,438	1,482	1,522	1,555	1,589	1,619	1,640	1,644	1,609	1,616	1,563	1,117	998	1,006	1,042	1,076
Consolidated Asset Management	304	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	381
UEP II Wake Effect	360	408	426	200	216	231	253	264	280	292	301	325	356	374	384	395	404	413
Total Consolidated Expenses	**14,087**	**16,284**	**16,779**	**16,507**	**16,879**	**17,025**	**17,444**	**18,147**	**17,924**	**18,690**	**18,965**	**19,363**	**19,384**	**15,655**	**15,715**	**15,997**	**16,398**	**17,093**
Consolidated EBITDA & CFADS ($'000)																		
Consolidated EBITDA	35,809	41,941	42,297	43,494	44,073	44,586	45,171	45,356	45,445	38,902	39,218	41,366	43,401	42,688	43,272	44,255	44,960	45,773
Consolidated Taxes	(32)	(644)	(451)	(667)	(1,058)	(1,334)	(2,423)	(2,753)	(3,150)	(2,914)	(1,868)	(2,200)	(2,994)	(3,748)	(7,452)	(5,255)	(5,856)	(6,314)
Consolidated Working Capital	2,057	(262)	80	(47)	95	68	185	67	432	(1,070)	237	569	1,619	378	409	162	280	255
Consolidated CFADS	**37,835**	**41,035**	**41,926**	**42,779**	**43,110**	**43,319**	**42,933**	**42,670**	**42,727**	**34,918**	**37,587**	**39,735**	**42,026**	**39,319**	**36,228**	**39,162**	**39,383**	**39,714**
Senior Debt ($'000)																		
Beginning of Period Balance	274,900	263,921	252,577	240,095	226,122	211,115	195,113	178,228	160,651	141,991	129,608	115,090	98,638	80,317	65,589	51,551	35,433	18,327
Senior Debt - Interest	(12,444)	(15,061)	(14,390)	(13,652)	(12,838)	(11,966)	(11,040)	(10,068)	(9,041)	(8,057)	(7,300)	(6,454)	(5,509)	(4,531)	(3,723)	(2,878)	(1,943)	(948)
Senior Debt - Amortization	(10,979)	(11,344)	(12,482)	(13,974)	(15,007)	(16,002)	(16,885)	(17,577)	(18,661)	(12,383)	(14,518)	(16,452)	(18,321)	(14,728)	(14,038)	(16,118)	(17,106)	(18,327)
End of Period Balance	**263,921**	**252,577**	**240,095**	**226,122**	**211,115**	**195,113**	**178,228**	**160,651**	**141,991**	**129,608**	**115,090**	**98,638**	**80,317**	**65,589**	**51,551**	**35,433**	**18,327**	**0**
Debt Service	**23,784**	**26,872**	**27,343**	**28,101**	**28,322**	**28,444**	**28,399**	**28,121**	**28,136**	**20,846**	**22,225**	**23,319**	**24,248**	**19,851**	**18,378**	**19,615**	**19,669**	**19,765**
DSRA Beginning of Period Balance	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,431**	**15,505**	**15,505**	**15,505**	**15,505**	**19,765**	**19,765**	**19,765**	**19,765**	**19,765**
DSCR (Average 1.69x)	1.59x	1.53x	1.53x	1.52x	1.52x	1.52x	1.51x	1.52x	1.52x	1.68x	1.69x	1.70x	1.73x	1.98x	1.97x	2.00x	2.00x	2.01x

Note: Years shown are 9/30 Year End periods, 2021 corresponds to 12/2020 to 9/2021 period.

Figure 5.4: Financial Overview – P50 (1 Year) Base Case (Results not reviewed/checked by UL)

P90 Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Macro Assumptions (%)																		
Panama CPI	1.0%	1.3%	1.4%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
US CPI	1.7%	1.9%	2.2%	1.9%	1.8%	1.8%	1.8%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%	2.0%	1.9%	1.9%	1.9%	1.9%
Performance (MWh)																		
UEP II Gross Generation	374,239	431,614	431,610	431,603	431,595	431,587	431,579	431,574	431,568	431,560	431,574	431,574	431,625	432,418	432,500	432,500	432,500	432,251
Tecnisol Gross Generation	65,472	79,646	81,413	81,533	80,973	80,409	79,844	81,581	81,671	81,081	80,489	79,896	81,600	81,679	81,086	80,492	79,898	81,424
Tecnisol - UEP II Backup PPA Generation	30,730	37,930	38,101	38,402	38,749	39,097	39,454	39,641	39,938	40,301	39,620	39,676	37,405	3,139	0	0	0	0
Tecnisol - Other Backup PPA Generation	17,995	24,887	25,246	25,653	26,096	26,545	27,002	27,382	27,834	28,314	27,485	27,451	17,200	0	0	0	0	0
Total Tecnisol Generation	**114,197**	**142,463**	**144,760**	**145,588**	**145,817**	**146,052**	**146,301**	**148,604**	**149,443**	**149,696**	**147,594**	**147,022**	**136,205**	**84,818**	**81,086**	**80,492**	**79,898**	**81,424**
End User Demand (MWh) (A)																		
DisCo PPA Demand	292,184	336,641	336,641	336,641	336,641	336,641	336,641	336,641	315,618	102,930	102,930	102,930	102,930	19,828	0	0	0	0
Tecnisol - UEP II Backup PPA	30,730	37,930	38,101	38,402	38,749	39,097	39,454	39,641	39,938	40,301	39,620	39,676	37,405	3,139	0	0	0	0
Merchant Energy Sales	44,067	48,248	48,077	47,777	47,430	47,082	46,724	46,538	67,264	279,589	280,270	280,214	282,485	399,853	422,820	422,820	422,820	422,579
Reimbursed Transmission Losses	7,258	8,794	8,790	8,783	8,775	8,767	8,759	8,754	8,748	8,740	8,754	8,754	8,805	9,598	9,680	9,680	9,680	9,672
Total UEP II End Uses	**374,239**	**431,614**	**431,610**	**431,603**	**431,595**	**431,587**	**431,579**	**431,574**	**431,568**	**431,560**	**431,574**	**431,574**	**431,625**	**432,418**	**432,500**	**432,500**	**432,500**	**432,251**
Large Client PPA Demand	88,889	113,584	114,724	115,875	117,042	118,216	119,403	120,601	121,811	123,033	120,397	120,308	99,210	6,155	0	0	0	0
Merchant Energy Sales	23,200	25,778	26,882	26,538	25,622	24,704	23,789	24,842	24,451	23,506	24,062	23,603	33,832	75,482	77,928	77,357	76,786	78,276
Reimbursed Transmission Losses	2,108	3,101	3,155	3,175	3,153	3,131	3,109	3,161	3,180	3,157	3,134	3,111	3,162	3,181	3,158	3,134	3,111	3,148
Total Tecnisol End Uses	**114,197**	**142,463**	**144,760**	**145,588**	**145,817**	**146,052**	**146,301**	**148,604**	**149,443**	**149,696**	**147,594**	**147,022**	**136,205**	**84,818**	**81,086**	**80,492**	**79,898**	**81,424**
Average Implied Prices ($/MWh) (B)																		
UEP II DisCo PPA	102.93	103.20	103.57	103.97	104.43	104.89	105.37	105.85	106.60	115.91	116.46	117.02	117.58	118.01	0.00	0.00	0.00	0.00
Tecnisol Large Client PPA	86.76	85.45	86.03	91.50	95.07	97.72	100.51	102.32	102.46	103.07	103.37	104.55	105.79	104.13	0.00	0.00	0.00	0.00
Tecnisol - UEP II Backup PPA	65.30	65.30	65.30	65.30	64.04	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	0.00	0.00	0.00	0.00
UEP II Merchant	52.17	47.77	53.91	54.20	58.20	61.15	66.36	69.41	72.37	76.27	78.19	84.78	93.41	98.16	100.65	102.79	104.94	107.49
Tecnisol Merchant	54.75	53.76	56.74	57.73	60.93	63.40	67.25	70.08	73.43	77.10	79.50	86.64	91.79	97.18	98.99	102.33	103.75	105.14
UEP II - Transmission Reimbursement	102.93	103.20	103.56	103.96	104.42	104.89	105.36	105.85	106.34	106.84	107.34	107.86	108.38	108.92	109.50	110.07	110.63	111.19
Tecnisol - Transmission Reimbursement	92.97	92.49	92.65	92.79	92.94	93.10	93.25	93.42	93.56	93.72	93.78	93.78	93.79	93.78	93.78	93.78	93.78	93.82
Average Implied Backup Costs ($/MWh)																		
Tecnisol - UEP II Backup PPA	65.30	65.30	65.30	65.30	64.04	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	0.00	0.00	0.00	0.00
Tecnisol - Other Backup PPA	67.15	53.47	48.10	46.07	47.59	48.39	49.28	49.79	50.72	51.72	52.32	53.44	56.56	0.00	0.00	0.00	0.00	0.00
Consolidated Revenues ($'000) (AxB=C)																		
UEP II DisCo PPA	30,073	34,743	34,866	35,000	35,154	35,312	35,472	35,635	33,643	11,930	11,987	12,044	12,103	2,340	0	0	0	0
Tecnisol Large Client PPA	7,712	9,706	9,870	10,603	11,127	11,552	12,001	12,340	12,481	12,681	12,446	12,578	10,496	641	0	0	0	0
UEP II Backup PPA	2,007	2,477	2,488	2,508	2,481	2,346	2,367	2,378	2,396	2,418	2,377	2,381	2,244	188	0	0	0	0
UEP II Merchant	2,299	2,305	2,592	2,589	2,760	2,879	3,100	3,230	4,868	21,325	21,913	23,757	26,387	39,248	42,558	43,462	44,369	45,422
Tecnisol Merchant	1,270	1,386	1,525	1,532	1,561	1,566	1,600	1,741	1,795	1,812	1,913	2,045	3,105	7,335	7,714	7,916	7,967	8,230
UEP II Transmission Reimbursement	747	908	910	913	916	920	923	927	930	934	940	944	954	1,045	1,060	1,065	1,071	1,075
Tecnisol Transmission Reimbursement	196	287	292	295	293	291	290	295	298	296	294	292	297	298	296	294	292	295
Total Consolidated Revenues	**44,304**	**51,810**	**52,543**	**53,439**	**54,293**	**54,866**	**55,753**	**56,546**	**56,412**	**51,397**	**51,870**	**54,041**	**55,587**	**51,096**	**51,628**	**52,737**	**53,699**	**55,022**
Consolidated Expenses ($'000)																		
Turbine Operations & Maintenance	3,546	4,532	4,614	4,967	5,155	5,249	5,343	5,440	5,542	6,073	6,330	6,450	6,573	6,698	6,830	6,961	7,093	7,208
Blade Operations & Maintenance	560	646	655	668	679	690	701	713	724	780	799	812	825	838	967	999	1,015	1,027
Module Operations & Maintenance	269	341	345	350	356	361	367	373	379	385	391	397	404	410	417	423	430	436
Land & Other Plant Maintenance	2,717	2,299	2,742	2,258	2,295	2,333	2,477	2,939	2,451	2,490	2,530	2,679	3,155	2,659	2,701	2,745	2,898	3,377
Total Operations & Maintenance	**7,092**	**7,818**	**8,356**	**8,243**	**8,485**	**8,633**	**8,888**	**9,464**	**9,095**	**9,728**	**10,050**	**10,338**	**10,956**	**10,605**	**10,915**	**11,129**	**11,437**	**12,047**
Consolidated G&A, Labor	2,010	2,478	2,511	2,547	2,588	2,629	2,671	2,714	2,757	2,801	2,846	2,892	2,938	2,985	3,033	3,081	3,131	3,173
Tecnisol - UEP II Backup PPA Purchases	2,007	2,477	2,488	2,508	2,481	2,346	2,367	2,378	2,396	2,418	2,377	2,381	2,244	188	0	0	0	0
Tecnisol - Other Backup PPA Purchases	1,208	1,331	1,214	1,182	1,242	1,284	1,331	1,363	1,412	1,464	1,438	1,467	973	0	0	0	0	0
Consolidated Transmission & Regulatory Fees	1,074	1,317	1,315	1,357	1,396	1,428	1,460	1,488	1,507	1,512	1,480	1,487	1,429	979	871	877	909	938
Consolidated Asset Management	304	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	381
UEP II Wake Effect	312	353	369	173	187	201	219	229	243	253	261	282	309	324	333	343	350	358
Total Consolidated Expenses	**14,007**	**16,156**	**16,636**	**16,393**	**16,762**	**16,904**	**17,319**	**18,019**	**17,793**	**18,559**	**18,835**	**19,229**	**19,233**	**15,464**	**15,534**	**15,813**	**16,209**	**16,898**
Consolidated EBITDA & CFADS ($'000)																		
Consolidated EBITDA	30,297	35,654	35,907	37,046	37,531	37,963	38,434	38,527	38,619	32,838	33,034	34,813	36,354	35,632	36,094	36,924	37,490	38,125
Consolidated Taxes	(12)	(121)	(12)	(122)	(465)	(725)	(1,366)	(1,679)	(2,064)	(1,896)	(1,066)	(1,269)	(1,963)	(2,589)	(5,520)	(4,041)	(4,618)	(5,033)
Consolidated Working Capital	1,035	(257)	65	(53)	91	64	173	63	388	(926)	224	504	1,544	388	368	153	265	231
Consolidated CFADS	**31,320**	**35,276**	**35,960**	**36,871**	**37,157**	**37,302**	**37,242**	**36,912**	**36,943**	**30,015**	**32,192**	**34,047**	**35,935**	**33,431**	**30,942**	**33,037**	**33,137**	**33,322**
Senior Debt ($'000)																		
Beginning of Period Balance	274,900	263,921	252,577	240,095	226,122	211,115	195,113	178,228	160,651	141,991	129,608	115,090	98,638	80,317	65,589	51,551	35,433	18,327
Senior Debt - Interest	(12,444)	(15,061)	(14,390)	(13,652)	(12,838)	(11,966)	(11,040)	(10,068)	(9,041)	(8,057)	(7,300)	(6,454)	(5,509)	(4,531)	(3,723)	(2,878)	(1,943)	(948)
Senior Debt - Amortization	(10,979)	(11,344)	(12,482)	(13,974)	(15,007)	(16,002)	(16,885)	(17,577)	(18,661)	(12,383)	(14,518)	(16,452)	(18,321)	(14,728)	(14,038)	(16,118)	(17,106)	(18,327)
End of Period Balance	**263,921**	**252,577**	**240,095**	**226,122**	**211,115**	**195,113**	**178,228**	**160,651**	**141,991**	**129,608**	**115,090**	**98,638**	**80,317**	**65,589**	**51,551**	**35,433**	**18,327**	**0**
Debt Service	**23,784**	**26,872**	**27,343**	**28,101**	**28,322**	**28,444**	**28,399**	**28,121**	**28,136**	**20,846**	**22,225**	**23,319**	**24,248**	**19,851**	**18,378**	**19,615**	**19,669**	**19,765**
DSRA Beginning of Period Balance	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,431**	**15,505**	**15,505**	**15,505**	**15,505**	**19,765**	**19,765**	**19,765**	**19,765**	**19,765**
DSCR (Average 1.44x)	1.32x	1.31x	1.32x	1.31x	1.31x	1.31x	1.31x	1.31x	1.31x	1.44x	1.45x	1.46x	1.48x	1.68x	1.68x	1.68x	1.68x	1.69x

Note: Years shown are 9/30 Year End periods, 2021 corresponds to 12/2020 to 9/2021 period.

Figure 5.5: Financial Overview – P90 (1 Year) Case (Results not reviewed/checked by UL)

P99 Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Macro Assumptions (%)																		
Panama CPI	1.0%	1.3%	1.4%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
US CPI	1.7%	1.9%	2.2%	1.9%	1.8%	1.8%	1.8%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%	2.0%	1.9%	1.9%	1.9%	1.9%
Performance (MWh)																		
UEP II Gross Generation	327,344	377,513	377,508	377,502	377,494	377,485	377,477	377,472	377,466	377,457	377,471	377,471	377,524	378,327	378,409	378,409	378,409	378,191
Tecnisol Gross Generation	61,200	74,449	76,070	76,171	75,643	75,111	74,575	76,157	76,222	75,659	75,092	74,522	76,063	76,124	75,571	75,018	74,464	75,886
Tecnisol - UEP II Backup PPA Generation	31,060	38,339	38,521	38,814	39,170	39,537	39,909	40,104	40,403	40,782	40,093	40,141	37,802	3,139	0	0	0	0
Tecnisol - Other Backup PPA Generation	18,114	25,055	25,414	25,832	26,284	26,741	27,207	27,587	28,047	28,533	27,689	27,664	17,307	0	0	0	0	0
Total Tecnisol Generation	**110,373**	**137,843**	**140,005**	**140,816**	**141,097**	**141,389**	**141,692**	**143,849**	**144,673**	**144,974**	**142,874**	**142,326**	**131,172**	**79,263**	**75,571**	**75,018**	**74,464**	**75,886**
End User Demand (MWh) (A)																		
DisCo PPA Demand	255,641	294,539	294,539	294,539	294,539	294,539	294,539	294,539	276,145	90,057	90,057	90,057	90,057	17,349	0	0	0	0
Tecnisol - UEP II Backup PPA	31,060	38,339	38,521	38,814	39,170	39,537	39,909	40,104	40,403	40,782	40,093	40,141	37,802	3,139	0	0	0	0
Merchant Energy Sales	34,383	37,062	36,879	36,587	36,230	35,864	35,492	35,296	53,391	239,100	239,790	239,742	242,080	349,452	369,939	369,939	369,939	369,729
Reimbursed Transmission Losses	6,260	7,573	7,569	7,563	7,554	7,546	7,537	7,533	7,526	7,517	7,532	7,532	7,584	8,388	8,469	8,469	8,469	8,462
Total UEP II End Uses	**327,344**	**377,513**	**377,508**	**377,502**	**377,494**	**377,485**	**377,477**	**377,472**	**377,466**	**377,457**	**377,471**	**377,471**	**377,524**	**378,327**	**378,409**	**378,409**	**378,409**	**378,191**
Large Client PPA Demand	88,889	113,584	114,724	115,875	117,042	118,216	119,403	120,601	121,811	123,033	120,397	120,308	99,210	6,155	0	0	0	0
Merchant Energy Sales	19,513	21,359	22,333	21,975	21,110	20,248	19,385	20,297	19,893	18,994	19,553	19,116	29,014	70,144	72,629	72,096	71,564	72,953
Reimbursed Transmission Losses	1,970	2,899	2,948	2,966	2,946	2,925	2,904	2,951	2,968	2,946	2,924	2,902	2,948	2,964	2,943	2,921	2,900	2,934
Total Tecnisol End Uses	**110,373**	**137,843**	**140,005**	**140,816**	**141,097**	**141,389**	**141,692**	**143,849**	**144,673**	**144,974**	**142,874**	**142,326**	**131,172**	**79,263**	**75,571**	**75,018**	**74,464**	**75,886**
Average Implied Prices ($/MWh) (B)																		
UEP II DisCo PPA	102.93	103.20	103.57	103.97	104.43	104.89	105.37	105.85	106.60	115.91	116.46	117.02	117.58	118.01	0.00	0.00	0.00	0.00
Tecnisol Large Client PPA	86.76	85.45	86.03	91.50	95.07	97.72	100.51	102.32	102.46	103.07	103.37	104.55	105.79	104.13	0.00	0.00	0.00	0.00
Tecnisol - UEP II Backup PPA	65.30	65.30	65.30	65.30	64.03	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	0.00	0.00	0.00	0.00
UEP II Merchant	52.22	47.84	54.19	54.55	58.51	61.32	66.48	69.57	72.33	76.28	78.19	84.78	93.41	98.16	100.65	102.79	104.94	107.49
Tecnisol Merchant	54.80	53.85	56.93	57.94	61.11	63.52	67.35	70.21	73.53	77.25	79.65	86.88	91.60	97.19	98.99	102.33	103.75	105.14
UEP II - Transmission Reimbursement	102.93	103.20	103.56	103.96	104.42	104.89	105.36	105.85	106.34	106.84	107.34	107.86	108.38	108.92	109.50	110.07	110.63	111.19
Tecnisol - Transmission Reimbursement	92.97	92.49	92.65	92.79	92.94	93.10	93.25	93.42	93.56	93.72	93.78	93.78	93.79	93.78	93.78	93.78	93.78	93.82
Average Implied Backup Costs ($/MWh)																		
Tecnisol - UEP II Backup PPA	65.30	65.30	65.30	65.30	64.03	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	0.00	0.00	0.00	0.00
Tecnisol - Other Backup PPA	67.16	53.47	48.10	46.07	47.59	48.40	49.30	49.80	50.74	51.75	52.35	53.48	56.54	0.00	0.00	0.00	0.00	0.00
Consolidated Revenues ($'000) (AxB=C)																		
UEP II DisCo PPA	26,312	30,398	30,505	30,622	30,758	30,895	31,036	31,178	29,436	10,438	10,488	10,538	10,589	2,047	0	0	0	0
Tecnisol Large Client PPA	7,712	9,706	9,870	10,603	11,127	11,552	12,001	12,340	12,481	12,681	12,446	12,578	10,496	641	0	0	0	0
UEP II Backup PPA	2,028	2,504	2,515	2,535	2,508	2,372	2,395	2,406	2,424	2,447	2,406	2,408	2,268	188	0	0	0	0
UEP II Merchant	1,795	1,773	1,998	1,996	2,120	2,199	2,359	2,456	3,862	18,238	18,748	20,325	22,612	34,303	37,235	38,026	38,820	39,741
Tecnisol Merchant	1,069	1,150	1,272	1,273	1,290	1,286	1,306	1,425	1,463	1,467	1,557	1,661	2,658	6,817	7,189	7,378	7,425	7,670
UEP II Transmission Reimbursement	644	782	784	786	789	791	794	797	800	803	808	812	822	914	927	932	937	941
Tecnisol Transmission Reimbursement	183	268	273	275	274	272	271	276	278	276	274	272	276	278	276	274	272	275
Total Consolidated Revenues	**39,745**	**46,580**	**47,217**	**48,090**	**48,865**	**49,369**	**50,161**	**50,878**	**50,743**	**46,351**	**46,728**	**48,595**	**49,721**	**45,188**	**45,628**	**46,610**	**47,454**	**48,627**
Consolidated Expenses ($'000)																		
Turbine Operations & Maintenance	3,546	4,532	4,614	4,967	5,155	5,249	5,343	5,440	5,542	6,073	6,330	6,450	6,573	6,698	6,830	6,961	7,093	7,208
Blade Operations & Maintenance	560	646	655	668	679	690	701	713	724	780	799	812	825	838	967	999	1,015	1,027
Module Operations & Maintenance	269	341	345	350	356	361	367	373	379	385	391	397	404	410	417	423	430	436
Land & Other Plant Maintenance	2,716	2,298	2,741	2,257	2,294	2,332	2,475	2,937	2,449	2,488	2,529	2,677	3,153	2,657	2,699	2,743	2,896	3,374
Total Operations & Maintenance	**7,091**	**7,817**	**8,355**	**8,242**	**8,484**	**8,632**	**8,887**	**9,462**	**9,094**	**9,726**	**10,048**	**10,336**	**10,954**	**10,603**	**10,913**	**11,126**	**11,434**	**12,045**
Consolidated G&A, Labor	2,010	2,478	2,511	2,547	2,588	2,629	2,671	2,714	2,757	2,801	2,846	2,892	2,938	2,985	3,033	3,081	3,131	3,173
Tecnisol - UEP II Backup PPA Purchases	2,028	2,504	2,515	2,535	2,508	2,372	2,395	2,406	2,424	2,447	2,406	2,408	2,268	188	0	0	0	0
Tecnisol - Other Backup PPA Purchases	1,217	1,340	1,222	1,190	1,251	1,294	1,341	1,374	1,423	1,477	1,449	1,479	979	0	0	0	0	0
Consolidated Transmission & Regulatory Fees	1,022	1,226	1,214	1,255	1,294	1,324	1,355	1,381	1,399	1,404	1,374	1,381	1,320	866	766	772	800	826
Consolidated Asset Management	304	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	383	381
UEP II Wake Effect	273	309	323	152	164	175	192	200	212	222	229	246	270	284	292	300	306	313
Total Consolidated Expenses	**13,945**	**16,056**	**16,523**	**16,303**	**16,671**	**16,809**	**17,223**	**17,920**	**17,692**	**18,459**	**18,735**	**19,126**	**19,113**	**15,308**	**15,386**	**15,663**	**16,054**	**16,738**
Consolidated EBITDA & CFADS ($'000)																		
Consolidated EBITDA	25,800	30,524	30,694	31,786	32,194	32,560	32,939	32,958	33,051	27,892	27,992	29,469	30,609	29,879	30,242	30,947	31,401	31,889
Consolidated Taxes	0	0	0	0	(170)	(309)	(477)	(680)	(984)	(974)	(931)	(932)	(1,078)	(1,465)	(3,764)	(2,871)	(3,531)	(3,991)
Consolidated Working Capital	201	(252)	52	(58)	87	60	163	60	352	(810)	214	450	1,485	396	334	146	252	211
Consolidated CFADS	**26,001**	**30,272**	**30,746**	**31,729**	**32,111**	**32,311**	**32,625**	**32,338**	**32,420**	**26,108**	**27,275**	**28,987**	**31,016**	**28,811**	**26,812**	**28,222**	**28,121**	**28,110**
Senior Debt ($'000)																		
Beginning of Period Balance	274,900	263,921	252,577	240,095	226,122	211,115	195,113	178,228	160,651	141,991	129,608	115,090	98,638	80,317	65,589	51,551	35,433	18,327
Senior Debt - Interest	(12,444)	(15,061)	(14,390)	(13,652)	(12,838)	(11,966)	(11,040)	(10,068)	(9,041)	(8,057)	(7,300)	(6,454)	(5,509)	(4,531)	(3,723)	(2,878)	(1,943)	(948)
Senior Debt - Amortization	(10,979)	(11,344)	(12,482)	(13,974)	(15,007)	(16,002)	(16,885)	(17,577)	(18,661)	(12,383)	(14,518)	(16,452)	(18,321)	(14,728)	(14,038)	(16,118)	(17,106)	(18,327)
End of Period Balance	**263,921**	**252,577**	**240,095**	**226,122**	**211,115**	**195,113**	**178,228**	**160,651**	**141,991**	**129,608**	**115,090**	**98,638**	**80,317**	**65,589**	**51,551**	**35,433**	**18,327**	**0**
Debt Service	**23,784**	**26,872**	**27,343**	**28,101**	**28,322**	**28,444**	**28,399**	**28,121**	**28,136**	**20,846**	**22,225**	**23,319**	**24,248**	**19,851**	**18,378**	**19,615**	**19,669**	**19,765**
DSRA Beginning of Period Balance	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,431**	**15,505**	**15,505**	**15,505**	**15,505**	**19,765**	**19,765**	**19,765**	**19,765**	**19,765**
DSCR *Average* 1.24x	1.09x	1.13x	1.12x	1.13x	1.13x	1.14x	1.15x	1.15x	1.15x	1.25x	1.23x	1.24x	1.28x	1.45x	1.46x	1.44x	1.43x	1.42x

Note: Years shown are 9/30 Year End periods, 2021 corresponds to 12/2020 to 9/2021 period.

Figure 5.6: Financial Overview – P99 (1 Year) Case (Results not reviewed/checked by UL)

P50 Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Macro Assumptions (%)																		
Panama CPI	1.0%	1.3%	1.4%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
US CPI	1.7%	1.9%	2.2%	1.9%	1.8%	1.8%	1.8%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%	2.0%	1.9%	1.9%	1.9%	1.9%
Performance (MWh)																		
UEP II Gross Generation	431,646	497,841	497,837	497,831	497,823	497,815	497,808	497,803	497,797	497,789	497,803	497,803	497,852	498,635	498,717	498,717	498,717	498,430
Tecnisol Gross Generation	70,820	86,151	88,099	88,242	87,642	87,040	86,439	88,365	88,486	87,864	87,241	86,618	88,523	88,623	87,979	87,335	86,690	88,346
Tecnisol - UEP II Backup PPA Generation	30,391	37,488	37,674	37,951	38,279	38,624	38,974	39,151	39,451	39,803	39,119	39,186	36,994	3,139	0	0	0	0
Tecnisol - Other Backup PPA Generation	17,850	24,690	25,043	25,449	25,892	26,335	26,784	27,165	27,603	28,074	27,269	27,226	17,077	0	0	0	0	0
Total Tecnisol Generation	**119,061**	**148,329**	**150,816**	**151,642**	**151,812**	**152,000**	**152,196**	**154,681**	**155,540**	**155,741**	**153,630**	**153,030**	**142,593**	**91,762**	**87,979**	**87,335**	**86,690**	**88,346**
End User Demand (MWh) (A)																		
DisCo PPA Demand	336,918	388,182	388,182	388,182	388,182	388,182	388,182	388,182	363,940	118,689	118,689	118,689	118,689	22,864	0	0	0	0
Tecnisol - UEP II Backup PPA	30,391	37,488	37,674	37,951	38,279	38,624	38,974	39,151	39,451	39,803	39,119	39,186	36,994	3,139	0	0	0	0
Merchant Energy Sales	55,858	61,885	61,699	61,422	61,094	60,749	60,399	60,222	84,163	329,063	329,747	329,680	331,873	461,552	487,555	487,555	487,555	487,278
Reimbursed Transmission Losses	8,479	10,286	10,282	10,276	10,268	10,260	10,252	10,248	10,242	10,234	10,248	10,248	10,297	11,080	11,162	11,162	11,162	11,153
Total UEP II End Uses	**431,646**	**497,841**	**497,837**	**497,831**	**497,823**	**497,815**	**497,808**	**497,803**	**497,797**	**497,789**	**497,803**	**497,803**	**497,852**	**498,635**	**498,717**	**498,717**	**498,717**	**498,430**
Large Client PPA Demand	88,889	113,584	114,724	115,875	117,042	118,216	119,403	120,601	121,811	123,033	120,397	120,308	99,210	6,155	0	0	0	0
Merchant Energy Sales	27,892	31,390	32,678	32,331	31,358	30,394	29,428	30,656	30,284	29,286	29,835	29,349	39,953	82,156	84,553	83,934	83,314	84,931
Reimbursed Transmission Losses	2,280	3,355	3,413	3,436	3,413	3,389	3,366	3,424	3,446	3,421	3,397	3,373	3,430	3,451	3,426	3,401	3,376	3,415
Total Tecnisol End Uses	**119,061**	**148,329**	**150,816**	**151,642**	**151,812**	**152,000**	**152,196**	**154,681**	**155,540**	**155,741**	**153,630**	**153,030**	**142,593**	**91,762**	**87,979**	**87,335**	**86,690**	**88,346**
Average Implied Prices ($/MWh) (B)																		
UEP II DisCo PPA	102.93	103.20	103.57	103.97	104.43	104.89	105.37	105.85	106.60	115.91	116.46	117.02	117.58	118.01	0.00	0.00	0.00	0.00
Tecnisol Large Client PPA	86.76	85.45	86.03	91.50	95.07	97.72	100.51	102.32	102.46	103.07	103.37	104.55	105.79	104.13	0.00	0.00	0.00	0.00
Tecnisol - UEP II Backup PPA	65.30	65.30	65.30	65.30	64.05	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	0.00	0.00	0.00	0.00
UEP II Merchant	41.70	38.17	42.96	43.16	46.38	48.82	53.02	55.44	57.93	61.02	62.55	67.83	74.73	78.52	80.52	82.23	83.95	85.99
Tecnisol Merchant	43.77	42.94	45.25	46.04	48.61	50.63	53.72	55.97	58.67	61.57	63.49	69.14	73.57	77.73	79.19	81.87	83.00	84.11
UEP II - Transmission Reimbursement	102.93	103.20	103.56	103.96	104.42	104.89	105.36	105.85	106.34	106.84	107.34	107.86	108.38	108.92	109.50	110.07	110.63	111.19
Tecnisol - Transmission Reimbursement	92.97	92.49	92.65	92.79	92.94	93.10	93.25	93.42	93.56	93.72	93.78	93.78	93.79	93.78	93.78	93.78	93.78	93.82
Average Implied Backup Costs ($/MWh)																		
Tecnisol - UEP II Backup PPA	65.30	65.30	65.30	65.30	64.05	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	0.00	0.00	0.00	0.00
Tecnisol - Other Backup PPA	66.68	45.83	38.49	36.86	38.07	38.72	39.43	39.84	40.58	41.38	41.87	42.76	45.26	0.00	0.00	0.00	0.00	0.00
Consolidated Revenues ($'000) (AxB=C)																		
UEP II DisCo PPA	34,677	40,062	40,204	40,358	40,536	40,718	40,903	41,090	38,794	13,757	13,822	13,888	13,956	2,698	0	0	0	0
Tecnisol Large Client PPA	7,712	9,706	9,870	10,603	11,127	11,552	12,001	12,340	12,481	12,681	12,446	12,578	10,496	641	0	0	0	0
UEP II Backup PPA	1,985	2,448	2,460	2,478	2,452	2,317	2,338	2,349	2,367	2,388	2,347	2,351	2,220	188	0	0	0	0
UEP II Merchant	2,329	2,362	2,650	2,651	2,834	2,966	3,202	3,339	4,875	20,078	20,625	22,362	24,801	36,242	39,259	40,093	40,930	41,901
Tecnisol Merchant	1,221	1,348	1,479	1,488	1,524	1,539	1,581	1,716	1,777	1,803	1,894	2,029	2,939	6,386	6,696	6,871	6,915	7,144
UEP II Transmission Reimbursement	873	1,062	1,065	1,068	1,072	1,076	1,080	1,085	1,089	1,093	1,100	1,105	1,116	1,207	1,222	1,229	1,235	1,240
Tecnisol Transmission Reimbursement	212	310	316	319	317	316	314	320	322	321	319	316	322	324	321	319	317	320
Total Consolidated Revenues	**49,009**	**57,297**	**58,044**	**58,965**	**59,862**	**60,484**	**61,420**	**62,239**	**61,706**	**52,121**	**52,553**	**54,631**	**55,850**	**47,686**	**47,498**	**48,511**	**49,397**	**50,605**
Consolidated Expenses ($'000)																		
Turbine Operations & Maintenance	3,900	4,985	5,075	5,464	5,670	5,773	5,877	5,984	6,096	6,680	6,963	7,095	7,230	7,368	7,513	7,657	7,803	7,929
Blade Operations & Maintenance	616	711	721	735	747	759	772	784	796	858	879	893	907	922	1,064	1,099	1,116	1,130
Module Operations & Maintenance	296	375	380	385	391	397	404	410	417	423	430	437	444	451	458	466	473	479
Land & Other Plant Maintenance	3,547	3,215	3,714	3,220	3,284	3,339	3,510	4,031	3,509	3,614	3,689	3,869	4,409	3,879	3,955	4,023	4,210	4,751
Total Operations & Maintenance	**8,359**	**9,286**	**9,889**	**9,804**	**10,092**	**10,269**	**10,562**	**11,209**	**10,818**	**11,575**	**11,960**	**12,294**	**12,990**	**12,620**	**12,990**	**13,245**	**13,602**	**14,289**
Consolidated G&A, Labor	2,366	2,921	2,959	3,002	3,050	3,099	3,148	3,199	3,250	3,302	3,355	3,408	3,463	3,518	3,574	3,632	3,690	3,739
Tecnisol - UEP II Backup PPA Purchases	1,985	2,448	2,460	2,478	2,452	2,317	2,338	2,349	2,367	2,388	2,347	2,351	2,220	188	0	0	0	0
Tecnisol - Other Backup PPA Purchases	1,190	1,132	964	938	986	1,020	1,056	1,082	1,120	1,162	1,142	1,164	773	0	0	0	0	0
Consolidated Transmission & Regulatory Fees	1,131	1,420	1,431	1,475	1,515	1,548	1,581	1,611	1,631	1,628	1,570	1,570	1,513	1,057	910	907	940	972
Consolidated Asset Management	360	453	453	453	453	453	453	453	453	453	453	453	453	453	453	453	453	452
UEP II Wake Effect	393	445	463	192	207	222	243	253	269	280	289	312	342	359	369	379	388	396
Total Consolidated Expenses	**15,783**	**18,104**	**18,619**	**18,342**	**18,755**	**18,927**	**19,382**	**20,156**	**19,907**	**20,788**	**21,116**	**21,552**	**21,753**	**18,196**	**18,296**	**18,616**	**19,072**	**19,848**
Consolidated EBITDA & CFADS ($'000)																		
Consolidated EBITDA	33,226	39,193	39,425	40,623	41,107	41,557	42,038	42,083	41,798	31,334	31,437	33,079	34,097	29,490	29,202	29,896	30,324	30,756
Consolidated Taxes	(9)	(243)	(119)	(239)	(611)	(876)	(1,608)	(1,921)	(2,299)	(1,779)	(1,097)	(1,105)	(1,181)	(1,039)	(1,645)	(1,486)	(1,859)	(2,329)
Consolidated Working Capital	1,643	(297)	60	(54)	83	58	168	59	516	(1,867)	217	471	1,693	(139)	331	142	250	214
Consolidated CFADS	**34,859**	**38,653**	**39,366**	**40,330**	**40,579**	**40,739**	**40,598**	**40,221**	**40,015**	**27,687**	**30,558**	**32,445**	**34,609**	**28,313**	**27,888**	**28,551**	**28,716**	**28,640**
Senior Debt ($'000)																		
Beginning of Period Balance	274,900	263,921	252,577	240,095	226,122	211,115	195,113	178,228	160,651	141,991	129,608	115,090	98,638	80,317	65,589	51,551	35,433	18,327
Senior Debt - Interest	(12,444)	(15,061)	(14,390)	(13,652)	(12,838)	(11,966)	(11,040)	(10,068)	(9,041)	(8,057)	(7,300)	(6,454)	(5,509)	(4,531)	(3,723)	(2,878)	(1,943)	(948)
Senior Debt - Amortization	(10,979)	(11,344)	(12,482)	(13,974)	(15,007)	(16,002)	(16,885)	(17,577)	(18,661)	(12,383)	(14,518)	(16,452)	(18,321)	(14,728)	(14,038)	(16,118)	(17,106)	(18,327)
End of Period Balance	**263,921**	**252,577**	**240,095**	**226,122**	**211,115**	**195,113**	**178,228**	**160,651**	**141,991**	**129,608**	**115,090**	**98,638**	**80,317**	**65,589**	**51,551**	**35,433**	**18,327**	**0**
Debt Service	**23,784**	**26,872**	**27,343**	**28,101**	**28,322**	**28,444**	**28,399**	**28,121**	**28,136**	**20,846**	**22,225**	**23,319**	**24,248**	**19,851**	**18,378**	**19,615**	**19,669**	**19,765**
DSRA Beginning of Period Balance	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,431**	**15,505**	**15,505**	**15,505**	**15,505**	**19,765**	**19,765**	**19,765**	**19,765**	**19,765**
DSCR (*Average* 1.43x)	1.47x	1.44x	1.44x	1.44x	1.43x	1.43x	1.43x	1.43x	1.42x	1.33x	1.37x	1.39x	1.43x	1.43x	1.52x	1.46x	1.46x	1.45x

Note: Years shown are 9/30 Year End periods, 2021 corresponds to 12/2020 to 9/2021 period.

Figure 5.7: Financial Overview – Sensitized P50 (1 Year) – 20% Spot Price Stress, 10% O&M Stress (Results not reviewed/checked by UL)

P90 Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Macro Assumptions (%)																		
Panama CPI	1.0%	1.3%	1.4%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
US CPI	1.7%	1.9%	2.2%	1.9%	1.8%	1.8%	1.8%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%	2.0%	1.9%	1.9%	1.9%	1.9%
Performance (MWh)																		
UEP II Gross Generation	374,239	431,614	431,610	431,603	431,595	431,587	431,579	431,574	431,568	431,560	431,574	431,574	431,625	432,418	432,500	432,500	432,500	432,251
Tecnisol Gross Generation	65,472	79,646	81,413	81,533	80,973	80,409	79,844	81,581	81,671	81,081	80,489	79,896	81,600	81,679	81,086	80,492	79,898	81,424
Tecnisol - UEP II Backup PPA Generation	30,730	37,930	38,101	38,402	38,749	39,097	39,454	39,641	39,938	40,301	39,620	39,676	37,405	3,139	0	0	0	0
Tecnisol - Other Backup PPA Generation	17,995	24,887	25,246	25,653	26,096	26,545	27,002	27,382	27,834	28,314	27,485	27,451	17,200	0	0	0	0	0
Total Tecnisol Generation	**114,197**	**142,463**	**144,760**	**145,588**	**145,817**	**146,052**	**146,301**	**148,604**	**149,443**	**149,696**	**147,594**	**147,022**	**136,205**	**84,818**	**81,086**	**80,492**	**79,898**	**81,424**
End User Demand (MWh) (A)																		
DisCo PPA Demand	292,184	336,641	336,641	336,641	336,641	336,641	336,641	336,641	315,618	102,930	102,930	102,930	102,930	19,828	0	0	0	0
Tecnisol - UEP II Backup PPA	30,730	37,930	38,101	38,402	38,749	39,097	39,454	39,641	39,938	40,301	39,620	39,676	37,405	3,139	0	0	0	0
Merchant Energy Sales	44,067	48,248	48,077	47,777	47,430	47,082	46,724	46,538	67,264	279,589	280,270	280,214	282,485	399,853	422,820	422,820	422,820	422,579
Reimbursed Transmission Losses	7,258	8,794	8,790	8,783	8,775	8,767	8,759	8,754	8,748	8,740	8,754	8,754	8,805	9,598	9,680	9,680	9,680	9,672
Total UEP II End Uses	**374,239**	**431,614**	**431,610**	**431,603**	**431,595**	**431,587**	**431,579**	**431,574**	**431,568**	**431,560**	**431,574**	**431,574**	**431,625**	**432,418**	**432,500**	**432,500**	**432,500**	**432,251**
Large Client PPA Demand	88,889	113,584	114,724	115,875	117,042	118,216	119,403	120,601	121,811	123,033	120,397	120,308	99,210	6,155	0	0	0	0
Merchant Energy Sales	23,200	25,778	26,882	26,538	25,622	24,704	23,789	24,842	24,451	23,506	24,062	23,603	33,832	75,482	77,928	77,357	76,786	78,276
Reimbursed Transmission Losses	2,108	3,101	3,155	3,175	3,153	3,131	3,109	3,161	3,180	3,157	3,134	3,111	3,162	3,181	3,158	3,134	3,111	3,148
Total Tecnisol End Uses	**114,197**	**142,463**	**144,760**	**145,588**	**145,817**	**146,052**	**146,301**	**148,604**	**149,443**	**149,696**	**147,594**	**147,022**	**136,205**	**84,818**	**81,086**	**80,492**	**79,898**	**81,424**
Average Implied Prices ($/MWh) (B)																		
UEP II DisCo PPA	102.93	103.20	103.57	103.97	104.43	104.89	105.37	105.85	106.60	115.91	116.46	117.02	117.58	118.01	0.00	0.00	0.00	0.00
Tecnisol Large Client PPA	86.76	85.45	86.03	91.50	95.07	97.72	100.51	102.32	102.46	103.07	103.37	104.55	105.79	104.13	0.00	0.00	0.00	0.00
Tecnisol - UEP II Backup PPA	65.30	65.30	65.30	65.30	64.04	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	0.00	0.00	0.00	0.00
UEP II Merchant	41.73	38.21	43.12	43.36	46.56	48.92	53.08	55.53	57.90	61.02	62.55	67.83	74.73	78.53	80.52	82.23	83.95	85.99
Tecnisol Merchant	43.80	43.01	45.39	46.19	48.74	50.72	53.80	56.06	58.74	61.68	63.60	69.32	73.43	77.74	79.19	81.87	83.00	84.11
UEP II - Transmission Reimbursement	102.93	103.20	103.56	103.96	104.42	104.89	105.36	105.85	106.34	106.84	107.34	107.86	108.38	108.92	109.50	110.07	110.63	111.19
Tecnisol - Transmission Reimbursement	92.97	92.49	92.65	92.79	92.94	93.10	93.25	93.42	93.56	93.72	93.78	93.78	93.79	93.78	93.78	93.78	93.78	93.82
Average Implied Backup Costs ($/MWh)																		
Tecnisol - UEP II Backup PPA	65.30	65.30	65.30	65.30	64.04	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	0.00	0.00	0.00	0.00
Tecnisol - Other Backup PPA	66.69	45.83	38.48	36.85	38.07	38.71	39.42	39.83	40.58	41.38	41.86	42.75	45.25	0.00	0.00	0.00	0.00	0.00
Consolidated Revenues ($'000) (AxB=C)																		
UEP II DisCo PPA	30,073	34,743	34,866	35,000	35,154	35,312	35,472	35,635	33,643	11,930	11,987	12,044	12,103	2,340	0	0	0	0
Tecnisol Large Client PPA	7,712	9,706	9,870	10,603	11,127	11,552	12,001	12,340	12,481	12,681	12,446	12,578	10,496	641	0	0	0	0
UEP II Backup PPA	2,007	2,477	2,488	2,508	2,481	2,346	2,367	2,378	2,396	2,418	2,377	2,381	2,244	188	0	0	0	0
UEP II Merchant	1,839	1,844	2,073	2,072	2,208	2,303	2,480	2,584	3,894	17,060	17,531	19,006	21,110	31,398	34,046	34,769	35,496	36,337
Tecnisol Merchant	1,016	1,109	1,220	1,226	1,249	1,253	1,280	1,393	1,436	1,450	1,530	1,636	2,484	5,868	6,171	6,333	6,373	6,584
UEP II Transmission Reimbursement	747	908	910	913	916	920	923	927	930	934	940	944	954	1,045	1,060	1,065	1,071	1,075
Tecnisol Transmission Reimbursement	196	287	292	295	293	291	290	295	298	296	294	292	297	298	296	294	292	295
Total Consolidated Revenues	**43,590**	**51,072**	**51,720**	**52,615**	**53,429**	**53,977**	**54,813**	**55,552**	**55,079**	**46,769**	**47,104**	**48,881**	**49,688**	**41,779**	**41,574**	**42,462**	**43,232**	**44,292**
Consolidated Expenses ($'000)																		
Turbine Operations & Maintenance	3,900	4,985	5,075	5,464	5,670	5,773	5,877	5,984	6,096	6,680	6,963	7,095	7,230	7,368	7,513	7,657	7,803	7,929
Blade Operations & Maintenance	616	711	721	735	747	759	772	784	796	858	879	893	907	922	1,064	1,099	1,116	1,130
Module Operations & Maintenance	296	375	380	385	391	397	404	410	417	423	430	437	444	451	458	466	473	479
Land & Other Plant Maintenance	3,546	3,214	3,712	3,219	3,282	3,337	3,508	4,030	3,507	3,612	3,687	3,867	4,407	3,877	3,953	4,021	4,207	4,749
Total Operations & Maintenance	**8,358**	**9,285**	**9,888**	**9,803**	**10,091**	**10,267**	**10,561**	**11,207**	**10,816**	**11,573**	**11,959**	**12,292**	**12,988**	**12,618**	**12,988**	**13,243**	**13,599**	**14,286**
Consolidated G&A, Labor	2,366	2,921	2,959	3,002	3,050	3,099	3,148	3,199	3,250	3,302	3,355	3,408	3,463	3,518	3,574	3,632	3,690	3,739
Tecnisol - UEP II Backup PPA Purchases	2,007	2,477	2,488	2,508	2,481	2,346	2,367	2,378	2,396	2,418	2,377	2,381	2,244	188	0	0	0	0
Tecnisol - Other Backup PPA Purchases	1,200	1,141	972	945	993	1,028	1,065	1,091	1,129	1,172	1,150	1,174	778	0	0	0	0	0
Consolidated Transmission & Regulatory Fees	1,068	1,310	1,310	1,352	1,391	1,423	1,454	1,482	1,501	1,499	1,448	1,448	1,387	928	793	790	819	847
Consolidated Asset Management	360	453	453	453	453	453	453	453	453	453	453	453	453	453	453	453	453	452
UEP II Wake Effect	340	386	402	166	180	192	210	220	233	243	251	270	297	311	320	329	336	344
Total Consolidated Expenses	**15,699**	**17,972**	**18,471**	**18,230**	**18,640**	**18,807**	**19,259**	**20,030**	**19,778**	**20,660**	**20,992**	**21,425**	**21,610**	**18,017**	**18,129**	**18,447**	**18,898**	**19,668**
Consolidated EBITDA & CFADS ($'000)																		
Consolidated EBITDA	27,892	33,100	33,249	34,385	34,789	35,170	35,555	35,522	35,301	26,109	26,112	27,456	28,078	23,763	23,445	24,015	24,334	24,624
Consolidated Taxes	0	0	0	0	(196)	(340)	(564)	(768)	(1,123)	(935)	(976)	(966)	(1,016)	(669)	(931)	(1,211)	(1,425)	(1,513)
Consolidated Working Capital	655	(292)	47	(61)	79	54	158	56	461	(1,621)	206	419	1,633	(75)	297	135	237	194
Consolidated CFADS	**28,547**	**32,807**	**33,296**	**34,324**	**34,673**	**34,884**	**35,150**	**34,810**	**34,639**	**23,553**	**25,342**	**26,908**	**28,695**	**23,018**	**22,811**	**22,939**	**23,146**	**23,305**
Senior Debt ($'000)																		
Beginning of Period Balance	274,900	263,921	252,577	240,095	226,122	211,115	195,113	178,228	160,651	141,991	129,608	115,090	98,638	80,317	65,589	51,551	35,433	18,327
Senior Debt - Interest	(12,444)	(15,061)	(14,390)	(13,652)	(12,838)	(11,966)	(11,040)	(10,068)	(9,041)	(8,057)	(7,300)	(6,454)	(5,509)	(4,531)	(3,723)	(2,878)	(1,943)	(948)
Senior Debt - Amortization	(10,979)	(11,344)	(12,482)	(13,974)	(15,007)	(16,002)	(16,885)	(17,577)	(18,661)	(12,383)	(14,518)	(16,452)	(18,321)	(14,728)	(14,038)	(16,118)	(17,106)	(18,327)
End of Period Balance	**263,921**	**252,577**	**240,095**	**226,122**	**211,115**	**195,113**	**178,228**	**160,651**	**141,991**	**129,608**	**115,090**	**98,638**	**80,317**	**65,589**	**51,551**	**35,433**	**18,327**	**0**
Debt Service	**23,784**	**26,872**	**27,343**	**28,101**	**28,322**	**28,444**	**28,399**	**28,121**	**28,136**	**20,846**	**22,225**	**23,319**	**24,248**	**19,851**	**18,378**	**19,615**	**19,669**	**19,765**
DSRA Beginning of Period Balance	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,467**	**16,431**	**15,505**	**15,505**	**15,505**	**15,505**	**19,765**	**19,765**	**19,765**	**19,765**	**19,765**
DSCR (Average 1.20x)	1.20x	1.22x	1.22x	1.22x	1.22x	1.23x	1.24x	1.24x	1.23x	1.13x	1.14x	1.15x	1.18x	1.16x	1.24x	1.17x	1.18x	1.18x

Note: Years shown are 9/30 Year End periods, 2021 corresponds to 12/2020 to 9/2021 period.

Figure 5.8: Financial Overview – Sensitized P90 (1 Year) – 20% Spot Price Stress, 10% O&M Stress (Results not reviewed/checked by UL)

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APPENDIX A—IKAKOS ENERGY PRODUCTION REPORT

INDEPENDENT ENERGY REPORT

Photovoltaic Project

PREPARED FOR:
INTERENERGY

Ref. No.: PR-005231

IKAKOS PV PROJECT
Chiriquí, Panamá

05 October 2020

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DOCUMENT HISTORY

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A	05 October 2020	Final

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ACRONYMS

Acronym		Description
A	AC	Alternating Current
	AWST	AWS Truepower, SLU, a UL Company
D	DC	Direct Current
	DHI	Diffuse Horizontal Radiation
G	GHI	Global Horizontal Irradiance
	GWh	Gigawatt Hours
H	HV	High Voltage
I	IAM	Incident Angle Modifier
	ILID	Initial Light-Induced Degradation
	IER	Independent Engineering Report
K	kW	Kilowatt
L	LID	Light Induced Degradation
	LV	Low Voltage
M	MCP	Measure Correlate Predict
	MV	Medium Voltage
	MW	Megawatt
	MWh	Megawatt Hours
	m/s	Meters per second
	MPPT	Maximum Power Point Tracker
N	NREL	National Renewable Energy Laboratory
O	O&M	Operations and Maintenance
P	POA	Plane of Array
	POI	Point of Interconnection
	PPA	Power Purchase Agreement
	PR	Performance Ratio
	PV	Photovoltaic
S	STC	Standard Test Conditions
	SCADA	Supervisory Control and Data acquisition
T	TMY	Typical Meteorological Year
U	UL	Underwriters Laboratories
W	WRDC	Wold Radiation Data Center

EXECUTIVE SUMMARY

UL was retained by InterEnergy (“Client “) to evaluate the long-term solar resource and energy at the proposed Ikakos Project located in Chiriquí, Panama. Onsite measurements at the project site were not evaluated.

UL performed the energy production estimate (“EPE”) for the Ikakos project current design named as standard scenario and presented in the main body of this report. In addition, UL estimated the energy production for the repowering scenario as per the information provided by the Client. Details of Repowering strategy is included under, with an additional capacity to be installed every 5 years of 1.7 MWp. The energy production estimate for the Repowering Scenario is included in Appendix E.

The following table presents key aspects of the project and a summary of the results.

Table 0.1: Project Summary

Project Location	**Standard Scenario**	**Repowering Scenario**
Location	Hicacos, Chiriqui (Panama)	
Project Coordinates (Lat/Lon)	8.3694, -82.3481	
Solar Resource Estimate		
Data Source	SolarGIS (1999-2019)	
GHI (kWh/m^2/year)	2,007	
DHI (kWh/m^2/year)	821	
Temperature (°C) / Wind Speed (m/s)	26.4 / 1.29	
PV Project Assumptions		
DC/AC Capacity (@40°C)	45.6 MW_{DC}/40.8 MW_{AC}	45.6 MW_{DC}/40.8 MW_{AC} 1.7 MW_{DC} to be added every 5 years
POI Capacity MW_{AC}	40.0 MW_{AC}	
DC-AC Ratio (@40°C)	1.12	1.12 (year 1-4)
DC-AC Ratio at POI (@40°C)	1.14	1.14 (year 1-4)
Evaluation Period	25 Years	
Energy Simulation Results		
POA Irradiation (kWh/m^2/year)	2,393	
Annual Degradation (material / system average)	0.51% / 0.7%	0.51% / 0.7%
First-Year Net Energy (GWh)	87.66	87.66
First-Year Performance Ratio	80.3%	80.3%
First-Year AC Capacity Factor	24.5%	24.5%
Evaluation Period Average Net Energy (GWh)	80.80	87.51
Uncertainty Results		
First-Year Energy Uncertainty	6.4% (5,628 MWh/yr)	5.8% (116 kWh/m²/yr)
First-Year P90 (GWh) / AC Capacity Factor	80.45 / 22.5%	73.73 / 20.6%
Annual Average Energy Uncertainty	6.6% (5,349 MWh/yr)	7% (6152 MWh/yr)
Annual Average P90 (GWh) / AC Capacity Factor	73.94 / 20.7%	79.63 / 22.3%
Evaluation Period Energy Uncertainty	5.9% (4,785 MWh/yr)	6.4% (5581 MWh/yr)
Evaluation Period Average P90 (GWh) / AC Capacity Factor	74.67 / 20.9%	80.36 / 22.5%

1. INTRODUCTION

UL Services Spain SL, a UL Company ("UL"), was retained by InterEnergy ("Client") to evaluate the long-term solar resource and energy production potential of the Ikakos photovoltaic (PV) project, located in Chiriquí, Panama. The Project consists of the following:

Table 1.1: Project Overview

Project Name		Ikakos PV
Project Capacity (DC/Inverter/POI)		45.64 MW_{DC} / 40.8 MW_{AC} limited to 40 MWAC at POI
Project location		Chiriquí, Panama
Equipment	**Module**	PV Modules: Jinko Solar 330/325 Wp
	Inverter	Inverter: Jema IFX6
	Mounting System	Tracker: N-S single axis tracker
Commercial Operation		August 2018

The Project is a 45.64 Megawatt direct current ("MW_{DC}") PV plant with a total capacity of 40.80 Megawatt Alternating Current ("MW_{AC}") at 50°C at the inverter output. Due to interconnection agreement, at POI the capacity of the Project is 40.00 MW_{AC}

The Project is to consist of either 96,960 Jinko Solar JKM330PP-72-V (330Wp), 42,000 Jinko Solar JKM325PP-72-V (325Wp) photovoltaic modules and 16 Inverter- Jema IFX6 TL.620 2,550 kW inverters. Available satellite-modeled solar radiation data and meteorological data from nearby reference stations were used to estimate the long-term climatology of the project area. These estimates were then used, along with plant specifications developed and supplied by Client, loss factors developed by UL, and an energy simulation program, to estimate the long-term energy production of the plant. Through this process, several sources of uncertainty were identified and quantified in order to estimate the energy production at several confidence levels.

UL performed the energy production estimate ("EPE") for the Ikakos project current design named as standard scenario and presented in the main body of this report. In addition, UL estimated the energy production for the repowering scenario as per the information provided by the Client. Details of Repowering strategy is included under, with an additional capacity to be installed every 5 years of 1.7 MWp. The energy production estimate for the Repowering Scenario is included in Appendix E.

In this report decimals are indicated with a point-indicator ("."), and thousands separator is specified with the comma-indicator (",").

2. SITE DESCRIPTION

The Ikakos Project is located in Chiriquí approximately 10 km Southeast of David District, Panama. Site coordinates are specified in Table 2.1.

Table 2.1: Description of the Ikakos PV

Site ID	Latitude	Longitude	Elevation
Ikakos PV	8.367755	-82.349685	14 m

Its location is indicated on the regional map in Figure 2.1. The project site is located on relatively flat terrain at a site mean elevation of approximately 14 m. A topographic map depicting the terrain surrounding the project area is presented in Figure 2.2. The project site is surrounded by low bushes in all directions.

Figure 2.1: Regional Map Ikakos, Chiriquí

Figure 2.2: Topographical Map of the Ikakos Project

3. SOLAR RESOURCE

3.1 Reference Data Sources

In order to adequately assess the long-term solar resource characterization for the specific project site, UL evaluated datasets within an appropriate proximity to the project site and geographical reference points as they relate to the region. UL relied on the following sources of reference data:

- Historic data series with 250 m resolution based on satellite-modeled solar radiation data produced by Solargis using Meteosat Second Generation satellite data.
- An hourly 8760 data set containing modeled solar radiation data from the Meteonorm simulation program.
- Monthly observed solar radiation measurements collected and distributed by the World Radiation Data Center (WRDC).
- A global modeled data set A global modeled data based upon solar radiation derived from satellite observations and meteorological data from assimilation models produced by the National Aeronautics and Space Administration (NASA Power).
- Modeled solar radiation data from the National Solar Radiation Database (NSRDB) model sponsored by the National Renewable Energy Laboratory (NREL).

The surface-based reference station locations discussed above are shown on the regional map in Figure 2.1 and are summarized in Table 3.1.

Table 3.1: Site-Specific Information for Various nearby Reference Stations

Reference Station	Network	Period Of Record	Distance to Project Site (km)	Elevation (m)
David	WRDC	Monthly Values	12	42

A detailed discussion of each reference data source can be found in Appendix A.

3.2 Long Term Solar resource

UL examined the aforementioned data models and reference stations to determine their usefulness in estimating the long-term solar resource for the Ikakos in Chiriquí, Panama.

Nearby the project site, additional station data was available at David District made available through WRDC network.

Comparison of results of available models performing at the project site and at the reference station locations has been performed to identify similar climatic trends between project site and station sites. Since WRDC station is located approximately 12 km from the project site only low confidence could be set on this data source, when evaluating the representativeness of the project site, due to relative distance and limited period of record. Therefore, the WRDC station was mostly used to analyze modeled data trends and discrepancies, not as data reference for the project.

The available station data did not provide clear aligned trends supporting to use those to validate the available models. The David District reference station from WRDC also showed differences among their relative behavior, that call into question the quality level of these data to represent the project site. The considerable high distance and the lack of information about the data quality and availability of the reference station network seem to lie behind the differences in the radiation profiles. Considering this, WRDC data was not proven to be of high enough quality, so they were not further considered for this assessment.

An overview of the reviewed reference station trends is displayed in Figure 3.4. Due to the limited number of long-term high-quality surface-based solar radiation measurements, model-based data sources were considered in this case to assess the resource assessment in Ikakos site.

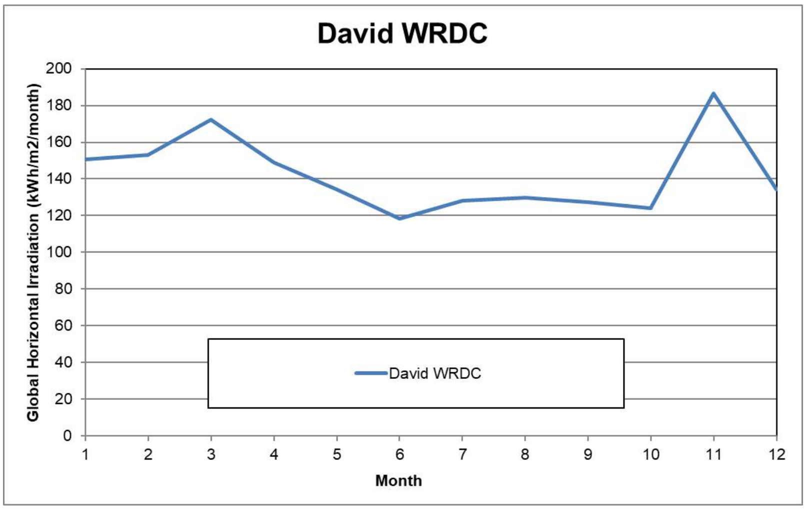

Figure 3.1: Long Term Monthly GHI from nearby stations

Among the analyzed models, daily and monthly irradiation for a 1° X 1° grid cell covering the proposed project site was compiled and examined from the NASA Power database. The annual GHI for the grid cell covering the project site is approximately 1,671 kWh/m^2/year. However, this value represents the average value over the entire grid cell, which incorporates various topography and land types in the region and represents a variety of climates. The actual solar climate at the project site is likely underrepresented due to the relatively low spatial and temporal resolution of NASA-Power. data set. As a result, we elected to remove this data set from consideration as a primary reference.

Further modeled reference data sources were considered: a time series of the Solargis satellite model from Month-year through Month-year, which suggests that the long-term solar resource at the project site is 2,007 kWh/m^2/year; the Meteonorm database, which utilizes both satellite and numerical modeling methods and estimates the solar resource to be 1,996 kWh/m^2/year. Month by month GHI values from each data source is shown in Figure 3.5. Due to the considerable uncertainty of the Meteonorm compared to Solargis, and the lower spatial resolution, Meteonorm was removed from further consideration.

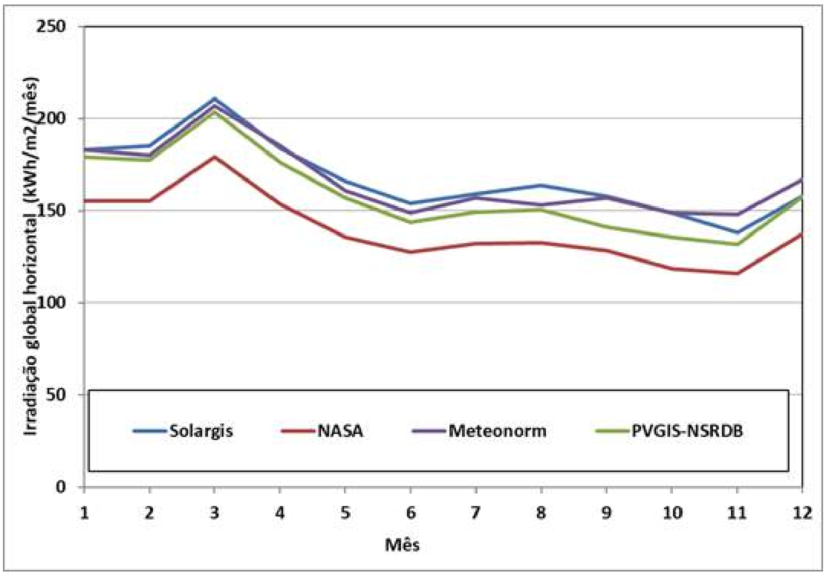

Figure 3.2: Long-Term Monthly GHI from modeled data at the Ikakos Project Site

NRSDB hourly data covering a period from 2005-2015 was also analyzed. This dataset results in a Long term value of 1,903 kWh/m^2/year; while a consistent historical long term period of data was available for this data source, a high uncertainty is assigned to this source based on the methodology applied to obtain the long term values and the limited validation data available, NRSDB data were only considered to compare the trends expected at the project site.

In conclusion, due to the lower spatial resolution and greater uncertainty of the NASA-Power, Meteonorm and NRSDB data sets and the consistency of the estimated solar resource between various modeled and observed reference data sources, UL selected the Solargis satellite model to represent the long-term solar resource at the Ikakos Chiriquí.

The overview of LT-yearly radiation values derived from each source are displayed in Table 3.2

The long-term GHI and optimal is estimated to be 2,007 kWh/m^2/year. Detailed monthly and diurnal long-term GHI is presented in Appendix B

Table 3.2: Annual Modeled Irradiation Data (kWh/m2/year) from Analyzed Sources and Albedo value

Radiation Component	GHI	DHI
Solargis	2,007	821
NASA Power	1,671	-
Meteonorm	1,996	-
NSRDB – PVGIS	1,903	-

4. TYPICAL METEOROLOGICAL YEAR DATASET DEVELOPMENT

In order to accurately characterize the solar resource potential and to define its seasonal and diurnal distributions, a TMY data set was constructed. A TMY data set is defined as a long-term annualized hourly time series of insolation and meteorological parameters. When available, a historical data set with a long period of record is preferred. The primary historical database used in this analysis was the Solargis satellite model. This data source was selected due to its consistent 20-year data record, representativeness of solar radiation specific to the project site and inclusion of multiple solar components.

UL relied on the TMY derived from Solargis hourly long term series, considering this dataset to provide the most appropriate data source to characterize the long-term solar resource for the project area given available data sources.

The resulting long-term annual GHI and DHI are estimated to be 2,007 kWh/m^2 and 821 kWh/m^2, respectively. Estimated annual irradiation for the project area is shown in Table 4.1.

The annual average temperature at the Ikakos is estimated to be 26.4°C, whereas the annual average wind speed is estimated to be 1.29 m/s, consistent with the Solargis data. Considering the long period of data of the Solargis dataset, this data series was considered as a long term reference data. Estimated annual irradiation and meteorological components for the project area is shown in Table 4.1, whereas the annual temperature and radiation distribution for the Project is shown in Table 4.1

Table 4.1: Estimated Annual Irradiation Components and Meteorological components for the Project Site

Radiation Component	Value
GHI(kWh/m2/year)	2,007
DHI (kWh/m2/year)	821
Temperature ºC	26.4
Wind Speed m/s	1.29

The monthly solar distribution for the TMY data set is shown in Figure 4.1

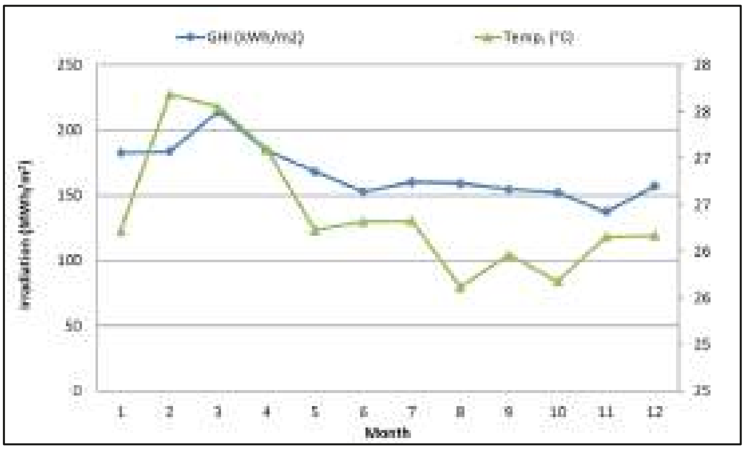

Figure 4.1: Monthly Irradiation Distribution in the project area

The hourly and monthly values of the GHI are presented in Appendix B.

5. LONG TERM ENERGY ASSESSMENT

5.1 Plant Design

During the evaluation, UL considered all Client provided information regarding plant design and system specifications. This information, along with the derived site-specific TMY, was used as an input for the production modeling process.

Annual energy production was estimated for the Ikakos project site using details summarized below. These details were provided to UL from Company and reviewed according to project design criteria. Table 5.1 provides an overview of main equipment and design specifications.

Table 5.1: Solar Project Design and Main Equipment

Metric	Value
AC/DC Rating [Pnom Ratio]	45.65 MW_{DC}/40.80 MW_{AC} [1.12]
AC limitation at POI	40.00 MW_{AC}
Modules	Jinko Solar JKM330PP-72-V
Inverter	Jema IFX IFX6 -2550 TL.620
Tilt (°)	16
Azimuth (°)	180
Tracking	N-S Single axis ±60°. Backtracking strategy.
Module configuration	2 modules in Portrait
Pitch distance (m)	7.15; 8.00; 7.25; 7.985
Total strings	4,632
Total modules	138,960
Total inverters	16

The main equipment and design aspects characterizing the plant are:

- **Power plant capacity**: The Energy Assessment assumes the use of the following PV modules for each PV plant of 11.41 MW_{DC} and 10.20 MW_{AC}:
  - o 24,240 Jinko Solar JKM330PP-72-V (Polycrystalline) and 10,500 Jinko Solar JKM325PP-72-V PV modules rated at 330 Wp and 325 Wp;
- **Plant Configuration**: F The energy assessment was evaluated for each plant configuration based on single-axis tracker (N-S) PV array with a ±55° range of motion and an orientation of 0° azimuth (True South).
  - o **IKO:** The provided project design specifications include a pitch distance of 7.15 m;
  - o **IK1:** The provided project design specifications include a pitch distance of 8.00 m;
  - o **IK2:** The provided project design specifications include a pitch distance of 7.25 m;
  - o **IK3**: The provided project design specifications include a pitch distance of 7.95 m;

  and a collector band width of 3.95 m for all PV Plants.
- **Panels**: The analysis was conducted using Jinko Solar JKM330PP-72-Vwith a rated power of 330 Wp and 325 Wp and efficiency up to 17.01% and 16.75 respectively at Standard Test Conditions (STC). The operating temperature range is –40°C to 85°C, with a power tolerance of -0/+3%. The 25-year transferrable power output warranty is rated at 1-year/97.5% and 25-year/80.7% to account for module degradation.
- **Inverter**: The system design utilizes 16 inverters Jema IFX IFX6 -2550 TL.620. The operating voltage for this inverter is 890–1,250 V_{DC} with a nominal power of 2,550 kVA at 50°C and 2,675 kVA at 25°C. A power factor of 1.00 is considered according to Client information. The maximum input voltage is 1,500 V_{DC}. Detailed information on the selected inverter can be found in Table 5.2.

Table 5.2: Inverter Specifications

Metric	Jema – IFX6
Nominal AC Power (kVA) @50°C	2,550
Nominal AC Power (kVA) @25°C	2,675

Table 5.2: Inverter Specifications

Metric	Jema – IFX6
Power Factor	1.00
Frequency (Hz)	50/60
Operating Voltage Range (V)	890-1,250
Maximum Input Voltage (V)	1,500
Peak/CEC Efficiency (%)	98.70/98.40
Ambient Operating Temperature (°C)	-20ºC to 50ºC

- **Array**: The specific array configuration for each sub-array is 4,632strings of 138,960 Jinko Solar JKM330PP-72-Vmodules connected in parallel across 16 inverters yielding an AC capacity of 40.80 MW and a DC/AC ratio of 1.12, considering a power factor of 1.00 at 50°C. The lower temperature for Absolute Voltage limit is 10°C at 1000W/m^2 considering that the temperature will be higher at this radiation value according to Client information.
- **Transformers and Collection System**: Each 5.00 MVA$_{AC}$ section of the facility is expected to have a collector transformer to increase the voltage from the inverter voltage to 34.5kV. The full facility is connected to the SIN at 34.5 kV.
- **Solar sunpath and horizon topography**: This analysis considers site specific information detailing any impacts the surrounding environment may have on the project site, primarily shading of the modules. UL reviewed about possible impact on the project area based on satellite images y SRTM data of surrounding geography, completing a desktop analysis to account for applicable shading impact.

5.2 Energy Simulation and Loss Assumptions

Annual net energy production was simulated for every hour of the calendar year using PVsyst. As part of the energy simulation, loss factors were also computed for each hour of the calendar year. Some loss factors were applied uniformly to all operating conditions. These were estimated based on the local environment and industry-standard values, then entered directly into the energy model. Other loss factors were calculated during the energy simulation process based on user-defined simulation settings and the hourly solar and meteorological input data. Plant losses are grouped into four main categories:

- **Effective Irradiation:** Horizon shading, near shading, incident angle modifier factor, and soiling
- **Photovoltaic Conversion**: Initial light induced degradation, non-STC operation due to irradiance and temperature, module quality, and module mismatch
- **Electrical**: DC wiring, inverter efficiency, inverter limitation, inverter de-rating, AC wiring, and transformer efficiency
- **Operational**: System losses, including HVAC and auxiliary components, system availability, collection and substation availability, utility grid availability, and POI curtailment

The combined first-year losses, which are computed as efficiencies, total 19.6% Figure 5.1 and Figure 5.2 show how GHI, losses, and performance vary month-to-month based on the TMY and meteorological conditions.

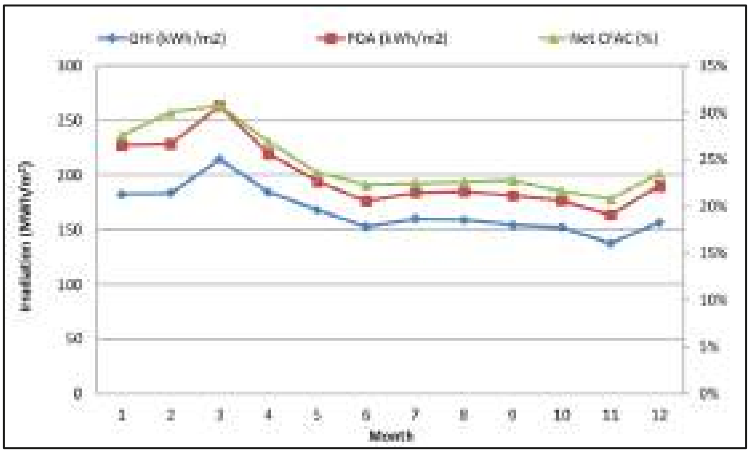

Figure 5.1: Monthly Resource and monthly albedo values

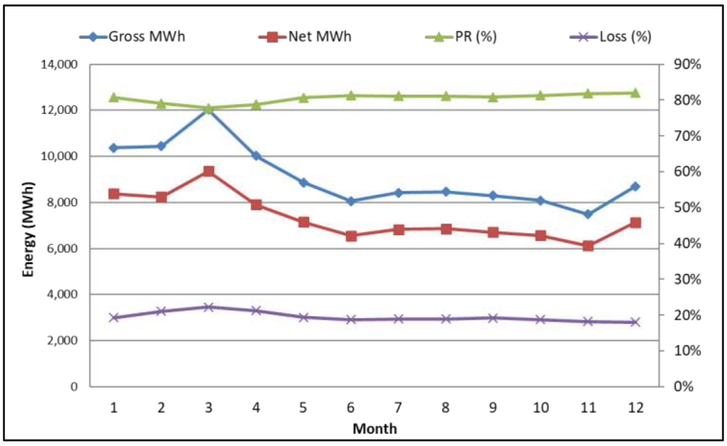

Figure 5.2: Monthly Energy and Performance

Energy production is expected to decrease throughout the system lifetime due to annual performance degradation of the module. Therefore, the system performance is provided assuming no degradation (a new and clean system) initially, and is reduced for all subsequent years of the evaluation period. The annual degradation in module output of 0.51%/year is based on information provided by the manufacturer, typical industry values, the local climate, and UL's experience with similar projects.

Calculation Approach: Long term applicable loss balance is calculated from year zero and applicable adjustments to characterize year X. Material degradation was applied subtractively to the partial net energy at the point of the module in the system's energy flow (i.e., not being applied to those losses not impacted by material degradation). UL considers the year-zero subtractive approach to be most appropriate when considering the physical realities of degradation and its impact on the system's energy.

A detailed breakdown and explanation for each loss assumption including loss variability along the plant life is contained in Appendix C.

5.3 Energy Production Estimate

Using the output from the PVsyst simulation, UL post-processed the results to obtain the preliminary energy production estimate for the project. The following computed performance parameters describe annual system performance:

- **Gross energy** refers to the production of an ideal system with no loss factors.
- **Net energy** represents the total energy produced after all losses have been applied.
- **Performance ratio** denotes the ratio of the net energy to the gross energy, or 100% minus the total plant loss.
- **Capacity factor** signifies the ratio of the net energy production to the production of the system if it operated at rated capacity for the entire year.
- **Energy yield ratio** indicates the ratio of the net energy production divided by the DC nameplate capacity of the plant.

The combined gross energy output for the Ikakos project was estimated to be 109.22 GWh. First-year net energy production was estimated to be 87.66 GWh, with a performance ratio of 80.3%. The first-year AC capacity factor is estimated to be 24.5%. Averaged over a 25-year evaluation period and including the estimated system performance degradation impact, the average annual net energy production is estimated to be 80.80 GWh, with a performance ratio of 74.0% and AC capacity factor of 22.6%. Table 5.3 lists the estimated net energy, performance ratio, and DC/AC capacity factors for the first year and the 25 year average Long Term period, while Table 5.4 provides the estimated net energy production for each year of the evaluation period.

Table 5.3: Estimated PV System Performance

Performance Metric	First Year	Lifetime
Global Horizontal Irradiation (kWh/m^2/yr)	2,007	2,007
Plane-of-Array Irradiation (kWh/m^2/yr)	2,393	2,393
Gross Energy (GWh/yr)	109.22	109.22
Net Energy (GWh/yr)	87.66	80.80
Performance Ratio (%)	80.3	74.0
AC Capacity Factor (%)	24.5	22.6
Energy Yield Ratio (kWh/kW$_{DC}$)	1,920	1,770
Total Lifetime (25-year) Energy Production (GWh)	-	2,019.94

Table 5.4: Estimated Evaluation Period Annual PV System Performance

Year	Net Energy Production (GWh)	Performance Ratio (%)	AC Capacity Factor (%)
1	87.66	80.3	24.5
2	87.18	79.8	24.4
3	86.60	79.3	24.2
4	86.02	78.8	24.1
5	85.44	78.2	23.9
6	84.86	77.7	23.7
7	84.28	77.2	23.6
8	83.70	76.6	23.4
9	83.12	76.1	23.3
10	82.54	75.6	23.1
11	81.96	75.0	22.9
12	81.38	74.5	22.8
13	80.80	74.0	22.6

Table 5.4: Estimated Evaluation Period Annual PV System Performance

Year	Net Energy Production (GWh)	Performance Ratio (%)	AC Capacity Factor (%)
14	80.22	73.5	22.4
15	79.64	72.9	22.3
16	79.06	72.4	22.1
17	78.48	71.9	22.0
18	77.90	71.3	21.8
19	77.32	70.8	21.6
20	76.74	70.3	21.5
21	76.16	69.7	21.3
22	75.58	69.2	21.1
23	75.00	68.7	21.0
24	74.42	68.1	20.8
25	73.84	67.6	20.7
Average	**80.80**	**74.0**	**22.6**

Note: Year 1 degradation loss is applied at mid-year.

Detailed monthly and diurnal net energy productions are presented in Appendix D for the first year and long term.

6. UNCERTAINTY ANALYSIS

An uncertainty analysis was conducted to quantify the confidence in the provided GHI and energy estimates and to calculate P75, P90, P95, and P99 energy estimates for financial models and risk assessments. The sources of uncertainty are described below in more detail. For this analysis, uncertainty was defined as the standard error for a normal probability distribution. Uncertainty factors summarized in this chapter specify values applying to energy results.

6.1 Measurement Accuracy

This uncertainty addressed the accuracy of modeled data used to estimate the solar resource at the project site. Factors considered for the model data related to this uncertainty factor include published model accuracies of data provider, extent of model validation and when applicable, any corrections performed to account for model bias. Considering these factors as applicable to the modeled data at the project site, the measurement uncertainty of 5.0%.was assigned.

6.2 Inter-Annual Variability

This uncertainty addressed natural differences in the solar resource from year to year. Inter-annual variability calculations came from multiple years of high-quality reference data and varied by region. Local climates could cause this uncertainty to vary considerably over short distances.

Based on nearby reference data sources in the region, the meteorologist assigned an inter-annual variability in irradiation of 2.9% for a single year and 0.9% over the long-term.

6.3 Representativeness of Monitoring Period

This uncertainty addressed how well the estimated long-term resource could represent the site's historical average. Considerations for this uncertainty included the solar resource's inter-annual variability, the data recovery at the site, and (where applicable) the degree of correlation between the target and reference stations and the length of the reference record period.

For representativeness of the monitoring period, the uncertainty amounted to 0.6%.

6.4 Spatial Variability

This uncertainty addressed the spatial variation in the solar resource across the approximate project area. UL assigned an uncertainty of 0.1%.

6.5 Simulation and Plant Losses

This uncertainty addressed the performance simulation, derived plant loss factors, configuration details, and transposition to plane of array, which refer to the accuracy of the transposition of the horizontal radiation components to the plane of array. The uncertainty amounted to 2.6%

6.6 Module Degradation

UL applied an increasing uncertainty of 0.1% per year to account for the annual system performance degradation. This increasing uncertainty rate relied on the historical degradation rate range experienced by modules in the field and assigned for pre-construction projects.

6.7 Combined Uncertainty

UL then took the following steps to determine energy production at various desired confidence levels:

- The uncertainty percentages were combined in the solar resource as the square root of the sum of squares. These numbers integrated into the time series data set to quantify the uncertainty in the solar resource.
- The project output's sensitivity to changes in annual irradiation were calculated. Calculations for this ratio compared the system's energy output for the estimated long-term average annual irradiation to the system's predicted output with the uncertainty-adjusted resource estimate (estimated long-term data set minus uncertainty).
- The project output's sensitivity to changes in irradiation was multiplied by each irradiation uncertainty to estimate the corresponding project energy output uncertainty.
- The uncertainty in the simulation and plant losses was combined with the previous total using the square root of the sum of squares.
- Assuming a normal error distribution, UL calculated the energy production levels that the project would exceed with 75%, 90%, 95%, and 99% confidence.

For more information, review the total and individual uncertainties for the energy estimate are shown in Table 6.1, Table 6.2, and Table 6.3 for the first-year annual average, and evaluation period average, respectively.

Table 6.1: Uncertainty Summary Resource and Energy - First-Year

Source of Uncertainty	GHI (%)	GHI ($kWh/m^2/yr$)	Energy (%)	Energy (MWh/yr)
Measurement Accuracy	5.0%	100	5.0%	4,383
Inter-Annual Variability	2.8%	56	3.0%	2,646
Representativeness of Monitoring Period	0.6%	12	0.6%	532
Spatial Variability	0.1%	2	0.1%	88
Simulation and Plant Losses	-	-	2.6%	2,273
Annual Degradation	-	-	*0.1/yr*	-
Combined Uncertainty	**5.8%**	**116**	**6.4%**	**5,628**

Note: First-year combined uncertainty does not account for degradation uncertainty, which only impacts energy uncertainty in future years

Table 6.2: Uncertainty Summary Resource and Energy - Long Term 25-Year Annual Average

Source of Uncertainty	GHI (%)	GHI (kWh/m²/yr)	Energy (%)	Energy (MWh/yr)
Measurement Accuracy	5.0%	100	5.0%	4,040
Inter-Annual Variability	2.9%	58	3.1%	2,500
Representativeness of Monitoring Period	0.6%	12	0.6%	490
Spatial Variability	0.1%	2	0.1%	81
Simulation and Plant Losses	-	-	2.6%	2,095
Annual Degradation	-	-	*1.3%*	*1020*
Combined Uncertainty	**5.8%**	**116**	**6.6%**	**5,349**

Note: 25 year average energy uncertainty accounts for increasing degradation loss/uncertainty and increasing climate uncertainty.

Table 6.3: Uncertainty Summary Resource and Energy –25-Year Evaluation Period Average

Source of Uncertainty	GHI (%)	GHI (kWh/m²/yr)	Energy (%)	Energy (MWh/yr)
Measurement Accuracy	5.0%	100	5.0%	4,040
Inter-Annual Variability	0.9%	18	0.9%	737
Representativeness of Monitoring Period	0.6%	12	0.6%	490
Spatial Variability	0.1%	2	0.1%	81
Simulation and Plant Losses	-	-	2.6%	2,095
Annual Degradation	-	-	*1.3%*	*1020*
Combined Uncertainty	**5.1%**	**103**	**5.9%**	**4,785**

Note: Annual average energy uncertainty accounts for degradation and climate uncertainty over the project's lifetime. Evaluation period uncertainty adjusts for the reduced effect of inter-annual variability over the project's lifetime

P table for annual energy production is included in and Table 6.4.

Table 6.4: Uncertainty Summary Resource and Energy –25-Year Evaluation Period Average

Probability of Exceedance	First Year		Annual Average		Evaluation Period Average	
	Annual Energy Production (GWh)	AC Capacity Factor	Annual Energy Production (GWh)	AC Capacity Factor	Annual Energy Production (GWh)	AC Capacity Factor
P50	87.66	24.5%	80.80	22.6%	80.80	22.6%
P75	83.87	23.5%	77.19	21.6%	77.57	21.7%
P90	80.45	22.5%	73.94	20.7%	74.67	20.9%
P95	78.41	21.9%	72.00	20.1%	72.93	20.4%
P99	74.57	20.9%	68.36	19.1%	69.67	19.5%

Year-by-year uncertainties for a 25-year timeframe and associated P values are included in Table 6.5.

Table 6.5: Evaluation Period Uncertainty Summary and P Tables

Year	P50 Net AEP (GWh)	Uncertainty (%)	Uncertainty (GWh)	P75 (GWh)	P90 (GWh)	P95 (GWh)	P99 (GWh)
1	87.66	6.4%	5.63	83.87	80.45	78.41	74.57
2	87.18	6.4%	5.60	83.40	80.00	77.97	74.15
3	86.60	6.4%	5.57	82.85	79.47	77.44	73.65
4	86.02	6.4%	5.54	82.29	78.93	76.92	73.14
5	85.44	6.4%	5.51	81.73	78.38	76.38	72.63
6	84.86	6.5%	5.48	81.17	77.84	75.85	72.12
7	84.28	6.5%	5.45	80.60	77.30	75.32	71.60
8	83.70	6.5%	5.43	80.04	76.75	74.78	71.08
9	83.12	6.5%	5.40	79.48	76.20	74.24	70.56
10	82.54	6.5%	5.38	78.91	75.65	73.69	70.03
11	81.96	6.5%	5.36	78.35	75.10	73.15	69.50
12	81.38	6.6%	5.34	77.78	74.54	72.60	68.96
13	80.80	6.6%	5.32	77.21	73.99	72.05	68.43
14	80.22	6.6%	5.30	76.65	73.43	71.50	67.89
15	79.64	6.6%	5.28	76.08	72.87	70.95	67.35
16	79.06	6.7%	5.27	75.51	72.31	70.40	66.80
17	78.48	6.7%	5.25	74.94	71.75	69.84	66.26
18	77.90	6.7%	5.24	74.37	71.19	69.28	65.71
19	77.32	6.8%	5.23	73.80	70.62	68.72	65.16
20	76.74	6.8%	5.22	73.22	70.06	68.16	64.61
21	76.16	6.8%	5.21	72.65	69.49	67.60	64.05
22	75.58	6.9%	5.20	72.08	68.92	67.04	63.50
23	75.00	6.9%	5.19	71.50	68.36	66.47	62.94
24	74.42	7.0%	5.18	70.93	67.79	65.91	62.38
25	73.84	7.0%	5.17	70.36	67.22	65.34	61.82
Annual Average	**80.80**	**6.6%**	**5.35**	**77.19**	**73.94**	**72.00**	**68.36**
Evaluation Period Average*	**80.80**	**5.9%**	**4.78**	**77.57**	**74.67**	**72.93**	**69.67**

*Evaluation period cumulative energy uncertainty adjusts for the reduced effect of inter-annual variability over the project's.

The combined annual average GHI uncertainty was determined to be 5.8%, or 116 kWh/m^2/year. The combined first-year energy uncertainty was determined to be 6.4%, or 5,628 MWh per year. This corresponds to first-year P90 and P99 values of 80.45 GWh and 74.57 GWh, respectively. Over the 25-year evaluation period, the average annual uncertainty was determined to be 6.6%, or 5,349 MWh per year, corresponding to a P90 and P99 of 73.94 GWh and 68.36 GWh, respectively. Over the same evaluation period accounting for reduced inter-annual variability uncertainty, the average annual uncertainty was determined to be 5.9%, or 4,785 MWh, corresponding to a P90 and P99 of 74.67 GWh and 69.67 GWh, respectively.

7. SUMMARY

UL considered available datasets within the region to determine their appropriateness for estimating the long-term solar resource. In absence of suitable ground measurement data, UL used satellite-modeled TMY from SolarGIS database extracted at the Project location to estimate the long-term solar resource. The long-term GHI and the long-term POA at the project site was estimated to be 2,007 kWh/m^2/year and 2,393 kWh/m^2/year, respectively.

Based on the insolation and meteorological parameters defined previously and the selected PV plant specifications provided by the Sponsor, the electrical energy output of the project was modeled using UL's energy simulation model that includes PVsyst 6.86.

The first-year net energy production is estimated to be 87.66 GWh with a performance ratio of 80.3% and an AC capacity factor of 24.5% (evaluated for the rated plant capacity of 40.80 MW_{AC}). Averaged over a 25-year evaluation period and including the estimated system performance degradation rate of 0.70% per year, the average annual net energy production is estimated to be 80.80 GWh.

An uncertainty analysis was conducted to calculate P75, P90, P95, and P99 energy estimates. The first-year energy production uncertainty was calculated to be 6.4%, corresponding to first-year P90 and P99 values of 80.45 GWh and 74.57 GWh, respectively.

Over the 25-year evaluation period, considering the reduced impact of inter-annual variability over the evaluation period, the uncertainty was reduced to 5.9 %, corresponding to P90 and P99 values of 74.67 GWh and 69.67 GWh, respectively.

APPENDIX A - RESOURCE DATA SOURCES

Solargis Satellite Model – Solargis has developed a solar radiation data set as part of their high-resolution climate database through SolarGIS© v1.5[1], with primary layers including solar radiation, temperature and terrain data. The database was developed using a modified version of the Heliosat-2 method created from Meteosat Second Generation satellite and atmospheric data using in-house algorithms, including inputs and improvements suggested by Perez et al. (2002)[2], Duerr and Zelenka (2009)[3], Cebecauer et al. (2010 a,b)[4,5] and others. The model has been validated using high-quality ground measurements throughout Europe and North Africa. Time series data are available with a 250 m spatial resolution (disaggregated from 5 km using a Digital Elevation Model SRTM-3) and a 15-minute temporal resolution. Model outputs for this study included GHI and DHI components for the project site.

WRDC – The WRDC serves as a data repository for solar radiation data measured across the globe. Maintained by the Russian Federal Service for Hydrometeorology and Environmental Monitoring for the World Meteorological Organization (WMO), data collected at over 1,000 sites are available through an online data management service. Monthly radiation data are available for select WRDC stations, utilizing measurements between 1964 and 1993. Because data are being utilized from many different international networks, specific information on instrument types, measurement protocols, and sensor maintenance is limited.

NASA Power – To support the commercial use of global solar and meteorological data, NASA played an integral role in the development of the surface meteorology and solar energy data set, which is designed specifically for renewable energy system design. Solar radiation is developed by inputting cloud data from the International Satellite Cloud Climatology Project[6] DX data set (ISCCP) into the Pinker/Laszlo shortwave algorithm[7]. After re-gridding the output data through a replication process, solar radiation data are made available in one-degree latitude by one-degree longitude grids. Meteorological data for the same grid spacing are generated using the NASA Goddard Earth Observing System – Version 4 (GEOS 4) Multiyear Assimilation Time Series Data. Monthly-averaged data from 1983-1993 satellite measurements are available for any location on Earth.

Meteonorm – Meteonorm is a meteorological reference database developed for solar applications and system design at any location in the world. The database incorporates climatological data from over 8,000 meteorological stations, including over 1,500 with measured solar radiation over varying time periods. Meteonorm uses several solar radiation and other meteorological models that allow interpolation to any particular point location. Accuracy of the data set varies depending on the number of nearby measurement stations. Data can be exported in over 30 different formats, allowing for

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[1] http://solargis.info/

[2] Perez, R., Ineichen, P., Moore, K., Kmiecik, M., Chain, C., George, R., Vignola, F., A new operational satellite-to-irradiance model – description and validation. *Solar Energy*, 73, 307-317.

[3] Duerr, B. and A. Zelenka, 2009. Deriving surface global irradiance over the Alpine region from METEOSAT Second Generation data by supplementing the HELIOSAT method. *Int. Jour. Of Remote Sensing*, 30, 5821-5841.

[4] Cebecauer, T., Suri, M., Perez, R., High performance MSG satellite model for operational solar energy applications. ASES SOLAR 2010 Conference, Phoenix (AZ), May 2010.

[5] Cebecauer, T., Suri, M., Accuracy improvements of satellite-derived solar resource based on GEMS re-analysis data. SolarPACES 2010 Conference, Perpignan, France, Sept. 2010.

[6] http://isccp.giss.nasa.gov/

[7] Pinker, R.T. and Laszlo, 1992. Modeling of surface solar irradiance for satellite applications on a global scale. *J. Appl. Meteor.*, 31, 194-211.

compatibility with a variety of other software packages. For this analysis, an hourly-interpolated Meteonorm 8760 time series was considered.

NSRDB – The National Solar Radiation Database (NSRDB) This data provides monthly average and annual average daily total solar resource averaged over surface cells of 0.038 degrees in both latitude and longitude, or nominally 4 km in size. The solar radiation values represent the resource available to solar energy systems. The data was created using cloud properties which are generated using the AVHRR Pathfinder Atmospheres-Extended (PATMOS-x) algorithms. Fast all-sky radiation model for solar applications (FARMS) in conjunction with the cloud properties, and aerosol optical depth (AOD) and precipitable water vapor (PWV) from ancillary source are used to estimate DNI and GHI. The direct normal irradiance (DNI) and GHI are computed for clear skies using the REST2 model. For cloud scenes identified by the cloud mask, the FARMS is used to compute the GHI. The DNI for cloud scenes is then computed using the DISC model. The data are averaged from hourly model output over 17 years (1998-2014). The PATMOS-X model uses half-hourly radiance images in visible and infrared channels from the GOES series of geostationary weather satellites, daily snow cover data from the NSIDC and mixing ratio, temperature and pressure profiles from the Modern Era-Retrospective Analysis (MERRA) dataset. The REST2 model uses daily aerosol optical depth from a combination of the MODIS and MISR satellites and the AERONET ground based stations to calculate GHI and DNI, water vapor and other inputs for REST 2 are obtained from the MERRA.

APPENDIX B – LONG TERM GHI 12 X 24

Table B.1: GHI Long Term 12 x 24 Matrix

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg (Wh/m^2)	Tot Month(kWh/m^2)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	3	4	9	24	32	31	23	23	24	27	19	7	19	7
7	110	114	155	171	177	170	150	169	184	171	174	129	156	57
8	322	343	390	370	355	336	322	363	397	362	351	322	352	129
9	536	568	621	569	538	495	476	530	576	546	501	494	537	196
10	702	749	806	730	688	620	608	667	720	667	618	629	683	249
11	813	869	933	846	742	684	723	754	751	727	632	728	766	280
12	835	938	960	887	813	718	746	813	763	757	619	720	796	291
13	782	907	945	836	799	751	765	712	697	664	620	677	762	278
14	702	797	818	710	583	566	593	508	519	515	515	614	619	226
15	558	623	642	524	376	375	390	292	313	283	335	415	426	155
16	364	418	416	319	208	226	228	182	144	138	157	244	253	92
17	155	199	197	142	97	101	116	99	60	53	42	83	111	41
18	13	29	30	23	18	23	25	23	5	2	0	3	16	6
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Average(Wh /m^2)	246	273	288	256	226	212	215	214	215	205	191	211	229	
Total (Wh/m^2/day)	5894	6557	6919	6152	5427	5096	5166	5136	5153	4913	4583	5064		**Total (kWh/m^2/yr) 2,007**
Total (kWh/m^2/mth)	183	184	214	185	168	153	160	159	155	152	137	157		

APPENDIX C - DETAILED ENERGY LOSSES

Table C.1: Project Detailed System Loss Factors

Detailed Loss Category	Percent Loss
Effective Irradiation	
Horizon Shading	0.0%
Near Shading	3.0%
Incident Angle Modifier Factor (Reflection)	0.8%
Soiling and Snow	0.6%
Effective Irradiation Total	**4.3%**
Photovoltaic Conversion	
Initial Light Induced Degradation	1.0%
Non-STC Operation (Irradiance Level)	0.4%
Non-STC Operation (Temperature)	8.4%
Module Quality	-1.5%
Module Mismatch	0.8%
Photovoltaic Conversion Total	**9.1%**
Electrical	
DC Wiring	0.8%
Inverter Limitation	0.3%
Inverter Efficiency	1.4%
Medium-Voltage Transformer Efficiency	0.9%
AC Wiring - Collection System	0.7%
External High Voltage Transformer Efficiency	0.0%
Transmission Line to Point of Interconnection Efficiency	2.5%
Electrical Total	**6.5%**
Operational	
Tracking System Performance	0.2%
DC System Performance (Module/String Failures)	0.1%
Availability of AC System (Inverters & MV Transformers)	0.8%
Availability of Collection, HV Transformer, & Substation	0.2%
Availability of Utility Grid	0.2%
System Consumption (Inverters, HVAC)	0.3%
POI Curtailment (Before Degradation)	0.0%
Operational Total	**1.7%**
Annual Performance Degradation (Material/System Average) *	***0.51% / 0.7%***
Combined Loss	**19.6%**

EFFECTIVE IRRADIATION

- **Horizon Shading:** This loss accounts for the decrease in radiation due to the horizon. Far objects or topography (i.e., hills and mountains) can result in a horizon line that may cause shading over the project area. The horizon line and position of the sun help to estimate this loss on an hourly basis.
- **Near Shading:** This loss accounts for the decrease in radiation caused by row-to-row and nearby obstacle shading. Array geometry and sun position estimate this loss on an hourly basis. UL assumes trees and scattered brush throughout the project site to be removed so that they will not cast shadows on the modules.
- **Incident Angle Modifier Factor IAM (Reflection) -** The incident angle modifier ("IAM") effect was modeled according to the module specific IAM parameterization; and
- **Soiling Losses -** Soiling impact was estimated on a monthly basis based on precipitation data from nearby available data sources. Per the Sponsors' agreement, there will be soiling control and cleaning activities throughout the year. The soiling loss was estimated assuming 1 cleaning is to be performed every year during the dry season; considering site conditions and maintenance.

PHOTOVOLTAIC CONVERSION

- **Initial Light-Induced Degradation—ILID:** This loss accounts for the initial light induced degradation in power output that a PV module may experience after its first exposure to sunlight. Module power ratings established from flash tests will typically adjust to represent the stabilized power output after the initial degradation period.
- **Non-STC Operation (Irradiance Level and Temperature):** These losses account for energy lost due to operation at conditions other than standard testing conditions, including changes in performance due to irradiance and temperature. UL assumes that the module's thermal behavior results from incident radiation, ambient temperature, wind speed, and the module's thermal characteristics.
- **Module Quality:** This loss accounts for the deviation from the average effective module power output (i.e., average power magnitude) with respect to the manufacturer supplied ratings. The deviation can occur due to manufacturer tolerances used for module binning or varying operating conditions across the array. While PV modules are typically placed into power bins depending on flash test results, actual powers will depend on the bin range and the manufacturer's measurement accuracy. The flash test provided by the Client represented a gain value of -1.5%
- **Module Mismatch:** This loss accounts for the differences in the electrical characteristics of the array's modules (i.e., variation in module power) given the same environmental conditions due to manufacturer tolerances and operating conditions. When connected together, the modules do not operate at their individual peak efficiencies, but instead operate at the collective maximum power point. UL estimates the loss based on the array configuration and the expected tolerances on module output. For this project, module mismatch was estimated to be 0.8% at the start of the project. Additionally, as the system ages, mismatch loss should gradually increase due to system aging (material degradation and component/wiring aging), increasing the impact of mismatch.

ELECTRICAL

- **DC and AC Wiring**: Low voltage wiring accounts for the distance between inverters and Medium voltage transformers, considered standard electrical efficiency loss references for the proposed design. Since the detailed site specific electrical loss calculation was not available for review, UL relied on basic inputs to the simulation model that represent typical electrical design for utility-scale projects and provided plant design information;
- **Inverter Efficiency –**This loss accounts for the DC-to-AC conversion efficiency evaluated for the inverter equipment and site conditions;
- **Medium-Voltage Transformer Efficiency** – Since the detailed site specific electrical loss calculation was not available for review, UL relied on a standard 1.0% electrical efficiency loss at STC;
- **AC Low Voltage Wiring - Collection System** – The Energy Assessment considered an AC LV wiring loss of 1.1% in STC; this value is considered standard reference for this electrical efficiency loss. Since the detailed site specific electrical loss calculation was not available for review, UL relied on basic inputs to the simulation model that represent typical electrical design for utility-scale projects and provided plant design information;
- **High Voltage Transformer Efficiency –** This loss is estimated based on the HV transformers specifications provided. Neither a detailed site-specific electrical loss evaluation nor an electrical design with wires sizes were available for review; and
- **Transmission Line to Point of Interconnection (POI):** UL evaluated this loss based on the transmission line information available including a transmission line length of 13.5km at 34.5kV. Neither a detailed site-specific electrical loss evaluation nor electrical designs with wire sizes were available for review.

OPERATIONAL

- **Tracking System Performance:** This loss accounts for the possibility of tracker accuracy and downtime for motor failures and wind stow. While tracker availability should be high, wind stow events, backtracking algorithm accuracy, and tracker accuracy should also result in a loss factor of 0.2% for N-S axis tracking projects.
- **DC System Performance:** This loss accounts for undetected DC-system failures and underperformance related to maintenance routines. Some module failures, wiring failures, and underperforming modules may occur in the DC system. As the system ages, these failures will increase in frequency; thus, UL has modeled DC system performance loss in 0.1% for year 1, and gradually increase along the long term;
- **HVAC & Auxiliary System Consumption:** This loss accounts for the heating and cooling of the inverter enclosure (if any) and the power consumption of auxiliary components, including tracking motors, data acquisition, electronics, and lighting. According to manufacturer information, a consumption of 3 W/kW from an output power of 100 kW was considered for each inverter. Therefore, for this study the HVAC & Auxiliary components loss further than the inverter consumption is not included in the loss analysis;
- **Availability of Power Plant:** A value of 1.0% was assumed in the assessment. This value was adopted according to the Sponsor’s expectation that O&M services will result in 99.0% plant availability. UL attributes availability losses based on the typical contractual availability for utility-scale projects, and non-contractual availability, primarily due to force majeure events, scheduled maintenance, unscheduled maintenance, and repair delays;

- **Grid Availability of Utility Grid:** UL assumed a grid availability loss of 0.2%, which corresponds to four 6-hour events per year during daylight hours. This is a standard assumption for grid reliability and is consistent with typical local grid operation; and
- **POI Limitation Curtailment** – This loss accounts for lost production due to power purchase agreement curtailment or grid restrictions. A power plant limitation of 40.00MW$_{AC}$ at POI was considered according to Project available information, resulting in a value of 0.0% loss.

MATERIAL DEGRADATION

The material degradation rate represents degradation of the solar module material. The annual degradation in module output is estimated based on module specifications provided by the manufacturer, industry typical values, and UL's experience with similar projects. The module supplier warrants that annual degradation will not exceed a certain amount in 25, resulting in a material degradation percentage per year. UL assumes that actual degradation rate equivalent to the warranted period during the years after the end of the warranty (i.e. years 26/31 to 40).The project-specific material degradation rate is estimated based on the site-specific climate (e.g., plane-of-array irradiance).

The most common range of the module performance warranty for the first year is around 2.0% to 2.5% for conventional technologies (monocrystalline and polycrystalline silicon based modules). Relatively new PV modules in the industry using monocrystalline Passivated Emitter and Rear ("PERC") high efficiency cells provide 2.0% of performance warranty for the first year.

Regarding the long-term performance degradation, the industry standard is 0.7% per year for a 25-year periods for conventional technologies (Si-modules). However, UL notes that double glass, bifacial modules or in some cases high efficiency PERC modules currently provide a 0.5% degradation rate per year for a 30-year period.

Considering the UL degradation assumption for a large data base of project worldwide, UL expects an actual degradation rate of 0.4%-0.6% for real material degradation during operation depending on the cell technology, manufacturer warranty and project site conditions [1] and [2].

LONG TERM CALCULATION APPROACH

Energy System Output is estimated along the Long Term according to plant technology, industry typical values, the local climate, and UL's experience with similar projects. Together with impact of Material Degradation, the Long Term Assessment accounts for additional adjustments of system factors that are expected to impact the long-term energy output of the project:

- **Inverter and Curtailment Loss Reclamation:** If relevant, inverter limitation loss and curtailment loss reclamation are assessed. As the DC array reduces in capacity, UL expects these loss factors to also gradually reduce.
- **DC System Performance Loss Increase:** DC system performance loss is expected to increase by 0.04% per year, cumulating to 1.1% in 25 years due to component/wiring failures, underperforming and broken modules, and other array-level events that may not be identified or addressed immediately by O&M activities.

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[1] [1] D. C. Jordan and S. R. Kurtz, (2013). Photovoltaic Degradation Rates-an Analytical Review. Progress in Photovoltaics: Research and Applications. 21, no. 1, pp. 12–29.

[2] M. Optis, P. Johnson, E. Mayo, J. Pollard. Lessons Learned from Operational Energy Data to Inform Pre-Construction Estimates (2018).

- **Mismatch Loss Increase:** As the DC array reduces in capacity, it is expected that mismatch losses will increase. An annual mismatch loss increase of 0.01% per year was assigned, cumulating to 1.21% mismatch loss by year 25.

Calculation Approach: Long term applicable loss balance is calculated from year zero and additional applicable adjustments to characterize year X. Material degradation was applied subtractively to the partial net energy at the point of the module in the system's energy flow (i.e., not being applied to those losses not impacted by material degradation). UL considers the year-zero subtractive approach to be most appropriate when considering the physical realities of degradation and its impact on the system's energy.

UL evaluated all loss categories based on the level of detail provided in Project contracts, the Project design, and the selected equipment.

APPENDIX D - ENERGY MATRICES 12 X 24

Table D.1: First Year - Estimated Annual and Monthly Net Energy (kWh)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average (kWh)	Total (MWh)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	102	911	1440	1375	801	856	979	1062	622	49	685	250
7	6681	6968	9538	10269	10646	10261	8792	10716	11737	10261	11062	8008	9579	3499
8	21611	22969	24703	21481	19953	18708	18275	22303	24083	20683	20994	20647	21340	7795
9	29304	30951	31514	26807	24963	22804	21849	25470	27575	25259	23521	25045	26211	9573
10	30751	32571	33541	29644	28235	25681	25220	28084	29910	27497	25561	26933	28594	10444
11	31598	33079	34496	31586	28523	26682	28210	29321	28979	28079	24606	28523	29440	10753
12	30911	33660	33792	31968	30412	27222	28219	30379	28601	28653	23794	27333	29543	10791
13	29699	33269	34156	31187	30813	29129	29373	27542	27075	26103	24683	26745	29106	10631
14	29260	32124	32453	28760	24140	23332	24363	20663	21550	21978	22360	26516	25572	9340
15	27384	29379	29714	24026	16337	16613	17104	11991	13796	12807	16429	20745	19622	7167
16	22702	25292	24110	17583	9861	10921	10941	7957	6402	6892	8225	14611	13720	5011
17	9592	12561	11832	7886	4730	4686	5935	4760	2396	2388	1953	4568	6071	2217
18	252	1158	1178	758	498	756	903	819	19	0	0	0	524	192
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Average (kWh)	11239	12249	12547	10953	9606	9090	9166	9203	9296	8819	8492	9572	10000	
Total (MWh)	8362	8231	9335	7886	7147	6545	6820	6847	6693	6562	6114	7121		87663

Table D.2: Long Term 25-Year - Estimated Annual and Monthly Net Energy (kWh)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average (kWh)	Total (MWh)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	94	839	1327	1267	738	789	903	979	574	45	631	231
7	6158	6422	8791	9465	9812	9458	8104	9877	10817	9458	10196	7381	8829	3225
8	19918	21170	22769	19799	18390	17243	16844	20557	22197	19063	19350	19030	19669	7184
9	27009	28527	29046	24708	23008	21018	20138	23475	25415	23281	21679	23084	24158	8824
10	28343	30020	30914	27322	26023	23669	23244	25885	27568	25344	23560	24823	26355	9626
11	29123	30488	31795	29112	26290	24592	26001	27025	26709	25880	22679	26289	27135	9911
12	28490	31024	31145	29464	28030	25090	26009	28000	26361	26409	21930	25192	27230	9946
13	27373	30663	31481	28745	28400	26848	27073	25385	24954	24059	22750	24650	26827	9799
14	26968	29608	29911	26507	22250	21505	22455	19045	19863	20257	20609	24439	23569	8609
15	25239	27078	27387	22144	15057	15312	15765	11052	12715	11804	15143	19120	18086	6606
16	20924	23311	22222	16206	9089	10065	10084	7334	5901	6352	7581	13466	12646	4619
17	8840	11577	10906	7268	4360	4319	5470	4387	2208	2201	1800	4211	5595	2044
18	232	1068	1086	699	459	697	832	755	17	0	0	0	483	177
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Average (kWh)	10359	11290	11564	10095	8854	8378	8448	8482	8568	8129	7827	8822	9217	
Total (MWh)	7707	7587	8604	7268	6587	6032	6285	6311	6169	6048	5635	6564		80798

APPENDIX E – REPOWERING SCENARIO

UL has performed an independent resource and energy assessment based on review of provided equipment characteristics, Project documents, contracts, and design according to the level of provided design. UL evaluated two scenarios for the PV Project; standard scenario with the current PV Project configuration and a repowering scenario based on the information provided.

UL was provided with a repowering implementation plan from the Client for the PV Project. The repowering strategy consist of installing an additional DC peak power capacity of 1.7 MWp every 5-year period. UL notes that no replacement of PV modules or any components is considered, only additional capacity to be added, therefore, extension of PV Project area will be required in order to place new trackers and PV modules.

The repowering strategy is considered to optimize the energy output of the PV Project, considering that PV modules degradation will progressively reduce the actual effective installed DC capacity. The inverter numbers will remain constant while the DC/AC capacity will be increased every 5-year period. UL notes that the DC/AC ratio of year 1 is 1.14, which is considered to be industry standard and this does not provoke a considerable inverter limitation loss. Although the new repowering capacity will increase the DC/AC ratio, the PV module degradation also will contribute to a reduction of the year-to-year DC/AC ratio.

UL was informed that no detailed documentation is still available regarding repowering capacity configuration for the PV Project. UL notes that additional new capacity should be added as complete strings addition (without mixing previously installed PV modules with new PV modules). Single line diagrams should be evaluated to divide new additional strings connections to already installed inverters. UL recommends performing an independent review on the detailed engineering before installing the new capacity at year 5.

UL performed a high-level energy assessment of the repowering scenario considering Client provided information and PV project energy assessment for standard scenario (without repowering). UL evaluated the energy increase of the 1.7 MWp new capacity to be added every 5 years based on the equivalent PV Project estimated energy yield (kWh/kWp). As the system degradation needs to be considered, UL assumed that year 5 annual energy production will be equal to year 5 production of standard scenario plus the new equivalent energy generation of 1.7 MWp (this is a simplification and rough estimation due to the fact that not specific design and detail calculation have been made at this moment). Then the system degradation was estimated for the additional capacity (considering that was installed at year 5). The process was repeated for each 5-year period where new additional 1.7 MWp blocks were considered (assuming specific system degradation for each period).

The uncertainty assessment was estimated for the repowering scenario considering a specific uncertainty for the repowering energy production. UL evaluated the uncertainty of the new installed capacity production based on the level of detail of the information provided by the Client. The new energy production of the repowering scenario was estimated to be 12%.

Table E.1: Solar Project Design and Main Equipment – Repowering Scenario

Metric	Value
AC/DC Rating [Pnom Ratio]	45.65 MW_{DC}/40.80 MW_{AC} [1.12]
Repowering Strategy	Additional 1.7 MWp every 5-year period
AC limitation at POI	40.00 MW_{AC}
Modules	Jinko Solar JKM330PP-72-V
Inverter	Jema IFX IFX6 -2550 TL.620
Tilt (°)	16
Azimuth (°)	180
Tracking	N-S Single axis ±60°. Backtracking strategy.
Module configuration	2 modules in Portrait
Pitch distance (m)	7.15; 8.00; 7.25; 7.985
Total strings	4,632
Total modules	138,960
Total inverters	16

Table E.2: Estimated PV System Performance – Repowering Scenario

Performance Metric	First Year	Lifetime
Global Horizontal Irradiation (kWh/m^2/yr)	2007	2007
Plane-of-Array Irradiation (kWh/m^2/yr)	2393	2393
Gross Energy (GWh/yr)	109.22	113.29
Net Energy (GWh/yr)	87.66	87.51
Performance Ratio (%)	80.3	74.3
AC Capacity Factor (%)	24.5	24.5
Energy Yield Ratio (kWh/kW_{DC})	1920	1910
Total Lifetime (25-year) Energy Production (GWh)	-	2187.78

Table 0E.3: Estimated Evaluation Period Annual PV System Performance – Repowering Scenario

Year	Net Energy Production (GWh)	Performance Ratio (%)	AC Capacity Factor (%)
1	87.66	80.3	24.5
2	87.18	79.8	24.4
3	86.60	79.3	24.2
4	86.02	78.8	24.1
5	88.71	78.3	24.8
6	88.11	77.8	24.7
7	87.51	77.2	24.5
8	86.90	76.7	24.3
9	86.30	76.2	24.1
10	88.97	75.8	24.9
11	88.35	75.3	24.7
12	87.72	74.8	24.5
13	87.10	74.2	24.4
14	86.48	73.7	24.2
15	89.12	73.4	24.9
16	88.48	72.9	24.8
17	87.83	72.3	24.6
18	87.19	71.8	24.4
19	86.54	71.3	24.2
20	89.16	71.1	24.9
21	88.50	70.5	24.8
22	87.84	70.0	24.6
23	87.17	69.5	24.4
24	86.50	68.9	24.2
25	85.84	68.4	24.0
Average	**87.51**	**74.3**	**24.5**

Note: Year 1 degradation loss is applied at mid-year.

Table E.4: Uncertainty Summary Resource and Energy - First-Year – Repowering Scenario

Source of Uncertainty	GHI (%)	GHI ($kWh/m^2/yr$)	Energy (%)	Energy (MWh/yr)
Measurement Accuracy	5.0%	100	5.0%	4,383
Inter-Annual Variability	2.8%	56	3.0%	2,646
Representativeness of Monitoring Period	0.6%	12	0.6%	532
Spatial Variability	0.1%	2	0.1%	88
Simulation and Plant Losses	-	-	3.5%	3,062
Annual Degradation	-	-	0.1/yr	-
Combined Uncertainty	**5.8%**	**116**	**6.8%**	**5,990**

Note: First-year combined uncertainty does not account for degradation uncertainty, which only impacts energy uncertainty in future years

Table E.5: Uncertainty Summary Resource and Energy - Long Term 25-Year Annual Average – Repowering Scenario

Source of Uncertainty	GHI (%)	GHI (kWh/m^2/yr)	Energy (%)	Energy (MWh/yr)
Measurement Accuracy	5.0%	100	5.0%	4,376
Inter-Annual Variability	2.9%	58	3.1%	2,710
Representativeness of Monitoring Period	0.6%	12	0.6%	531
Spatial Variability	0.1%	2	0.1%	88
Simulation and Plant Losses	-	-	3.5%	3,056
Annual Degradation	-	-	1.3%	1138
Combined Uncertainty	**5.8%**	**116**	**7.0%**	**6,152**

Note: 25 year average energy uncertainty accounts for increasing degradation loss/uncertainty and increasing climate uncertainty.

Table E.6: Uncertainty Summary Resource and Energy –25-Year Evaluation Period Average – Repowering Scenario

Source of Uncertainty	GHI (%)	GHI (kWh/m^2/yr)	Energy (%)	Energy (MWh/yr)
Measurement Accuracy	5.0%	100	5.0%	4,376
Inter-Annual Variability	0.9%	18	0.9%	809
Representativeness of Monitoring Period	0.6%	12	0.6%	531
Spatial Variability	0.1%	2	0.1%	88
Simulation and Plant Losses	-	-	3.5%	3,056
Annual Degradation	-	-	1.3%	1138
Combined Uncertainty	**5.1%**	**103**	**6.4%**	**5,581**

Note: Annual average energy uncertainty accounts for degradation and climate uncertainty over the project's lifetime. Evaluation period uncertainty adjusts for the reduced effect of inter-annual variability over the project's lifetime

P table for annual energy production is included in the following table.

Table 0E.7: Uncertainty Summary Resource and Energy –25-Year Evaluation Period Average – Repowering Scenario

Probability of Exceedance	First Year		Annual Average		Evaluation Period Average	
	Annual Energy Production (GWh)	AC Capacity Factor	Annual Energy Production (GWh)	AC Capacity Factor	Annual Energy Production (GWh)	AC Capacity Factor
P50	87.66	24.5%	87.51	24.5%	87.51	24.5%
P75	83.62	23.4%	83.36	23.3%	83.75	23.4%
P90	79.99	22.4%	79.63	22.3%	80.36	22.5%
P95	77.81	21.8%	77.39	21.7%	78.33	21.9%
P99	73.73	20.6%	73.20	20.5%	74.53	20.9%

Year-by-year uncertainties for a 25-year timeframe and associated P values are included in the following table.

Table E.8: Evaluation Period Uncertainty Summary and P Tables – Repowering Scenario

Year	P50 Net AEP (GWh)	Uncertainty (%)	Uncertainty (GWh)	P75 (GWh)	P90 (GWh)	P95 (GWh)	P99 (GWh)
1	87.66	6.8%	5.99	83.62	79.99	77.81	73.73
2	87.18	6.8%	5.96	83.16	79.54	77.38	73.32
3	86.60	6.8%	5.92	82.60	79.01	76.86	72.82
4	86.02	6.8%	5.89	82.05	78.47	76.33	72.32
5	88.71	6.9%	6.08	84.60	80.91	78.70	74.56
6	88.11	6.9%	6.05	84.03	80.36	78.16	74.04
7	87.51	6.9%	6.02	83.45	79.79	77.61	73.51
8	86.90	6.9%	5.99	82.87	79.23	77.05	72.97
9	86.30	6.9%	5.96	82.28	78.66	76.50	72.44
10	88.97	6.9%	6.16	84.81	81.07	78.83	74.64
11	88.35	6.9%	6.13	84.21	80.49	78.26	74.08
12	87.72	7.0%	6.11	83.60	79.90	77.68	73.51
13	87.10	7.0%	6.08	83.00	79.30	77.09	72.95
14	86.48	7.0%	6.06	82.39	78.71	76.51	72.38
15	89.12	7.0%	6.27	84.89	81.08	78.81	74.53
16	88.48	7.1%	6.25	84.26	80.47	78.20	73.94
17	87.83	7.1%	6.23	83.63	79.85	77.59	73.34
18	87.19	7.1%	6.21	83.00	79.23	76.97	72.74
19	86.54	7.2%	6.19	82.37	78.61	76.36	72.14
20	89.16	7.2%	6.41	84.84	80.95	78.62	74.25
21	88.50	7.2%	6.39	84.19	80.31	77.98	73.63
22	87.84	7.3%	6.38	83.53	79.66	77.34	73.00
23	87.17	7.3%	6.36	82.88	79.01	76.70	72.37
24	86.50	7.3%	6.35	82.22	78.37	76.06	71.73
25	85.84	7.4%	6.34	81.56	77.72	75.41	71.10
Annual Average	**87.51**	**7.0%**	**6.15**	**83.36**	**79.63**	**77.39**	**73.20**
Evaluation Period Average*	**87.51**	**6.4%**	**5.58**	**83.75**	**80.36**	**78.33**	**74.53**

*Evaluation period cumulative energy uncertainty adjusts for the reduced effect of inter-annual variability over the project's.

APPENDIX B—PENONOMÉ II OPERATIONAL ENERGY PRODUCTION REPORT

OPERATIONAL ENERGY PRODUCTION REPORT

PREPARED FOR:
UEP PENONOME II, S.A.

Ref. No.: ES-AA20-13321645-04.07

OEPR PENONOMÉ II
Panamá
Penonomé

05 October 2020

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DOCUMENT HISTORY

ISSUE	DATE	SUMMARY
A	4th June 2020	First emission
B	15th June 2020	Add sub-project analysis
C	19th June 2020	Additional data and sub-project analysis modifications
D	10th August 2020	Long-term reference update
E	20th August 2020	Long-term reference corrections
F	15th September 2020	Contractual availability and energetic losses updates
G	16th September 2020	Rewording and changes in losses names
H	05th October 2020	Future availability and curtailment revised

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ACRONYMS

Acronym		Description
C	COD	Commercial Operating Date
E	EAF	Equivalent Availability Factor
	EC	Environment Canada
	ECMWF	European Centre for Medium-Range Weather Forecasts
	ERA-I	ERA-Interim
G	GW, GWh	Gigawatt, Gigawatt hour
I	IEC	International Electrotechnical Commission
	ISH	Integrated Surface Hourly database
K	km	Kilometer
L	LT	Long-term
M	m	Meter
	MCP	Measure-Correlate-Predict
	MERRA-2	Modern-Era Retrospective Analysis for Research and Applications
	MW, MWh	Megawatt, Megawatt hours
	m/s	Meters per second
N	NA	Not Available
	NCDC	National Climatic Data Center
	NCEP	National Centers for Environmental Prediction
	NNRP	NCEP/NCAR Reanalysis Project
	NOAA	National Oceanic and Atmospheric Administration
P	POR	Period of Record
R	r	Pearson correlation coefficient
	R^2, r^2, r-squared	Coefficient of determination
W	WRF	Weather Research and Forecasting
Y	Yr	Year

LIST OF DEFINITIONS

Name	Definition
Evaluation Period	The time period immediately following the operational POR to which future estimates of energy are applied. The evaluation period is typically 10 years.
Operational POR	The months within the wind plant total period of operation for which reported energy and loss data have been quality-controlled and determined to be valid for use in this analysis.

1. EXECUTIVE SUMMARY

UL was retained by UEP Penonome II, S.A. to evaluate the long-term energy production potential of Penonomé II wind farm, located in Panamá, using operational data. The project has a nominal capacity of 215 MW with 86 Goldwind GW 106/2500 wind turbines on site. All turbines have a rotor diameter of 107.5 meters and a hub height of 90 meters. Penonomé II farm achieved COD in 2015.

The analysis relied on the monthly operational report data to estimate LT plant performance over an evaluation period of 15 years. The data were first quality screened and evaluated for factors such as plant-startup bias and other one-time events which were assessed individually and removed from the analysis where appropriate. Monthly gross energy production values were then calculated from the reported monthly energy production data by adjusting for availability and other losses. These gross energy values were then normalized to 30-day standard months to provide a consistent baseline. Suitable LT reference datasets were then identified by analyzing r-squared coefficients between the density-adjusted monthly reference wind speeds and the normalized monthly gross energy production over the operational POR. Regression relationships between selected LT reference wind speed datasets and normalized gross energy production were used to calculate long-term gross energy production on a monthly and annual basis. Finally, estimates of future project availability, blade degradation and electrical losses were applied to the gross energy to estimate the LT net energy production potential for the project.

This report presents the results of this analysis and discusses the methods used to develop the future availability, losses, gross and net energy production, as well as uncertainty estimates. A summary of the project and results is presented in the following tables.

Table 1.1: Project results summary

Project Name	Penonomé II
Project Location	Panamá
Nominal Capacity	215 MW
Turbine Model	Goldwind GW 106/2500
Hub Height	90 m
Rotor Diameter	107.5 m
Number of Turbines	86
Commercial Operation Date	2015
Operational POR	January 2016 - July 2020
Projected Future Operational Gross Energy Production	554.1 GWh/year
Availability	5.4% loss (94.6% eff)
Curtailment Loss	0.2% loss (99.8% eff)
Electrical Loss	4.5% loss (95.5% eff)
Blade Degradation losses	0.2% loss (99.8% eff)
P50 Average Annual Net Production	498.7 GWh/year
P50 Net Capacity Factor	26.5%
P90 Average Annual Net Production - Evaluation Period	471.4 GWh/year
P90 Net Capacity Factor	25.0%
P99 Average Annual Net Production – 1 Year	368.3 GWh/year
P99 Net Capacity Factor – 1 Year	19.5%

2. INTRODUCTION

UL was retained by UEP Penonome II, S.A. to evaluate the long-term energy production potential of Penonomé II wind farm, located in Panamá, using operational data. The project has a nominal capacity of 215 MW with 86 Goldwind GW 106/2500 wind turbines on site. All turbines have a rotor diameter of 107.5 meters and a hub height of 90 meters. Penonomé II farm achieved COD in 2015.

This report presents the results of this operational energy assessment and discusses the methods used to develop the future project availability, other losses and blade degradation losses, gross and net energy production, as well as the uncertainty estimates.

3. DATA SUMMARY

UEP Penonome II, S.A. provided the data from September 2015 to July 2020 which included the following information:

- Monthly reports with wind turbine availability and power generation: IEH reports with information from 2016 to 2020, and Goldwind reports with information since 2018.
- 10-minutal SCADA wind turbine data.
- Event log and alarms description.
- Revenue meters hourly information “Medidores SMEC” (sum of input and output).
- Documentation with additional energy losses considerations, “UL Energy Meeting Requests.doc”
- Monthly production data summary, ” YTD Generation vs. UL.xlsx”, including additional energy losses.

The IEH data was used for wind turbine energy (i.e. SCADA sum-of-turbine production), availability and plant level production.

No energy production invoices were provided.

Table 1.1 presents the production, availability and loss data extracted from the reports, as well as density-corrected wind speeds from the reference data sets (discussed in detail in section 4.2).

3.1 Availability

When evaluating the project availability, careful attention should be paid to the subsystems that make up the availability in order to appropriately assess the forecasted energy production of the site. A frequently used term in monthly reporting mechanisms is contractual turbine availability, specifically defined by the manufacturer for the project. The turbine contractual availability is typically the ratio between the time in which the turbine is operational according to the manufacturer-specific contractual language (“turbine ok time”), not considering excluded events, and the total possible time (calendar time). Contractual turbine availability represents one of the subsystems of the plant.

The total plant availability is typically defined as the combination of availability statistics from the following subsystems: turbine (contractual), collection system including substation and grid, and other non-contractual events (e.g., test, environmental). Since turbine faults and downtime not included in the warranty are the responsibility of the plant operator, plant-level availability is typically a more accurate representation of the plant production potential. Ultimately, due to the nature of contractual agreements, there are a wide range of possible availability definitions. UL considers both the contractual or plant definitions provided by the customer and any project-specific operational considerations to make a decision on the most appropriate availability definition to use for each project.

UL typically prefers to use energy-based availability for operational energy production estimates since it more directly relates lost production to energy. This generally results in a better correlation (as measured by R^2) of availability-corrected production to wind speed, which in turn leads to lower uncertainty in the energy estimates. However, in certain instances where inconsistencies in reported energetic availability data are detected, UL may elect to use time-based availability to correct the production data and to make future energy projections. The choice of availability definition is not expected to have a significant impact on the result.

For this assessment UL was provided time-based metrics of Plant Availability from the IEH data. Historical reported turbine and plant availability data are shown in Table 1.1 and Figure 7.2.

3.2 Electrical loss

Electrical losses were calculated from the IEH data. UL assumed these losses were representative of the losses incurred from the turbine terminals to the POI. The electrical loss was calculated as the difference between the monthly net energy production and the monthly wind turbines production.

Historical electrical collection system losses are shown in Table 1.1.

3.3 Other losses

Additional energetic losses have been provided by the client ("UL Energy Meeting Requests.doc").UL has categorized these losses into 2 categories. Force Majeure , these are energetic losses that are considered extraordinary and likely will not occur again in the future evaluation period and normal, these are energetic losses likely to be repeated periodically during the wind farm life.

4. PLANT POWER CURVE

A plant power curve represents the relationship between monthly gross energy production from a wind farm (i.e. corrected for availability and curtailment) and density-corrected monthly average wind speed at a reference station. The curve is used to derive the LT gross energy production estimate from which the LT net energy production estimate can then be calculated by accounting for future availability, curtailment, and other losses.

Since the wind climate can vary considerably over time scales of months to years, it is important to adjust the gross energy production over the operational POR to reflect long-term historical wind conditions as closely as possible. The method used to make this adjustment is known as measure-correlate-predict, or MCP. In MCP, a linear regression or other relationship is established between two or more data sources over a concurrent POR. One, the target, spans a relatively short period and the other, the reference, spans a much longer period. More than one reference may be used. The regression relationship is then applied to the LT historical reference wind speeds to estimate the LT gross energy production for the wind farm.

Normally, the most important factor determining the success of MCP is the choice of reference datasets, particularly the quality of the relationship with the target site (which should ideally be linear with a high correlation coefficient) and the consistency and length of the reference data record.[1]

[1] Taylor, Mark, et al., "An Analysis of Wind Resource Uncertainty in Energy Production Estimates," Proceedings of the European Wind Energy Conference, November 2004.

4.1 Normalized Gross Energy Production

Since monthly energy production reflects variations in the length of each month as well as changing availability and losses, it must be normalized to a consistent standard to develop a representative plant power curve. The benchmark selected is the gross energy production for 30-day months. This value does not include availability, electrical losses or curtailment losses but does include other plant losses (e.g. wake) as well as losses relating to environmental factors and power curve windiness adjustments.

The net energy production during each month over the operational POR was converted to gross energy production using Eq 1:

$$Prod_{100} = \frac{Prod_{obs}}{Avail_{plant}} + Losses \qquad \text{Eq. 1}$$

where:

$Prod_{100}$ = Estimated monthly gross energy production (i.e. 100% availability and no curtailment)
$Prod_{obs}$ = Reported monthly energy production
$Avail_{Plant}$ = Time-based plant availability for the month, expressed as a fraction
$Losses$ = Measured losses not include in the availability factor (i.e. electrical, other,…)

Gross energy production values calculated using Eq. 1 are representative of a full month of operation for the number of days in that month. To give equal weight to each month, the gross energy production values were normalized to standard 30-day months:

$$Prod_{norm} = Prod_{100}\left(\frac{30}{Days_{Month}}\right) \qquad \text{Eq. 2}$$

where:

$Prod_{norm}$ = Estimated monthly gross energy production for a 30-day month
$Days_{month}$ = Number of days in the month.

Plant power curves should be based on periods of consistent operation. Significant changes in wind turbine control parameters, uprates, or changes in wake from the construction of neighboring wind farms, among other factors, can affect gross energy production and should be considered in constructing the power curve. For this analysis the following months were excluded for this reason:

- February 2018 – inconsistent reporting of losses
- March 2018 – inconsistent reporting of losses
- March 2019 – inconsistent reporting of losses

Because of uncertainty over the true energy lost due to downtime, months in which the availability is below 83% are generally excluded from the regression analysis. The following months were excluded for uncertainty over true energy lost:

- July 2017 to October 2017 – high “force majeure losses”
- August 2019 to September 2019 – low availability

4.2 Long-term Reference Datasets

The following datasets were considered as possible long-term references:

- MERRA-2 reanalysis dataset[2]: Since January 1997
- ERA5 reanalysis dataset[3]: Since January 2004

The locations of the LT reference datasets are indicated on the regional map in Figure 7.1. These datasets were extracted at the closest available model heights to hub height of 90 m of the Goldwind GW 106/2500 turbines.

Although the reanalysis datasets go back several decades, the starting date was limited to January 1997 to reduce the risk of introducing significant biases in the results due to major changes in measurement systems that occurred in the earlier periods.

Variations in air density may contribute to variations in normalized monthly gross energy production. The International Electrotechnical Commission (IEC) describes a method for adjusting observed wind speed data collected during wind turbine performance testing to account for fluctuations in air density.[4] For pitch-regulated turbines, the adjustment equation is as follows:

$$V_n = V_{obs} \left(\frac{\rho_{obs}}{\rho_0}\right)^{1/3} \qquad \text{Eq. 3}$$

where:

V_n = Density-Adjusted Wind Speed;
V_{obs} = Measured Wind Speed;
ρ_{obs} = Measured Air Density;
ρ_0 = Annual Average Air Density.

This formula was used to adjust both the observed and long-term monthly average wind speeds for each reference source. The air densities for all reference sources were based on the MERRA-2 interpolated dataset at 50 m height above ground-level.

4.3 Measure Correlate Predict (MCP)

Linear regression models were established between the monthly normalized gross energy production for the wind farm and the concurrent density-adjusted monthly mean wind speeds calculated for each of the LT references. For the reanalysis models (i.e. ERA5 and MERRA-2), data from the 4 horizontal grid points closest to the wind farm as well as data interpolated to a representative location within the

[2] The Modern-Era Retrospective Analysis for Research and Applications Version 2 (MERRA-2) dataset was developed by the National Aeronautics and Space Administration (NASA). MERRA-2 utilizes a variety of observing systems which have been assimilated into a global three-dimensional grid by numerical atmospheric models at a horizontal resolution of 1/2° latitude and 2/3° longitude. Multiple interpolated data points as well as the 4 surrounding grid points were assessed.

[3] The ERA5 dataset was developed by the European Centre for Medium-Range Weather Forecasts (ECMWF). ERA5 utilizes a variety of observing systems which have been assimilated into a global three-dimensional grid by numerical atmospheric models at a spectral resolution of T255, or an approximate horizontal resolution of 79 km. Multiple elevations at interpolated data points as well as the 4 surrounding grid points were assessed.

[4] IEC 61400-12-1, 2005 First Edition. Wind Turbines – Part 12-1, Power Performance Measurement of electricity producing wind turbines.

project area were considered (see Figure 7.1). The highest MERRA-2 correlation was at grid point 1 which had an r-squared of 0.931. The highest ERA5 correlation was at grid point 1 which had an r-squared of 0.950.

Figure 7.3 shows annual mean wind speed anomalies of the long term datasets. The annual deviations of all reference data points appear consistent over time and track each other reasonably well. No abrupt changes or discontinuities are found in either dataset which would indicate some change in the source data or analytical techniques used to simulate the wind speed. There is however a strong downward trend in the MERRA2 reanalysis (0.72%/yr) which is the basis for its exclusion from further analysis. .

The regression equation between the normalized monthly gross energy production and the density-adjusted monthly reference wind speeds over the operational POR is as follows:

$$Prod_{norm} = a \times WS_{ref} + b \qquad \text{Eq. 4}$$

where:

WS_{ref} = Density-adjusted monthly reference wind speeds;
a = Regression slope;
b = Regression intercept

The regression analysis over the operational POR at the wind farm produced $a = 20.18$; $b = -35.56$ for the ERA5 reanalysis. This regression relationships was then applied to the LT density-adjusted reference wind speeds in order to calculate the LT normalized gross energy production for the wind farm. These normalized gross energy values were then converted back to gross energy values for each calendar month based on its number of days by inverting Eq. 2:

$$Prod_{100} = Prod_{norm}\left(\frac{Days_{Month}}{30}\right) \qquad \text{Eq. 5}$$

4.4 Long-term Gross Energy Production

Finally, annualized monthly production was calculated from the LT gross energy production and then summed as presented in Table 7.3. The resulting long-term annual gross energy was 554.1 GWh/yr. This future estimate is higher than the annualized gross energy over the plant operational POR (533.0 GWh/yr) by about 4.0% due to wind speeds being below average during the POR.

5. LONG-TERM NET ENERGY PRODUCTION

LT net annual energy production is calculated from LT gross annual energy production by adjusting for future blade degradation losses (currently not reflected in the operational data), availability losses, and other losses. These losses and adjustments are described below.

5.1 Blade Degradation Adjustment

UL considers blade degradation as cumulative, aggregating at a rate of approximately 0.12%/year, or 1.2% every 10 years. This is accompanied by an assumption that blades are refinished to a near new condition every 10 years, resulting in an average blade degradation of about 0.6%. These assumptions were applied to the evaluation period of 10 years and resulted in an adjustment of 0.2%, as the degradation inherent in the operational data is not yet representative of what is expected over the future evaluation period.

5.2 Availability

The expected future availability of a wind plant is usually based on past performance after corrections for start-up issues, one-time events, and other factors where applicable. The historical annualized plant availability was 94.1%.

According to the information provided by the client (Blades Strategy Plan UEPII - Executive Report V4.pdf), a long-term future availability has been projected considering the operational availability closer to the real behavior of the windfarm. For that purpose, a future availability has been estimated by the Client based on the contractual availability, blades strategy plan unavailability, preventive maintenance (WTG and BOP), unscheduled maintenance and blades wind turbine events. As a result of the previous considerations, the future operational average availability has been estimated to be 94.6%. UL reviewed these estimations for the future availability calculation and considers that the client's assumptions are reasonable.

As a result the future availability was assumed to be 94.6% going forward.

5.3 Electrical and Collection System

Annualized electrical and collection system losses over the historical record were calculated and found equal to 4.5%. Future electrical and collection system losses are expected to be in line with the historical average and as such a future value of 4.5% was applied going forward.

5.4 Curtailment

Historical curtailment was calculated and found to equal 1.5 % . UL expects an average annual curtailment of 0.2% which represents the expected average availability/unrestricted scenarios expected in the ETESA long term planification. UL is not aware and does not have sufficient information to estimate how much of this figure would be sourced in grid unavailability and which part on generation is redispatch. UL is aware and can confirms that part of the re-dispatched generation of the wind farm is repaid with the spot price during the restriction event. That means that part of this 0.2% generation curtailed will be reimbursed to the Project. In any case, UL therefore recommends applying a scenario where no curtailment is repaid and considering and assuming an annual curtailment of 0.2% as the future curtailment.

5.5 Other Losses

Other losses when annualized were equal to 0.4% and are related to force majeure events which are not typical of future operations. These are considered one-time non-periodic events over the evaluation period and as such the future loss associated with other was 0.0%.

5.6 Net Energy Production

To determine the expected annual net energy production (i.e. the P50), the estimated gross energy production was calculated based on the combined assumptions of expected future blade degradation, availability and other losses. The resulting annual average net energy production estimate was calculated as 498.7 GWh (26.5% NCF) for the 10-year evaluation period. This calculation is summarized in Table 7.3.

It should be noted that no energy production invoices were provided by the client and the predicted long-term net energy production represents the expected future production of the project based on the operational conditions and assumptions which formed the basis of this analysis. Future energy production could be significantly impacted in the event of changes in average plant downtime, turbine performance or curtailments, changes to avian curtailment settings or installation of additional nearby wind plants.

6. UNCERTAINTY ANALYSIS

The use of operational wind plant data removes or reduces many of the uncertainty elements associated with the use of pre-construction estimates. In particular, the extrapolation of observed wind speeds to hub height, the distribution of the wind resource over the site, the performance of the turbines, and other plant losses are all implicitly accounted for in the operational data (assuming they do not change in the future).

There remains, however, uncertainty associated with the power measurements, air density adjustments, variations in the wind resource, future plant performance, and future availability, curtailment, and other losses. Uncertainties with respect to the mean wind speed were converted to energy production using the slope (change in production for a given change in speed) of the plant power curve, which is referred to as the energy-to-speed ratio. Other uncertainties were calculated directly from energy. Uncertainties considered in this analysis are described below.

6.1 Power Measurement and Gross Power Adjustment

This category addresses the uncertainty in energy measurements by revenue meters as well as the uncertainty in calculating gross energy from energy values provided.

The measurement uncertainty of the revenue meter was estimated to be no more than 0.5% of the plant energy production based on current international standards[5].

The uncertainty in calculating gross energy from monthly energy values at turbine level depends on the monthly availability, curtailment, and other losses. UL quantified the uncertainty based on the variations of the reported energy loss data and the sample size.

These uncertainty sources were combined to yield a total measurement uncertainty of 1.1% in energy production over the evaluation period.

6.2 Air Density Adjustment

The uncertainty in the density-adjusted reference wind speed data depends on the variation in air density throughout the year relative to the annual mean value. The adjustment applied to the monthly reference wind speeds used to develop the plant power curve formed one component of this uncertainty; the LT adjustment applied to account for the seasonal distribution of air density formed the second component. These two components were combined to yield a density adjustment uncertainty of 0.1% over the evaluation period.

6.3 Representativeness of Historical Period

This uncertainty addresses how well the wind resource may represent historical average conditions during the operational POR and during the LT reference period. UL has undertaken a study of wind

[5] IEC 60688: 2012 Electrical measuring transducers for converting A.C. and D.C. electrical quantities to analogue or digital signals

speed interannual variability (IAV) using the long term global reanalysis datasets.[6] Based on that analysis, the IAV (defined as the standard deviation of annual mean wind speeds) was 5.9%. Based on the reference and plant periods of record and correlation coefficient, the plant power curve, and the spread of estimates from different reference sources, a total uncertainty of 2.5% was estimated for the evaluation period.

6.4 Future Wind Resource

This uncertainty represents how closely the wind resource estimated over the evaluation period may match the historical average. UL calculated the uncertainty over the evaluation period as well as for any single year within that period. Using a calculated IAV of 5.9% and assuming an uncertainty of 0.75% per 15 years to account for possible climate oscillations and trends, and considering the plant power curve, an energy uncertainty of 3.0% associated with the annual mean wind speed was estimated over the evaluation period.

6.5 Wind Speed and Direction Frequency Distribution

The wind speed and direction frequency distribution can vary over time, producing changes in energy production unrelated to changes in the average speed. UL research indicates that the interannual variability of the energy production directly related to wind speed frequency distribution is approximately 2%. Variations in wind direction frequency distribution are assumed to be minor and contained in this estimate. The uncertainty in the long-term energy production estimate resulting from variations in the speed frequency distribution is related to the on-site period of record and the length of the evaluation period. Considering each of these factors, this uncertainty over the evaluation period was calculated as 0.8%.

6.6 Future Project Availability

In this context, for uncertainty estimation, UL considers two sources of uncertainty associated with the future project availability: the variation in project availability observed during the operational POR, and the size of any adjustments made to future availability. It was assumed that the standard deviation of the monthly availability during the operational POR provided a reasonable estimate of the uncertainty in the future availability for a single month. The availability uncertainty over the evaluation period was calculated as 0.6%. Note this assumed no significant changes in plant operation and maintenance practices affecting availability.

6.7 Electrical Loss

This uncertainty is associated with the electrical loss. UL considers the uncertainty to be approximately 20% of the magnitude of the loss itself. The uncertainty associated with the electrical loss was estimated to be 0.9%.

6.8 Curtailment

This uncertainty is associated with the curtailment loss. UL considers the uncertainty to be approximately 20% of the magnitude of the loss itself. The uncertainty associated with the curtailment loss was estimated to be 0.0% when rounded to one significant figure.

[6] Michael C. Brower, et al., "A Study of Wind Speed Variability Using Global Reanalysis Data", AWS Truepower, May 2013.

6.9 Other Loss

This uncertainty is associated with the normal other loss is assumed to be 20 % of the magnitude of the loss itself. As the loss was equal to 0.0% the uncertainty is also 0.0%.

6.10 Future Blade Degradation Loss

This uncertainty is associated with changes in plant performance due to blade degradation over time. UL assumes a constant value, based on the evaluation period length that is applied as an annualized loss in the conversion from gross energy to net energy. The future loss uncertainty over the evaluation period is 0.1%.

6.11 Results

The sensitivity of normalized gross energy production to changes in wind speed is the slope of the linear plant power curve. This energy-to-speed ratio was used to adjust the uncertainty components related to wind speed to their corresponding energy equivalents.

Assuming statistical independence, all of the uncertainties associated with energy production were combined using the square root of the sum of their squares. The total and individual uncertainties for the project are shown in Table 7.5.

Assuming a normal distribution of errors, the combined uncertainty was 4.3%, or 21.3 GWh/yr over the evaluation period. For any single year, the uncertainty was 11.2%, or 56.1 GWh/yr.

Table 7.6 provides also a summary of the uncertainty estimates and the energy production levels that would be exceeded by the project with 50%, 75%, 90%, 95%, and 99% confidence.

7. SUMMARY

Long-term energy production of the Penonomé II wind farm was estimated using production data provided by UEP Penonome II, S.A. as well as LT density-corrected wind speed data from the ERA5 mesoscale dataset from 1997. Plant power curves comparing monthly gross energy and monthly reference wind speeds were used to develop regression relationships and to calculate the expected future annual gross energy production. Long-term net energy production was then calculated based on future plant availability , blade degradation and other future-losses. For the 15 year evaluation period, the expected long-term net energy production (i.e. P50) was calculated as 498,7 GWh/yr (26.5% net capacity factor).

Figure 7.1: Regional Map Indicating nearest MERRA-2 (green dots), and ERA5 (blue dots) reference long-term grid data points.

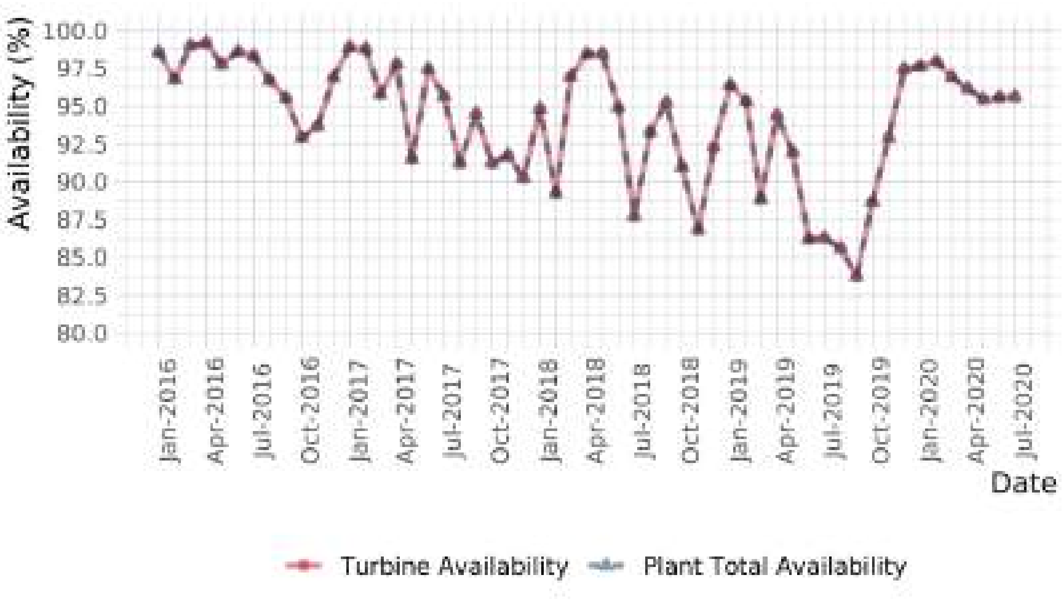

Figure 7.2: Plant Time-based Availability

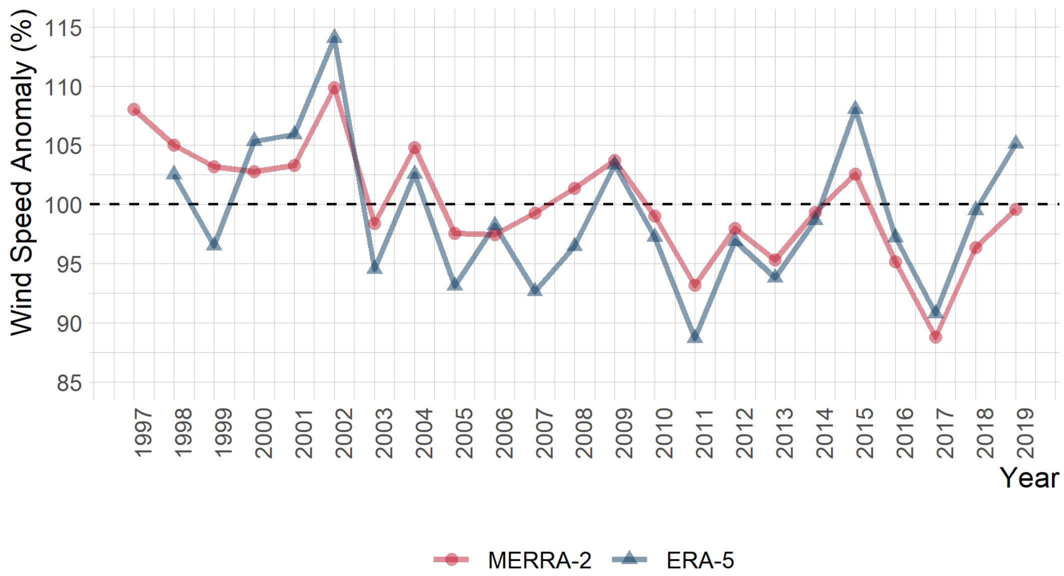

Figure 7.3: MERRA-2 and ERA5 Annual Mean Wind Speed Anomaly

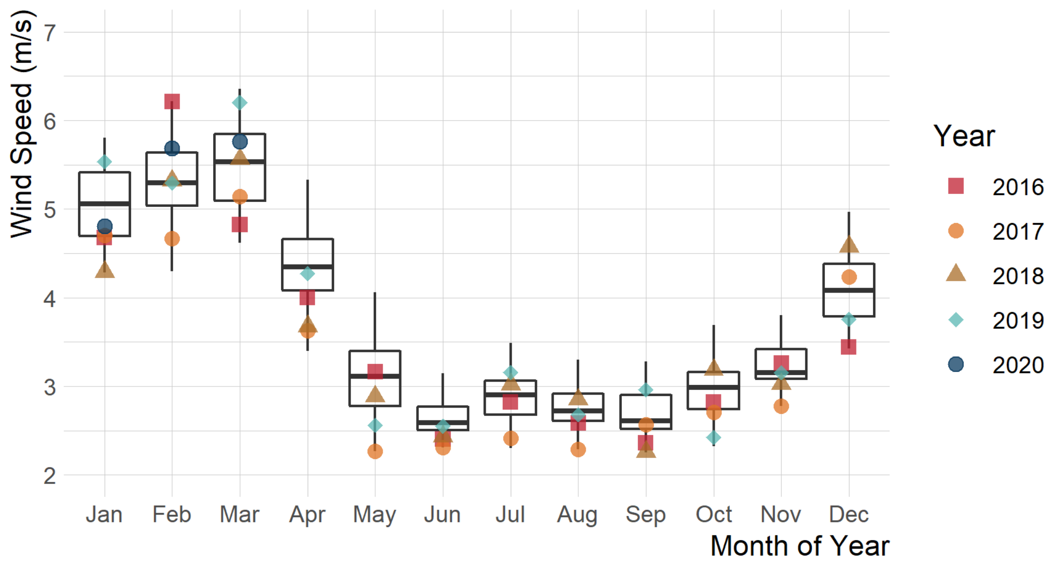

Figure 7.4: Box Plots of Monthly Long-Term ERA5 Reanalysis Wind Speeds*

***The grey box denotes the interquartile range, the horizontal line denotes the mean, and the vertical lines denote the data range. Operational POR with the color markers**

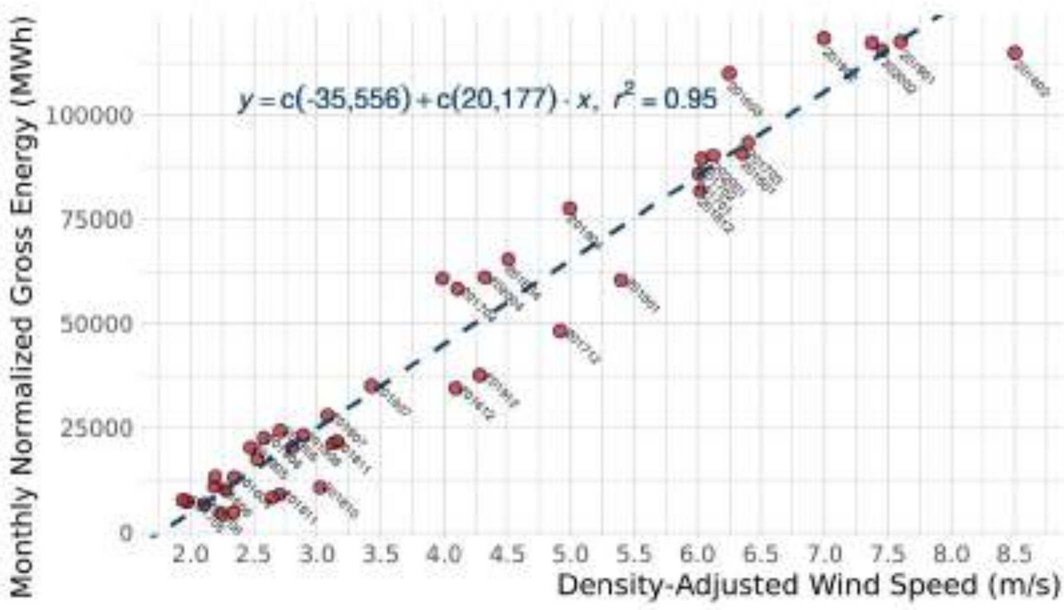

Figure 7.5: Plant Power Curves based on ERA5 Reanalysis Data

Table 7.1: Relevant Monthly Reported and Modeled data over operational POR

Month	Site Wind Speed (m/s)	Sum of Turbine Generation (MWh)	NHI Generation (MWh)	Turbine Availability	Normal Loss (MWh)	Electrical Loss (MWh)	Force Majeure Loss (MWh)	ERA5 Density Adj. Wind Speed (m/s)
Jan-16	8.19	91,410	89,340	98.6%	0	2,070	1,050	6.35
Feb-16	10.10	106,560	105,730	96.8%	0	830	1,050	8.50
Mar-16	9.06	112,480	109,770	99.0%	0	2,710	0	6.25
Apr-16	6.33	64,900	63,290	99.2%	0	1,610	0	4.51
May-16	3.85	24,634	23,750	97.8%	0	884	0	2.71
Jun-16	2.86	10,870	10,300	98.6%	0	570	0	2.19
Jul-16	3.78	20,700	19,950	98.3%	0	750	0	2.80
Aug-16	3.08	13,220	12,610	96.7%	0	610	0	2.35
Sep-16	2.77	9,690	9,160	95.5%	0	530	0	2.28
Oct-16	2.28	4,600	4,230	92.9%	0	370	0	2.34
Nov-16	2.67	8,600	7,920	93.7%	0	680	0	2.70
Dec-16	4.68	34,670	33,170	96.9%	0	1,500	0	4.09
Jan-17	7.47	87,243	84,850	98.9%	0	2,393	600	6.01
Feb-17	7.68	81,873	79,500	98.8%	0	2,373	600	6.03
Mar-17	7.94	92,008	89,370	95.8%	0	2,638	600	6.40
Apr-17	5.92	56,519	54,720	97.8%	0	1,799	600	4.10

Table 7.1: Relevant Monthly Reported and Modeled data over operational POR

Month	Site Wind Speed (m/s)	Sum of Turbine Generation (MWh)	NHI Generation (MWh)	Turbine Availability	Normal Loss (MWh)	Electrical Loss (MWh)	Force Majeure Loss (MWh)	ERA5 Density Adj. Wind Speed (m/s)
May-17	2.60	6,999	6,350	91.5%	0	649	0	1.98
Jun-17	2.49	6,576	5,980	97.5%	0	596	0	2.11
Jul-17	3.17	10,755	9,480	95.7%	2,130	1,275	0	2.53
Aug-17	2.79	7,597	6,900	91.2%	1,630	697	0	2.29
Sep-17	2.32	4,016	3,470	94.5%	890	546	0	2.13
Oct-17	2.69	6,957	6,340	91.2%	1,290	617	0	2.76
Nov-17	2.62	7,574	6,960	91.7%	140	614	0	2.65
Dec-17	5.44	44,387	42,410	90.3%	900	1,977	0	4.92
Jan-18	6.34	56,752	54,890	94.8%	2,760	1,862	0	5.40
Feb-18	8.51	90,099	87,440	89.2%	0	2,659	9,550	7.07
Mar-18	8.72	111,857	108,010	97.0%	0	3,847	1,250	6.91
Apr-18	6.16	59,917	57,870	98.4%	0	2,047	0	3.99
May-18	3.24	17,911	16,910	98.5%	0	1,001	0	2.53
Jun-18	3.12	12,721	11,830	94.9%	0	891	0	2.19
Jul-18	4.18	25,480	24,300	87.7%	0	1,180	0	3.08
Aug-18	3.83	22,560	21,370	93.3%	0	1,190	0	2.89
Sep-18	2.58	7,384	6,590	95.2%	0	794	0	1.94
Oct-18	2.89	10,209	9,370	91.0%	0	839	0	3.02
Nov-18	3.63	18,656	17,960	86.8%	0	696	0	3.13
Dec-18	7.19	77,720	74,060	92.3%	590	3,660	0	6.02
Jan-19	8.95	116,387	112,537	96.4%	945	3,850	0	7.60
Feb-19	8.98	104,635	101,144	95.3%	890	3,491	0	6.99
Mar-19	9.67	114,732	110,775	88.9%	0	3,956	10,560	7.80
Apr-19	6.89	73,049	70,404	94.4%	0	2,645	370	4.99
May-19	3.25	19,425	18,454	92.0%	0	971	0	2.47
Jun-19	3.79	19,666	19,029	86.2%	0	637	0	2.58
Jul-19	4.58	31,438	30,707	86.3%	0	731	0	3.43
Aug-19	3.56	16,578	15,855	85.6%	0	723	0	2.83
Sep-19	2.54	6,565	6,222	83.8%	0	344	0	2.47
Oct-19	2.17	4,173	3,883	88.7%	0	290	0	2.25
Nov-19	3.76	20,328	19,824	92.9%	0	504	0	3.16
Dec-19	4.98	37,932	37,365	97.4%	0	567	0	4.28
Jan-20	7.64	91,153	89,022	97.6%	0	2,131	0	6.12
Feb-20	8.99	109,433	106,636	98.0%	0	2,797	0	7.46
Mar-20	8.94	117,640	114,689	96.9%	0	2,951	0	7.37
Apr-20	6.01	58,858	57,532	96.2%	0	1,326	0	4.32
May-20	3.75	24,411	23,743	95.5%	0	668	0	
Jun-20	2.31	5,993	5,644	95.6%	0	349	0	

Table 7.1: Relevant Monthly Reported and Modeled data over operational POR

Month	Site Wind Speed (m/s)	Sum of Turbine Generation (MWh)	NHI Generation (MWh)	Turbine Availability	Normal Loss (MWh)	Electrical Loss (MWh)	Force Majeure Loss (MWh)	ERA5 Density Adj. Wind Speed (m/s)
Jul-20	3.01	13,900	13,520	95.6%	0	380	0	
Avg.	**4.90**	**45,891**	**40,326**	**94.0%**	**225**	**1,395**	**437**	**3.96**
Total		**550,688**	**483,910**		**2,705**	**16,741**	**5,246**	

Table 7.2: Summary of reverence data

Reference	Type	Start Month	End Month	r-squared
ERA-5 Interpolated	Reanalysis (ERA-5)	199701	202004	0.943
ERA-5 grid point 1	**Reanalysis (ERA-5)**	**199701**	**202004**	**0.950**
ERA-5 grid point 2	Reanalysis (ERA-5)	199701	202004	0.939
ERA-5 grid point 3	Reanalysis (ERA-5)	199701	202004	0.916
ERA-5 grid point 4	Reanalysis (ERA-5)	199701	202004	0.916
MERRA-2 Interpolated	Reanalysis (MERRA-2)	199701	202006	0.925
MERRA-2 grid point 1	Reanalysis (MERRA-2)	199701	202006	0.931
MERRA-2 grid point 2	Reanalysis (MERRA-2)	199701	202006	0.923
MERRA-2 grid point 3	Reanalysis (MERRA-2)	199701	202006	0.845
MERRA-2 grid point 4	Reanalysis (MERRA-2)	199701	202006	0.844

Table 7.3: ERA5 based Annualized Monthly Energy Production Summary

Month	Number of Days	ERA5 Average Wind Speed (m/s)	ERA5 Density-Adjusted Average Speed (m/s)	Operational Gross Energy Production Estimate (MWh)
January	31	6.5	6.5	98,482
February	28.25	6.8	6.8	96,747
March	31	6.6	6.6	101,337
April	30	4.9	4.9	62,085
May	31	3.0	3.0	25,721
June	30	2.4	2.4	12,513
July	31	2.8	2.8	22,483
August	31	2.6	2.6	17,783
September	30	2.2	2.2	9,556
October	31	2.6	2.6	17,525
November	30	3.1	3.1	26,841
December	31	4.8	4.8	63,050
Long-term Operational Gross Annual Production				**554,123**

Table 7.4: Combined Net Energy Production Calculations

	Value
Long-Term Gross Annual Energy Production (GWh)	554.1 GWh/year
Projected Future Project Availability	5.4% loss (94.6% eff)
Other Loss	0.2% loss (99.8% eff)
Electrical Loss	4.5% loss (95.5% eff)
Blade Degradation Losses	0.2% loss (99.8% eff)
Long-Term Net Annual Energy Production or P50 (GWh)	498.7 GWh/year
Net Capacity Factor	26.5%

Table 7.5: 15-year Evaluation Period Uncertainty

Uncertainty Source	Evaluation Period		Annual	
	%	GWh/yr	%	GWh/yr
Power Measurement and Gross Power Adjustment	1.1	5.3	1.1	5.3
Air Density Adjustment	0.1	0.3	0.1	0.3
Representativeness of Historical Period	2.5	12.3	2.5	12.3
Future Wind Resource	3.0	15.2	10.6	52.7
Wind Speed and Direction Frequency Distribution	0.8	4.1	1.6	7.9
Projected Future Project Availability	0.6	2.9	2.0	10.1
Other Loss	0.0	0.2	0.0	0.2
Electrical Loss	0.9	4.5	0.9	4.5
Future Blade Degradation Loss Uncertainty	0.1	0.6	0.1	0.6
Combined All Sources	**4.3**	**21.3**	**11.2**	**56.1**

Table 7.6: Combined Net Energy Production and Net Capacity Factor at Five Confidence Levels (15-year Evaluation Period and 1-Year)

Probability of Exceedance	Evaluation Period		Annual	
	Net Energy Production (GWh/yr)	Net Capacity Factor (%)	Net Energy Production (GWh/yr)	Net Capacity Factor (%)
P50	498.7	26.5	498.7	26.5
P75	484.3	25.7	460.9	24.5
P90	471.4	25.0	426.9	22.6
P95	463.6	24.6	406.5	21.6
P99	449.1	23.8	368.3	19.5

APPENDIX A – MONTHLY AND ANNUAL LONG-TERM ENERGY

Table A.1 shows the monthly and annual wind speed, and the gross and net energy long-term production. In this analysis, a ERA5 long-term source has been used (Table 7.3).

Table A.1: Monthly and annual Long-term energy

Month	Number of Days	Density-Adjusted Average Speed (m/s)	Operational Gross Energy Production Estimate (MWh)	P50 Net Production (MWh)
January	31	5.8	98,482	89,648
February	28.25	6.1	96,747	88,069
March	31	6.0	101,337	92,247
April	30	4.6	62,085	56,516
May	31	3.1	25,721	23,413
June	30	2.5	12,513	11,391
July	31	2.9	22,483	20,466
August	31	2.7	17,783	16,188
September	30	2.5	9,556	8,699
October	31	2.8	17,525	15,953
November	30	3.2	26,841	24,433
December	31	4.4	63,050	57,394
Long-term Operational Annual Production			**554,123**	**504,418**

APPENDIX B – OTHER LOSSES

Table B.1 shows the additional losses provided by the client ("UL Energy Meeting Requests.doc"), associated energy per event and loss categorization (section 3.3).

Table B.1: Additional losses

From	To	Event	IEH comments	Future loss	Availability affected	Loss (GWh)
Jan-16	Feb-16	Late commissioning	Commercial losses due to the impossibility of connecting Portobelo to the substation, UEPI was using the cell (position) destined for Portobelo for UEPI capacitor banks. Although the losses mainly occurred in 2015, January and February 2016 were also affected. Energy loses (January-February 2016): 2.1 GWh.	No, punctual loss	No	2.1
Jan-17	Apr-17	Wtg limitation, curtailment	Economic losses due to the impossibility of operating at full load during the first quarter of 2017, due to the lack of spare parts for IGBTs in the wind farm and the arrival of these replacements by transport. Goldwind limited the wind turbines production to avoid overheating of the IGBTs, due to the lack of spare parts on site. Energy losses: 2.4 GWh (From January-April 2017).	No, punctual loss, IGBT error and no replacements	No	2.4
Jul-17	Dec-17	Limitations in network	Extraordinary limitations in the transmission network by CND due to high hydrology and low regulation reserve. These extraordinary limitations were claimed and paid by the CND. Energy losses: 6.97 GWh (between July-December 2017). Reference: DTE claims	Yes	No	6.97
Oct-17	Oct-17	Circuit out of line	Economic losses because of circuit 34-79 being out of line (New Chagres 2 circuit 3 - 5 turbines), due to a damage caused in the MV underground line caused by UEPI's backhoe (working during gutter cleaning). This issue is considered an external event, caused by third parties and without any relation to the park's own operation. Event occurred on October 23, 2017. Energy losses: 0.56 GWh. Reference: Proforma Invoice No. 002	No, error in line	Yes, 5 turbines affected, with mean availability of 70%	-
Dec-17	Dec-17	WTG22 stopped	Production losses in turbine 22 (Rosa de los Vientos). The WTG22 was stopped because the blade collar detachment. The event occurred between December 2 and 29, 2017. Energy loses: 0.73 GWh. Reference: Proforma Invoice No. 001 (potential corrective maintenance).	No, turbine error	Yes, WTG22 availability, 11%	-

Table B.1: Additional losses

From	To	Event	IEH comments	Future loss	Availability affected	Loss (GWh)
Jan-18	Feb-18	Curtailment	Extraordinary limitations in the transmission network by CND due to high hydrology and low regulation reserve. Energy loses: 3.1 GWh. Reference: DTE claims	Yes, as jan-17. Feb-18 discarded, loses provided by the client does no match between "UL Energy Meeting Requests.doc" and "YTD Generation vs. UL.xlsx"	No	2.76 (only January)
Feb-18	Mar-18	Limitations	Commercial losses suffered because of limitations during the first quarter of 2018 (IGBTs). The value of the proforma invoice was negotiated with GWi to reduce the payment of the Bond. Energy losses: 9.96 GWh. Reference: Proforma Invoice No. 004B	No, but discarded, loses provided by the client does no match between "UL Energy Meeting Requests.doc" and "YTD Generation vs. UL.xlsx"	No	(data discarded)
Feb-18	Feb-18	Circuit out of line	New affectation in circuit 34-79 being out of line (New Chagres 2 circuit 3 - 5 turbines), caused by UEPI's backhoe (working during gutter cleaning). This event produced 0.74 GWh of additional losses in February 2018. Reference: Proforma Invoice No. 003	No, but discarded, loses provided by the client does no match between "UL Energy Meeting Requests.doc" and "YTD Generation vs. UL.xlsx"	Yes, 5 turbines affected, with mean availability of 67%	-
Dec-18	Dec-18	limitations due to changes in plc	Loss of production caused by the limitations in some turbines due to parameter changes in the PLC for the HVRT. The proforma invoice No. 005 was made, which partially included the claim for December 2018 and January 2019. Energy losses: 0.6 GWh (December 2018). Reference: Proforma Invoice No. 005	Yes		0.6
Jan-19	Apr-19	limitations due to changes in plc	Additional loss of production caused by the limitations in some turbines due to parameter changes in the PLC for the HVRT. The proforma invoice No. 005 was made, which partially included the claim for December 2018 and January 2019. Energy losses: 0.98 GWh (January 2019). Reference: Proforma Invoice No. 005	Yes		2.21 (according to "YTD Generation vs. UL.xlsx", losses also in February, March and April)

Table B.1: Additional losses

From	To	Event	IEH comments	Future loss	Availability affected	Loss (GWh)
Mar-19	Mar-19	Losses and av loss not explained in word doc, but additional 9GWh of loss in excel	-			(data discarded)
May-19	Nov-19	Retrofits	2019 was characterized by a year where all the pending GW retrofits, were concentrated and performed. These actions are considered extraordinary events, because these retrofits were pending to be carried out by Goldwind since the wind farm was commissioned. The availability has been corrected according to this additional unavailability (Between 3.5% and 9.7% from May to November). Reference: O&M Monthly operation report.	No, punctual update not affecting future production ("G25AM060661 EC G25 Pitch Brg OR Stiffener InstallUEPII.pdf")	Yes, turbines stopped for the upgrade	-
Jan-20	Aug-20	Blade cracks	Three turbines remain stopped due to a blade crack. The affected ones are: No.39 (end of December), No. 41 (March the 2nd) and No. 108 (April the 3rd). This is not a usual situation and turbines could not be repaired in a short response time due to the Blades Strategy Plan elaboration and the COVD-19 affectation. Reference: O&M Monthly operation report and GW's monthly reports.	No, failures not repaired due to COVID-19	Yes, turbines stopped	-

APPENDIX C—PENONOMÉ II TURBINE INSPECTION REPORT AND BLADE STRATEGY PLAN

REPLACEMENT BLADES STRATEGY

86 WTs Goldwind - 2,5 MW

PREPARED FOR:
UEP PENONOMÉ II S.A

Ref. No.: UL-ES-AM20-1101772929-01.06

REPLACEMENT BLADES STRATEGY
Penonomé
Panamá

15 September 2020

CLASSIFICATION
CLIENT'S DISCRETION

ISSUE
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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ACRONYMS

Acronyms		Description
B	BOP	Balance of Plant
C	CAPEX	CAPital EXpenditures
	CENACE	Centro Nacional de Control de Energía
	CFE	Comisión Federal de Electricidad
	CONAGUA	National Water Commission or "*Comisión Nacional del Agua*" in Spanish
	COD	Commercial Operations Date
	Cp	Power coefficient
	CPTT	CFE's Construction Department
	CRE	Energy Regulatory Commission or "*Comisión Reguladora de Electricidad*" in Spanish
D	DECS	Design Evaluation Conformity Statement
	DFIG	Doubly Fed Induction Generator
	DGAC	General Directorate of Civil Aviation or "*Dirección General de Aeronáutica Civil*" in Spanish
	DSA	Development Services Agreement
E	EOW	End of Warranty
	EXW	Ex Works
F	FM	Financial Model
G	GCOD	Guaranteed Commercial Operation Date
	GSU	Generator Step-UP
	GWh	Gigawatt Hours
H	HH	Hub Height
	HV	High Voltage
I	IA	Interconnection Agreement
	IEC	International Electrotechnical Commission
	IER	Independent Engineering Report
	IEEE	Institute of Electrical and Electronic Engineers
	IFC	Issued For Construction
	INAH	National Institute of Anthropology and History or "*Instituto Nacional de Antropología e Historia*" in Spanish
	IR	Infra Red
K	kW	Kilowatt
L	LCs	Letters of Credit
	LDs	Liquidated Damages
	LNTP	Limited Notice To Proceed
	LPS	Light Protection System
	LT	Long-term
	LV	Low Voltage
	LVRT	Low-Voltage Ride Through
M	MASW	Multi-Channel Analysis of Surface Waves
	MIA-R	Environmental Impact Assessment Regional Modality or "*Manifiesto de Impacto Ambiental Modalidad regional*" in Spanish
	MPT	Main Power Transformer

LIST OF ACRONYMS

Acronyms		Description
	MRA	Maintenance Reserve Account
	MV	Medium Voltage
	MW	Megawatt
	MWh	Megawatt Hours
	m/s	Meters per second
N	NCF	Net Capacity Factor
	NEH	Net Equivalent Hours
	NRG	Neutral Grounding Reactor
	NTP	Notice to Proceed
O	O&M	Operations and Maintenance
	OEM	Original Equipment Manufacturer
	OHTL	Over Head Transmission Line
	OPEX	OPErational EXpenditures
P	PMT	Pad Mounted Transformer
	POI	Point of Interconnection
	PVC	Polyvinyl Chloride
Q	QA	Quality Assurance
	QC	Quality Control
R	R&D	Research and Development
	RCA	Root Cause Analysis
	RD	Rotor Diameter
	RTB	Ready to Build
	RTI	Representative Turbulence Intensity
S	SAR	Site Assessment Report
	SCADA	Supervisory Control and Data Acquisition
	SEMARNAT	Secretary of Environment and Natural Resources or "*Secretaría de Medio Ambiente y Recursos Naturales*" in Spanish
	SENER	Secretary of Energy or "*Secretaría de Energía*" in Spanish
	SME	Subject Matter Expert
	SPT	Standard Penetration Test
	SPV	Special Purpose Vehicle
T	TBD	To Be Defined
	TC	Type Certificate
	TI	Turbulence Intensity
U	UL	Underwriters Laboratories
	UEP	UEP PEnonome II
V	VRT	Voltage Ride Through
	VAT	Value Added Tax
W	WSM	Wind Sector Management
	WTG	Wind Turbine Generator

1. INTRODUCTION

UL International GmbH Sucursal en España ("UL" or "Consultant"), a UL company, has been engaged by UEP Penonome II, S.A. (the "Client") to perform the following services : Replacement Blade Strategy of the site of Penonome (The Project).. The WF is located in Penonome, Panama. The project consists of 86 WTs type Goldwind with a rated power of 2.5 MW.

Next table summarizes the main aspects of the Project:

Table 1.1: Summary of Project Characteristics

Project Characteristics	
Project Name	Penonomé Wind Farm
Project Location	Penonome, Panama
Installed Capacity	215 MW
Technology	86 x Goldwind GW109/2500
Power Output	2.5 MW
Rotor Diameter	110 m
Hub Height	90m
Commissioning Year	2016
Blade Model	Sinoma 52.5
Manufacturer	Sinoma
Material	Epoxi

The works to be carried out by UL are intended to evaluate the quality of workmanship performed by the service provider, as well as turbine component endurance and overall conditions, in particular the Wind Turbine blades, to be used as a basis for a blade risk management strategy: maintenance, repairment and / or replacement.

The general Blade inspection targets to receive a profound view on the condition of a specific rotor blades. These have been done by means of two different teams. The first one by UL technicians, as part of general wind turbine inspections and the second one was carried out by our partner TSR, a specialized company in blade inspections, with support of our SME remotely.

As a part of the general wind turbines inspections a total of 86 turbines were inspected, representing 100% of the wind farm. These inspections focus on:

- Rotor Hub: Bolts, Pitch bearings, Pitch drives and motors, Pitch rim gear & Pitch battery boxes.
- Blades (A, B & C): Bolts, Lightning system, Outside structure (binocular means) & Root structure,

A detailed external inspections focus on the full external body of the blades were performed on 72 turbine´s blades, representing 84% of the wind farm. UL consider this as an acceptable representative sample.

Figure 1.1: General project layout

Figure 1.2: Full blade on site

2. PROJECT SAFETY

The Client and its subcontractor maintain a positive safety culture on site. It has been identified that the personnel provided safety and site orientation. The focus on the safety aspect of the assignment is intended to set expectations for all site activity. Good task preparation was observed as Client utilized specific procedures for turbine work, lock out tag out (LOTO), and performed Job Safety Analysis prior to starting each job. Appropriate Personal Protective Equipment was worn. Incidents, near miss reports and other safety concerns were communicated immediately to project management.

3. EXECUTIVE SUMMARY

The scope of work performed by UL according to the agreed proposal (1101772929-2_WTI UEP PANAMA) is summarized in the following table:

Table 3.1: Summary of the Scope of Work Covered by UL in this Report

Section	Status	Comment
General Wind Turbine Inspection	Completed	No recommendation of stopping any turbine. No critical issues found related to blade components No critical issues found related to blade tips.
Blades and Hub Inspection	External Completed in 72 Turbines Internal not Performed	External Inspection, 2 turbines with recommendation of imitate actions (T39 & T41). New potential risks identified. Internal inspection was not performed due to specific blade´s brake system design

All findings have been noted on a punch list provided to the Client, by means of summary results for each specific inspection.
No Serial Defects have been identified.
Finding on the punch list, otherwise indicated, are expected to be addressed by OEM or by the Client during the next maintenance cycle.

Reference documents for the inspection:

Standards

The inspection has been performed following standard for wind turbines and the associated normative documents as well as the Guideline for the Certification of Wind Turbines:

- ***International Electrotechnical Commission (IEC): IEC 61400-1 Wind turbine generator systems Part 1: Design Requirements, Ed. 3, 08-2005.***
- ***International Electrotechnical Commission (IEC): IEC 61400-22 Conformity testing and certification, Ed. 1.0 05-2010.***
- ***Germanischer Lloyd: GL Renewables Guidelines 4.0 Edition 2010***
- ***UL 4143 Standard for Safety: Wind Turbine Generator - Life Time Extension (LTE) February 9 (2019) Ed. 1.***

Manuals and documentation

For the appraisal of the condition of the wind turbine and its components, it is assumed that the wind turbine is compliant with the regulations and standards stated in section here above as well as the specific design approval documents.

4. PENONOME II MAJOR BLADE DEFECTS

According to documents provided, there have been identified two major defects related to blades supplied to UEP II by Goldwind/Sinoma. One that could lead to blade tip detachment (7 kg tip weight) and a second that could lead to entire blade detachment (11,000 kg total blade weight).

UL has reviewed three documents, submitted and listed in the References of this report.

On **July 7th 2016** GOLDWIND issued an Engineering Correspondence, subject: Penonome II Sinoma Blade Inspection Update. This customer service Bulletin (G25PA030080 - GW25 CL Sinoma Blade Tip Inspections.pdf), updates the status of close-up inspections of Penonome II blades being conducted by Sinoma, Goldwind, and Client personnel.

The goal of these inspections was to collect information on the condition of the blades; categorize observed conditions; identify the extent of areas of concern, if any, observed on each blade; provide data to those analyzing the cause of any areas of concern and develop a procedure, if necessary, to address any areas of concern; and confirm the turbines' ability to operate safely.

The focus of the close-up inspections is the blade tip element diagrammed below and the area beyond the blade tip element safely and reasonably accessible to inspectors during the close-up inspection process.

The blade tip element is a part of the turbine lightning protection system. It is made of aluminum and is mechanically connected via a tapered end that is bonded into a socket in the blade's composite structure. There are distinct sections of the blade tip element as measured from the tip: 0 - ~150mm is bare aluminum, from ~150 - 300mm is painted aluminum, and from 300 - 380mm is the painted area over the structural bond between the tapered tip and the composite blade structure. Please refer to the drawing below for general guidance.

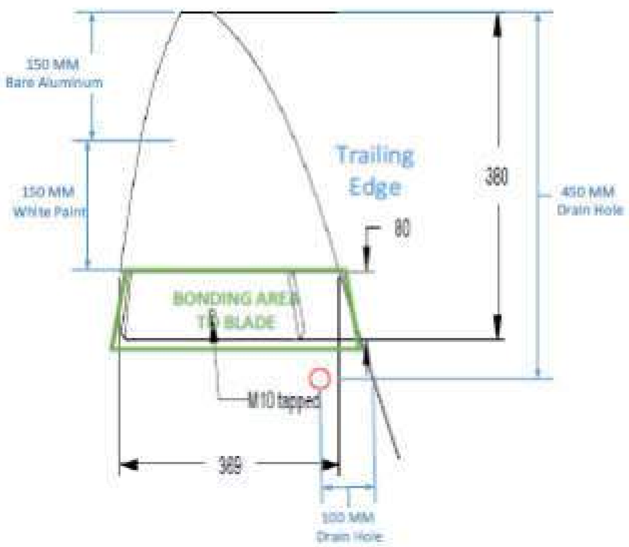

Figure 4.1: Blade Tip Element Diagram

To enable consistent collection of information Goldwind, along with Sinoma, developed an inspection checklist (G25PA03008 – GW25 CL Sinoma Blade Tip Inspection) for collection and documentation of observations made regarding the blade tip elements and reasonably and safely accessible areas beyond the blade tip element. The information collected provides a basis to evaluate operational risks from these observations, if any, and to classify any concerns observed into three categories: Category 0, Category 1 and Category 2.

- Category 0: No category 1 or category 2 conditions observed.
- Category 1: Coating delamination and other observed conditions occurring up to 300mm from the blade tip. The checklist reflects observations of coating delamination's and other conditions involving coating, including Blisters and Delamination. Sinoma classifies coating conditions in this category as "cosmetic" and has determined that their existence does not pose any operational concerns. They recommend, as stipulated in the checklist, removal of any hanging or loose coating pieces to prevent potential exacerbation of delamination until the investigation is completed and a plan implemented.
- Category 2: Coating delamination or other conditions occurring in the "bonding area" between 300 and 380mm from the blade tip. Additional inspection will be performed to determine if the conditions are simply coating issues or if there are indications of delamination within the composite blade structure. Sinoma recommends removal of any loose coating. If there is evidence of or basis for concern regarding delamination of the composite blade structure, then any such turbine is to be left out of service until a plan can be developed and any corrective action implemented.

All inspections were carried out between 11th June 2016 to 4th July 2016. The resultant classification for all individual blades were identified as category 1, except blade 2 at turbine T70 which was identified as category 0.

The previously released limitations in the Engineering Correspondence Customer Service Bulletin dated June 7, 2016 (G25PA060250) are rescinded for the turbines which have been through the close-up inspection process, and such turbines are released to operate in normal status with no limitations. At this point, the limitations in Engineering Correspondence Customer Service Bulletin G25PA060251 released July 7, 2016 will apply, out of an abundance of caution, to the turbines that have not yet been through the close-up inspection process.

UL has reviewed the documentation submitted and listed in the Appendix of this report. The documentation reviewed covers a thorough description of the condition of the blades, categorize damage found, identify areas of concern (if any), proposed inspection criteria to address any areas of concern; and confirm the turbines' ability to operate safely.

UL agrees that the inspection instruction is adequate and sufficient for detection of all relevant damages, including the criteria for repairability. The repair and upgrade instructions should be adequate and sufficient for restoring the blade to design intent.

UL understand that all corrective actions identified in the previous Engineering Correspondence have been implemented and have no further comments.

On **January 23rd, 2019**, WINDprove issued a Memorandum, subject: Tip Reinforcement Method. This memorandum is summary of the key concepts, features, and execution of the GW 2.5 tip reinforcement.

The Memorandum specifies Reinforcement features as follows:

The reinforcement employs a thick layer (~3mm) of woven fiberglass material laid over and bonded to the blade shell in the region that overlaps the tip tab. Its purpose is to provide fabric that wraps around
the blade leading edge, and stiffens the material located over the tip tab bond. In the trailing edge region, a pattern of holes are drilled to accept fiberglass dowels that are bonded in place just aft of the tip tap aft edge, whose purpose is to reinforce that area against splitting, thereby completing a hoop path around the tip tab to hold it in place even if the bond is completely lost.

Figure 4.2 shows the fiberglass band bonded in place, with the dowel pattern toward the aft edge also visible. At this point, the excess material at the trailing edge has been ground away, but smoothing and painting have not yet been accomplished

Figure 4.2: Fiberglass bonded in place

Functional Expectations: With the hoop path complete around the tip tab, even if the bond is completely gone, the aluminum tip is physically captured within the composite blade tip. As all the material added are composite rather than metallic, they provide further insulation against a lightning strike, rather than creating new lightning attachment points. If an over pressure from a lightning strike were to occur, the trailing edge inboard of the reinforcement, which lacks dowels, should split much more easily than that at the tip, so the aluminum tip would be retained even in that event.

It should be noted that continued water access and ongoing corrosion of the tip tab will occur, and thus
the reinforcement is not a permanent fix, as that would require addressing the root cause, which is the use of an incorrect, corrosion prone material in the tips. Note that this addresses only a temporary extension of tip retention lifetime, not other known defects in the blades.

UL has reviewed the documentation submitted and listed in the Appendix of this report. The documentation reviewed covers a thorough description of the Tip Reinforcement Method and addresses functional expectations.

UL agrees that the instruction is adequate and sufficient for assuring that the aluminum tip keeps physically captured within the composite blade tip.

UL understand that all corrective actions identified in the previous Engineering Correspondence have been implemented. UL aggress that this Reinforce Method addresses only a temporary extension of tip retention lifetime.

On **October 14th, 2019**, WINDprove issued an Executive Summary, subject: UEP II Major Blade Defect. This Executive Summary identified that the blades supplied to UEP II by Goldwind/Sinoma possess two major defects.

Issue 1: The blade tip is made of scrap metal that is causing De-bonding of the Blade Tip

According to documentation review the following points were noted:

1. The blade tips were designed to be composed of a corrosion-resistant material
2. Sinoma Manufactured blade tips composed of scrap aluminum susceptible to corrosion
3. Corrosion is causing the blade tips to De-bond.
4. Tip detachment can occur after a blade tip De-bonds from the Blade Shell.

Figure 4.3 shows a close photograph of the tip region on T37 blade 2, with presence of corrosion of the aluminum tip and failure of the protective coating.

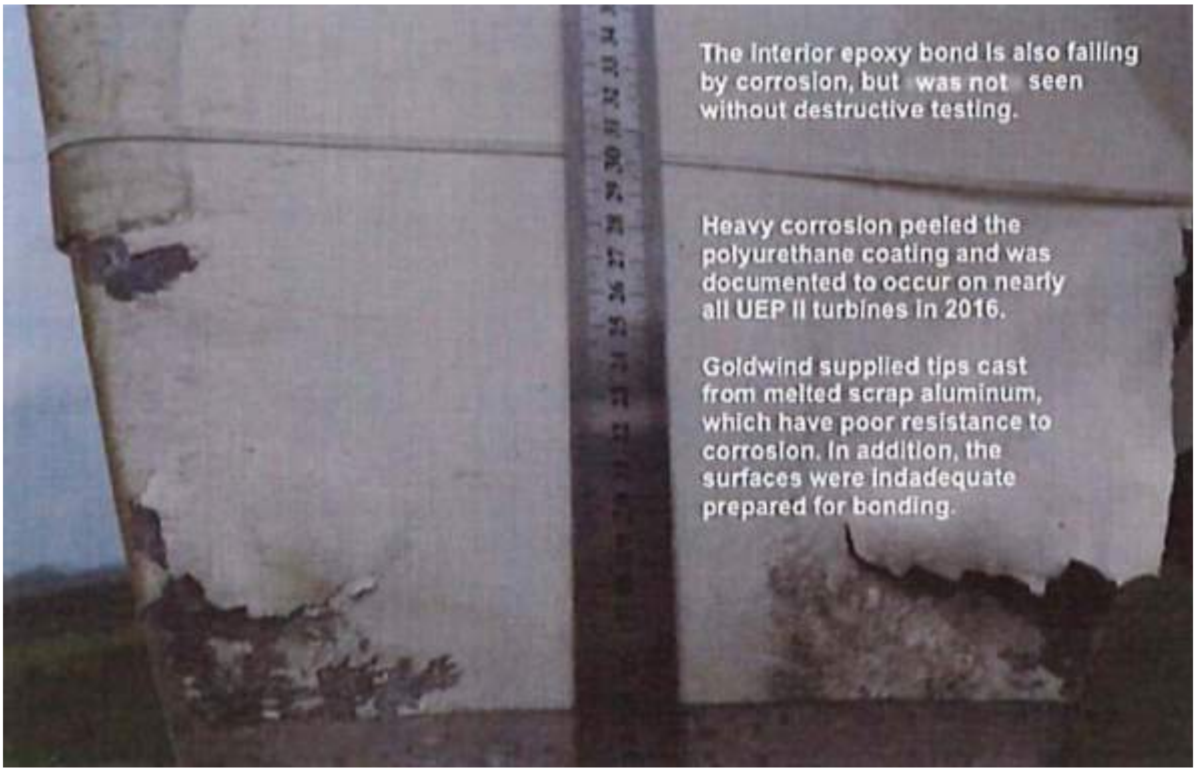

Figure 4.3: Turbine 37, blade 2 showing corrosion of the aluminum tip

Issue 2: Blade Root Bushing Exhibits Voids that could cause detachment of the root.

According to documentation review the following points were noted:

1. The blade roots were designed to employ Pre-Cast inserts of root bushings
2. Sinoma did not manufacture blades using pre-cast inserts of root bushings
3. Sinoma´s failure to follow TRES4 design resulted in supplying of blades with significant voids along the root bushings.
4. The presence of voids in the root bushings will reduce the blade operating Lifetime.

Figure 4.4 (reference as Zuteck 2018) is an example of the examination of root bushings from blades at UEP II which showed large voids that extend across sections of the bond area in four out of four bushings specimens from two blades.

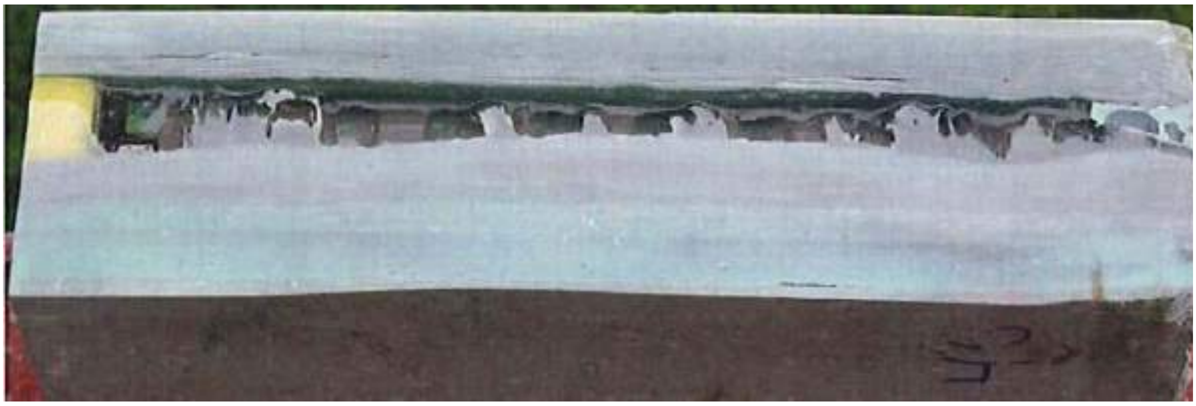

Figure 4.4: Examination of root bushing from blades at UEP II

UL has reviewed the documentation submitted and listed in the Appendix of this report. The documentation is an executive summary which describe two major defects identified. UL understand this summary is part of a more comprehensive report. Without a full review of all documents noted in the executive summary and the complete report UL cannot make further comments at this stage.

Note:

UL noted that if tips were not manufacture according to design specifications this can cause a potential risk of tips detachment.

UL noted that voids replaces structural material with air, will potentially reduce lifetime in long-term fatigue which is a fundamental structural requirement for safe operation.

5. GENERAL WIND TURBINE INSPECTION

The goal of these inspections was to collect information on the condition of the blades; categorize observed conditions; identify the extent of areas of concern, if any, observed on each blade; provide data to those analyzing the cause of any areas of concern and develop a procedure, if necessary, to address any areas of concern; and confirm the turbines' ability to operate safely. In addition, on previous section, a special attention was performed regarding the status of the tips blade.

The inspection is mostly visual, but some test and checks were performed. For each turbine inspections a detailed reported was submitted to customer, as well as a general punch list with the findings. During the detailed inspection, the turbine is scrutinized, and issues are reported in several component groups. The specific scope for these works is focused on blades and its components, and these are detailed as follows:

- Rotor Hub: Bolts, Pitch bearings, Pitch drives and motors, Pitch rim gear & Pitch battery boxes.
- Blades (A, B & C): Bolts, Lightning system, Outside structure (binocular means) & Root structure,

Every single inspection point of the 86 turbines are reported on the checklist with conditions categorized in 5 areas:

- **Unchecked (0)**: No Access
- **Good (1)**: Component in good status / no conspicuous issues found
- **Minor Defect (2)**: Component has minor defects / nonconformities
- **Major Defects (3)**: Component has major defects / nonconformities. Immediate action is recommended.
- **Severe Defect (4)**: Component has severe defects / nonconformities. The further operation of the turbine is not recommended. Immediate action is recommended.

No turbine was found with Sever Defects during the inspections. Numbers between brackets shows UL´s raking methodology according to its accreditation ISO/IEC 17020 for wind turbines.

- UL have identified 4 Turbines as category 3 related to grease leakage at Pitch Bearings: T9, T18, T59 & T60. UL recommends to clean and performed Maintenance on Pitch bearings on next schedule maintenance.

- Ul have identified 3 turbines were identified as category 3 related to grease leakage at Pitch drives and motors: T18, T60 and T63. UL recommends to clean and performed Maintenance on Pitch bearings on next schedule maintenance.

- UL have identified 4 turbines, as category 2, with lose of torque mark references at turbines T6, T12, T22 and T112. UL recommends remarking torque for future references.

- Rest of critical components were mainly identified as Category 1. UL recommends updating status on next Maintenance schedule.

All inspections components and findings items are supported by a picture added to the checklist, these are also documented as per previous categorization. These are expected to be update / review during the maintenance schedule.

UL have no further comments at this stage.

5.1 Rotor hub

5.1.1 Rotor Bolts

UL have identified 4 turbines with lose of torque mark references at turbines T6, T12, T22 and T112. **UL recommends remarking torque for future references.**

Figure 5.1: Lose torque mark T12

Figure 5.2: Lose torque mark T112

5.1.2 Pitch Bearing

Ul have identified 4 turbines were identified as category 3 related to grease leakage at Pitch Bearings: T9, T18, T59 & T60

Figure 5.3: Grease bearing leakage T9

Figure 5.4: Grease bearing leakage T59

5.1.3 Pitch drives and motors

UL have identified 3 turbines as category 3 related to grease leakage at Pitch Bearings: T18, T60 and T63.

Figure 5.5: Oil leak and low oil level T18

Figure 5.6: Oil leak and low oil level T63

5.1.4 Pitch rim gear

UL have not identified any issues.

5.1.5 Pitch battery boxes

UL have not identified any issues.

5.2 Blades

5.2.1 Blade bolts

UL have identified 4 turbines with lose of torque mark references at turbines T6, T12, T22 and T112. **UL recommends to remark torque for future references.**

Figure 5.7:Lose marks T6

Figure 5.8: Lose marks T22

5.2.2 Lightning system

UL have not identified any issues.

5.2.3 Outside structure (binocular means)

UL have not identified any issues.

5.2.4 Root structure

UL have not identified any issues.

UL have no further comments at this stage.

6. BLADES INSPECTIONS - EXTERNAL

The general Blade inspection targets to receive a profound view on the condition of each induvial rotor blades. The goal of these inspections was to collect information on the condition of the blades; categorize observed conditions; identify the extent of areas of concern, if any, observed on each blade; provide data to those analyzing the cause of any areas of concern and develop a procedure, if necessary, to address any areas of concern; and confirm the turbines' ability to operate safely. In addition, on previous section, a special attention was performed regarding the status of the tips blade. All inspections components and findings items are supported by a picture added to the checklist.

6.1 Blades External Inspection

The external blade inspections were performed by the taking HD images through Robot EOLOS. The robot is operated by remote control and capable of climbing the tower of wind turbines. It incorporates a camera of high quality and photographs the complete blades (its 4 surfaces) and not only the damages. A total of 72 Wind Turbine Blades were inspected.

Every single inspection point of the 72 turbines (216 individual blades) are reported on the checklist with conditions categorized in 5 areas:

- **Category 1**: Blade in good conditions. No further actions are recommended
- **Category 2**: Blade shows early signs of damage. Track and repair within 12 months
- **Category 3**: Blade shows signs of damage. Track and repair within 6 months
- **Category 4**: Blade shows advanced signs of damage. Track and repair within 3 months
- **Category 5**: Blade shows severe signs of damage. Blade must be repaired immediately

A summary of the finding is as follows:

- UL have identified a total of 6 turbines with Category 5. Turbines: T7, T16, T25, T39, T41 & T106.

- A total of 56 turbines were found with Category 4 during the inspections, adding a total number of 93 individual blades.

- A total of 72 turbines were found with Category 3 during the inspections, adding a total number of 163 individual blades.

- A total of 53 turbines were found with Category 2 during the inspections, adding a total number of 82 individual blades.

- A total of 17 turbines were found with Category 1 during the inspections, adding a total number of 30 individual blades.

- A total of 17 turbines were found with Category 1 during the inspections, adding a total number of 30 individual blades.

Figure 6.1 shows the percentage of categories per turbine.

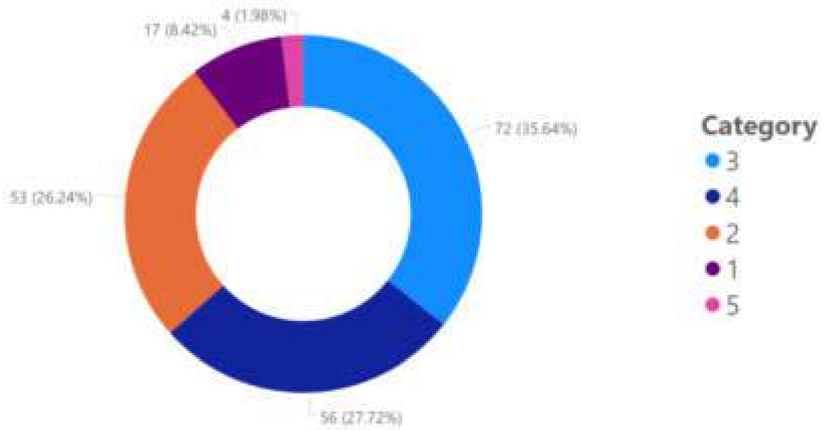

Figure 6.1: Number of turbine by category

Analyses shows that the most common issues are remark as category 3 (36%) and at the same time these are generally found on the leading edge of the blades, see figure 6.2.

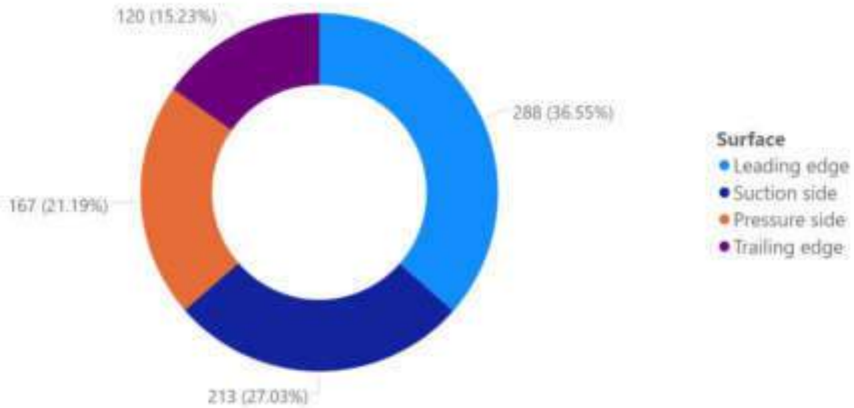

Figure 6.2: Number of comments per surface.

It must be noted that all findings are considering worst case scenario, meaning that some categorization may change after technicians going on site an inspect each specific blade. As per initial report UL have identified a total of 6 turbines with Category 5. Turbines: T7, T16, T25, T39, T41 & T106.

UL recommendation is to stop these turbines, inspect (by means of rope access) and repair blades immediately if needed. UL recommends following the relevant OEM´s instructions. The repair instructions should be adequate and sufficient for restoring the blades to design intent.

Base on UL´s recommendations, the client performed detailed blade inspections. These inspections where done by means of rope access technique by the company HGWintec S.A. The inspections were performed from 10th to 23rd December 2019. Main findings as follows:

- T39: Inspection carried out on December 10-2019, average wind 7 m/s. There is a crack equal to that reported by UL in blade 1, there is complete delamination and separation of the PVC core, delamination of 1 m x 60 cm. **The turbine is stopped pending to repair.**

Figure 6.3: T39 - Blade 1

Figure 6.4: T39 - Blade 1, detail

- T41: Inspection performed on December 21-2019; average wind 8 m/s. Blade 1 damage not found as reported by UL. Blade 2 damage not found as reported by U. Damage similar to T39 was found but without presence of crack. There is delamination and separation of the PVC core, 1.2 x 0.6 m. Operating the turbine put in risk the damage to progress critically. **The turbine is stopped pending to repair.**

Figure 6.5: T41 delamination and separation of the PVC core

Figure 6.6: T41 close view

- T07: Inspected on December 22-2019, average wind 2 m/s. Blades inspected 1 & 2 damages not found as reported by UL. A superficial scratch and a paint flaw on blade 2 only.

Figure 6.7: T7 Paint flow

Figure 6.8: T7 Superficial Scratch

- T16: Inspected on December 22-2019, average wind 2 m/s. Blades inspected 1 & 2, damages not found as reported by UL. Only stains on the paint.

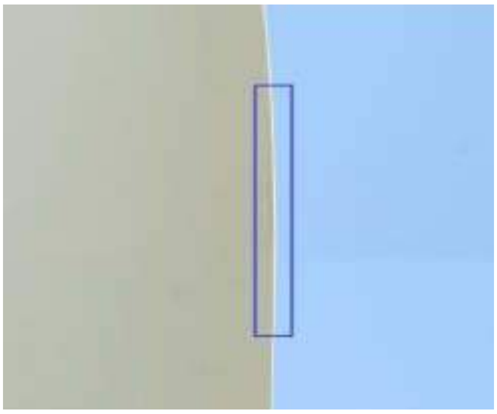

Figure 6.9: No damage found

Figure 6.10: Grease on blade

- T25: Inspected on December 23-2019, average wind not recorded. UL findings reviewed to Category 4. BS paint missing and crack on blade 3


Figure 6.11: T25 - BS paint missing


Figure 6.12: T25 - Crack on BS

T106: Inspected on December 23-2019, average wind not recorded. Blade inspected 3, damages not found as reported by UL. It has been paint damage without delamination or cracks.


Figure 6.13: T106 - Paint damage


Figure 6.14: T106 – Crack no delamination

Based on UL initial finding and the update review of inspections provided by the client, UL issue the following actions to be performed.

Table 6.1 shows the actions and recommendation to be done as per initial 6 turbines with finding category 5. **Only two turbines recommended to kept STOP until repairs are done (T39 and T41).**

Table 6.1: Issues identified by UL and recommendations

Wind turbine	Model	Blade	Date Inspected rope	Turbine STOP	UL comments
T39	GW109/2500	1	10-Dec-19	YES	Recommend Inspecting by rope Access blade 3
T41	GW109/2500	1 & 2	21-Dec-19	YES	Recommend Inspecting by rope Access blade 3
T7	GW109/2500	1 & 2	22-Dec-19	NO	Recommend Inspecting by rope Access blade 3

Table 6.1: Issues identified by UL and recommendations

Wind turbine	Model	Blade	Date Inspected rope	Turbine STOP	UL comments
T16	GW109/2500	3	22-Dec-19	**NO**	Recommend Inspecting by rope Access blade 1
T25	GW109/2500	3	23-Dec-19	**NO**	Recommend Inspecting by rope Access blade 1 & 2
T106	GW109/2500	2	23-Dec-19	**NO**	No further Action

Following the previous analysis and UL finding, further actions are recommended:

- **All blades with Category 5**: Blade must be repaired immediately. See table 6.1.
- **All blades with Category 4**: Track and repair within 3 months
- **All blades with Category 3**: Track and repair within 6 months
- **All blades with Category 2**: Track and repair within 12 months
- **All blades with Category 1**: Blade in good conditions. No further actions are recommended

Table 6.2 shows details of Turbines, Blades with Category 4. It identifies blade serial number, surface and typology of findings.

Within these turbines is UL recommendation to track and repair (by means of rope access) within 3 months' time frame.

Table 6.2: Turbines details with Category 4

Wind turbine No	Serial No	Surface	Typology
T102	B-14-009	Suction side	Transverse fissure
T102	D-14-011	Suction side	Transverse fissure
T103	B-14-034	Suction side	Deterioration of the SAR receiver
T104	A-14-034	Pressure side	Transverse fissure
T104	A-14-034	Suction side	Transverse fissure
T104	B-14-037	Pressure side	Transverse fissure
T104	B-14-037	Suction side	Transverse fissure
T104	B-14-038	Pressure side	Transverse fissure
T104	B-14-038	Suction side	Transverse fissure
T106	A-14-016	Trailing edge	Cracks in the trailing edge adhesive union
T107	A-14-026	Suction side	Transverse fissure
T107	A-14-027	Suction side	Transverse fissure
T107	B-14-027	Pressure side	Transverse fissure
T108	D-14-041	Pressure side	Transverse fissure
T108	D-14-041	Suction side	Transverse fissure

Table 6.2: Turbines details with Category 4

Wind turbine No	Serial No	Surface	Typology
T109	A-14-036	Pressure side	Damage to blade sides laminates
T109	D-14-045	Suction side	Transverse fissure
T11	A-14-029	Pressure side	Transverse fissure
T11	A-14-029	Suction side	Transverse fissure
T11	A-14-030	Suction side	Transverse fissure
T11	B-14-030	Suction side	Transverse fissure
T112	A-14-028	Leading edge	Detachment of the coat from the leading edge
T12	A-14-012	Suction side	Transverse fissure
T12	A-14-015	Suction side	Transverse fissure
T12	A-14-016	Suction side	Transverse fissure
T13	A-14-028	Pressure side	Transverse fissure
T13	B-14-029	Pressure side	Cracks in the coat
T14	A-14-038	Pressure side	Transverse fissure
T14	B-14-004	Leading edge	Rubbing in gel coat
T14	B-14-004	Pressure side	Transverse fissure
T14	B-14-041	Suction side	Transverse fissure
T15	A-14-020	Suction side	Transverse fissure
T15	B-14-021	Leading edge	Longitudinal crack
T15	B-14-021	Suction side	Transverse fissure
T15	B-14-022	Pressure side	Transverse fissure
T15	B-14-022	Suction side	Transverse fissure
T16	D-14-037	Suction side	Transverse fissure
T17	A-14-033	Pressure side	Transverse fissure
T17	A-14-033	Suction side	Transverse fissure
T17	B-14-033	Pressure side	Transverse fissure
T17	B-14-051	Pressure side	Transverse fissure
T17	B-14-051	Suction side	Transverse fissure
T18	B-14-011	Trailing edge	Cracks in adhesive union of the leading edge
T18	B-14-011	Trailing edge	Cracks in the trailing edge adhesive union
T18	D-14-014	Suction side	Transverse fissure
T19	B-14-012	Trailing edge	Cracks in the trailing edge adhesive union
T19	C-14-006	Trailing edge	Cracks in the trailing edge adhesive union
T2	B-14-015	Leading edge	Leading edge unstuck
T20	A-14-008	Trailing edge	Cracks in the trailing edge adhesive union
T21	B-14-006	Suction side	Damage to blade sides laminates
T21	B-14-007	Pressure side	Damage to blade sides laminates
T21	B-14-007	Suction side	Damage to blade sides laminates
T21	B-14-008	Suction side	Damage to blade sides laminates
T22	B-14-002	Suction side	Missing or blockage of blade drain holes
T22	D-14-004	Suction side	Damage to blade sides laminates
T23	B-14-004	Leading edge	Transverse fissure

Table 6.2: Turbines details with Category 4

Wind turbine No	Serial No	Surface	Typology
T23	B-14-004	Pressure side	Transverse fissure
T23	B-14-005	Leading edge	Transverse fissure
T23	B-14-005	Suction side	Transverse fissure
T23	B-14-009	Leading edge	Transverse fissure
T23	B-14-009	Pressure side	Damage to blade sides laminates
T23	B-14-009	Suction side	Transverse fissure
T24	A-14-003	Leading edge	Longitudinal crack
T24	C-14-004	Suction side	Damage to blade sides laminates
T24	C-14-004	Trailing edge	Cracks in the trailing edge adhesive union
T25	B-14-034	Trailing edge	Cracks in the trailing edge adhesive union
T25	C-14-025	Trailing edge	Cracks in the trailing edge adhesive union
T25	D-14-033	Pressure side	Break in fabrics trailing edge
T25	D-14-033	Suction side	Break in fabrics trailing edge
T27	B-14-040	Pressure side	Damage to blade sides laminates
T29	D-14-008	Suction side	Transverse fissure
T29	D-14-010	Suction side	Transverse fissure
T3	FN-A-14018	Pressure side	Transverse fissure
T3	FN-A-14019	Leading edge	Longitudinal crack
T3	FN-A-14019	Suction side	Cracks in the PVC
T30	A-14-031	Suction side	Transverse fissure
T31	A-14-023	Trailing edge	Cracks in the trailing edge adhesive union
T32	B-14-014	Pressure side	Transverse fissure
T32	B-14-014	Suction side	Transverse fissure
T32	B-14-015	Pressure side	Transverse fissure
T32	B-14-015	Suction side	Transverse fissure
T32	B-14-015	Trailing edge	Cracks in the trailing edge adhesive union
T32	B-14-016	Pressure side	Transverse fissure
T32	B-14-016	Suction side	Transverse fissure
T33	B-14-011	Pressure side	Transverse fissure
T33	B-14-011	Suction side	Transverse fissure
T33	B-14-012	Pressure side	Rubbing in gel coat
T33	B-14-012	Pressure side	Transverse fissure
T33	B-14-012	Suction side	Transverse fissure
T33	B-14-013	Pressure side	Transverse fissure
T33	B-14-013	Suction side	Transverse fissure
T34	A-14-011	Pressure side	Transverse fissure
T34	B-14-018	Pressure side	Damage to blade sides laminates
T35	D-14-015	Suction side	Transverse fissure
T36	A-14-004	Suction side	Transverse fissure
T36	A-14-006	Suction side	Transverse fissure
T36	A-14-007	Pressure side	Transverse fissure

Table 6.2: Turbines details with Category 4

Wind turbine No	Serial No	Surface	Typology
T36	A-14-007	Suction side	Transverse fissure
T39	D-14-018	Pressure side	Transverse fissure
T39	D-14-018	Suction side	Transverse fissure
T4	JQ-C-14-012	Trailing edge	Cracks in adhesive of trailing edge with flank
T4	JQ-C-14-012	Trailing edge	Cracks in the trailing edge adhesive union
T40	A-14-002	Pressure side	Transverse fissure
T40	A-14-002	Suction side	Transverse fissure
T40	B-14-002	Pressure side	Transverse fissure
T40	B-14-003	Pressure side	Transverse fissure
T40	B-14-003	Suction side	Transverse fissure
T41	D-14-030	Suction side	Transverse fissure
T42	C-14-008	Pressure side	Deterioration of the SAR receiver
T43	D-14-026	Trailing edge	Cracks in the trailing edge adhesive union
T43	D-14-027	Trailing edge	Cracks in the trailing edge adhesive union
T44	A-14-024	Pressure side	Transverse fissure
T44	A-14-025	Pressure side	Transverse fissure
T44	B-14-026	Pressure side	Transverse fissure
T45	A-14-011	Suction side	Transverse fissure
T45	A-14-013	Suction side	Transverse fissure
T45	A-14-014	Suction side	Transverse fissure
T46	A-14-003	Suction side	Transverse fissure
T48	B-14-024	Pressure side	Cracks in the laminate
T5	JQ-C-14-003	Trailing edge	Trailing edge open
T6	JQ-D-14-024	Suction side	Damage to blade sides laminates
T60	C-14-038	Leading edge	Marks
T62	C-14-032	Leading edge	Longitudinal crack
T69	C-14-034	Suction side	Damage to blade sides laminates
T69	D-14-040	Suction side	Damage to blade sides laminates
T69	D-14-040	Suction side	Others
T7	C-14-013	Suction side	Longitudinal crack
T7	D-14-020	Suction side	Surface geometrical deviations> 5 mm
T8	A-14-022	Pressure side	Damage to blade sides laminates
T9	B-14-027	Leading edge	Erosion with damage to the laminate
T9	B-14-027	Leading edge	Longitudinal crack
T9	C-14-018	Trailing edge	Cracks in the trailing edge adhesive union
T9	D-14-028	Suction side	Damage to blade sides laminates
T9	D-14-028	Suction side	Deterioration of the SAR receiver
T93	D-14-034	Suction side	Transverse fissure
T94	B-14-047	Pressure side	Transverse fissure

Table 6.2: Turbines details with Category 4

Wind turbine No	Serial No	Surface	Typology
T94	B-14-047	Suction side	Transverse fissure
T94	B-14-048	Pressure side	Transverse fissure
T94	B-14-048	Suction side	Transverse fissure
T95	A-14-043	Pressure side	Transverse fissure
T95	A-14-043	Suction side	Transverse fissure
T95	B-14-046	Pressure side	Transverse fissure
T96	D-14-042	Pressure side	Transverse fissure
T96	D-14-042	Suction side	Transverse fissure

Table 6.3 shows details of Turbines, and the maximum findings for categories 5, 4 and 3.

Table 6.3: Turbines blades details for Category 5, 4 & 3

Wind Turbine Number	Blade 1	Blade 1	Blade 1	Max.
T25	4	4	5	5
T39	5	3	4	5
T41	3	5	4	5
T7	3	5	4	5
T102	4	3	4	4
T103	4	3	3	4
T104	4	4	4	4
T106	3	4	3	4
T107	4	4	4	4
T108	4	3	3	4
T109	4	4	3	4
T11	4	4	4	4
T112	3	4	3	4
T12	4	4	4	4
T13	4	4	3	4
T14	4	4	4	4
T15	4	4	4	4
T16	4	3	3	4
T17	4	4	4	4
T18	4	4	3	4
T19	4	4	3	4
T2	3	3	4	4
T20	3	4	3	4
T21	4	4	4	4

Table 6.3: Turbines blades details for Category 5, 4 & 3

Wind Turbine Number	Blade 1	Blade 1	Blade 1	Max.
T22	3	4	4	4
T23	4	4	4	4
T24	4	3	4	4
T27	3	3	4	4
T29	3	4	4	4
T3	4	3	4	4
T30	3	4	3	4
T31	3	3	4	4
T32	4	4	4	4
T33	4	4	4	4
T34	3	4	4	4
T35	3	3	4	4
T36	4	4	4	4
T4	4	3	3	4
T40	4	4	4	4
T42	4	3	3	4
T43	4	3	4	4
T44	4	4	4	4
T45	4	4	4	4
T46	4	3	3	4
T48	3	3	4	4
T5	4	3	3	4
T6	4	3	3	4
T60	4	3	3	4
T62	3	4	3	4
T69	4	3	4	4
T8	4	3	3	4
T9	4	4	4	4
T93	4	3	3	4
T94	4	3	4	4
T95	3	4	4	4
T96	4	3	3	4
T1	3	3	3	3
T10	3	3	3	3
T101	3	3	3	3
T105	3	3	3	3
T110	3	3	3	3
T111	3	3	3	3
T26	3	3	3	3
T28	3	3	3	3
T37	3	3	3	3

Table 6.3: Turbines blades details for Category 5, 4 & 3

Wind Turbine Number	Blade 1	Blade 1	Blade 1	Max.
T38	3	3	3	3
T47	3	3	3	3
T54	3	3	3	3
T57	3	3	3	3
T66	3	3	3	3
T67	3	3	3	3
T70	3	3	3	3

For Categories identified as 2 and/or 1, this detailed can be extract from the individual check list and summary list, provided to the Client.

Within these turbines is UL recommendation to track and repair according to the following time frames:

- **All blades with Category 3**: Track and repair within 6 months
- **All blades with Category 2**: Track and repair within 12 months
- **All blades with Category 1**: Blade in good conditions. No further actions is recommended

Figure 6.15 shows an example of kind of pictures and layout provided within all individual blade´s report.

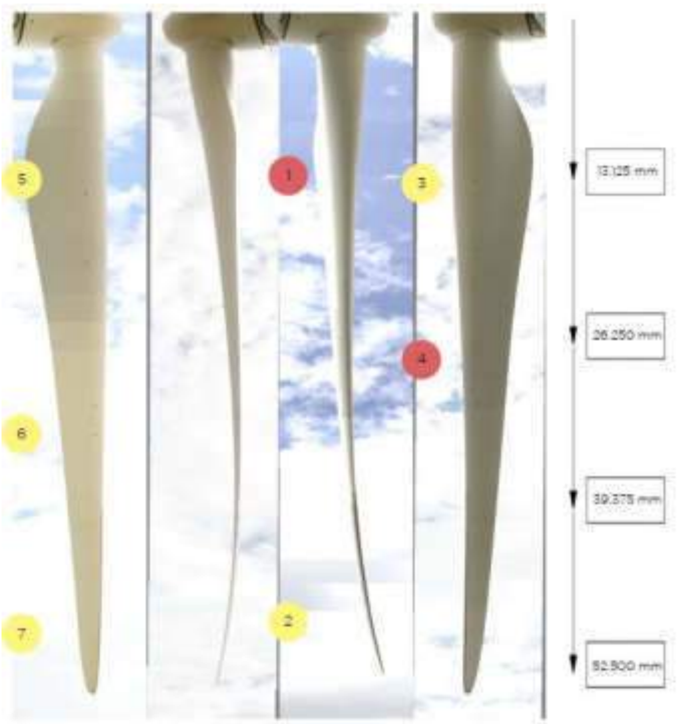

Figure 6.15: Example of reporting for WT 23 – blade 2

All inspections components and findings items are supported by a picture added to the checklist, these are also documented as per previous categorization. These are expected to be update / review during the next maintenance schedule, or within the time frame recommended.

At this stage, UL have no further comments.

6.2 Blades Internal Inspection

The external blade inspections UL was thought to be performed by taking HD images of the interior of the blades by means of its CERBERUS Robot. The Robot CERBERUS aims to perform tasks of internal inspection of blades in wind turbines, circulating inside the blade making snapshots and image recording of the elements and possible visible damage from the inside.

Internal blades could not been performed due to actual blade brake system design. The use of the CERBERUS robot was impossible, due to safety reasons. Several attempts were done by means of using a go-pro camera, but results were not as expected. Considering the low pictures resolutions and risk of technicians to performed these, the Client and UL agreed not to perform these inspections.

At this stage, UL have no further comments.

7. FINAL SUMMARY AND COMMENTS

UL has reviewed the documentation submitted and listed in the Appendix of this report.

The overall condition of the blades gathered through the described works appears to be acceptable outside of the major issues that were observed. These can be address with a proper action plan based on recommendations provided by UL. During the inspections neither detachments were detected in the tip of the blades root nor abnormal noises were detected which indicates to stop the turbines immediately.

Some of the items identified and documented on the punch list from the inspection process are relatively minor and can be addressed easily on the maintenance schedule. These should not require extensive amounts of time to address.

On a good note for the technicians on site, the turbines were relatively clean, hubs were very clean with the exception of the turbines that had some leaks, as reported.

Only 2 turbines (T39 and T41), have been identified as an immediate risk for the turbines in operation.

Rest of Turbines no critical finding identified as being an immediate risk for the turbines in operation.

UL noted that for the recommendations to be done on the blades to follow OEM´s procedures. The repair and upgrade instructions should be adequate and sufficient for restoring the blade to design intent.

7.1 Further considerations

This technical report is only valid for the submitted documentation listed and process evaluated during wind turbine inspections and test performed.

8. FURTHER WORKS TO BE DEVELOPED BY UL

As per the date of this report, UL have been requested to provide further support in regarding the major defect identified at the blade root joint section and explained in section 4 of the present report, which was communicated after the inspections and works were completed on site. This section describes the risk identified and the follow up actions to be performed by UL.

According to the Client and document provided and listed in the Appendix of this report, Blade root Bushings exhibits Voids that could cause detachment of the root.

The next topics were identified:

- The Blade Roots were designed to employ Pre-Cast inserts of root bushings
- Sinoma did not manufacture blades using pre-cast inserts on root bushings
- Sinoma´s failure to follow the TRES4 design resulted in supplying blades with significant voids along the root bushings.

UL understand that the presence of voids in the root bushings can reduce blades operating lifetime.

In order to have a clear and complete understanding that actual blades on site and to verify the potential risk of voids presence ai the root bushing, UL will carry out the following tasks:

- Verify actual status of entire blade fleet on site:
  - Check the status of the installed blades: NDTs + pull out test:
    - NDTs procedure definition: tomography will be used in a test specimen in order to have a proper reference on the status of the area around the insert. After this test, US (ultrasound) and thermography will be used in order to setup the recommended technique/s to be used in field.
    - Pull out test: Performing pull out test on the dismounted blades on field
    - NDTs in the entire wind farm (if applicable)

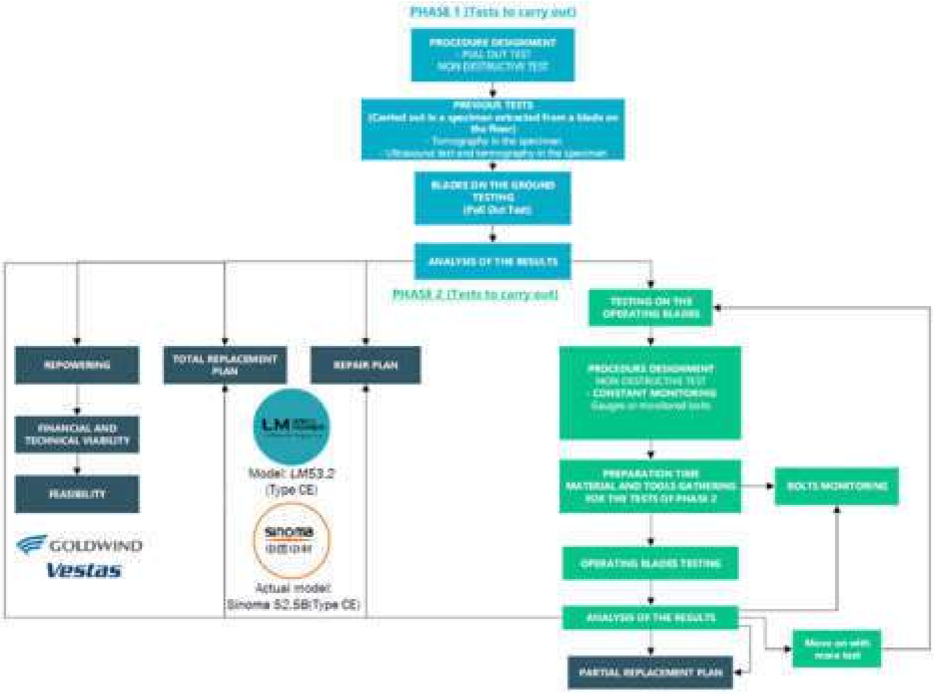

Figure 8.1: Test Procedure

Figure 8.1 shows test procedure to be performed by UL

UL is engaging on these works based on proposal: 1101832941-4_INTERENERGY PANAMA

At this stage, UL have no further comments.

9. REFERENCES

Documentation provided by the Client:

Table 9.1: Reference Files

Folder	Files Name
1. Prueba previa ultrasonidos 24-10-19 (Arth Wind)	ATW- UEP - PANAMA
2. Sinoma Blade Tip inspection Checklist	G25PA030080 - GW25 CL Sinoma Blade Tip Inspections
3. Inspección Tips realizado por Goldwind (Julio 2016)	G25PA060280 - EC Penonome II Blade Inspection Update
4. Reportes reparaciones palas anteriores (Turbinas T67 y T47)	Panama WTG 47 Report
	T67 repairment HP
	T67 repairment LP
5. Documento procedimiento refuerzo Tip Windprove	Wp TipReinf. Memo Rev1
6. Informes inspecciones palas mediante rapel (realizados por HG wintec)	A-14-016 Reporte de Inspección por cuerdas_WTG 106_PELaudato_2019
	A-14-021 Reporte de Inspección por cuerdas_WTG 41_PELaudato_2019
	C-14-033 Reporte de Inspección por cuerdas_WTG 41_PELaudato_2019
	D-14-020 Reporte de Inspección por cuerdas_WTG 07_PELaudato_2019
	D-14-033 Reporte de Inspección por cuerdas_WTG 25_PELaudato_2019
	D-14-050 Reporte de Inspección por cuerdas_WTG 16_PELaudato_2019
	SI525-FNB-14006_Reporte de Inspección por cuerdas_WTG_23_PELaudato2019 PALA 3
	SI525-FNB-14006_Reporte de Inspección por cuerdas_WTG_23_PELaudato2019 PALA 3
	SI525-FNB-14009_Reporte de Inspección por cuerdas_WTG_23_PELaudato2019 PALA 1
	SI525-JQB-14017_Reporte de Inspección por cuerdas_WTG_39_PELaudato2019 PALA 1
7. Informe Interenergy resumiendo los informes de HG wintec	INSPECCIONES FISICAS ASPAS
Email: Goldwind Maintence Manual	Maintenance Manual
Email: WINDprove	UEPII Major Blade Defects

UEP PENONOME II S.A.

REPORT REVIEW

BLADES STRATEGY PLAN
LAUDATO SI' WIND FARM
PENONOME (PANAMA)

On October 2019, UL was engaged by IE through UEP Penonome II (Interenergy Renewables or "IE") to support in the design of a blade replacement strategy. UL International GmbH – Sucursal en España had review, as a third party, the report on the Blades Strategy Plan, for Laudato SI´ Wind Farm, located in Penonome (Panama). The report defines a complete plan for the blade's strategy. UL have reviewed the report to assure its quality, and provide its independent opinion.

Documents used for validation:

- Blades Strategy Plan UEPII - Executive Report V4- REF: 06-04-LAUDATO-V2, dated 18th September 2020

The report consist on the main following sections:

1. **Blades damage history.** Summarizes all the featured events, from a legal and operational point of view, that affected the blades life between the arbitration process and the Independent Engineer selection process. It also includes major repairs carried out in the blades until December 2019.

UL has reviewed this section and agree with the content.

2. **Blades strategy plan design.** Includes all the necessary tests performed to analyze the current condition of the blades and serve as basis to define the Blades Strategy Plan.

UL has reviewed this section and agree with the content.

3. **Blades strategy plan.** This section includes detail of all the action lines to be carried out to ensure the optimal operation and performance during the lifetime of the blades.

UL has reviewed this section and agree with the content, with the following comments.

Monitoring System: To identify the need of replacement, a monitoring system will be installed in the blade roots to control in real-time the condition of it and manage the risks identified in the related report. **UL have been appointed to perform this works.**

Quality Control Plan: UL will verify that the requirements identified during the design evaluation with respect to critical Components and critical manufacturing processes were observed and implemented in production and assembly. **UL have no received evidence of any documentation of new blades as per the date of the present report.**

Quality Control Assurance: UL as the Independent Engineer of this Project, will be responsible of the supervision of all the works that make up the Blades Strategy, including inspection and repair works. In that sense, UL will validate the inspection and repair works carried out by the contractor. **UL have been appointed to perform this works.**

Shipping of new blades: The intention of UEP II is to purchase 7 sets of blades to be delivered by the end of the low-wind season, which is around end of November. Considering the shipping, the blade should leave the factory around September. **UL have no received evidence of any shipment as per today and is aware of the possible impact due to actual pandemic situation.**

4. **Schedule and financial assessment.** Describes Capital and Operational expenses for the Blades Strategy Plan execution.

UL has reviewed this section and agree with the content, with the following comments.

UL has reviewed and confirms that Plan Schedule includes detail planning of all the phases to have in consideration and the associated costs until the year 2020. In addition, the scheduled lifetime including Aging Management actions is described as well as costs related to them.

UL have reviewed the Blades inspection reports and repair works schedule. In addition, UL have received first reports for WTG02 and WTG03. Blades Inspections started on 11th September.

UL verify that condition monitoring system have been taken into account to manage risk and use to determine when a blade start to have an operational risk and follow up actions will be needed, as describe in the related report. Seven (7) full sets of blades will be available on site.

UL verify that a reserve account of 1 million have been taken into account. This is to be used for several purposes related to replacement and/or repair works. UL note that, in case the reserve account is used, IE indicates that the letter of credit will be maintained at its initial value. It is indicated that funds will be provided annually to this account during the next five years

UL verified the Blades Strategy Plan Cost and founds it reasonable as indicated and reviewed that all concepts describe in the document are taken into account.

It is UL opinion that all sections of the Blade Strategy Plan are successfully completed and in an ongoing process. In addition, UL note that main actions are taken into account:

- A global external blades repair plan
- A monitoring system consisting to manage risk
- Seven (7) new blades sets to be available on site
- A reserve account of 1 Million USD.

As an independent third party, UL has review and agree with the content of this document. UL considers the report consistent and traceable in all faces with supporting evidence in each section.

This Report review is only valid for the submitted documentation listed above.

Santiago Lopez
Global Director - Asset Management Services Renewables
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UL International GmbH Sucursal en España
Ansoain, 21. September 2020

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APPENDIX D—PENONOMÉ II PERFORMANCE ASSESSMENT REPORT

Performance Analysis and Energy Yield Assessment Comparison

PREPARED FOR:
UEP Penonomé II S.A. Renewables

Ref. No.: UL-ES-AA20-13321645-05.02

PERFORMANCE ANALYSIS AND ENERGY YIELD ASSESSMENT COMPARISON PENONOME
Penonomé
Panamá

20 August 2020

CLASSIFICATION
CLIENT'S DISCRETION

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DOCUMENT HISTORY

ISSUE	DATE	SUMMARY
A	14th August 2020	First emission
B	20th August 2020	Long-term information updated

NOTICE TO THIRD PARTIES

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

List of Acronyms

Acronym		Description
C	COD	Commercial Operating Date
E	EAF	Equivalent Availability Factor
	EC	Environment Canada
	ECMWF	European Centre for Medium-Range Weather Forecasts
	ERA-5	ERA-5nterim
G	GW, GWh	Gigawatt, Gigawatt hour
I	IEC	International Electrotechnical Commission
	ISH	Integrated Surface Hourly database
K	km	Kilometer
L	LT	Long-term
M	m	Meter
	MCP	Measure-Correlate-Predict
	MERRA-2	Modern-Era Retrospective Analysis for Research and Applications
	MW, MWh	Megawatt, Megawatt hours
	m/s	Meters per second
N	NA	Not Available
	NCDC	National Climatic Data Center
	NCEP	National Centers for Environmental Prediction
	NNRP	NCEP/NCAR Reanalysis Project
	NOAA	National Oceanic and Atmospheric Administration
	NWS	Nacelle Wind Speed
P	POR	Period of Record
R	r	Pearson correlation coefficient
	R^2, r^2, r-squared	Coefficient of determination
	RWS	Reference Wind Speed
T	TWS	Turbine Wind Speed
W	WRF	Weather Research and Forecasting
Y	Yr	Year

List of Definitions

Name	Definition
OEPR	Operational Energy Production Report
Evaluation Period	The time period immediately following the operational POR to which future estimates of energy are applied. The evaluation period is typically 10 years.
Operational POR	The months within the wind plant total period of operation for which reported energy and loss data have been quality-controlled and determined to be valid for use in this analysis.

1. EXECUTIVE SUMMARY

UL was retained by UEP Penonomé II. S.A. (UEP Penonomé II. S.A. or "the Client") to evaluate the operational performance of Penonomé II wind farm, located in Penonomé, Panamá. The analysis includes a comparison with the pre-construction Energy Yield Assessment ("EYA") provided by the Client [1]. The project has a nominal capacity of 215 MW and employs 86 Goldwind GW109 2.5MW wind turbines with rotor diameters of 107.5 m. All turbines have a hub height of 90 m. Penonomé II achieved COD in 2015.

The energy production during 2019 was 546.5 GWh according to the revenue meter, while 511.7 GWh were expected according to the results of the EYA provided by the Client [1]. Therefore, a relative difference of -6.80%[1] has been found. In the analysis presented in this report, losses have been evaluated by means of classification of the production variance sources in several categories. The categories considered in this analysis have been defined crossing the categories of energy losses in the EYA and the available operational information. Here it is a list of the categories: climatic conditions as wind anomaly (section 6.1.1), density variance (section 6.1.2) and wind modelling variance (section 6.2), wind turbines availability (section 4), electrical losses (section 7), and wind turbines performance (section 5).

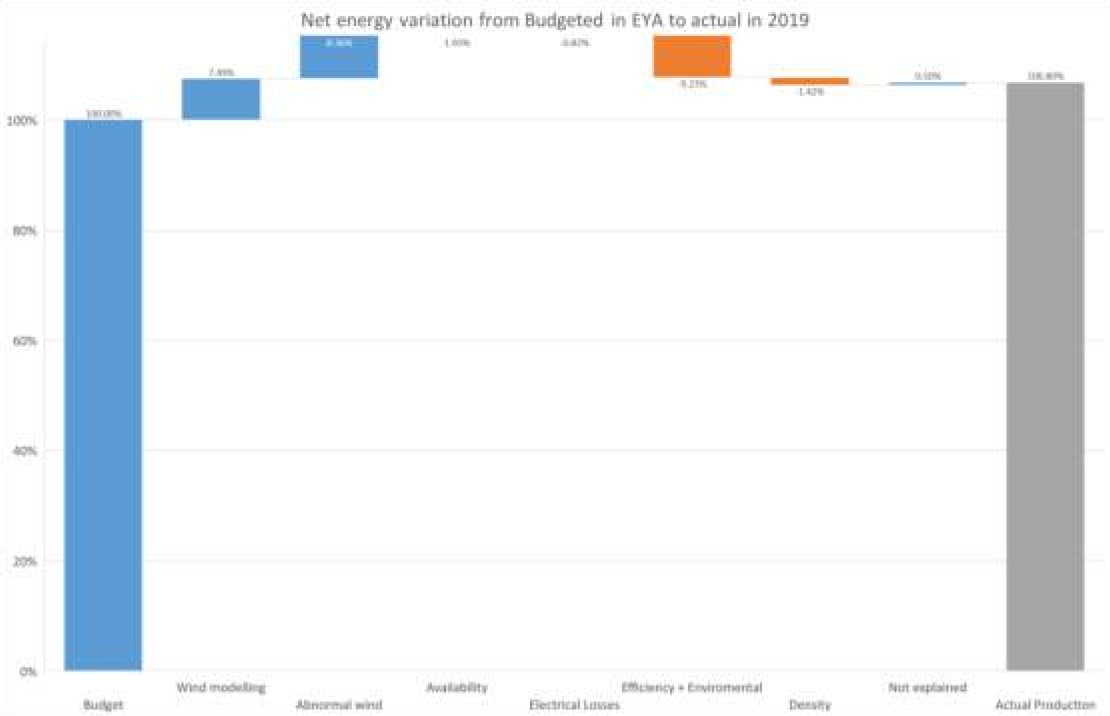

Figure 1.1: EYA P50 vs. Operational Data Analysis

Taking into consideration the losses obtained in the operational data analysis, comparing them with the EYA ones, and considering the EYA P50 (in revenue meter) value as reference, the next relative differences on each analyzed category were obtained translated to net energy:

- 7.49% positive variance on wind and wakes modelling: 38.31 GWh.
- 8.36% positive wind anomaly (2019) vs LT reference: 42.76 GWh.

[1] The negative difference indicates than the measured energy in the power meter is higher than the EYA net.

- 1.93% positive variance on availability losses: 9.86 GWh.
- 0.82% negative[2] variance on electrical losses: 4.2 GWh.
- 9.23% negative variance on operational under-performance[3] of the wind turbines: 47.24 GWh.
- 1.42% negative variance on density: 7.28 GWh.
- 0.50% as remaining variance this analysis: 2.55 GWh.

The presented variances are obtained as a percentage of the EYA P50 energy results. Additionally, the Client requested the comparison per category in order to review the assumptions on the pre-constructive analysis. This requires evaluation of the losses as a percentage of the gross energy before wakes. The comparison is presented in Figure 1.2 and Figure 1.3.

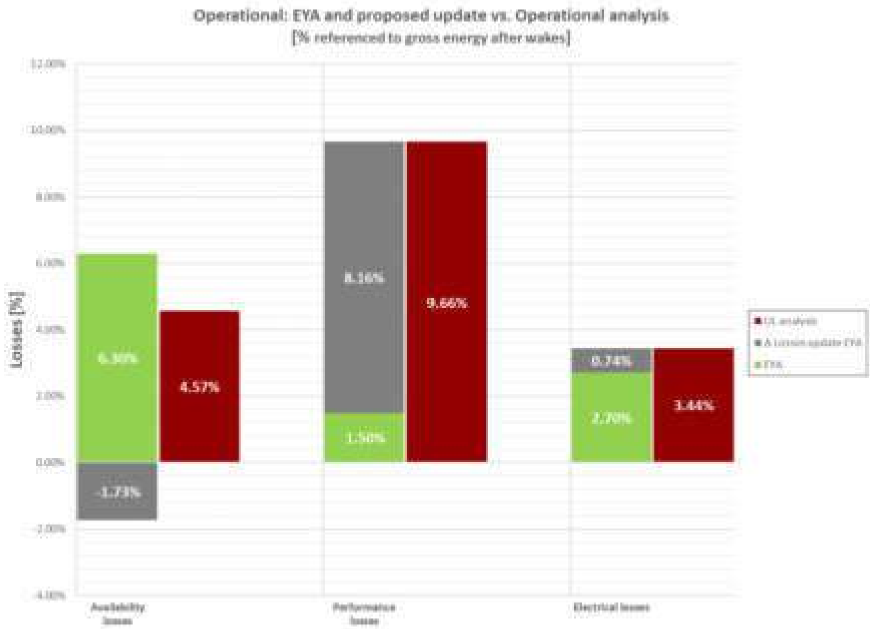

Figure 1.2: Differences on Availability, Performance and Electrical losses.

The not explained losses could be seen on Figure 1.3. This variance is the missing percentage after applying all the percentages from gross to net energy. On EYA analysis, the percentage of not explained losses reach to 6.80% (vs. 2019). This percentage is reduced to 0.08% considering the losses obtained in this operational data analysis.

It is worth to mention than the lack of the Power Performance Measurement [1], has been a handicap to apply the RWS methodology detailed in Annex C, although it was successfully applied. This correction allowed to reduce the uncertainty of the analysis drastically.

Considering the analysis results it could be concluded that main differences are properly classified and there is a significant reduction on the expected budget and produced energy considering the sources of variance obtained in the analysis. As an additional verification, considering the obtained variance factors and the gross energy in the EYA, the 2019 production is mainly explained and only a 0.08% is the remaining variance of this cross-check (Table 7.1).

[2] The negative variances (discrepancies) mean UL assessed energy loss using operational data is larger than the Client's assumptions as defined within the E.Y.A.

[3] The Environmental and Performance losses of the EYA have been considered here for the comparation. Further description in the section 5 of this report.

As a final crosscheck and considering the OEPR developed in 2020 [2], the P50 production should be 493.3 GWh, and applying the abnormal wind conditions in 2019, and considering the availability variance, it is obtained a production of 543.82 GWh (it differs from revenue meter energy in 0.49%, see Table 8.3).

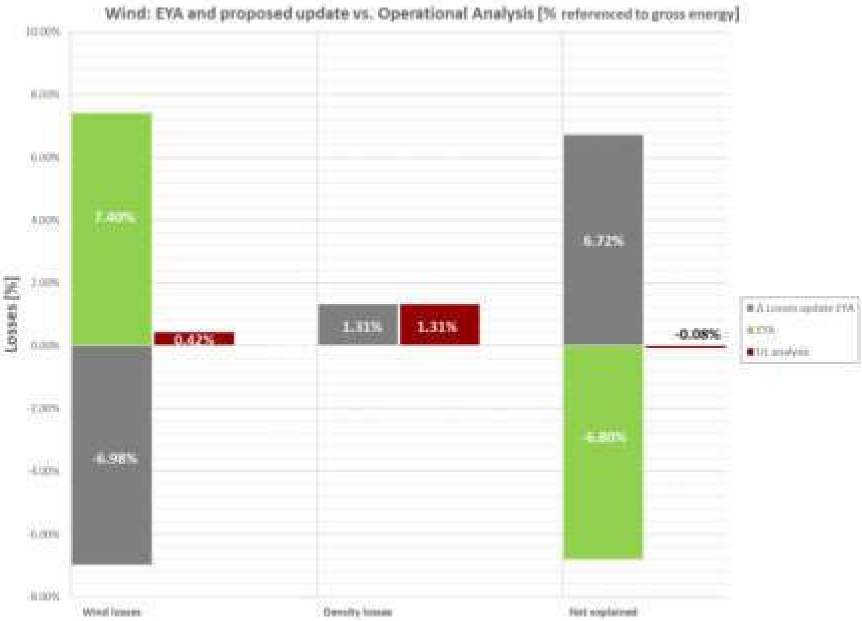

Figure 1.3: Wind related discrepancy, air density discrepancy and not explained losses.

Finally, they are listed recommendations related with this analysis:

- Review the nacelle anemometer calibration in order to avoid too early or too late de-rating strategies close to the cut-out wind speed. Too early application lead to underperformance and too late application implies additional risk on the structural integrity.
- Record in a proper log the curtailment strategies in order to enable an analysis with proper differentiation of performance and curtailments. Additionally, non-expected curtailments could be found in this kind of analysis.
- When several sources of information are involved, proper synchronization of the sources enables a more reliable analysis. Uncertainty related with the synchronization is drastically reduced and the synchronization effort will decrease drastically.
- Finally, having into consideration the alarm reports could enable a more accurate availability analysis.

2. INTRODUCTION

This report presents the results of this operational energy assessment and discusses the methods used to develop the project availability, wind turbine operational efficiency, wind yield energy modelling error, wind anomaly, electrical losses, gross and net energy production, to compare with the values assumed within the Energy Yield Assessment provided by the Client for the Penonomé II wind farm.

Penonomé II, located in Penonomé, Panamá, has a nominal capacity of 215 MW and employs 86 GW106 2.5MW wind turbines with rotor diameters of 107.5 m. All turbines have a hub height of 90 m. Penonomé II achieved COD in 2015. Penonomé II layout is shown in the Figure 2.1.

Figure 2.1: Penonomé II layout.

3. DATA FILTERING

3.1 Wind Direction

The wind direction distribution measured in the mast and the wind direction distribution measured on the wind turbines are different (see Figure 3.1). The one measured on the mast matches with the wind distribution detailed in the EYA, so for the following calculations the mast wind direction is considered over the wind turbine direction, in order to filter data for calibration or sector-wise analysis.

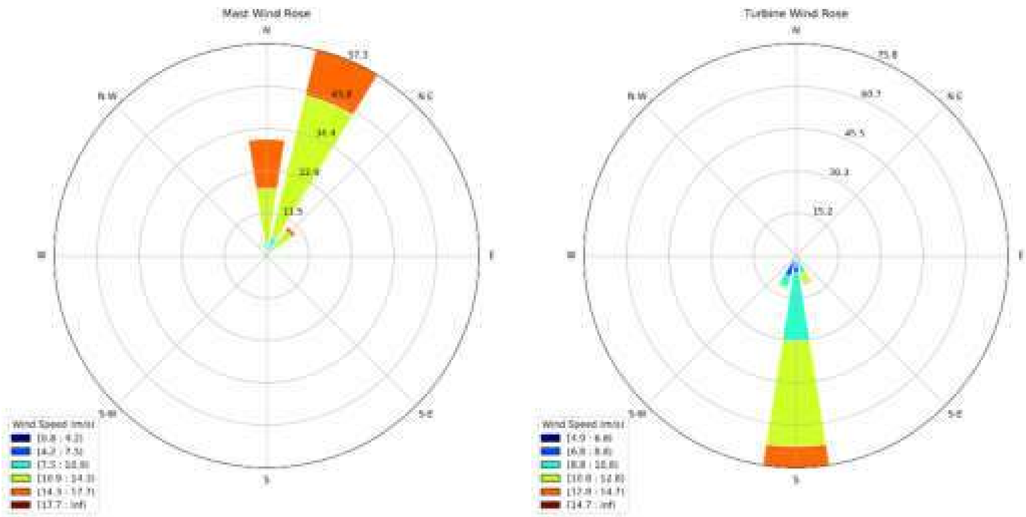

Figure 3.1: Mast and wind turbine wind roses.

4. AVAILABILITY ANALYSIS

To obtain an accurate availability estimation, UL has used the event-log status data provided by the client (Power production, Run up, Standstill, Starting, Service and Stop). The different statuses have been categorized according to the IEC-6100-26 [3].

The availability has been calculated according with the operational availability definition in IEC-6100-26 [3]. According with this definition, Eq. 1, performance categories are considered available (IAOG, information available operational generating), and all other IEC categories are considered unavailable for the base case, from the turbine owner/operator's perspective, excluding the information unavailable periods (no SCADA data registered in the turbine), where these time or energy is not considered in the calculation.

$$Availability_{Operational} = 1 - \frac{unavailability_{op.}}{(availability - unavaiability)_{op}} \qquad \text{Eq. 1}$$

where:

Availability$_{op.}$ = Sum of time (or energy) for the operational periods considered as available (IEC categories IAOG, 1 and 2)

Unavailability$_{op.}$ = Sum of time (or theoretical energy) for the operational periods considered as not available (IEC categories with information but not generating, IAONG, non-operative, IANO, or force majeure, IAFM, category number from 3 to 11)

The different availabilities calculated are in Table 4.1, where:

- **Operational time-based availability:** calculated according to the IEC 61400-26-1 [3]. Time with the turbine generating considered as availability, time with the turbine non-generating considered as unavailability, and time periods with information unavailable excluded from the calculation.
- **Operational energy-based availability:** calculated according to the IEC 61400-26-2 [4]. Energy in time periods generating considered as availability, difference between theoretical energy and measured energy in generating at partial performance periods (difference in performance at partial performance), and theoretical energy in non-generating periods (no

energy generated) considered as unavailable. Periods with information unavailability excluded from the calculation.

- **Operational energy-based availability (without "generating performance"):** theoretical energy in time periods generating considered as availability (performance losses not considered), and theoretical energy in non-generating periods considered as unavailable (no energy generated). The difference with the IEC definition [4] is that the performance in generating periods is not considered as availability, so it can be analyzed in the wind turbine performance analysis (section 5).

Table 4.1: Monthly wind farm operational availabilities.

Month	Operational time-based availability	Operational energy-based availability	Operational energy-based availability (without "generating performance")
Jan-18	98.07%	96.97%	98.07%
Feb-18	98.24%	97.06%	98.15%
Mar-18	94.37%	92.51%	94.58%
Apr-18	95.06%	94.35%	95.38%
May-18	92.42%	91.25%	93.85%
Jun-18	87.62%	84.87%	87.04%
Jul-18	87.80%	85.34%	87.09%
Aug-18	86.03%	81.18%	84.27%
Sep-18	83.48%	77.06%	81.39%
Oct-18	88.31%	80.60%	86.69%
Nov-18	94.12%	92.19%	93.43%
Dec-18	98.62%	97.56%	98.81%
Average	**92.48%**	**93.87%**	**95.53%**

There are two turbines worth to mention due to their long periods with almost zero operational time-based availability. This could be seen on Annex A in Table A.2, the turbine T31 is affected from January to July and T67 from April to September. For instance, the downtime in turbine T31 is due to *"Error_2#Converter Outlet Valve Pressure Super Low"* alarm. Figure 4.1 shows the IEC energy-based availability [4] per wind turbine.

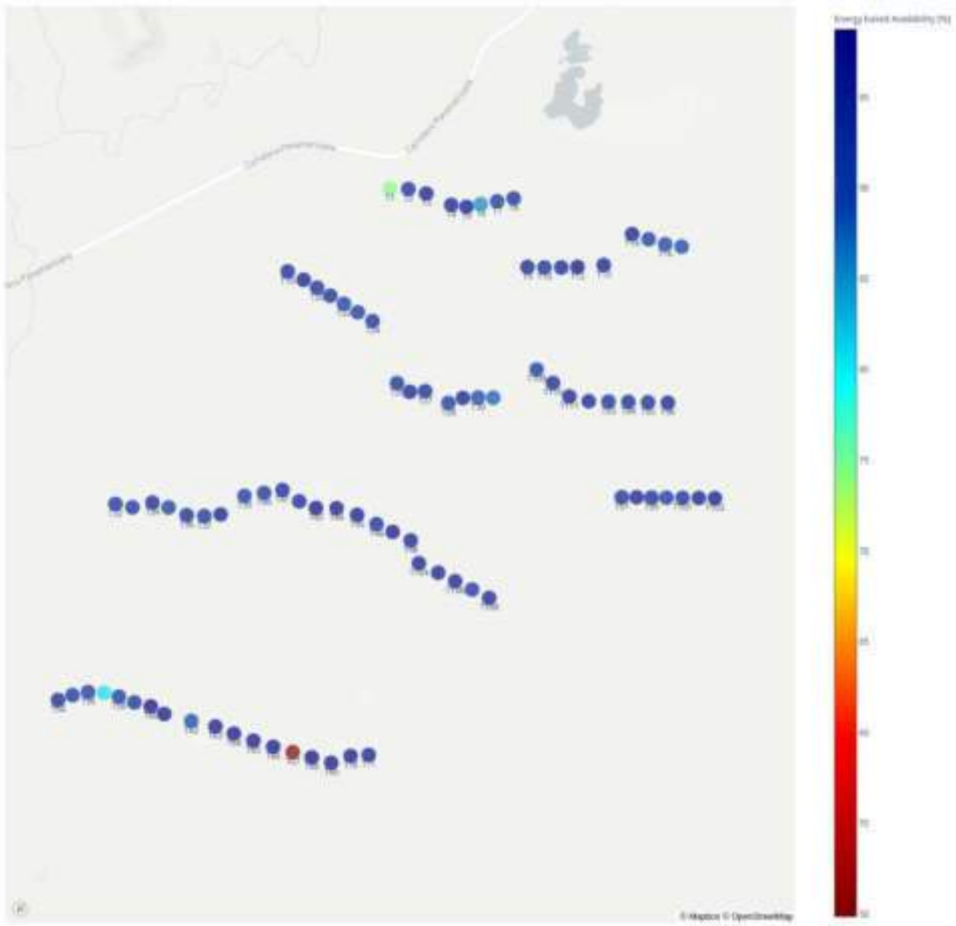

Figure 4.1: Graphical representation of IEC energy-based availability per wind turbine.

5. Wind turbines Performance Analysis

Wind Turbines performance ideal check requires strictly tying to follow IEC 61400-12 [5] recommendations. The use of operational data drives to incremental uncertainty, especially on the free wind speed characterization. Other operational phenomena like yaw misalignment, wind conditions out of specification, blade dirtiness, or curtailment strategies may increase performance losses when SCADA data are used instead of an IEC test, but it is a representation of the operational performance.

5.1 Methodology applied

The lack of a PPM[4] required to calculate the free wind directions and then filtering the data. The mast has been synchronized with the closest wind turbine data. Afterwards, wind turbine efficiency has been calculated using the turbine wind speed corrected according to the methodology of RWS, described on the Annex C.

In order to classify each generating 10-minutal data as *Full Performance* or *Partial Performance*, data sets have been filtered taking into consideration:

[4] Power Performance Measurement

- Only data records with generating status have been considered
- Active power vs RWS using 0.1 m/s width bins.
- 2 times standard deviation filter on each bin applied to categorize the performance statuses as *Full Performance* or *Partial Performance.*
- Categorization of *Non-declared curtailments* with an UL algorithm. This algorithm search for each power bins (ie. 100kW bins) continuous velocity data (ie. 3 consecutive hours) where turbine is underperforming for all the velocities inside this power bin.

The efficiency of the wind turbine is calculated as the ratio between the Annual Energy Production ("AEP") as defined on IEC 61400-12-1 [5] using measured and contractual power curves.

Several efficiency definitions are considered in this analysis:

- **Optimal performance:** this efficiency is calculated by using the 10-minutal data classified as *Full Performance.* This efficiency will be the highest efficiency calculated, and represents the efficiency that could be obtained in ideal operational conditions (no "ready" statuses, correct alignment, …)
- **Suboptimal performance:** in this case, all the 10-minutal generating data *(Full Performance* or *Partial Performance)* is used, but excluding the periods categorized as *Non-declared curtailments* with the UL algorithm. This efficiency is the expected efficiency if there are not curtailments events (ie. grid limitations or restrictions).
- **Generating performance:** all the 10-minutal generating information is considered in this efficiency, including the *Non-declared curtailments.* This is the real efficiency in this wind farm. All the events categorized as curtailments tends to lower the efficiency of the turbines, so the root cause of these non-declared events should be checked.

5.2 Results of the analysis

Figure 5.1 shows the main efficiency results for Penonomé. Detailed wind turbine efficiency results can be found in Annex D.

Table 5.1: Wind farm efficiency summary.

Optimal performance	Suboptimal performance	Generating performance
91.45%	90.41%	90.34%

Although average operational generating performance, several specific wind turbines show an operational underperformance out of the normal behavior in the wind farm. Normal behavior has been defined as the mean value with a coverage factor of 90%. Three main behaviors are detected: uncalibrated anemometers, curtailments (non-declared by UL algorithm) and bad fitting of the data on the power curve.

As the anemometer measures a wind speed that has been altered by the blades of the wind turbine, once the wind speed is corrected by the method presented on Annex C, the RWS correction (power curve in orange on Figure 5.1) shows an displacement to the right of the original power curve (power curve in blue on Figure 5.1)[5]. On Figure 5.1 is shown a comparison between the density correction, contractual power curve corrected to standard density (black) and the RWS methodology results.

[5] All the wind speeds have been normalized from on-site density to standard density of 1.225 Kg/m^3.

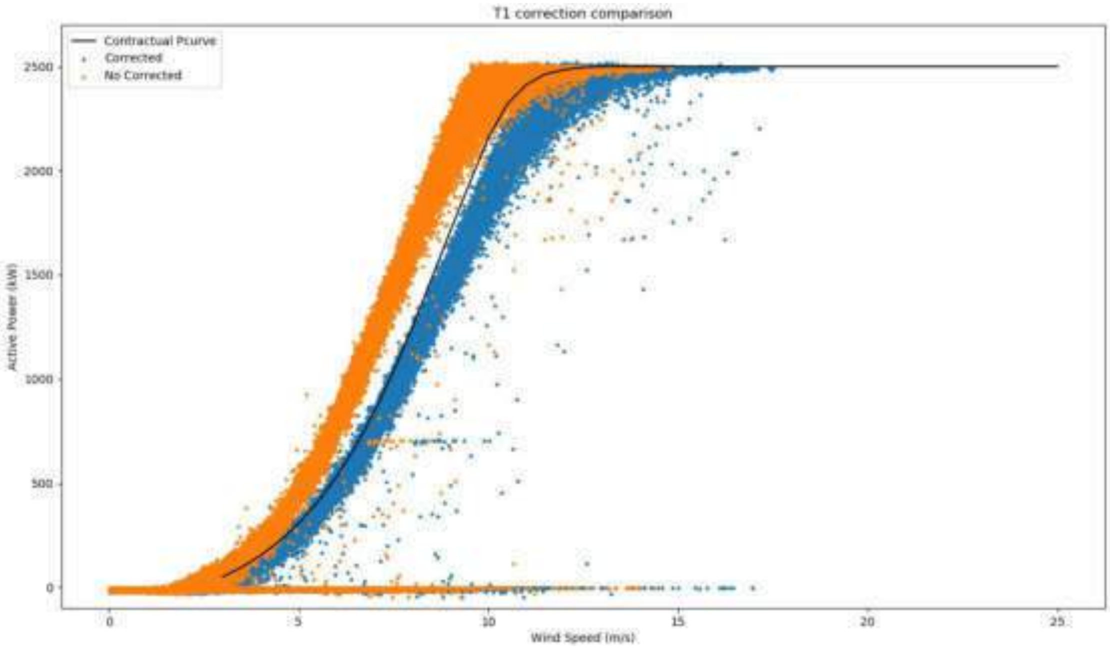

Figure 5.1: Comparison between no corrected wind speed (orange), contractual power curve (black) and RWS corrected wind speed (blue) in turbine T1.

Analyzing the Power vs Generator speed graphs (see Figure 5.2) indicates that the anemometer transfer function underestimate the wind speed magnitude (if the controller would have been changed, there will be multiple slopes in Figure 5.2), as explained in Annex C.

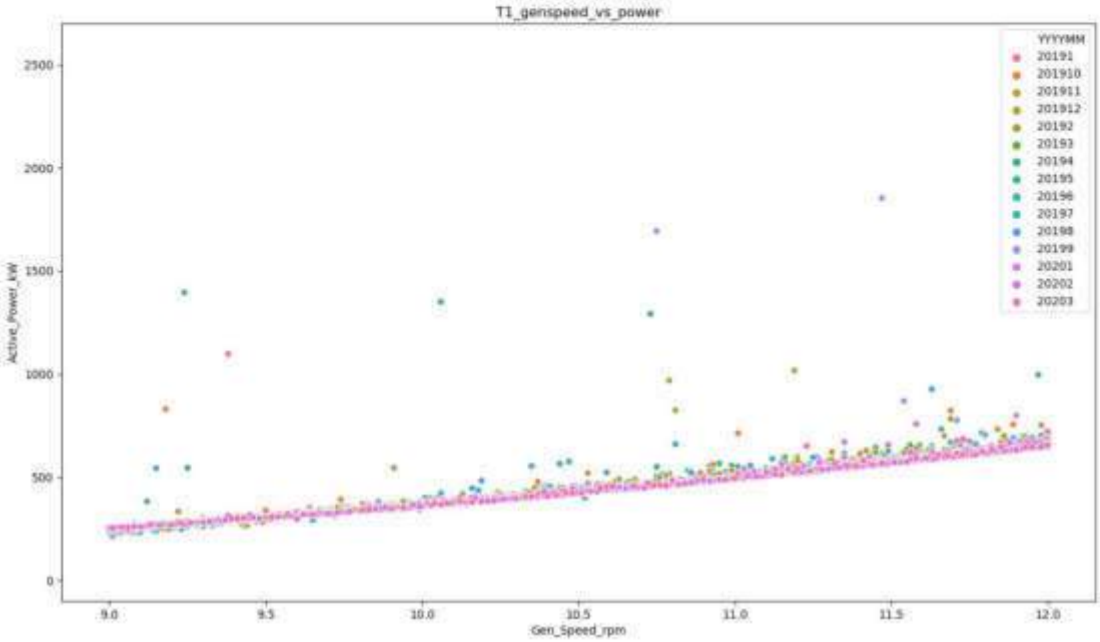

Figure 5.2: Power vs Generator speed in turbine T1.

On the turbine T110, the operational generation performance is 89.42% (suboptimal performance 89.42% and optimal performance 90.39%) the lowest in all the wind farm. On Figure 5.3, the RWS correction is applied to the power curve. It is remarkable that without this RWS correction, and considering the anemometer wind speed, this wind turbine seems to reach a performance over 126.44%.

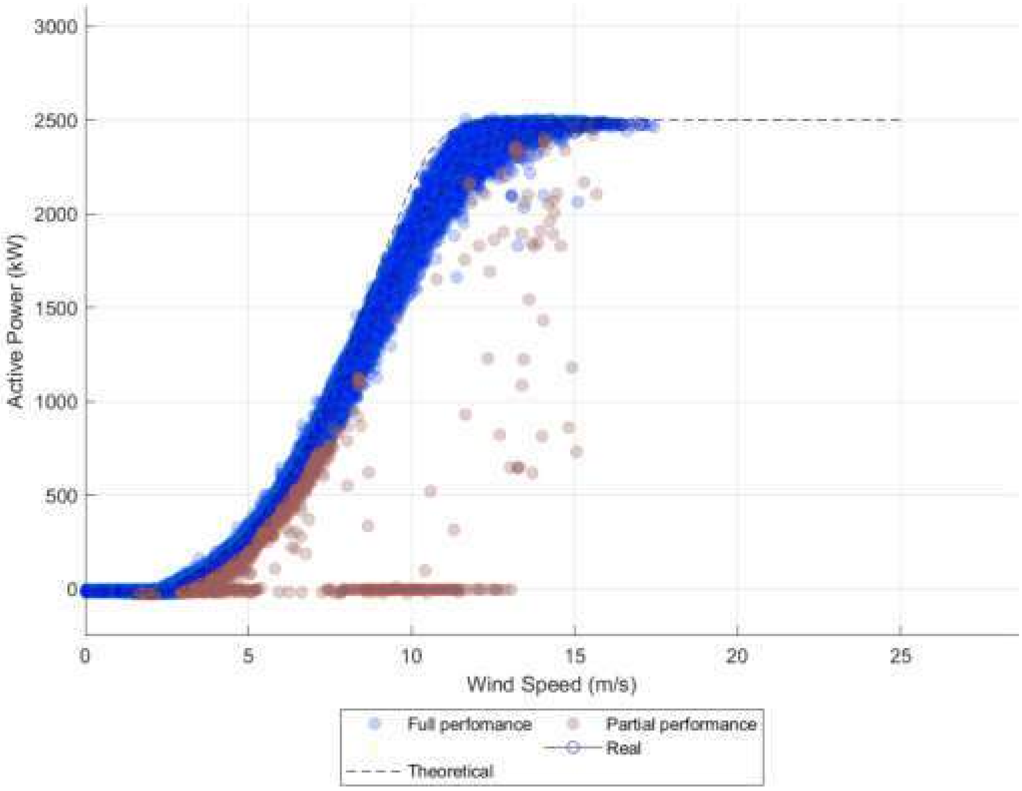

Figure 5.3: T110 Wind turbine Power Curve Performance with an operational generating performance of 89.42%.

The performance in wind turbine T3 reaches an operational generating performance of 92.85% (suboptimal performance 92.91 and optimal performance 93.34%). This is one of the best performing turbines on the wind farm. On Figure 5.4 is shown the power curve of the T3. In this turbine, the datapoints are concentrated in the upper left part of the curve, achieving this way the higher efficiency of the wind farm. Some non-declared curtailments are detected in this turbine by the UL algorithm.

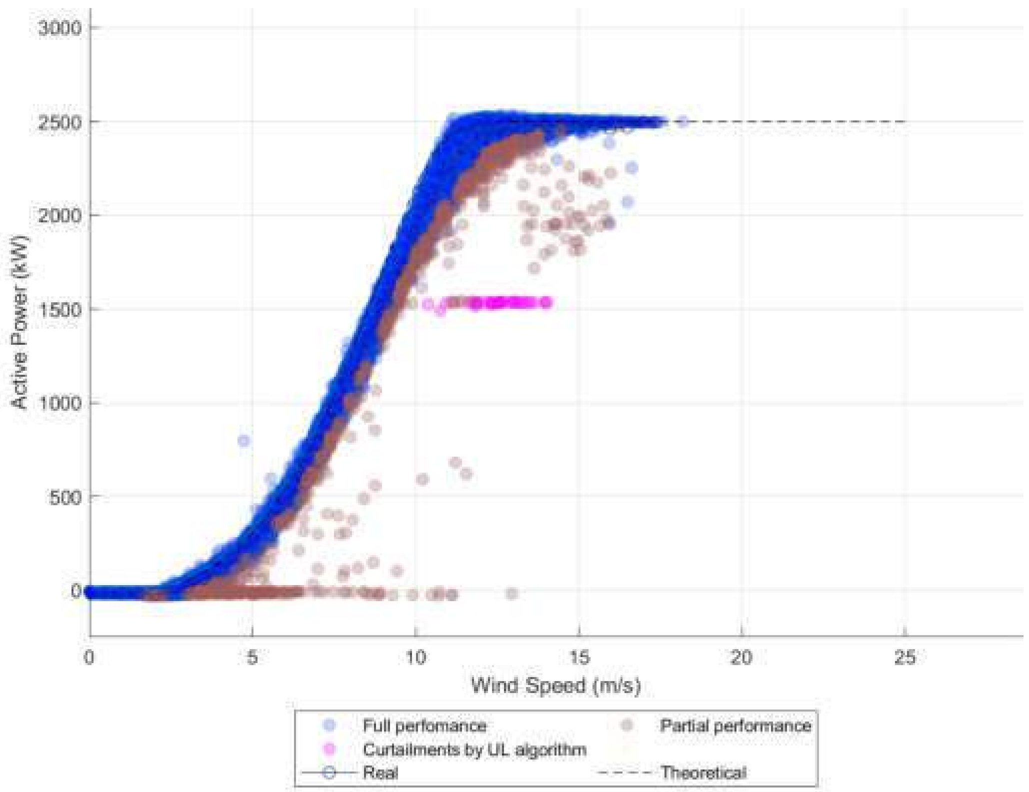

Figure 5.4: Z003 Wind turbine Power Curve Performance with an operational generating performance of 92.85%.

The heat-map on Figure 5.5 represents the average operational generating performance using the wind farm layout.

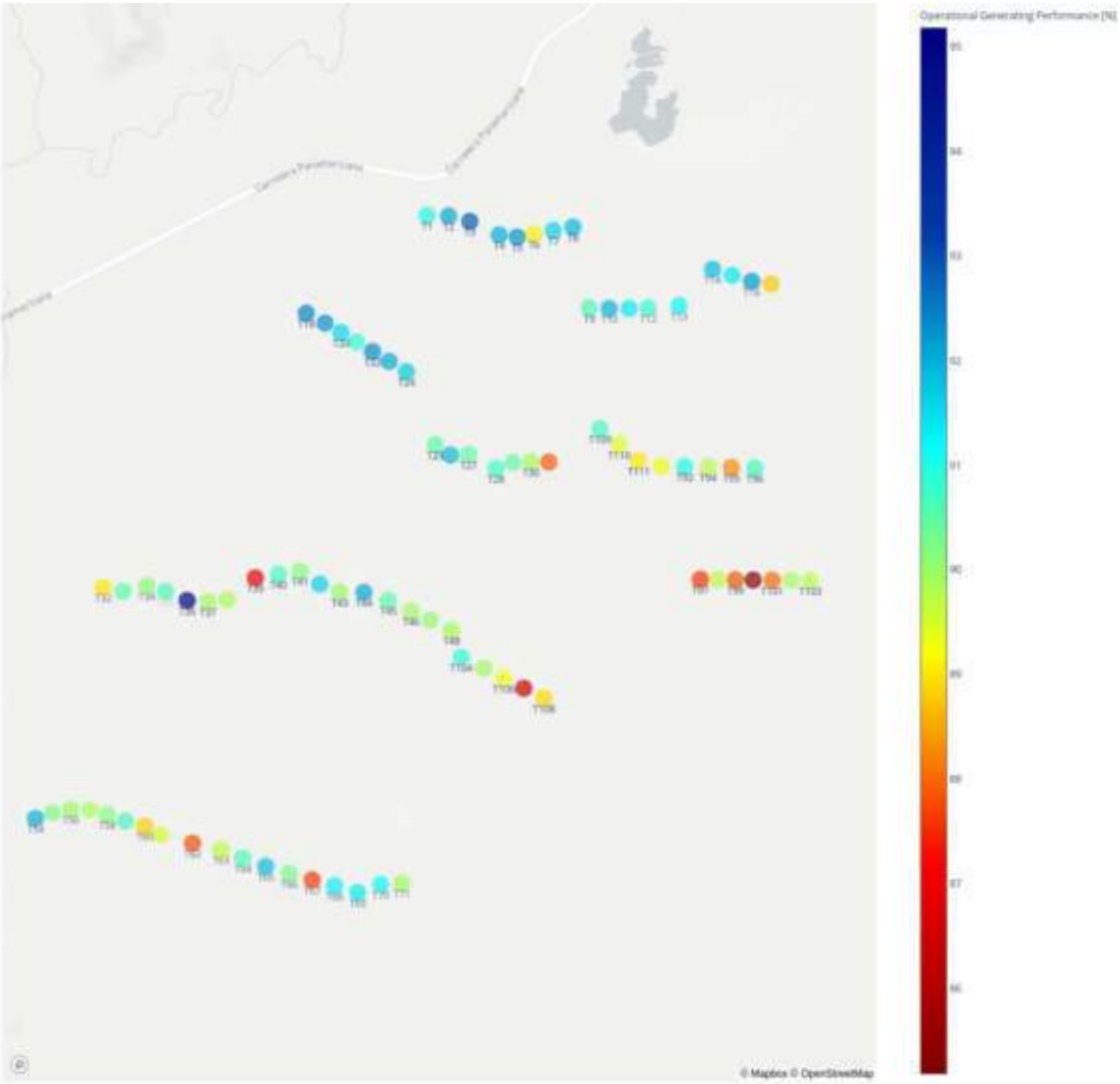

Figure 5.5: Wind turbines operational generating performance.

6. CLIMATIC VARIATIONS

After availability and performance, the third important group of discrepancies on any operating wind farm comparing the pre-constructive evaluation are related with climatic variations. Those differences can come from two main sources:

- Year anomalies vs longt-erm values
- Wind modelling errors

6.1 Year anomalies vs LT

6.1.1 Wind Anomaly

The following dataset is considered as possible long-term reference:

- MERRA-2 reanalysis dataset[6]: Since January 1997
- ERA-5 reanalysis dataset[7]: Since January 1997

Both sources have been analyzed, and for the final calculation, MERRA-2 long-term data has been discarded, due to discrepancies between the long-term interannual wind speed variation in all the period (since 1997) and the COD data (since 2015). An in-depth analysis of these variations can be found in the OEPR report [2]. So, the long-term database ERA-5 is used as the standard databases from UL for operational energy production estimations in this wind farm.

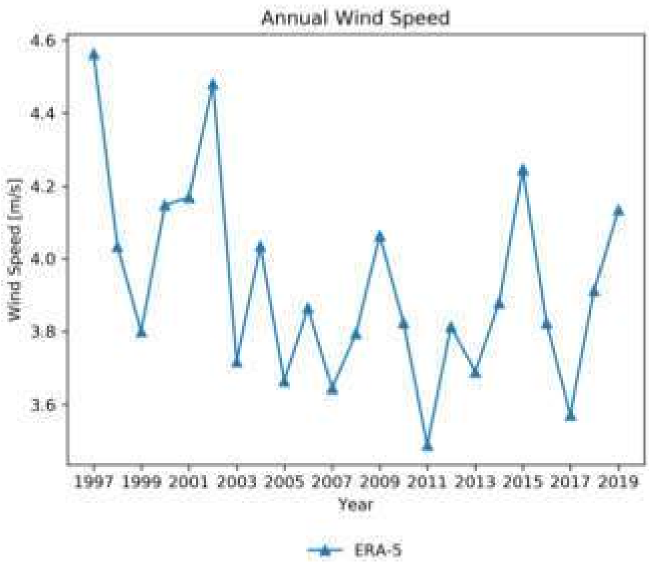

Figure 6.1: Wind Speed in the wind farm: ERA-5 reference.

The wind anomaly calculation consists on obtaining LT annual averages and calculating the relative difference with the average of the analyzed LT references (from 1997 to 2019). On Table 6.1 is shown

[6] The Modern-Era Retrospective Analysis for Research and Applications Version 2 (MERRA-2) dataset was developed by the National Aeronautics and Space Administration (NASA). MERRA-2 utilizes a variety of observing systems which have been assimilated into a global three-dimensional grid by numerical atmospheric models at a horizontal resolution of 1/2° latitude and 2/3° longitude. Multiple interpolated data points as well as the 4 surrounding grid points were assessed.

[7] The ERA-5 dataset was developed by the European Centre for Medium-Range Weather Forecasts (ECMWF). ERA-5 utilizes a variety of observing systems which have been assimilated into a global three-dimensional grid by numerical atmospheric models at a spectral resolution of T639, or an approximate horizontal resolution of 31 km. Multiple elevations at interpolated data points as well as the 4 surrounding grid points were assessed.

the wind anomaly for the analyzed LT source. The wind abnormally index for the wind farm in the analyzed period is 5.26%, so 2019 can be considered as a windy year (Table 6.1).

Table 6.1: Wind abnormally by source.

	ERA5
Wind abnormally	-5.26%

For each wind turbine, the impact on energy production is calculated displacing the whole timeseries wind speed data, according to the calculated wind anomaly average. Then the theoretical energy with using the power curve and this long-term corrected speed is obtained, and the energy difference between the theoretical energy with the current period measured wind and with the long-term corrected wind is the impact generated by the wind anomaly. The resultant energy mean of the wind farm is 8.36% higher than the estimated, producing 51.18 GWh more in terms of after wakes energy.

6.1.2 Air density anomaly

Additionally, to the wind difference, the EYA density [1] is 1.185 kg/m^3 but the average value registered in the met-mast during 2019 was 1.1562 kg/m^3. The difference is a 2.43% in density, but considering the wind condition in the wind farm and the power curve of the turbines installed in the wind farm, this difference in density could be translated to 1.31% of difference in energy.

Variations in air density may contribute to variations in normalized monthly gross energy production. The International Electrotechnical Commission (IEC) describes a method for adjusting observed wind speed data collected during wind turbine performance testing to account for fluctuations in air density. For pitch-regulated turbines, the adjustment equation is as follows:

$$V_n = V_{obs}\left(\frac{\rho_{obs}}{\rho_0}\right)^{1/3} \qquad \text{Eq. 2}$$

where:

V_n = Density-Adjusted Wind Speed;
V_{obs} = Measured Wind Speed;
ρ_{obs} = Measured Air Density;
ρ_0 = Annual Average Air Density.

This formula was used to adjust both the observed and long-term monthly average wind speeds for each reference source.

6.2 Wind Modelling Discrepancy

In this section, the reference wind speed (RWS) differs from the one used in the rest of the report. The EYA is referred to a long-term reference, so the RWS needs to be modified, discarding the annual wind anomaly and referring it to the long-term reference. The modified RWS is called long-term reference wind speed (RWS_{LT}).

The data used in the wind modelling calculation has been extracted from *"Table 3-4 Projected annual energy production of Penonomé wind farm – Phase II and III"* table and *"Table 3-14 Turbine layout with predicted wind speed and energy production – Phases II and III"* in [1].

The difference in average wind speed can be translated to a difference in energy production, by means of using the provided power curves and a wind speed distribution per wind turbine.

The differences energy-based are:

$$Difference_{Energy} = \frac{EYA_{Energy} - RWS_{LT\,Energy}}{EYA_{Energy}}$$

Energy in EYA has been considered is a modification (to obtain the EYA gross) of the "Energy Output" (EYA net) column from *"Table 3-14 Turbine layout with predicted wind speed and energy production – Phases II and III"* in the EYA provided by the client [1]. A positive difference in energy represents overestimation in the EYA.

The average value of the energy production losses due to wakes is 0.42%, from EYA free wind to the RWS_{LT} and is presented on Annex B in Table B.1 This value is lower than the 7.4% stated in [1].

Wind losses reported in Table B.1 are shown as a wind farm map in Figure 6.2.

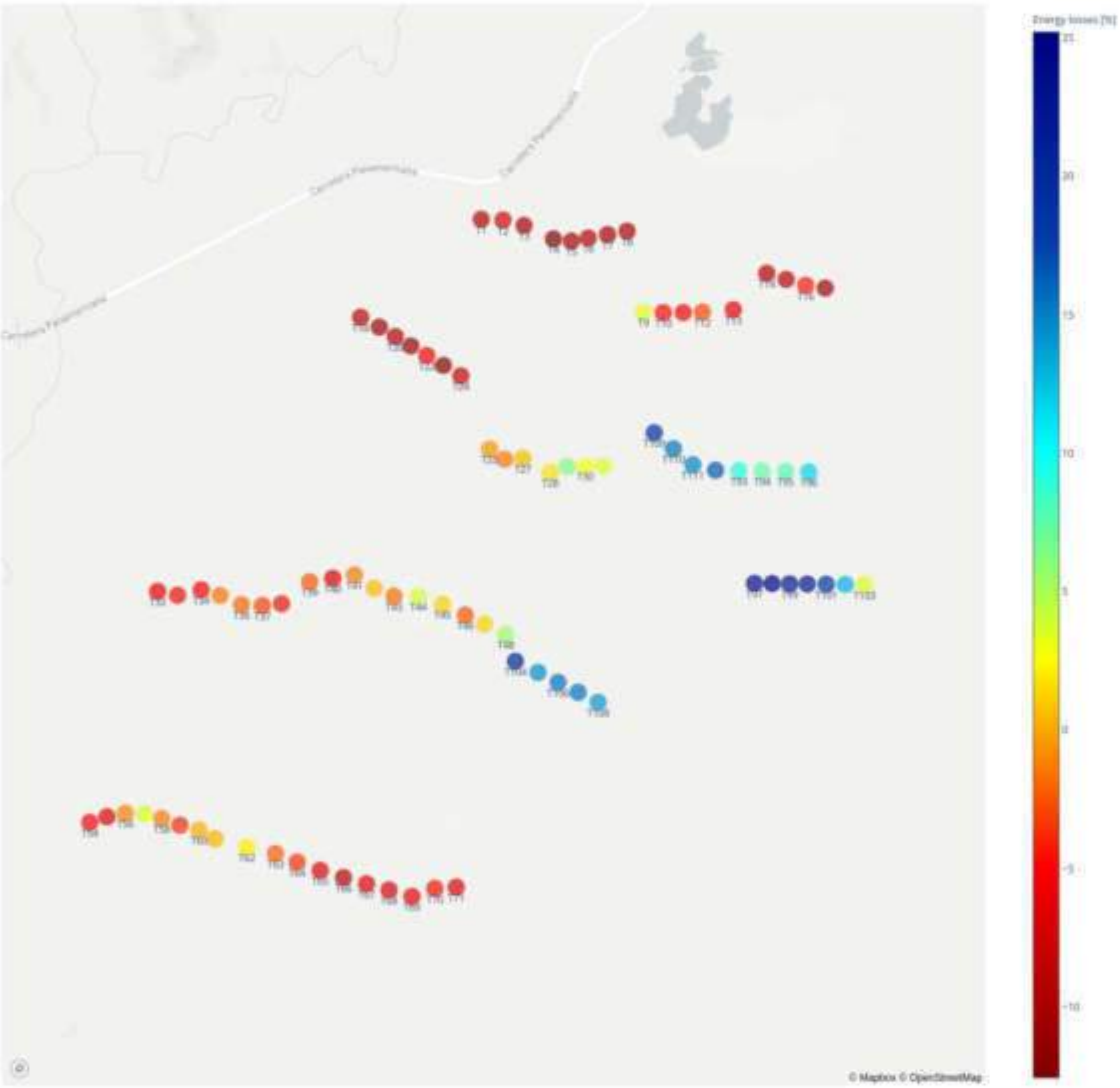

Figure 6.2: Wind energy losses in the wind farm: wake and other effects like blockage (considering as gross energy the one provided in the EYA [1]).

7. ELECTRICAL LOSSES

Other important source of losses is the difference between the energy supplied to the grid at the wind farm interconnection point and the individual energies generated in the turbines.

Usually this value can be calculated directly as relation between the sum of the energy measured in the revenue meter and the sum of the energy produced in all the turbines for the current period. This method can be very sensitive with the quality of the data, periods with turbines with information unavailable or with no data registered in the revenue meter creates noise that affects the electrical losses estimation, so a filtering of the data could be necessary.

In Penonomé II wind farm, during the 2019 period, the SCADA data allows to evaluate the electrical losses properly. The obtained value in the analysis is 3.44%.

8. VERIFICATION AND RECOMMENDATIONS

Table 8.1 shows actual energy production in the wind farm (546.5 GWh during 2019) and the estimated production using the UL analyzed losses. Using the EYA gross energy and applying the UL losses, it is got 546.07 GWh of energy production, which is quite similar to actual production.

Table 8.1: Verification of the results by comparison between actual production figures and calculated figures.

	Energy production [GWh]
REAL PRODUCTION: Revenue meter	546.5
Energy production obtained from individual WTG production estimated n EYA before wakes subtracting estimated losses from operational data	546.07

The factors affecting the estimated gross energy to the energy estimation in Table 8.1 are provided in Table 8.2.

Table 8.2: From Gross energy to NET production based on the calculated losses.

Cause	Loss	Factor
Wind Modelling	0.42%	99.58%
Wind anomaly	-8.36%	108.36%
Density	1.31%	98.69%
Availability[8]	4.47%	95.53%
Efficiency[9]	9.66%	90.34%
Electrical losses[10]	3.44%	96.56%
Global [-]	**11.25%**	**88.75%**
Gross Energy E.Y.A. [GWh]		615.305
Gross Energy by Global loss factor [GWh]		546.071
2019 Actual production [GWh]		546.495
Not Explained		-0.08%

These results can be considered as a proper verification of the proposed methodology.

However, this analysis shows around -0.08% energy production difference which cannot be explained by the assessment. This can come from undefined/unidentified sources or losses and/or errors/uncertainties on the methodology.

As a final verification, a crosscheck has been performing considering the OEPR results, and adapting them to 2019 circumstances by means of wind anomaly correction and availability variance. The remaining variance with the actual 2019 energy production is 0.49%, which is another verification on the obtained results.

[8] Operational energy-based availability (without "generating performance"), section 3.

[9] Operational generating performance presented in section 5.

[10] Electrical losses calculated according the methodology described in section 7.

Table 8.3: From OEPR P50 to 2019 NET production.

Cause	Loss	Factor
Wind anomaly	-8.36%	108.36%
Actual Availability[11]	4.47%	95.53%
OEPR correction factor [-]	**-3.52%**	**103.52%**
P50 OEPR [GWh]		493.3
OEPR Availability		93.9 %
2019 production from OEPR [GWh]		543.820
2019 Actual production [GWh]		546.495
Not Explained		0.49%

8.1 Recommendations

In order to improve the accuracy of the analysis results UL recommends:

- Repeating the analysis with 2020 data in order to have periodical review.
- If the data is presented from different sources, it might be a displacement of the data sampling. It is recommended to synchronize the data to prevent inaccuracies in the analysis.
- Power Performance Measurement test according to [5] could enable a more accurate calibration process in the RWS analysis.
- The curtailments should be recorded in the alarm records, improving this way the differentiation between inefficiency and curtailment.

[11] Operational energy-based availability (without "generating performance"), section 3.

ANNEX A: MONTHLY WIND TURBINE DATA

This annex contains tables per month and wind turbine for:

- Energy production
- Operational Time Availability

Table A.1: Wind turbine energy production per month (GWh).

Wt	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	All
All	115.38	103.33	112.30	71.91	18.30	19.01	30.62	15.50	5.75	3.20	19.93	37.93	553.16
T1	1.54	1.42	0.53	0.50	0.15	0.27	0.40	0.25	0.03	0.04	0.29	0.52	5.94
T2	1.50	1.37	1.50	0.99	0.25	0.28	0.39	0.24	0.03	0.03	0.28	0.51	7.38
T3	1.52	1.41	1.53	1.04	0.26	0.29	0.39	0.27	0.03	0.04	0.29	0.54	7.61
T4	1.53	1.41	1.50	1.05	0.26	0.28	0.46	0.26	0.05	0.03	0.30	0.52	7.64
T5	1.47	1.42	1.53	1.05	0.27	0.31	0.46	0.26	0.07	0.03	0.31	0.55	7.72
T6	1.51	1.38	1.13	0.70	0.28	0.31	0.47	0.18	0.07	0.03	0.30	0.54	6.88
T7	1.53	1.34	1.47	1.01	0.23	0.30	0.45	0.14	0.06	0.03	0.29	0.51	7.38
T8	1.48	1.40	1.49	0.98	0.26	0.27	0.32	0.22	0.05	0.03	0.28	0.51	7.30
T9	1.40	1.27	1.37	0.84	0.23	0.24	0.36	0.19	0.06	0.02	0.22	0.38	6.59
T10	1.48	1.36	1.45	0.91	0.19	0.28	0.41	0.21	0.06	0.02	0.27	0.47	7.12
T11	1.47	1.33	1.46	0.94	0.25	0.29	0.45	0.22	0.08	0.02	0.29	0.48	7.27
T12	1.45	1.32	1.44	0.92	0.25	0.28	0.46	0.27	0.11	0.03	0.28	0.47	7.28
T13	1.45	1.33	1.42	0.93	0.26	0.29	0.46	0.28	0.11	0.02	0.30	0.52	7.37
T14	1.49	1.36	1.46	0.94	0.26	0.28	0.47	0.19	0.11	0.05	0.30	0.52	7.44
T15	1.19	1.38	1.43	0.96	0.26	0.30	0.43	0.19	0.08	0.05	0.31	0.54	7.13
T16	1.44	1.28	1.19	0.92	0.24	0.28	0.46	0.05	0.10	0.05	0.31	0.53	6.86
T17	1.46	1.34	1.36	0.78	0.26	0.30	0.35	0.04	0.12	0.06	0.31	0.56	6.94
T18	1.51	1.41	1.65	1.01	0.25	0.31	0.32	0.22	0.09	0.05	0.27	0.49	7.58
T19	1.53	1.43	1.66	1.03	0.26	0.32	0.36	0.23	0.09	0.05	0.27	0.50	7.73
T20	1.43	1.44	1.58	1.02	0.25	0.33	0.33	0.23	0.09	0.05	0.28	0.51	7.53
T21	1.53	1.33	1.64	1.03	0.26	0.32	0.36	0.26	0.07	0.04	0.27	0.51	7.61
T22	1.26	1.43	1.56	1.04	0.26	0.27	0.33	0.26	0.08	0.04	0.27	0.51	7.31
T23	1.50	1.42	1.67	1.05	0.26	0.22	0.33	0.26	0.09	0.04	0.28	0.51	7.63
T24	1.52	1.41	1.65	1.02	0.26	0.25	0.31	0.21	0.09	0.04	0.27	0.51	7.53
T25	1.39	1.31	1.48	0.93	0.23	0.25	0.24	0.22	0.08	0.04	0.24	0.44	6.84
T26	1.45	1.34	1.59	0.95	0.24	0.27	0.28	0.22	0.08	0.04	0.25	0.48	7.20
T27	1.40	1.27	1.55	0.92	0.23	0.20	0.29	0.23	0.06	0.04	0.25	0.40	6.85
T28	1.38	1.27	1.37	0.91	0.23	0.17	0.35	0.21	0.05	0.05	0.25	0.45	6.69
T29	1.37	1.25	1.29	0.86	0.19	0.07	0.31	0.22	0.08	0.04	0.24	0.42	6.35
T30	1.38	1.27	1.22	0.88	0.22	0.07	0.24	0.17	0.09	0.04	0.24	0.44	6.26
T31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.09	0.02	0.23	0.43	0.99
T32	1.29	0.94	1.36	0.80	0.21	0.07	0.35	0.20	0.07	0.04	0.22	0.42	5.96
T33	1.28	0.94	1.40	0.85	0.23	0.09	0.35	0.21	0.06	0.04	0.23	0.44	6.13
T34	1.40	0.99	1.39	0.85	0.22	0.10	0.38	0.20	0.06	0.04	0.23	0.43	6.29
T35	1.32	0.98	1.40	0.85	0.22	0.08	0.38	0.20	0.06	0.02	0.00	0.29	5.79
T36	1.38	1.00	1.40	0.90	0.23	0.11	0.41	0.22	0.07	0.05	0.25	0.48	6.49

Table A.1: Wind turbine energy production per month (GWh).

Wt	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	All
T37	1.39	0.87	1.35	0.80	0.22	0.19	0.40	0.20	0.06	0.04	0.24	0.47	6.23
T38	1.40	1.01	1.37	0.90	0.23	0.19	0.42	0.21	0.06	0.04	0.24	0.48	6.55
T39	1.29	1.00	1.37	0.88	0.23	0.22	0.42	0.21	0.06	0.04	0.25	0.11	6.08
T40	1.36	1.04	1.40	0.76	0.23	0.21	0.43	0.21	0.06	0.04	0.25	0.47	6.46
T41	1.40	1.23	1.31	0.83	0.22	0.20	0.41	0.20	0.07	0.04	0.23	0.42	6.57
T42	1.39	1.23	1.27	0.87	0.22	0.20	0.39	0.20	0.07	0.04	0.22	0.43	6.53
T43	1.38	1.23	1.41	0.88	0.20	0.25	0.43	0.20	0.07	0.03	0.23	0.44	6.75
T44	1.31	1.18	1.36	0.79	0.19	0.24	0.41	0.20	0.08	0.04	0.22	0.43	6.47
T45	1.35	1.19	1.37	0.81	0.18	0.23	0.42	0.19	0.08	0.05	0.22	0.42	6.52
T46	1.33	1.21	1.25	0.87	0.19	0.24	0.40	0.19	0.08	0.04	0.23	0.45	6.48
T47	1.36	1.22	1.40	0.86	0.20	0.23	0.41	0.20	0.08	0.04	0.23	0.44	6.67
T48	1.31	1.17	1.35	0.82	0.17	0.23	0.37	0.19	0.06	0.04	0.22	0.38	6.31
T54	1.40	1.31	1.41	0.94	0.24	0.24	0.17	0.15	0.07	0.05	0.24	0.47	6.68
T55	1.39	1.29	1.37	0.91	0.23	0.23	0.17	0.15	0.06	0.04	0.23	0.45	6.52
T56	1.36	1.06	1.38	0.91	0.23	0.23	0.23	0.14	0.05	0.04	0.22	0.44	6.30
T57	1.36	1.28	0.55	0.68	0.22	0.23	0.25	0.14	0.04	0.04	0.22	0.44	5.43
T58	1.35	1.27	1.32	0.73	0.22	0.24	0.24	0.12	0.06	0.04	0.22	0.45	6.26
T59	1.40	1.30	1.45	0.89	0.23	0.23	0.26	0.10	0.06	0.04	0.22	0.44	6.63
T60	1.37	1.27	1.42	0.87	0.21	0.23	0.37	0.14	0.06	0.04	0.21	0.41	6.60
T61	1.39	1.29	1.40	0.89	0.23	0.24	0.31	0.15	0.07	0.05	0.22	0.44	6.68
T62	1.36	1.18	0.97	0.83	0.23	0.22	0.35	0.14	0.07	0.04	0.21	0.42	6.03
T63	1.34	1.29	1.42	0.91	0.24	0.24	0.40	0.16	0.07	0.04	0.22	0.45	6.78
T64	1.43	1.28	1.43	0.94	0.23	0.24	0.39	0.13	0.06	0.04	0.22	0.47	6.86
T65	1.45	1.36	1.49	0.97	0.24	0.24	0.41	0.15	0.07	0.05	0.24	0.48	7.15
T66	1.45	1.33	1.48	0.98	0.24	0.24	0.42	0.16	0.06	0.04	0.25	0.49	7.13
T67	1.45	1.33	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.24	0.47	3.86
T68	1.47	1.35	1.47	0.97	0.26	0.24	0.44	0.16	0.06	0.05	0.24	0.47	7.19
T69	1.44	1.35	1.43	0.99	0.25	0.22	0.44	0.12	0.08	0.05	0.23	0.49	7.09
T70	1.47	1.26	1.41	0.96	0.24	0.22	0.42	0.15	0.06	0.04	0.23	0.47	6.93
T71	1.40	1.32	1.45	0.94	0.25	0.23	0.43	0.06	0.06	0.05	0.23	0.46	6.89
T93	1.29	1.13	1.20	0.76	0.21	0.22	0.39	0.10	0.07	0.03	0.23	0.42	6.08
T94	1.33	1.14	1.17	0.82	0.20	0.22	0.40	0.16	0.03	0.03	0.25	0.44	6.21
T95	1.26	1.07	1.22	0.77	0.20	0.23	0.39	0.17	0.03	0.03	0.24	0.43	6.05
T96	1.27	1.09	1.23	0.77	0.20	0.22	0.39	0.19	0.03	0.04	0.24	0.43	6.09
T97	0.97	0.95	1.05	0.64	0.15	0.17	0.29	0.18	0.06	0.02	0.13	0.30	4.92
T98	1.11	0.97	1.06	0.62	0.15	0.16	0.30	0.17	0.06	0.01	0.15	0.32	5.09
T99	1.08	0.98	1.00	0.65	0.10	0.17	0.30	0.18	0.07	0.03	0.11	0.33	5.00
T100	1.07	0.92	0.97	0.56	0.10	0.19	0.31	0.16	0.07	0.03	0.14	0.34	4.84
T101	1.12	1.00	0.92	0.68	0.16	0.20	0.33	0.20	0.07	0.03	0.15	0.31	5.18
T102	1.17	1.07	1.10	0.72	0.17	0.23	0.37	0.20	0.08	0.04	0.18	0.41	5.75
T103	1.26	1.15	1.18	0.82	0.19	0.26	0.42	0.24	0.09	0.04	0.23	0.48	6.36
T104	1.15	1.07	1.26	0.67	0.17	0.19	0.33	0.16	0.06	0.02	0.17	0.33	5.59

Table A.1: Wind turbine energy production per month (GWh).

Wt	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	All
T105	1.14	1.11	1.26	0.76	0.19	0.20	0.31	0.16	0.06	0.02	0.19	0.37	5.76
T106	1.20	1.08	1.22	0.72	0.18	0.20	0.34	0.17	0.06	0.03	0.14	0.33	5.68
T107	1.13	1.01	1.01	0.69	0.16	0.20	0.33	0.17	0.05	0.02	0.13	0.36	5.24
T108	1.20	1.09	1.08	0.73	0.17	0.22	0.35	0.14	0.06	0.03	0.11	0.36	5.55
T109	1.21	1.06	1.19	0.64	0.19	0.18	0.34	0.03	0.03	0.01	0.18	0.35	5.43
T110	1.19	1.09	1.29	0.72	0.19	0.19	0.34	0.10	0.07	0.03	0.20	0.37	5.76
T111	1.22	1.05	1.20	0.71	0.18	0.19	0.34	0.13	0.07	0.03	0.20	0.37	5.71
T112	1.20	1.08	1.14	0.70	0.19	0.20	0.35	0.10	0.07	0.03	0.21	0.38	5.67

Table A.2: Wind turbine operational time availability per month (%).

Wt	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	All
All	98.07	98.24	94.37	95.06	92.42	87.62	87.80	86.03	83.48	88.31	94.12	98.62	92.48
T1	99.99	100.00	31.99	42.91	89.90	93.83	96.50	96.47	56.83	98.64	93.06	99.06	82.46
T2	99.99	99.74	92.05	98.46	98.09	93.66	87.16	94.97	61.13	80.96	98.51	98.62	92.03
T3	99.99	99.79	99.99	98.51	98.78	93.62	91.90	97.05	47.72	77.01	97.68	99.83	91.86
T4	99.99	99.99	98.89	99.05	93.81	94.37	96.34	89.94	48.76	80.54	98.63	98.25	91.51
T5	98.19	99.99	99.97	99.25	97.65	94.67	96.16	89.49	36.16	75.31	98.95	99.75	90.44
T6	98.98	97.29	81.58	80.60	98.77	96.52	99.62	72.61	35.82	70.10	97.92	99.24	85.57
T7	99.42	96.39	97.78	99.07	97.75	89.57	99.58	69.42	36.89	82.15	98.04	98.12	88.64
T8	98.46	100.00	99.97	99.43	97.82	87.03	79.55	83.77	38.66	92.39	98.03	99.80	89.52
T9	99.98	99.55	99.80	98.95	96.71	97.51	94.93	88.47	47.64	90.43	97.65	98.74	92.53
T10	99.98	99.99	99.52	98.55	94.39	97.46	98.75	88.03	40.48	49.70	98.61	99.12	88.50
T11	99.98	99.31	99.97	99.42	96.62	98.81	94.31	87.68	76.87	29.01	98.65	99.06	89.77
T12	99.98	99.60	99.98	99.48	97.79	98.70	98.08	98.30	97.73	49.81	98.89	99.71	94.70
T13	99.56	100.00	92.74	99.37	98.57	98.47	98.72	99.05	98.07	40.54	98.79	99.85	93.52
T14	99.99	100.00	99.97	99.39	98.61	97.09	98.31	47.14	95.55	98.49	97.42	99.87	94.19
T15	87.61	99.99	99.95	99.26	89.78	97.64	86.27	55.29	83.68	98.57	98.14	99.87	91.16
T16	99.13	97.91	89.67	96.24	98.37	91.29	98.15	9.11	90.97	97.29	98.61	98.64	88.59
T17	99.96	99.99	97.43	93.07	100.00	97.99	75.48	8.29	97.89	98.49	96.89	99.53	88.49
T18	99.99	100.00	99.99	95.65	98.80	97.71	62.56	87.40	98.54	97.40	98.81	99.65	94.62
T19	99.99	100.00	99.99	99.23	98.75	93.03	59.55	93.81	89.14	97.49	98.85	99.73	94.07
T20	96.04	100.00	98.79	95.65	97.76	93.30	59.78	93.94	88.33	97.58	97.39	99.46	93.06
T21	99.99	95.68	99.99	99.24	98.95	95.76	58.78	99.51	84.83	97.84	97.96	99.85	94.01
T22	96.25	99.99	95.85	99.39	98.69	84.44	60.06	99.54	88.26	97.75	97.23	99.80	93.07
T23	99.35	99.38	99.99	99.29	98.72	79.57	54.64	99.33	88.36	97.48	97.90	97.49	92.60
T24	99.99	99.99	99.92	99.12	98.72	95.47	56.59	99.28	80.51	99.04	97.24	99.58	93.72
T25	99.90	99.99	98.31	99.39	98.62	97.68	45.31	99.36	84.18	98.92	97.82	99.11	93.17
T26	99.99	99.71	99.84	99.29	98.74	97.89	50.43	96.51	84.24	99.16	98.07	99.32	93.55
T27	99.99	99.55	99.99	99.39	98.81	84.71	57.56	99.56	85.41	95.63	98.97	97.82	93.11
T28	99.89	99.03	91.04	99.41	96.04	77.83	81.72	94.93	84.84	98.78	97.24	98.91	93.30
T29	99.99	99.99	99.99	99.38	97.70	55.63	98.38	99.54	99.01	97.98	98.48	99.05	95.35
T30	99.97	99.99	88.11	99.27	98.68	54.83	83.79	97.91	98.78	97.08	98.45	99.52	93.21
T31	0.00	0.00	0.00	0.00	0.00	0.00	7.03	90.42	93.32	41.27	98.13	98.74	81.98
T32	99.98	99.97	99.99	99.40	97.74	58.96	96.20	99.42	88.31	91.13	98.44	99.34	93.98
T33	96.66	96.29	99.98	99.23	97.31	62.40	97.28	99.42	80.18	95.08	98.80	99.26	93.45
T34	99.99	99.96	99.56	99.36	97.45	63.48	98.42	99.47	81.01	96.02	98.48	98.50	94.22
T35	99.15	99.93	99.99	99.07	97.71	58.39	97.74	99.39	83.19	63.10	0.00	67.10	79.96
T36	97.44	99.74	99.99	97.05	86.65	61.42	97.78	99.54	92.84	96.27	99.09	99.60	93.84
T37	100.00	98.24	99.23	90.83	97.53	55.47	98.76	99.42	84.31	96.39	98.76	99.27	93.12
T38	99.99	99.99	99.94	99.77	97.56	54.63	98.77	99.38	90.45	97.61	97.94	99.55	94.58
T39	95.92	99.67	99.03	99.44	96.23	54.63	99.59	99.41	90.07	94.04	98.05	92.07	93.06
T40	99.71	99.77	91.45	85.94	95.86	55.55	98.89	99.42	92.72	93.46	98.50	98.72	92.34

Table A.2: Wind turbine operational time availability per month (%).

Wt	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	All
T41	99.99	99.35	95.47	99.18	95.63	56.94	97.38	99.45	93.38	96.10	98.07	97.23	94.01
T42	100.00	99.98	93.64	99.77	95.69	57.16	94.70	99.49	87.92	97.06	97.12	99.31	93.50
T43	100.00	99.99	99.99	99.77	63.04	99.31	99.00	96.99	88.09	94.77	98.35	99.52	94.80
T44	97.24	99.78	99.91	97.30	62.86	99.25	97.83	97.95	91.02	95.75	98.45	99.19	94.60
T45	100.00	99.94	99.94	94.96	62.89	98.82	98.84	96.48	87.73	97.21	97.68	98.60	94.32
T46	99.76	99.65	90.92	99.46	59.52	87.82	94.18	98.23	91.90	97.03	99.03	99.58	93.01
T47	99.99	99.99	99.90	99.80	61.26	77.79	96.91	99.39	95.57	95.92	99.00	99.56	93.66
T48	100.00	99.93	99.88	98.98	59.25	92.68	98.49	95.33	87.09	96.81	99.05	98.61	93.71
T54	99.92	99.99	99.99	99.50	98.33	97.49	54.90	99.48	91.76	97.53	98.52	99.12	94.51
T55	99.97	99.99	99.99	99.77	98.29	97.54	55.73	94.25	82.93	97.36	98.82	99.74	93.56
T56	99.82	90.56	98.87	99.75	98.42	97.30	71.43	85.21	89.20	95.23	97.78	99.39	93.68
T57	99.88	100.00	39.93	80.86	98.44	97.72	71.16	84.87	69.84	92.26	98.73	98.85	85.93
T58	99.91	99.58	95.90	79.40	92.29	98.30	74.67	73.58	91.02	97.26	98.35	99.65	91.86
T59	99.81	100.00	99.99	97.52	98.32	97.46	81.24	58.12	98.06	97.80	98.54	98.54	94.24
T60	99.98	100.00	99.99	99.76	98.42	98.38	99.36	83.81	96.64	95.58	99.16	99.24	97.71
T61	99.97	99.99	99.72	99.33	95.24	98.45	97.55	91.28	98.33	97.86	98.45	99.76	98.07
T62	99.77	97.51	70.18	99.27	98.10	96.62	95.75	79.80	98.38	94.94	99.08	98.67	93.93
T63	99.02	99.99	99.99	99.74	98.29	98.06	99.33	76.72	89.93	92.50	98.01	99.34	95.85
T64	99.98	99.57	99.98	99.76	98.34	98.81	96.66	73.29	98.45	94.95	97.62	99.60	96.24
T65	99.98	100.00	99.99	99.75	98.36	98.69	98.73	73.05	95.37	95.16	98.93	99.17	96.28
T66	99.42	99.04	99.95	99.78	98.61	88.53	99.03	86.41	92.65	79.68	99.13	99.38	95.26
T67	99.99	100.00	33.87	1.16	1.12	0.12	3.37	0.00	0.81	91.62	99.06	99.13	43.93
T68	99.98	99.99	99.99	99.79	98.62	97.97	98.12	96.21	79.10	94.89	99.46	99.27	96.92
T69	99.80	99.99	97.53	99.78	98.51	98.44	95.08	85.29	98.18	97.59	97.75	99.02	97.40
T70	99.98	96.68	96.87	99.76	97.73	97.77	98.60	96.39	90.29	95.75	97.87	98.89	97.32
T71	99.65	99.99	99.99	99.76	96.85	97.59	98.69	52.02	95.05	97.78	99.11	98.99	95.12
T93	99.90	99.89	96.29	98.03	97.61	98.94	99.19	60.76	94.90	93.88	98.01	99.65	94.64
T94	99.98	99.97	95.76	99.84	97.69	99.41	98.86	82.79	64.63	97.03	98.60	99.41	94.45
T95	99.97	99.32	98.59	99.28	97.48	99.50	99.00	83.31	60.00	97.12	98.13	99.12	94.20
T96	99.99	99.99	99.99	99.83	97.72	97.99	99.47	94.26	56.25	98.39	98.58	99.65	95.16
T97	92.04	98.44	99.99	99.79	97.96	97.80	98.75	99.11	96.28	56.17	84.63	98.67	93.15
T98	99.99	99.97	99.99	99.04	93.50	97.23	98.77	99.12	98.49	56.05	87.58	99.47	93.95
T99	99.86	99.97	96.83	99.70	93.48	97.83	98.69	98.94	98.35	91.47	61.91	99.54	94.77
T100	98.57	95.52	98.98	95.23	93.68	98.72	98.07	96.07	95.50	90.44	65.89	99.45	93.80
T101	99.99	99.99	91.13	99.79	96.63	90.55	98.60	99.03	98.53	90.09	66.44	91.45	93.54
T102	99.99	100.00	99.98	97.35	98.30	98.85	98.45	89.91	98.41	90.43	61.73	98.95	94.29
T103	99.83	99.99	99.98	99.81	97.81	98.64	98.65	94.17	98.40	95.00	76.27	99.51	96.45
T104	97.43	99.98	99.99	99.12	96.58	98.36	99.02	99.49	98.10	52.44	99.02	99.02	94.75
T105	93.00	99.76	97.79	99.75	98.02	97.40	96.22	97.34	97.92	56.11	98.30	99.15	94.10
T106	99.98	99.98	97.17	99.74	95.76	97.93	99.59	99.43	90.94	73.09	84.71	97.20	94.57
T107	99.17	99.15	98.50	99.77	97.99	97.82	99.35	99.52	80.96	75.60	77.25	98.49	93.58
T108	99.99	99.99	97.95	99.78	98.15	98.47	99.45	99.01	88.24	97.54	58.96	98.74	94.69

Table A.2: Wind turbine operational time availability per month (%).

Wt	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	All
T109	99.94	99.41	94.65	92.18	97.81	99.36	99.66	23.12	88.78	69.24	96.24	99.45	88.09
T110	99.05	99.97	99.98	99.81	97.55	99.42	99.30	63.24	88.40	97.22	98.68	99.61	95.09
T111	99.99	99.78	99.82	99.75	97.39	95.55	96.56	62.97	94.56	97.14	98.58	99.63	95.03
T112	99.91	99.47	97.46	98.97	97.80	99.50	99.12	62.68	91.69	97.50	98.52	99.30	95.07

ANNEX B: WIND MODELLING RESULTS

Table B.1: Wind modelling error: Losses from EYA gross to windfarm effects affected wind (wake, blocking, etc.).

Wind Turbine ID	Gross EYA[12] [MWh]	Energy measured on WT[13] [MWh]	Energy losses [%]
T1	7283	8031	-10.27%
T2	7340	7905	-7.71%
T3	7308	8073	-10.47%
T4	7206	8172	-13.40%
T5	7350	8159	-11.01%
T6	7350	8082	-9.95%
T7	7340	8136	-10.85%
T8	7196	7974	-10.82%
T9	7311	7064	3.38%
T10	7249	7639	-5.37%
T11	7290	7716	-5.84%
T12	7350	7614	-3.59%
T13	7206	7698	-6.82%
T14	7104	7827	-10.18%
T15	7124	7820	-9.77%
T16	7104	7469	-5.13%
T17	7165	7974	-11.29%
T18	7287	7994	-9.70%
T19	7269	8101	-11.46%
T20	7343	8085	-10.11%
T21	7375	8217	-11.42%
T22	7375	7802	-5.79%
T23	7379	8280	-12.21%
T24	7372	7988	-8.36%
T25	7311	7350	-0.54%
T26	7414	7509	-1.27%
T27	7380	7329	0.69%
T28	7380	7238	1.92%
T29	7473	6971	6.71%
T30	7391	7151	3.24%
T31	7414	7130	3.84%
T32	6381	6812	-6.75%
T33	6624	6991	-5.54%
T34	6662	7058	-5.94%

[12] The EYA Gross has been calculated from EYA net energy (methodology explained below in this section).

[13] This energy is average per turbine of the analyzed period. It is calculated with the RWS, excluding the wind anomaly influence, and interpolating the energy from the turbine power curve per 10 min data.

Table B.1: Wind modelling error: Losses from EYA gross to windfarm effects affected wind (wake, blocking, etc.).

Wind Turbine ID	Gross EYA[12] [MWh]	Energy measured on WT[13] [MWh]	Energy losses [%]
T35	6653	6814	-2.42%
T36	6756	6943	-2.77%
T37	6775	7040	-3.91%
T38	6918	7282	-5.26%
T39	6874	7080	-2.99%
T40	6870	7362	-7.17%
T41	6983	7103	-1.71%
T42	6956	6911	0.65%
T43	7024	7154	-1.85%
T44	7000	6701	4.26%
T45	7000	6903	1.38%
T46	6927	7069	-2.04%
T47	7239	7101	1.91%
T48	7227	6788	6.08%
T54	6775	7160	-5.68%
T55	6783	7265	-7.10%
T56	6865	6964	-1.44%
T57	6928	6682	3.55%
T58	6924	7019	-1.37%
T59	6978	7225	-3.54%
T60	7088	7060	0.40%
T61	7134	7081	0.74%
T62	7033	6874	2.25%
T63	7033	7181	-2.11%
T64	7033	7268	-3.35%
T65	7077	7500	-5.98%
T66	7033	7663	-8.97%
T67	7011	7484	-6.75%
T68	7088	7568	-6.77%
T69	7100	7497	-5.60%
T70	7076	7364	-4.06%
T71	7076	7495	-5.92%
T93	7349	6648	9.53%
T94	7372	6814	7.57%
T95	7291	6706	8.02%
T96	7322	6461	11.76%
T97	7352	5528	24.80%
T98	7402	5464	26.17%
T99	7292	5569	23.64%

Table B.1: Wind modelling error: Losses from EYA gross to windfarm effects affected wind (wake, blocking, etc.).

Wind Turbine ID	Gross EYA[12] [MWh]	Energy measured on WT[13] [MWh]	Energy losses [%]
T100	7275	5571	23.41%
T101	7167	5779	19.38%
T102	7069	6143	13.09%
T103	7028	6812	3.08%
T104	7625	5853	23.23%
T105	7227	6126	15.23%
T106	7272	6089	16.28%
T107	7110	5970	16.04%
T108	7099	6064	14.57%
T109	7497	5946	20.70%
T110	7466	6245	16.36%
T111	7332	6200	15.44%
T112	7407	6145	17.05%
Average	**7155**	**7117**	**0.42%**

In order to provide after wakes analysis, first, the after wakes wind speed is calculated using the columns *"Free wind speed [m/s]"* and *"Wake loss wind speed [%]"* [1]. Then after wakes energy is calculated using the net energy and the losses (*Environmental*, *Performance*, *Availability* and *Electrical*) presented on *"Table 3-4 Projected annual energy production of Penonomé wind farm – Phase II and III"* [1].

Once the after wakes wind and energy are calculated, a linear regression is adjusted (Figure B.1). This regression represents the relation between the wind and the energy generated.

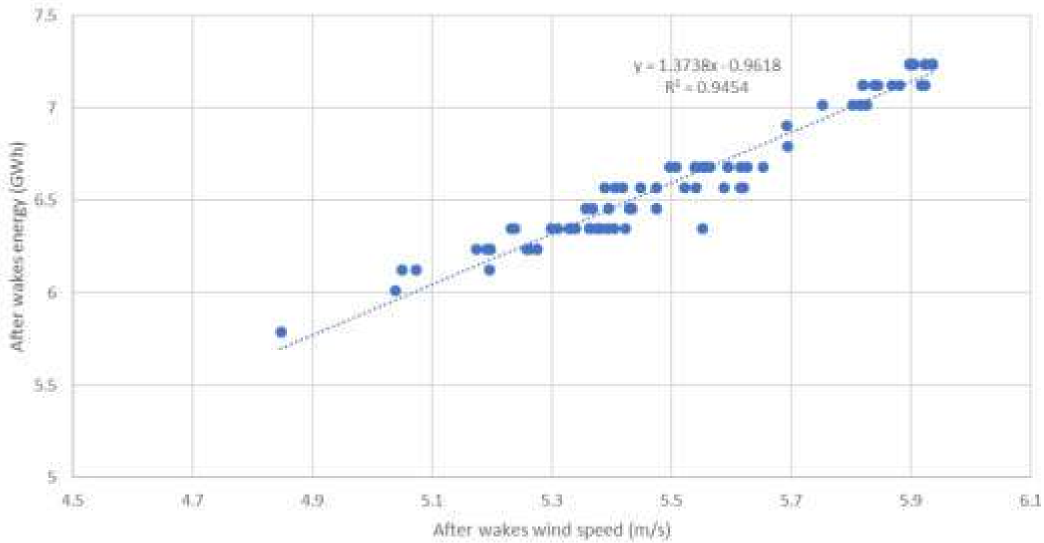

Figure B.1: After wakes linear regression.

This regression allows to obtain the *Wake loss energy [%]* and *Wake loss energy factor [%]*. Finally, the *Gross Energy [GWh/year]* is calculated applying all the losses.

Table B.2: Results of the procedure of calculating the

Turbine ID	Free wind speed [m/s]	Wake loss wind speed [%]	After wakes wind speed [m/s]	Net Energy [GWh/year]	Energy After wakes [GWh/year]	Wake loss energy [%]	Wake loss energy factor [%]	Gross Energy [GWh/year]
T1	6.1	2.70%	5.9	6.5	7.2	3.71%	96.29%	7.3
T2	6.1	3.20%	5.9	6.5	7.2	4.40%	95.60%	7.3
T3	6.1	2.90%	5.9	6.5	7.2	3.98%	96.02%	7.3
T4	6	3.00%	5.8	6.4	7.1	4.12%	95.88%	7.2
T5	6.1	3.30%	5.9	6.5	7.2	4.53%	95.47%	7.4
T6	6.1	3.30%	5.9	6.5	7.2	4.53%	95.47%	7.4
T7	6.1	3.20%	5.9	6.5	7.2	4.40%	95.60%	7.3
T8	6.1	2.90%	5.9	6.4	7.1	3.98%	96.02%	7.2
T9	6.1	8.30%	5.6	6	6.7	11.40%	88.60%	7.3
T10	6.1	4.50%	5.8	6.3	7.0	6.18%	93.82%	7.2
T11	6.1	3.80%	5.9	6.4	7.1	5.22%	94.78%	7.3
T12	6.1	3.30%	5.9	6.5	7.2	4.53%	95.47%	7.4
T13	6.1	3.00%	5.9	6.4	7.1	4.12%	95.88%	7.2
T14	6	3.10%	5.8	6.3	7.0	4.26%	95.74%	7.1
T15	6	3.30%	5.8	6.3	7.0	4.53%	95.47%	7.1
T16	6	3.10%	5.8	6.3	7.0	4.26%	95.74%	7.1
T17	6	2.60%	5.8	6.4	7.1	3.57%	96.43%	7.2
T18	6.1	2.70%	5.9	6.5	7.2	3.71%	96.29%	7.3
T19	6.1	3.60%	5.9	6.4	7.1	4.95%	95.05%	7.3
T20	6.1	4.30%	5.8	6.4	7.1	5.91%	94.09%	7.3
T21	6.1	4.60%	5.8	6.4	7.1	6.32%	93.68%	7.4
T22	6.1	4.60%	5.8	6.4	7.1	6.32%	93.68%	7.4
T23	6.1	5.70%	5.8	6.3	7.0	7.83%	92.17%	7.4
T24	6.1	6.70%	5.7	6.2	6.9	9.20%	90.80%	7.4
T25	6.1	8.30%	5.6	6	6.7	11.40%	88.60%	7.3
T26	6.1	9.20%	5.5	6	6.7	12.64%	87.36%	7.4
T27	6.1	8.90%	5.6	6	6.7	12.23%	87.77%	7.4
T28	6.1	8.90%	5.6	6	6.7	12.23%	87.77%	7.4
T29	6.1	9.70%	5.5	6	6.7	13.33%	86.67%	7.5
T30	6.1	9.00%	5.6	6	6.7	12.36%	87.64%	7.4
T31	6.1	9.20%	5.5	6	6.7	12.64%	87.36%	7.4
T32	5.7	2.60%	5.6	5.7	6.3	3.57%	96.43%	6.4
T33	5.7	2.80%	5.5	5.9	6.6	3.85%	96.15%	6.6
T34	5.8	3.20%	5.6	5.9	6.6	4.40%	95.60%	6.7
T35	5.8	3.10%	5.6	5.9	6.6	4.26%	95.74%	6.7
T36	5.8	3.00%	5.6	6	6.7	4.12%	95.88%	6.8

Table B.2: Results of the procedure of calculating the

Turbine ID	Free wind speed [m/s]	Wake loss wind speed [%]	After wakes wind speed [m/s]	Net Energy [GWh/year]	Energy After wakes [GWh/year]	Wake loss energy [%]	Wake loss energy factor [%]	Gross Energy [GWh/year]
T37	5.8	3.20%	5.6	6	6.7	4.40%	95.60%	6.8
T38	5.9	3.50%	5.7	6.1	6.8	4.81%	95.19%	6.9
T39	5.9	4.20%	5.7	6	6.7	5.77%	94.23%	6.9
T40	5.9	5.30%	5.6	5.9	6.6	7.28%	92.72%	6.9
T41	5.9	6.40%	5.5	5.9	6.6	8.79%	91.21%	7.0
T42	5.9	8.40%	5.4	5.7	6.3	11.54%	88.46%	7.0
T43	5.9	7.90%	5.4	5.8	6.5	10.85%	89.15%	7.0
T44	5.9	8.80%	5.4	5.7	6.3	12.09%	87.91%	7.0
T45	5.9	8.80%	5.4	5.7	6.3	12.09%	87.91%	7.0
T46	5.8	10.40%	5.2	5.5	6.1	14.29%	85.71%	6.9
T47	5.9	12.00%	5.2	5.6	6.2	16.49%	83.51%	7.2
T48	5.9	11.90%	5.2	5.6	6.2	16.35%	83.65%	7.2
T54	5.8	3.20%	5.6	6	6.7	4.40%	95.60%	6.8
T55	5.8	5.60%	5.5	5.8	6.5	7.69%	92.31%	6.8
T56	5.8	6.40%	5.4	5.8	6.5	8.79%	91.21%	6.9
T57	5.8	7.00%	5.4	5.8	6.5	9.62%	90.38%	6.9
T58	5.9	8.10%	5.4	5.7	6.3	11.13%	88.87%	6.9
T59	5.9	8.60%	5.4	5.7	6.3	11.81%	88.19%	7.0
T60	5.9	9.60%	5.3	5.7	6.3	13.19%	86.81%	7.1
T61	5.9	10.00%	5.3	5.7	6.3	13.74%	86.26%	7.1
T62	5.9	9.10%	5.4	5.7	6.3	12.50%	87.50%	7.0
T63	5.9	9.10%	5.4	5.7	6.3	12.50%	87.50%	7.0
T64	5.9	9.10%	5.4	5.7	6.3	12.50%	87.50%	7.0
T65	5.9	9.50%	5.3	5.7	6.3	13.05%	86.95%	7.1
T66	5.9	9.10%	5.4	5.7	6.3	12.50%	87.50%	7.0
T67	5.9	8.90%	5.4	5.7	6.3	12.23%	87.77%	7.0
T68	5.9	9.60%	5.3	5.7	6.3	13.19%	86.81%	7.1
T69	5.9	9.70%	5.3	5.7	6.3	13.33%	86.67%	7.1
T70	5.9	10.60%	5.3	5.6	6.2	14.56%	85.44%	7.1
T71	5.9	10.60%	5.3	5.6	6.2	14.56%	85.44%	7.1
T93	6	9.70%	5.4	5.9	6.6	13.33%	86.67%	7.3
T94	6	9.90%	5.4	5.9	6.6	13.60%	86.40%	7.4
T95	6	9.20%	5.4	5.9	6.6	12.64%	87.36%	7.3
T96	6	8.40%	5.5	6	6.7	11.54%	88.46%	7.3
T97	5.9	14.00%	5.1	5.5	6.1	19.23%	80.77%	7.4
T98	5.9	14.40%	5.1	5.5	6.1	19.78%	80.22%	7.4
T99	5.9	14.60%	5.0	5.4	6.0	20.06%	79.94%	7.3
T100	5.9	12.30%	5.2	5.6	6.2	16.90%	83.10%	7.3

Table B.2: Results of the procedure of calculating the

Turbine ID	Free wind speed [m/s]	Wake loss wind speed [%]	After wakes wind speed [m/s]	Net Energy [GWh/year]	Energy After wakes [GWh/year]	Wake loss energy [%]	Wake loss energy factor [%]	Gross Energy [GWh/year]
T101	5.9	9.20%	5.4	5.8	6.5	12.64%	87.36%	7.2
T102	5.9	7.20%	5.5	5.9	6.6	9.89%	90.11%	7.1
T103	5.9	5.70%	5.6	6	6.7	7.83%	92.17%	7.0
T104	6	19.20%	4.8	5.2	5.8	26.38%	73.62%	7.6
T105	5.9	11.90%	5.2	5.6	6.2	16.35%	83.65%	7.2
T106	5.9	11.20%	5.2	5.7	6.3	15.39%	84.61%	7.3
T107	5.9	10.90%	5.3	5.6	6.2	14.97%	85.03%	7.1
T108	5.9	10.80%	5.3	5.6	6.2	14.84%	85.16%	7.1
T109	6.1	12.00%	5.4	5.8	6.5	16.49%	83.51%	7.5
T110	6	12.80%	5.2	5.7	6.3	17.58%	82.42%	7.5
T111	6	11.70%	5.3	5.7	6.3	16.07%	83.93%	7.3
T112	6	10.20%	5.4	5.9	6.6	14.01%	85.99%	7.4

ANNEX C: RWS METHODOLOGY

The wind farm performance is driven mainly by three parameters: the wind turbines availability, the wind turbine performance and the wind resource available.

The wind turbine performance analysis, and the available wind resource analysis implies a very strong dependency on the selected reference wind speed. In most of the cases, the reference wind speed is simply acquired from wind turbine anemometry (Nacelle Wind Speed, “NWS”) without any treatment.

UL considers that the definition of a sound Reference Wind Speed (“RWS”) is key to ensure optimal results. This implies correlations with free wind speed sources and the use of wind turbine operational parameters (rpm, pitch, etc) to extract the best possible RWS.

If the nacelle transfer function is altered during the evaluation period, without any register of the changes, major errors will be found on the performance analyses.

Sometimes turbines show double power curves (Figure C.1) which is an indicator of two potential things: *control mode was modified* or *nacelle anemometer transfer function was altered*.

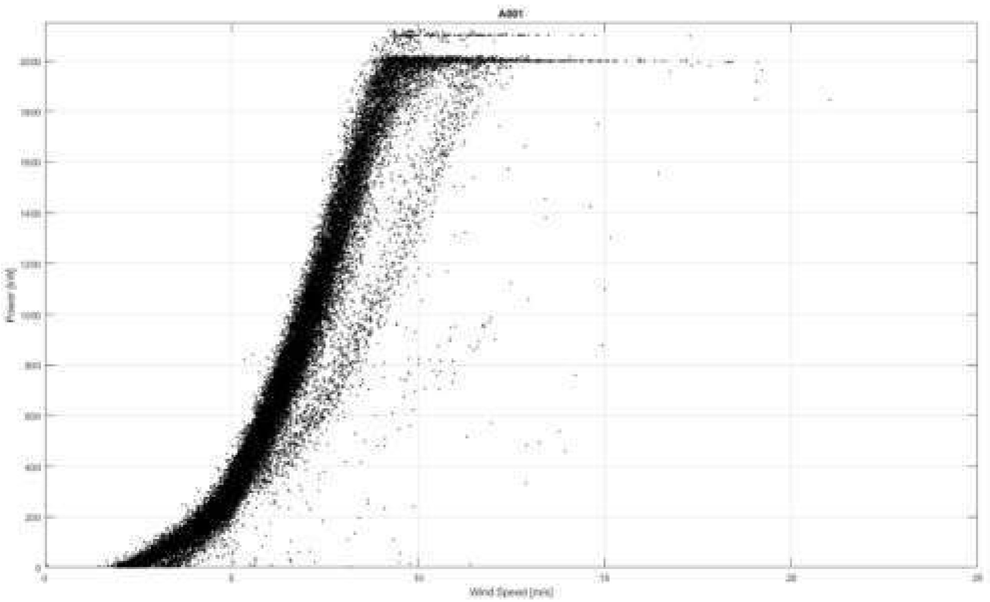

Figure C.1: Active power vs. NWS

A detailed analysis of the control parameters within the cubic area of the power curve can show if a potential change on turbine controls could have happen. This is shown in Figure C.2. Any variation on the control mode in this area must imply a variation in the relationship between the generator speed and the active power variables.

The generator speed signal and the active power signal are both measured by devices which usually present lower uncertainties in the measurements than nacelle anemometers.

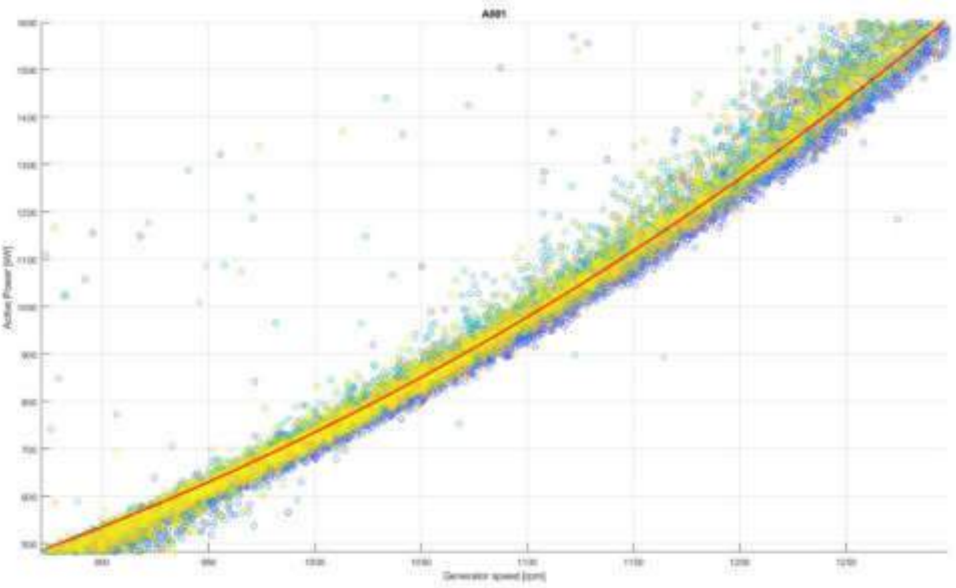

Figure C.2: Active power vs. generator speed (color represent different timescales)

The process of obtaining this transfer function (see Figure C.3) starts in the Power Performance Test, where a meteorological mast captures wind related data and its synchronized with a nearby turbine.

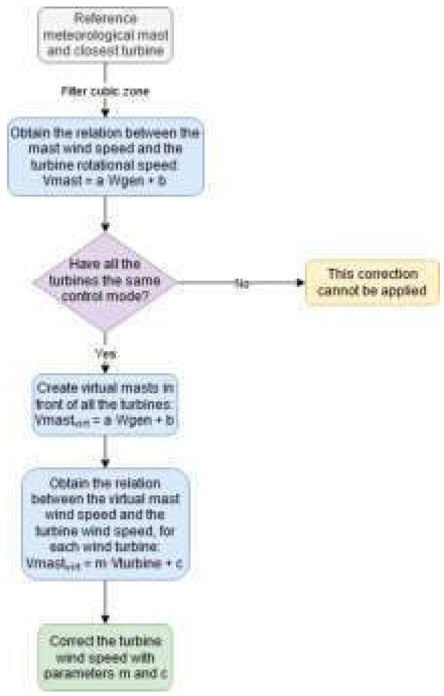

Figure C.3: RWS methodology flowchart.

The mast measurement gives a wakes-free wind measurement on the free wind directions, so the wind in these directions is used as a reference to calculate the relationship between wind speed and generator speed[14] on the cubic zone. This relationship allows to obtain a virtual wind reference (see

[14] The generator speed has a linear behavior in the cubic zone.

Figure C.4) on the cubic zone for the rest of the turbines in the wind farm, but only if the turbines share the same controller (see Figure C.5).

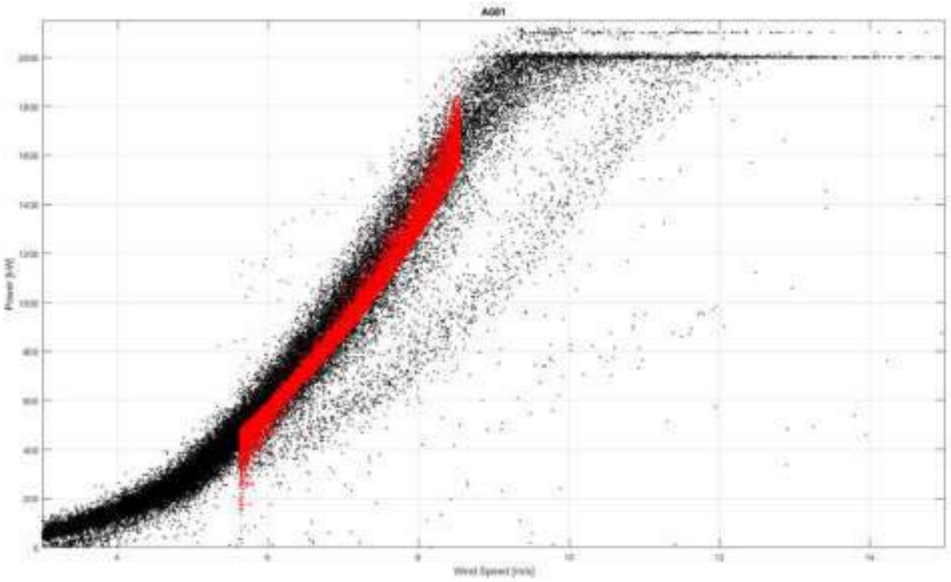

Figure C.4: Active Power vs Virtual wind speed (red, only cubic zone) & NWS (black)

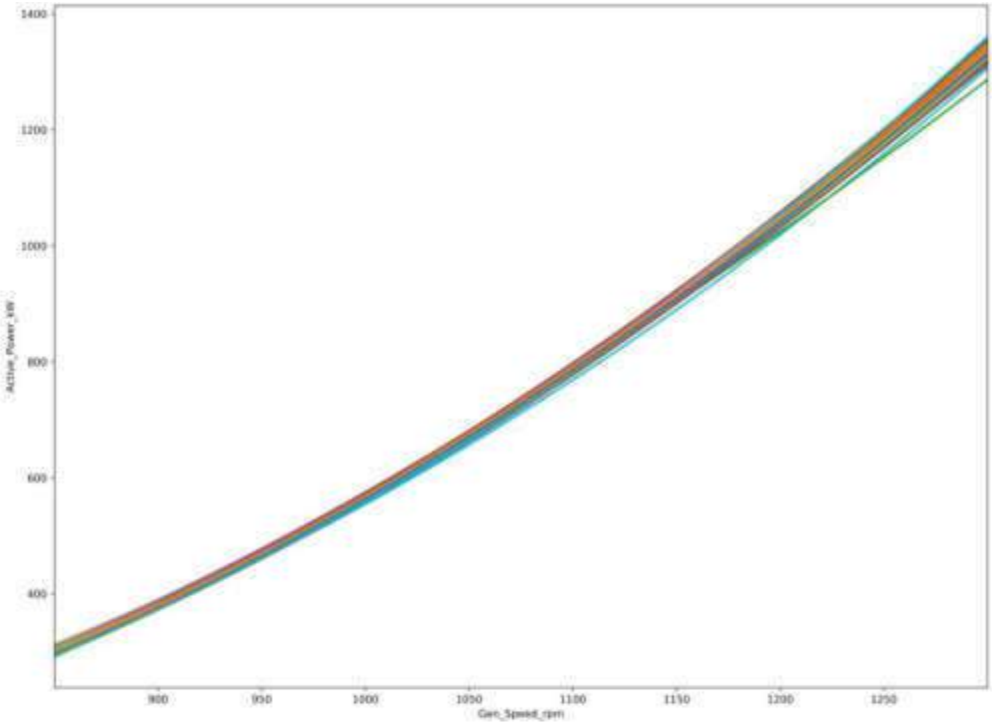

Figure C.5: Wind turbines sharing the same controller (Each line is a turbine).

Once the virtual wind references are created for the rest of the turbines, the relationship between NWS and virtual wind speed is obtained in the cubic zone for each wind turbine, although it could be translated to all the power curve. This relationship allows to correct the nacelle wind speed obtaining the Reference Wind Speed (RWS).

ANNEX D: WIND TURBINE PERFORMANCE

This annex contains tables per wind turbine for:

- Optimal performance
- Suboptimal performance
- Operational generating performance

Table D.1: Wind turbines performances.

Wind Turbine ID	Optimal Performance [%]	Suboptimal Performance [%]	Operational Generating Performance [%]
T1	92.53%	90.98%	90.98%
T2	93.21%	92.14%	92.09%
T3	93.34%	92.91%	92.85%
T4	92.54%	92.17%	92.01%
T5	93.17%	92.46%	92.30%
T6	93.27%	89.24%	89.08%
T7	92.75%	91.77%	91.61%
T8	92.71%	92.07%	91.91%
T9	91.57%	90.79%	90.63%
T10	92.84%	92.12%	91.97%
T11	92.02%	91.40%	91.40%
T12	91.44%	90.81%	90.81%
T13	91.60%	91.20%	91.20%
T14	92.46%	91.85%	91.85%
T15	92.93%	91.93%	91.39%
T16	94.77%	92.25%	92.25%
T17	90.53%	89.19%	88.77%
T18	92.97%	92.43%	92.43%
T19	92.68%	92.30%	92.30%
T20	92.86%	91.54%	91.54%
T21	91.44%	90.83%	90.83%
T22	95.22%	93.69%	92.35%
T23	93.00%	92.10%	92.10%
T24	93.06%	91.73%	91.73%
T25	91.91%	90.83%	90.49%
T26	92.34%	91.88%	91.88%
T27	91.24%	90.49%	90.49%
T28	92.28%	90.74%	90.74%
T29	91.12%	90.46%	90.46%
T30	91.58%	90.23%	89.94%
T31	89.37%	87.87%	87.87%
T32	90.16%	89.01%	89.01%
T33	91.30%	90.51%	90.51%
T34	90.79%	90.11%	90.11%

Table D.1: Wind turbines performances.

Wind Turbine ID	Optimal Performance [%]	Suboptimal Performance [%]	Operational Generating Performance [%]
T35	91.18%	90.69%	90.69%
T36	95.76%	95.18%	95.18%
T37	91.97%	89.93%	89.93%
T38	90.65%	89.83%	89.83%
T39	91.06%	86.96%	86.96%
T40	91.49%	90.70%	90.70%
T41	91.52%	90.30%	90.16%
T42	92.56%	91.62%	91.62%
T43	90.47%	90.03%	90.03%
T44	92.63%	92.09%	92.09%
T45	91.36%	90.49%	90.49%
T46	91.19%	89.91%	89.91%
T47	90.56%	90.03%	90.03%
T48	90.86%	89.89%	89.89%
T54	92.53%	92.02%	92.02%
T55	90.78%	90.21%	90.21%
T56	91.72%	89.98%	89.98%
T57	91.25%	89.88%	89.88%
T58	90.77%	90.11%	90.11%
T59	91.28%	90.66%	90.66%
T60	89.21%	88.82%	88.82%
T61	90.76%	89.55%	89.55%
T62	89.71%	88.46%	87.78%
T63	90.48%	89.95%	89.69%
T64	91.57%	90.66%	90.61%
T65	92.46%	91.81%	91.81%
T66	90.87%	90.26%	90.26%
T67	92.05%	87.63%	87.63%
T68	91.80%	91.27%	91.27%
T69	92.03%	91.36%	91.36%
T70	91.98%	91.10%	91.10%
T71	90.56%	89.92%	89.92%
T93	91.65%	90.99%	90.99%
T94	90.78%	89.74%	89.74%
T95	89.52%	88.58%	88.26%
T96	91.64%	90.73%	90.73%
T97	88.61%	87.56%	87.56%
T98	90.54%	89.70%	89.70%
T99	89.04%	87.85%	87.85%
T100	88.00%	85.18%	85.18%
T101	89.19%	88.01%	88.01%

Table D.1: Wind turbines performances.

Wind Turbine ID	Optimal Performance [%]	Suboptimal Performance [%]	Operational Generating Performance [%]
T102	90.58%	89.95%	89.89%
T103	90.47%	89.73%	89.73%
T104	91.74%	90.87%	90.87%
T105	90.67%	89.94%	89.94%
T106	89.91%	89.28%	89.28%
T107	88.67%	86.55%	86.48%
T108	89.83%	88.92%	88.92%
T109	92.31%	90.77%	90.77%
T110	90.39%	89.42%	89.42%
T111	89.63%	89.01%	89.01%
T112	89.66%	89.27%	89.27%
Average	**91.45%**	**90.41%**	**90.34%**

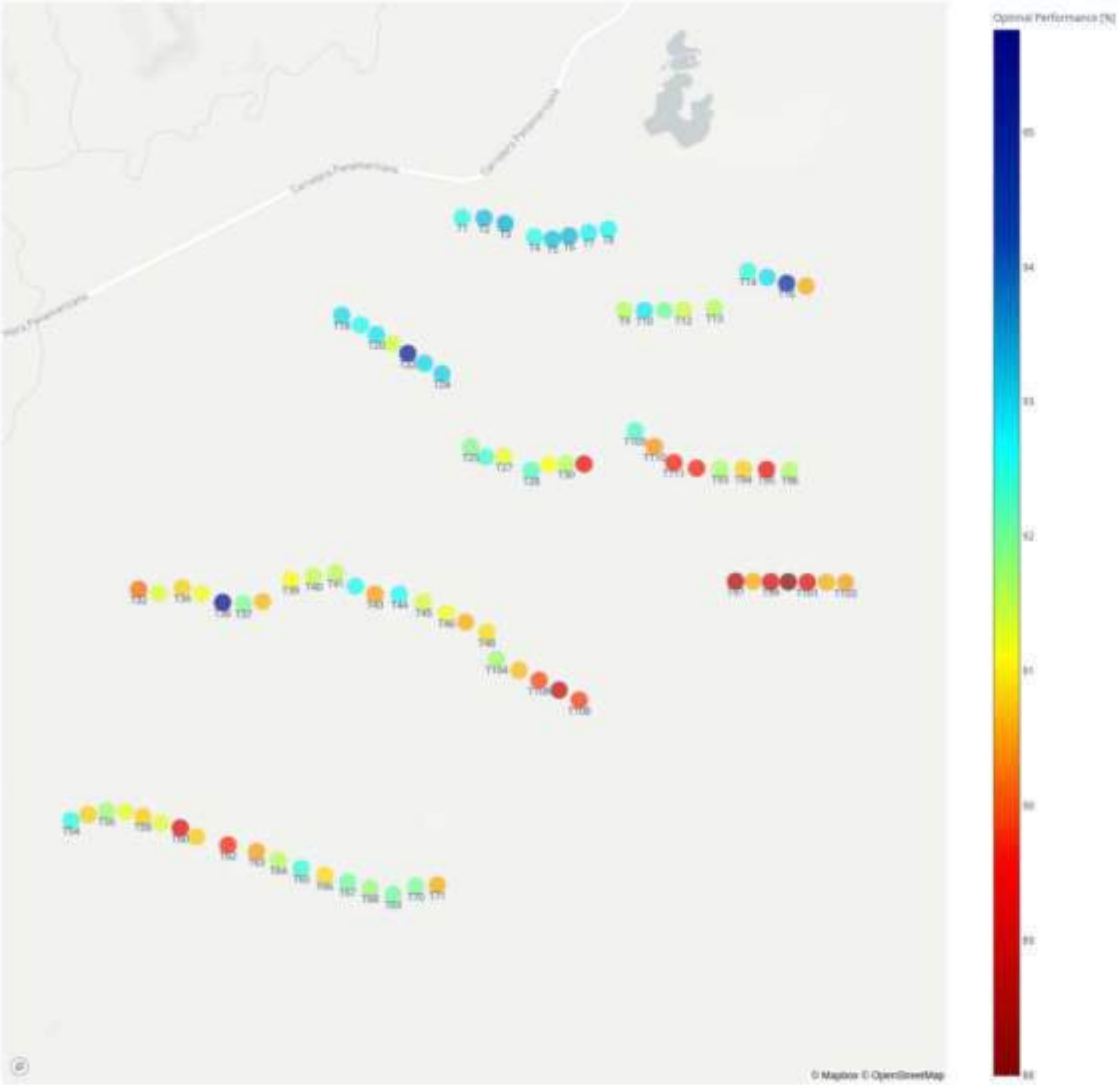

Figure D.1: Wind turbines optimal performance.

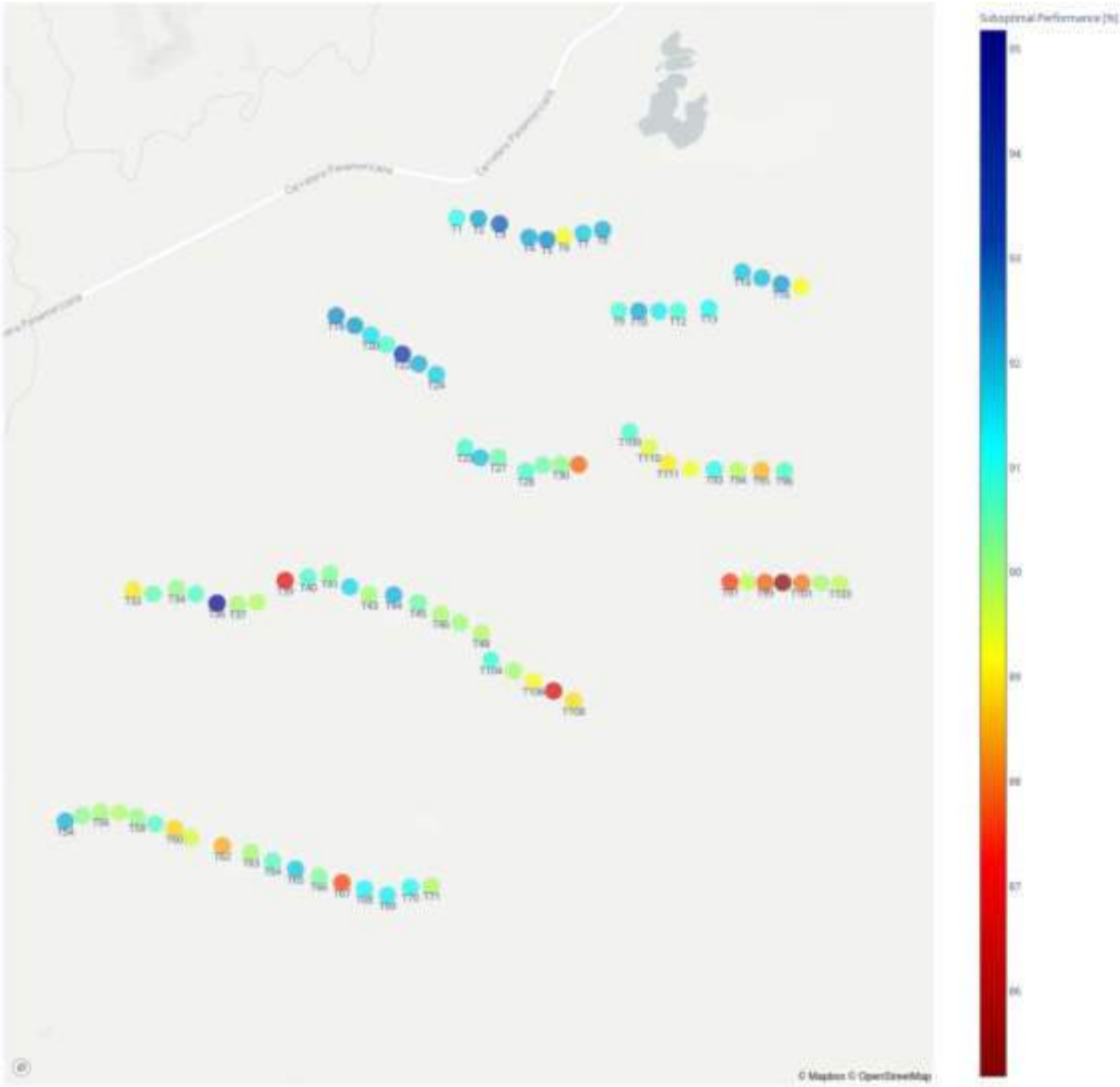

Figure D.2: Wind turbines suboptimal performance.

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[1] DNV, "PENONOMÉ WIND FARM Garrad Hassan Due Diligence," 2014.

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[3] International Electrotechnical Commission (2008), "IEC Wind Turbines - Part 26-1: Time-based availability for wind turbine generating systems," 2011.

[4] International Electrotechnical Commission (2008), "IEC Wind Turbines - Part 26-2: Production-based availability for wind turbines," 2014.

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APPENDIX E—PENONOMÉ II LIFE TIME EXTENSION ANALYSIS

Life Time Extension Analysis

PREPARED FOR:
UEP Penonomé II S.A.

Ref. No.: UL-ES-AA20-13321645-02.01

PENONOME II WIND FARM
Panamá

18 June 2020

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. EXECUTIVE SUMMARY

As part of the assessment on the Penonome II wind farm, a lifetime extension analysis has been performed for PENONOME II WIND FARM (Penonomé, Panamá), according to the methodology described in the ANSI/UL 4143 Guideline [1]. The analysis has considered the following:

- Certification conditions assuming a 20-year lifetime for all the components
- Site-specific wind conditions according to available information from OpenWind tool including the items below:
  - Wind speed probabilistic distribution
  - Maximum average wind shear
  - 90th percentile turbulence intensity (as stated by IEC 61400-1 Edition 3)
  - Annual average air density
- Independent Aeroelastic Model. IAM. considering available information
  - GoldWind GW106 2500 kW HH 90m (IIA IEC class certified according to [2])
- Appropriate Wöhler slopes related to key component materials (Ref. [3], Ref. [4], Ref. [5].and Ref. [6]).

It has to be remarked than the blade root bushing problems detected in the wind farm and reported in [7] is not included in this evaluation. The lifetime expectancy for this component is analyzed considering proper quality and strength (as it was considered in the design conditions). It is also remarkable that the fatigue load requirement level in the blade root joint is lower in this wind farm that in the design conditions Table 1.1, so the risk associated to defect in the blade joint is lower than in a more demanding scenario from the fatigue loads point of view.

The foundations and electrical equipment are outside of this review.

Lifetime extension factors have been calculated through a comparison between the certification damage equivalent loads (DELs) and site-specific DELs. Multiplying the certified lifetime (20 years) by this factor results in the estimate of useful life that is available.

When taking into account LTE factors from Table 6.2 and Table 7.3 the following summarized results (Table 1.1) regarding Lifetime Extension (LTE) can be expected for Penonomé II WF.

Table 1.1: Average LTE estimation summary for Penonomé II wind turbines including P50 and P90 load exceedance probabilities and LTE management plan costs per year

	P50	P90
Blade Root, Composite	>30.0[1]	24.9
Blade Root, Joint	>30.0	28.5
Hub	>30.0	27.8
Hub-Shaft Joint	>30.0	>30.0
Main Frame, Casting	>30.0	>30.0
Main Frame Welded	>30.0	>30.0
Main Frame Tower Joint	>30.0	>30.0
Tower Top	>30.0	>30.0
Tower Bottom	>30.0	>30.0
Years 1–5 Cost [k€/year]	0.0	0.0

[1] Considering that the blade quality is according to the design specifications. The blade root bushing issue is not considered in this figure.

Table 1.1: Average LTE estimation summary for Penonomé II wind turbines including P50 and P90 load exceedance probabilities and LTE management plan costs per year

Years 6–10 Cost [k€/year]	60.0	60.0
Years 11–15 Cost [k€/year]	60.0	63.4
Years 16–20 Cost [k€/year]	60.0	103.0
Years 21–25 Cost [k€/year]	60.0	198.0
Years 26–30 Cost [k€/year]	60.0	267.9

P50 results represent the lifetime estimation analysis according to the point 11 in the IEC 61400-1 Ed.3. as average lifetime for all the wind turbines of the wind farm. P90 includes the uncertainties acting in order to have a coverage factor of the load distribution of 90%.

As shown in Table 1.1 lifetime expectations can be increased to 30 years in almost all the components doing periodical inspections and with a proper maintenance plan to avoid further problems. It is recommended to implement this maintenance plan from P90 scenario figures in order to minimize the structural risk as far as possible. Here the blade root has to be highlighted as a specific issue. The lifetime of this component cannot be defined by analytical methods but only risk management actions could be implemented: periodical inspections (at least before and after high wind season) and a monitoring system in order to detect deviations as soon as possible.

Table 1.2: Aging Management Plan Summary [1.2]

Component	Failure Mode	Inspection	Intervals
Blade Overview including Tip	Fatigue	Visual Inspection (binoculars, high resolution camera, climbing robot, drones rope access, etc.)	One year
	Corrosion		
Blade Root. Bolted Joints	Fatigue	Tap testing of all rotor bolts Spot checks of the bolts preload are recommended.	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
	Fatigue and Corrosion	NDT (Ultrasonic analysis, magnetic particles testing or penetrating liquids)	Four years
Rotor Hub	Fatigue and Corrosion	NDT (Ultrasonic analysis, magnetic particles testing or penetrating liquids)	Four years
		Visual inspection	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
Hub to shaft bolted joint	Fatigue	Tap testing of all rotor bolts Spot checks of the bolts preload are recommended.	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
	Fatigue and Corrosion	NDT (Ultrasonic analysis. Magnetic particles testing or penetrating liquids)	Four years
Main frame	Fatigue	Visual inspection	One year
		NDT (Ultrasonic analysis. Magnetic particles testing or penetrating liquids)	Four years

[1.2] The analysis is based on the assumption that actual O&M will prevail as it is with an additional special care given to the corrosion issues.

Table 1.2: Aging Management Plan Summary [1,2]

Component	Failure Mode	Inspection	Intervals
Steel tower	Fatigue and Corrosion	Visual inspection of the tower welds Tap testing of all tower bolts. Spot checks of the bolts preload is recommended.	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
	Fatigue and Corrosion	NDT of the tower welds (magnetic particle testing)	Four years
Nacelle components	Corrosion	Installation of a filter in the nacelle	Once. Replaced or cleaned at maintenance interval
		Visual inspection	One year

The proposed inspection plan is based on the techniques mentioned Table 1.2. Consider that UL recommends an inspection plan based on the P90 scenario in order to reduce the risk due to uncertainties as much as possible.

The proposed inspection plan, based on P90 estimation, aims to detect failure in the incipient state when the retrofit of the component requires a low cost. In the event of doubt regarding the severity of a finding. further inspection techniques to define this severity or its reparation are recommended. The initial global budget for inspections through the lifetime of the assets (assuming P90 results) will be 3.46 M€. This budget includes the blade tip review regarding corrosion issues but it does not includes the root bushing specific inspection and the monitoring system.

Special remarks must be considered due to corrosion findings and bolted joints maintenance. The lack of action in order to achieve these improvements implies loss of validity of the lifetime analysis here reported.

The IEC 61400-1 standard provides design consideration and analysis procedures in order to maintain the catastrophic failure rate in an acceptable level (1/10000 in the lifetime). All the procedures proposed in the standard are focused on getting this safety levels. From specific site assessment point of view, IEC 61400-1 provides clear statement in its section 11 on how to proceed in order to perform a structural site suitability analysis. In order to perform lifetime analysis reported in this deliverable and in the P50 scenario the lifetime expectancy is analyzed as it is stated in section 11 of IEC 61400-1, maintaining the standard safety levels**.**

All the wind turbines have been inspected within an inspection campaign which started at the end of 2019. The inspections consist in general visual inspection of the wind turbine and blade inspection with TSR robot. There were no remarkable any kind of high severity finding during these inspections as it was reported in [8], but the blades issues.

In a separate piece of work, the blade root inserts will be analyzed by non-destructive testing. This task has started with a first tomography and even the destructive test on the sample as it is reported in [7]. The findings in the starting point of the evaluation are not in the line of the findings reported previously in [9], so further investigations are under execution.

Finally, this analysis has been repeated considering the GW109/2500 configuration with LM 53.2 blades, in order to understand the lifetime impact due to a possible blade replacement.

2. DEFINITIONS. SYMBOLS AND ACRONYMS

- A: Weibull's Distribution Scale Coefficient
- Cp: Power Coefficient
- DEL: Damage Equivalent Load
- DLC: Design Load Case
- HAWT: Horizontal Axis Wind Turbine
- HH: Hub Height
- IAM: Independent Aeroelastic Model
- Iu: Longitudinal Turbulence Intensity
- K: Weibull's distribution shape coefficient
- LTE: Lifetime Extension
- N: Number of Cycles
- NTM: Normal Turbulence Model
- ρ: Air Density
- SCADA: Supervisory Control And Data Acquisition
- SMT (Solid metal tip, part of lightning protection)
- WF: Wind Farm
- WSM: Wind Sector Management
- WT(s) or WTG(s): Wind Turbine(s)

3. INTRODUCTION

The Penonomé II Wind Farm is located in Penonomé, Panamá. There are 86 WTs in operation since year 2016. The following wind turbines form it:

- 86 WTs type GoldWind GW106 2500 kW HH 90m. The certified Wind Class is IEC IIA [2].

Details of the WTs' technical specifications are shown in the tables below (refer Table 3.1 and Table 3.2) for WTs' specifications and for blades' specifications.

Section 4 describes the scope of LTE estimation in this report.

WF overviews are provided in Section 5.1.

A summary of the environmental conditions relevant for LTE analysis (wind speed, wind rose, turbulence intensity, wind shear, air density, statistical properties, etc.) can be found in Section 5.2.

An Independent Aeroelastic Models (IAM) has been produced to characterize the WT for Penonomé II WF; its definition and properties are shown in Section 5.4.

Simulations (power production) using an aeroelastic model under certification conditions and site-specific conditions have been performed. This section also includes validation of the model when considering reference data from the WF (including power, power coefficient, and thrust coefficient). Campbell diagram has been produced and checked to ensure that resonances are avoided.

Section 5.5 contains the procedure followed in order to calculate the Lifetime Extension Analysis (LTE). Results regarding Lifetime Extension (LTE) factors are also shown in this section (LTE factors for Penonomé II wind turbines are listed in Table 5.7).

Section 7 reflects LTE results per component considering the uncertainties.

Considering these results. recommendations on Lifetime Extension (LTE) are included in Section 8. (summarized in Table 8.1) and associated expenses have been calculated and shown in Table 8.2 for the wind farm.

GoldWind GW106 2500 kW HH 90m (IIA IEC class certified)

Table 3.1: Summary of technical specifications for pitch regulated GoldWind GW106 2500 kW HH 90m wind turbine

Parameter	Value	Units	Description Notes	Ref.
Type	HAWT	-	-	
Onshore/Offshore	Onshore	-	-	
Rotor Location	Upwind	-	-	
Class/Category	IIA (IIIA for blade)	-	-	
Power Regulation	pitch	-	-	
P_Rated	2500	kW	Rated power	
N Blades	3	-	Number of blades	
Vr	10.3	m/s	Rated wind speed	
Vin	3	m/s	Cut-in wind speed	
Vout	25	m/s	Cut-out wind speed	
Tilt Angle	5	deg	-	
Coning Angle	2	deg	-	
Rotor Diameter	107.5	m	-	
Hub Height	90	m	-	
Hub Diameter	2.4	m	-	
Rotor Speed	14.5	rpm	-	
Generator Speed	14.5	rpm	-	
Gear Ratio	1	-	-	
Mass Rotor + Hub	59400	Kg	-	
Mass Nacelle	101500	Kg	-	
Mass Tower	246000	Kg	-	
Natural Freq. Tower (1st)	0.292	Hz	-	

Note 1: Data estimated by UL when comparing with wind turbines of similar specifications and/or calculations.

Table 3.2: Summary of technical specifications for blade of GoldWind GW106 2500 kW HH 90m

Parameter	Value	Units	Description/Notes	Ref.
Blade length	52.5	m	-	Note 1
Mass Blade	10540.0	Kg	-	Note 1
Natural Freq. Blade (1st Flapwise)	0.63	Hz	-	Note 1
Natural Freq. Blade (1st Edgewise)	1.2	Hz	-	Note 1

Note 1: Data estimated by UL when comparing with wind turbines of similar specifications and/or calculations.

4. SCOPE

LTE analysis is calculated based on a comparison of fatigue life (allowable number of cycles) that is performed at critical locations (load stations) of the wind turbine IAM under two scenarios of power production and external conditions:

- Those corresponding to certification (design basis of the turbine)
- Those estimated for the site-specific conditions

The LTE factors can be determined with a certain accuracy level, which is heavily influenced by the quantity and quality of available data (from design/certification phase and data gathered from on-site conditions), WT models, and simulations. The following remarks have to be considered regarding the data used in this report:

1. External Conditions
   - On-site meteorological data (wind speed, wind frequency distribution parameters, wind shear coefficient, air density, etc.) are considered.
2. IAM
   - In order to simulate turbulence in a representative way, every wind speed has been simulated using different turbulence seeds (several simulations per wind speed bin as stated in [10]).
   - Extreme load values are not considered because LTE calculation is based on fatigue life.
   - Available information on airfoils' data (polar curves) has been considered. Available technical specifications (e.g. mass, Stiffness, etc.) are considered.
   - Flex5 software has been used to carry out the load simulations and for post-processing (Ref. [11]).
   - Design Load Cases (DLCs) of power production conditions are according to the data in [10].
3. Determination of LTE
   - DEL (certification) is not available, but a reference set of design fatigue loads has been generated using the same IAM as was used to calculate the site-specific loads.

The following points can be considered as a limitation to the current LTE estimation:

1. Airfoil data (polar curves), which are based on in-house experience and well-known airfoil databases.
2. Internal structure of wind turbine's blades (mass distribution, stiffness distribution, position of center of gravity, etc.), which are based on UL knowledge.

In any case, the refined treatment of all available data and simulations has reduced the uncertainty and increased the accuracy of LTE estimation.

5. LIFETIME EXTENSION ANALYSIS

5.1 WF Data

The Penonomé II wind farm is located in the Coclé province in Panamá. Figure 5.1 shows Penonomé II wind farm.

Figure 5.1: Overview of Penonomé II WF. N Source: Google Earth

There are 86 wind turbines operating in this wind farm. The following list has been extracted from Ref. [12]:

- Penonomé II WF: 86 Wind turbines GoldWind GW106 2500 kW HH 90m IEC class IIA

Details of wind turbine technical specifications are shown in Table 3.1 while Table 3.2 contains the blade specifications.

5.2 Analysis of Environmental Conditions

For the calculation of the wind conditions at each wind turbine position and direction, firstly, an analysis of the wind resource data (Ref. [13] and Ref. [14]) has been carried out. With the wind data extracted from the wind resource analysis and other detailed data as the terrain elevation, the inflow, roughness and a mesoscale wind model of the area, a horizontal extrapolation of the mast to each wind turbine position has been accomplished. Thus, wake affected wind speed distributions, effective turbulence intensity, wind shear, air density and inflow angle are calculated for each wind turbine and wind direction.

5.2.1 Wind Speed Distributions

The following averaged wake affected wind speed has been used to calculate de LTE for Penonomé II WF. Table 5.1 shows the average mean wake affected wind speed per WT of the wind farm. Specific wind rose factors (84 sectors have been considered in the analysis) and wind speed per wind turbine and direction can be found on Appendix A - Wind site conditions

Table 5.1: Mean wake affected wind speed per WT for Penonomé II WF.

WT	Wake wind speed (m/s)	WT	Wake wind speed (m/s)	WT	Wake wind speed (m/s)
WTG001	6.4	**WTG030**	6.0	**WTG064**	6.0
WTG002	6.3	**WTG031**	6.0	**WTG065**	6.0
WTG003	6.3	**WTG032**	6.2	**WTG066**	6.0
WTG004	6.3	**WTG033**	6.2	**WTG067**	6.0
WTG005	6.3	**WTG034**	6.2	**WTG068**	6.0
WTG006	6.2	**WTG035**	6.2	**WTG069**	6.0
WTG007	6.2	**WTG036**	6.3	**WTG070**	5.9
WTG008	6.2	**WTG037**	6.2	**WTG071**	5.9
WTG009	6.0	**WTG038**	6.2	**WTG109**	6.0
WTG010	6.0	**WTG039**	6.2	**WTG110**	5.9
WTG011	6.1	**WTG040**	6.2	**WTG111**	5.9
WTG012	6.1	**WTG041**	6.2	**WTG112**	5.9
WTG013	6.1	**WTG042**	6.1	**WTG093**	5.9
WTG014	6.1	**WTG043**	6.2	**WTG094**	5.9
WTG015	6.1	**WTG044**	6.1	**WTG095**	5.9
WTG016	6.1	**WTG045**	6.1	**WTG096**	6.0
WTG017	6.1	**WTG046**	6.1	**WTG097**	5.8
WTG018	6.4	**WTG047**	6.0	**WTG098**	5.7
WTG019	6.4	**WTG048**	6.0	**WTG099**	5.7
WTG020	6.4	**WTG054**	6.0	**WTG100**	5.8
WTG021	6.4	**WTG055**	5.8	**WTG101**	5.8
WTG022	6.4	**WTG056**	5.9	**WTG102**	5.9
WTG023	6.4	**WTG057**	6.0	**WTG103**	5.9
WTG024	6.3	**WTG058**	6.0	**WTG104**	5.7
WTG025	6.1	**WTG059**	6.0	**WTG105**	6.0
WTG026	6.1	**WTG060**	5.9	**WTG106**	6.0
WTG027	6.0	**WTG061**	6.0	**WTG107**	6.0
WTG028	6.0	**WTG062**	6.0	**WTG108**	5.9
WTG029	5.9	**WTG063**	6.0		

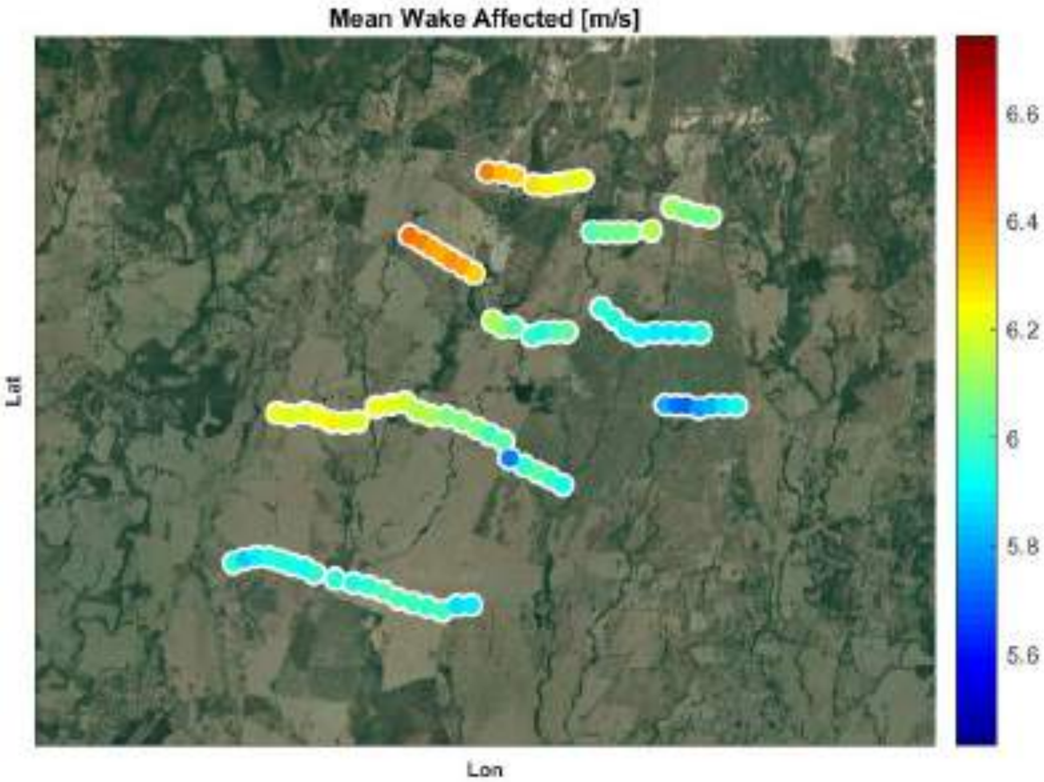

Figure 5.2: Average wake affected wind speed for Penonomé II WF.

5.2.2 Effective turbulence Intensity

Meteorological mast wind turbulence intensity data has been used in this analysis and OpenWind tool has been used for the calculation of the effective turbulence intensity, and the effect of the layout at Penonomé II wind farm has been taken into account (wake effects have been estimated using Frandsen method as described in [15]). The average calculated turbulence intensities at 15 m/s are shown in Table 6. The simulations have been performed in 84 sectors. The turbulence intensity that has been used in each sector includes the wake effect according to the layout of Penonomé II WF and nearby wind farms. In Appendix A - Wind site conditions can be found the turbulence intensity per wind turbine, bin speed and direction.

Table 5.2: Effective Turbulence Intensity from OpenWind tool for Penonomé II WF

WT	$IT_{ef,15m/s}$ [%]	WT	$IT_{ef,15m/s}$ [%]	WT	$IT_{ef,15m/s}$ [%]
WTG001	14.3	**WTG030**	14.7	**WTG064**	14.9
WTG002	14.4	**WTG031**	14.6	**WTG065**	14.8
WTG003	14.5	**WTG032**	14.3	**WTG066**	14.8
WTG004	14.5	**WTG033**	14.3	**WTG067**	14.8
WTG005	14.5	**WTG034**	14.3	**WTG068**	14.8
WTG006	14.6	**WTG035**	14.4	**WTG069**	14.8
WTG007	14.6	**WTG036**	14.4	**WTG070**	14.8
WTG008	14.7	**WTG037**	14.5	**WTG071**	14.9
WTG009	15.2	**WTG038**	14.5	**WTG109**	14.5
WTG010	14.9	**WTG039**	14.3	**WTG110**	14.7

Table 5.2: Effective Turbulence Intensity from OpenWind tool for Penonomé II WF

WT	$IT_{ef,15m/s}$ [%]	WT	$IT_{ef,15m/s}$ [%]	WT	$IT_{ef,15m/s}$ [%]
WTG011	15.0	**WTG040**	14.3	**WTG111**	14.9
WTG012	15.0	**WTG041**	14.3	**WTG112**	15.0
WTG013	15.0	**WTG042**	14.5	**WTG093**	15.0
WTG014	14.9	**WTG043**	14.4	**WTG094**	15.0
WTG015	15.0	**WTG044**	14.5	**WTG095**	15.0
WTG016	15.0	**WTG045**	14.5	**WTG096**	14.9
WTG017	15.0	**WTG046**	14.4	**WTG097**	15.1
WTG018	14.3	**WTG047**	14.6	**WTG098**	15.1
WTG019	14.3	**WTG048**	14.5	**WTG099**	15.1
WTG020	14.4	**WTG054**	14.7	**WTG100**	15.2
WTG021	14.4	**WTG055**	14.7	**WTG101**	15.2
WTG022	14.3	**WTG056**	14.6	**WTG102**	15.2
WTG023	14.2	**WTG057**	14.5	**WTG103**	15.2
WTG024	14.3	**WTG058**	14.5	**WTG104**	16.4
WTG025	14.5	**WTG059**	14.6	**WTG105**	14.8
WTG026	14.7	**WTG060**	14.7	**WTG106**	14.5
WTG027	14.6	**WTG061**	14.9	**WTG107**	14.6
WTG028	14.8	**WTG062**	14.8	**WTG108**	14.8
WTG029	14.8	**WTG063**	14.9		

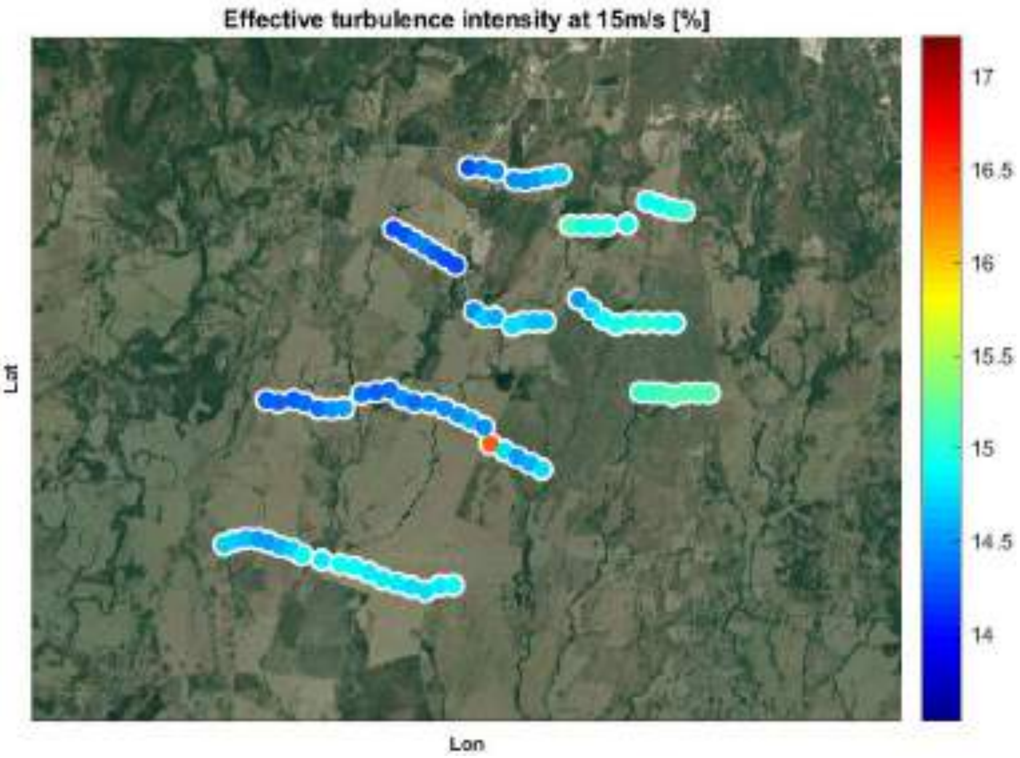

Figure 5.3: Effective TI at 15 m/s for Penonomé II WF.

As it can be seen in Figure 5.4 the effective turbulence intensity per wind speed bin is above wind Class A between 3 m/s and 8 m/s and bellow the wind Class for the rest of wind speed bins for most of the WTs.

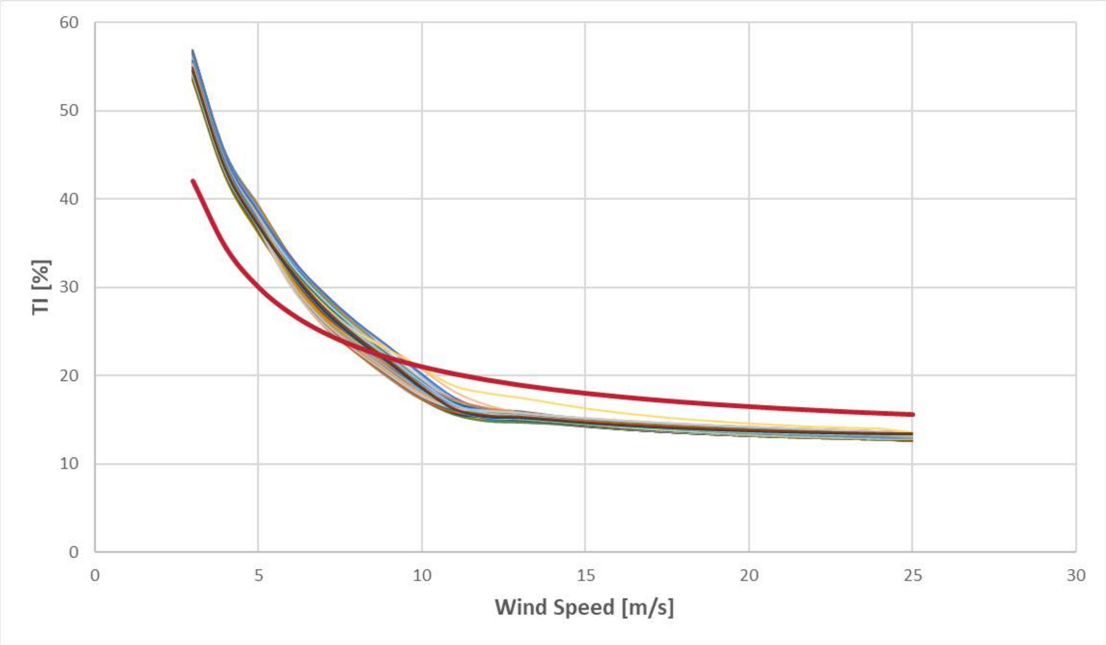

Figure 5.4: Effective TI per wind speed bin and wind turbine at Penonomé II WF.

5.2.3 Wind Shear

The site conditions (roughness) and data from OpenWind tool have been processed for the calculation of the wind shear exponent. Refer to Appendix A - Wind site conditions for detailed wind shear exponents per wind turbine and direction. Table 5.3 shows the average wind shear of the wind turbines that represent the average wind shear of the wind farm.

Table 5.3: Wind shear from OpenWind tool for Penonomé II WF [-]

Wind Direction	Shear [-]
0º (-15º - 15º)	0.23
30º (15º - 45º)	0.1
60º (45º - 75º)	0.08
90º (75º - 105º)	0.06
120º (105º - 135º)	0.1
150º (135º - 165º)	0.11
180º (165º - 195º)	0.1
210º (195º - 225º)	0.2
240º (225º - 255º)	0.29
270º (255º - 285º)	0.21
300º (285º - 315º)	0.1
330º (315º - 345º)	0.16

Table 5.3: Wind shear from OpenWind tool for Penonomé II WF [-]

Wind Direction	Shear [-]
Average	0.21

5.2.4 Air Density

The corresponding air density value has been extracted from meteorological mast data. In Appendix A - Wind site conditions can be found the air density used per wind turbine in the analysis.

Table 5.4: Air density from OpenWind tool for Penonomé II Wind Farm

Wind Farm	Density [kg/m^3]
Penonome2	1.165

5.2.5 Summary External Conditions

In Table 5.5. a comparison is presented between on-site and design conditions used for certification. A graphical indication of the implications of the difference in these conditions on lifetime has been included by each considered parameter. Green arrows suggest an opportunity for increased fatigue lifetime while red arrows indicate a negative impact on lifetime. The loads analysis determines to what degree the opportunities for enhanced fatigue life outweigh the negative factors.

Table 5.5: Environmental conditions. expected impact on LTE analysis for Penonomé II WF (GoldWind GW106 2500 kW HH 90m).

		Penonomé II WF (GoldWind GW106 2500 kW HH 90m Class IIIA)		LTE impact
Parameter	Units	Cert.	Site	
Air Density	kg/m^3	1.225	1.165	↑
Wind Shear Coeff	-	0.2	0.21	↓
Yaw Misalignment	deg	0.0	0.0	=
Inflow Angle	deg	8.0	0.02	↑
Wind speed	m/s	8.5	6.06	↑
Turbulence Intensity at 15 m/s	%	18.0	14.71	↑
Availability	%	100.0	100.0	=

5.3 Analysis of Operational Conditions

All the wind turbines have been inspected starting at the end of 2019. The inspections consist in general visual inspection of the wind turbine and blade inspection with TSR robot. Additionally, blade root inserts nondestructive testing has been performed for the Sinoma52.5. The actual conditions of the blade root bushing don’t allow to provide reliable results for the blade root component.

The related documents are the following:

- UL-ES-AM20-1101772929-01.05 [8]
- UL-ES-AA20-13321645-01.03_NDT_results [7]

As a summary of the most relevant findings:

Figure 5.5: Lose torque mark in rotor hub

Figure 5.6: Displaced nut

Figure 5.7: Pitch bearing grease leakage

Figure 5.8: Oil leakage and low oil level in pitch drive motor

Figure 5.9: Lose torque mark in blade bolts

Figure 5.10: Delamination in blade

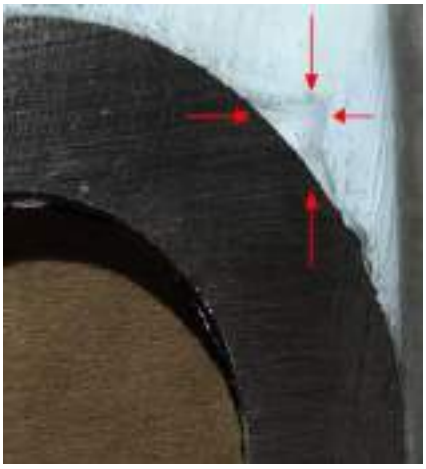

Figure 5.11: Void in the blade insert

Figure 5.12: Displaced nut

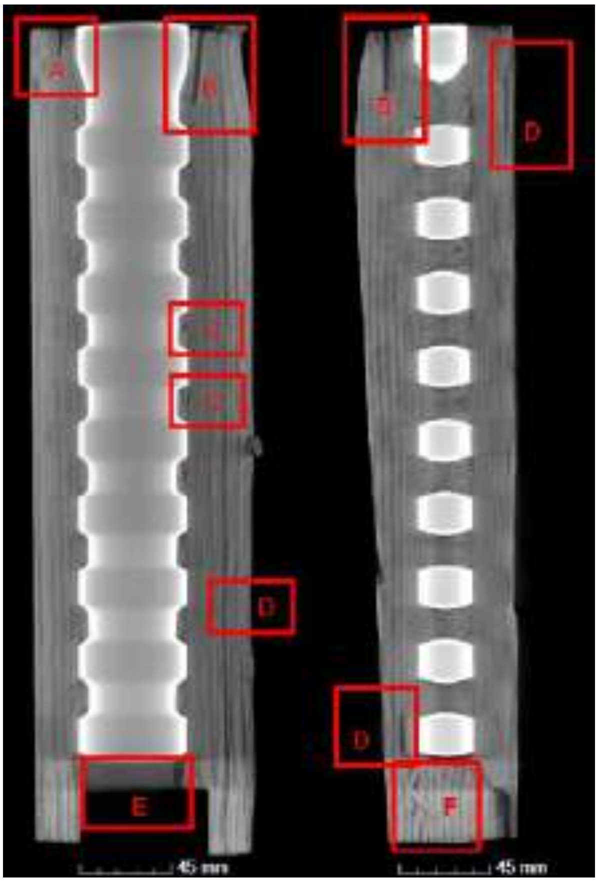

Figure 5.13: Blade root inserts NDT

A. Damage generated by a cutting tool.
B. Drilling tool cavity
C. Lack of material or low density material close to the root bushing
D. Lack of material or change in the fiber fraction in the laminate.
E. Porosity
F. Fiber misalignment

5.4 Aerodynamics / Independent Aeroelastic Model / Loads

An Independent Aeroelastic Model has been produced for Penonomé II wind farm. The Independent Aeroelastic Model has been produced by UL. Refer to Table 3.1 for a given wind turbine's specifications and Table 3.2 for blade's specifications. Flex5 software has been used to carry out the simulations and post processing [11].

The validation of the aeroelastic models of wind turbines consists of a comparison of power curve, power coefficient (CP) curve and thrust coefficient (CT) curve. In addition, the Campbell diagrams for the models to be validated have been produced. In these diagrams, the natural frequencies of tower/blade have been checked to be above operating frequencies that may produce high vibration/loads.

The Normal Turbulence Model (NTM) is used to determine the wind's statistical properties (as defined in IEC 61400-1 in section 7 (Ref. [15]). Kaimal Turbulent model has been used according to the state of the art (IEC 61400-1 Ed.3 [10]).

Refer to Section 5.2 for a detailed description of the environmental conditions considered for validation purposes.

The validation of the aeroelastic model is shown from Figure 5.14 to Figure 5.16 including the characteristic power curve, power coefficient, thrust coefficient and Campbell diagram.

GoldWind GW106 2500 kW HH 90m Wind Turbine Aeroelastic Model Validation

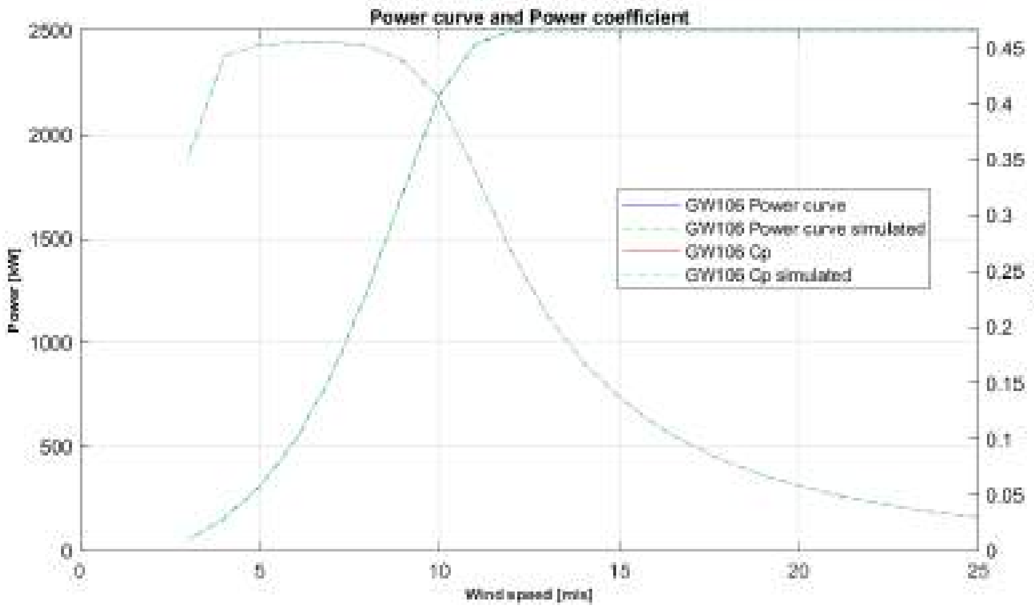

Figure 5.14: Power curve and power coefficient (Cp) of pitch-regulated wind turbine (GoldWind GW106 2500 kW HH 90m WT model validation)

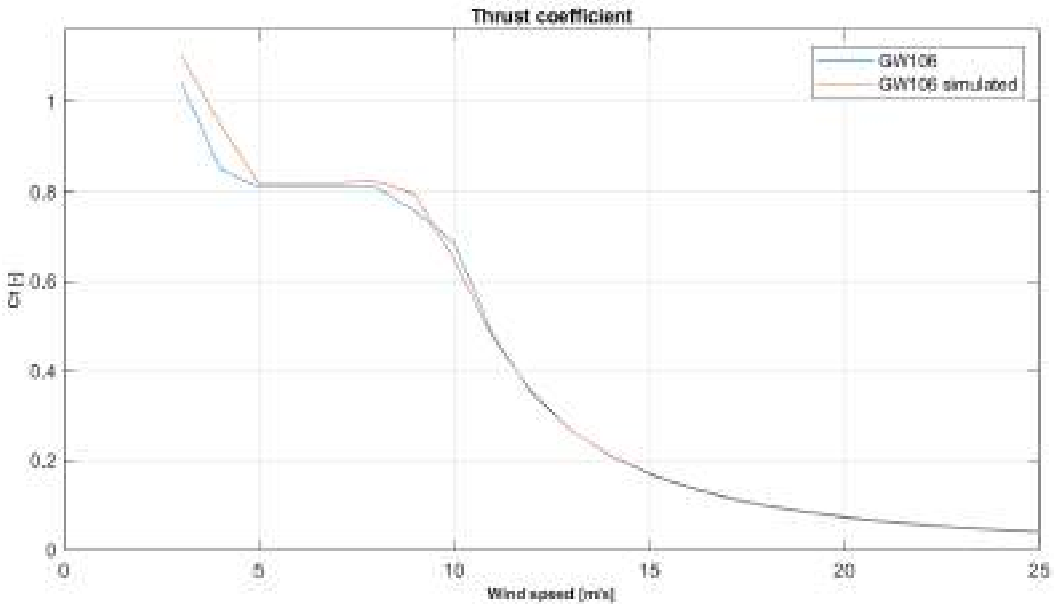

Figure 5.15: Thrust coefficient (CT) curve of pitch-regulated wind turbine (GoldWind GW106 2500 kW HH 90m WT model validation)

From Table 3.1. the following specifications of the GoldWind GW106 2500 kW HH 90m wind turbine are obtained:

- Rotor speed. Rg = 14.5 rpm
- Gear ratio GR = 1
- Natural freq. Tower (1st) = 0.292 Hz

From Table 3.2. the following blade's specifications for the GoldWind GW106 2500 kW HH 90m wind turbine are obtained:

- Natural freq. Blade (1st flapwise) = 0.63 Hz
- Natural freq. Blade (1st edgewise) = 1.2 Hz

Rated rotor speed (14.5 rpm) is shown as a vertical, dashed line in Figure 5.16.

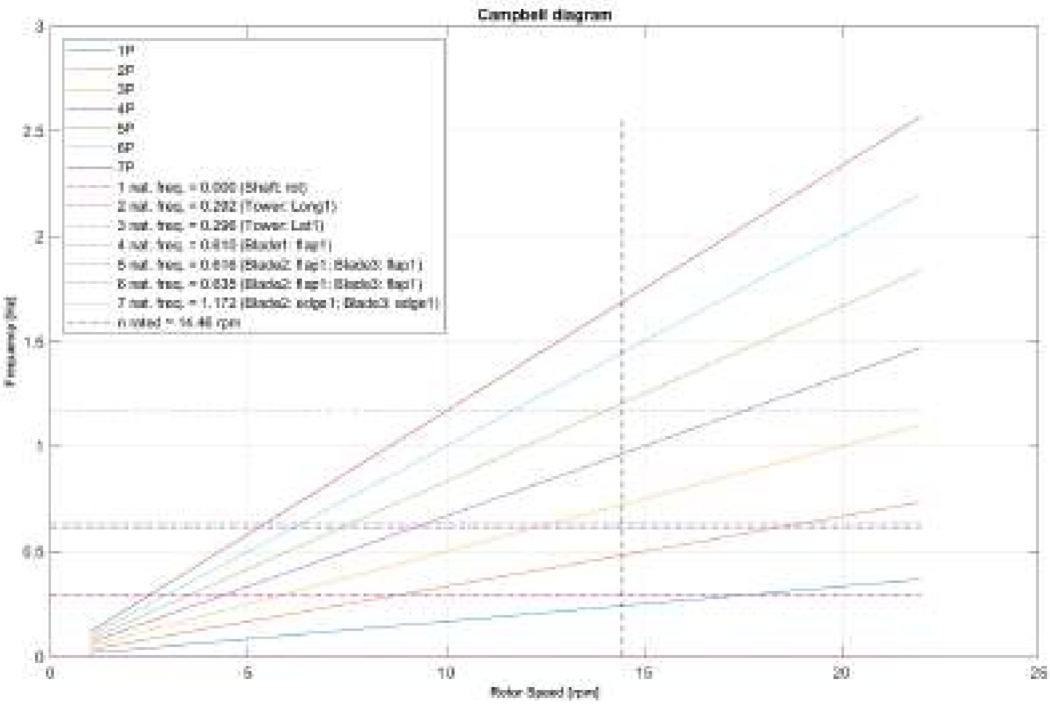

Figure 5.16: Campbell diagram of pitch-regulated wind turbine GoldWind GW106 2500 kW HH 90m

From inspection of the Campbell diagram in Figure 5.16. the following remarks can be made:

- The first natural frequency of the tower is above 1P at 14.5 rpm. Thus, the tower is not expected to be operating close to natural frequencies that may produce high vibrations/loads.
- The first natural frequency of the blade (flapwise) is below 3P at 14.5 rpm. The first natural frequency of the blade (edgewise) is above 5P at 14.5 rpm. The controller takes this frequencies into account to avoid the resonance of the wind turbine.

5.5 LTE Analysis

LTE Analysis is based on the calculation of “Lifetime Extension Factor” (LTE factor), which is calculated by comparing fatigue life (allowable number of cycles) at critical wind turbine’s components (those considered critical for its structural integrity) during one year in two scenarios (see 5.2 for a description of environmental conditions and 5.3 for a description of operational conditions):

1. Certification conditions
2. On-site conditions

A brief summary of the LTE factor calculation process is provided below.

Step 1) Damage Equivalent Load (DEL) and allowable number of cycles (under certification conditions):

- Run simulations of the aeroelastic model (time series).
- Perform rainflow counting of selected loads for critical components of the wind turbine and obtain Markov matrices.
- Calculate DEL considering the following:
  - the Markov matrices previously calculated
  - the annual distribution of 10-minutes long power production simulations
  - the Wöhler parameter (inverse of S-N fatigue’s curve slope) for the particular wind turbine component under consideration
  - and the number of allowable cycles in one year
    - from Ref [10], the minimum required lifetime for certification is 20 years
    - from Ref [10], 1e7 cycles are usually considered as a reference in certification documents for 20-year lifetime
    - thus, the number of allowable cycles in a year is 1.e7 / 20 years = 500000 cycles (designated as “N_cert”. N_cert=500000 cycles)

Step 2) Allowable number of cycles (under site-specific conditions):

- Run simulations of the aeroelastic model (time series). 84 sectors considered per wind turbine.
- Perform rainflow counting of selected loads for critical components of the wind turbine and obtain Markov matrices.
- Calculate the number of cycles the wind turbine component under consideration is able to withstand (designated as “N_site”) when considering the following:
  - the Damage Equivalent Loads (DEL’s) previously calculated for certification conditions
  - the Markov matrices calculated for site specific conditions
  - the annual distribution of 10-minute long power production simulations
  - the Wöhler parameter (inverse of S-N fatigue’s curve slope) for the particular wind turbine component under consideration

The LTE factor is calculated as the ratio between the number of allowable cycles obtained in Step 1 (N_cert) divided by the number of allowable cycles obtained in Step 2 (N_site):

LTE factor = (N_cert) / (N_site)

If the LTE factor is greater than one, the estimated fatigue life of wind turbine component is greater under site conditions than under certification conditions.

Expected life is obtained by multiplying the LTE factor by the certified lifetime:

Expected Life = 20 x (LTE factor)

The critical components, loads and Wöhler parameters considered for calculation of LTE factors are:

- Blade root composite: flapwise / edgewise moments m=10
- Blade root joint: flapwise / edgewise moments m=5
- Hub: flapwise / edgewise moments at blade root m=8
- Hub-shaft joint: rotating low-speed shaft bending moment (Mx. My) m=5
- Main frame casting: Hub fixed moment (Mx. My) m=8
- Main frame welded: Hub fixed moment (Mx. My) m=5
- Main frame-tower joint: tower-top bearing roll / pitch moment (My. Mz) m=5
- Tower top: tower-top bearing roll / pitch moment (My. Mz) m=5
- Tower bottom: tower base roll / pitch moment (My. Mz) m=5

LTE factors for pitch-regulated wind turbine in Penonomé II WF, as calculated following the procedure outlined above, are listed in Table 5.7 (critical components/loads have been highlighted).

The nomenclature of loads obtained in order to perform the LTE analysis and the coordinate systems that have been considered (from Ref [10]) are described in Table 5.6. The coordinate systems that these loads are referred to are shown in Figure 5.17 (tower top/yaw). Figure 5.19 (Hub fixed /nacelle). Figure 5.18 (low-speed shaft and high-speed shaft) and Figure 5.20 (blade).

Table 5.6: Nomenclature of loads used for LTE analysis

Component	Station	Description
Blade Root. Composite	BRMz10	Edgewise moment at the blade root with m=10
Blade Root. Joint	BRMz5	Edgewise moment at the blade root with m=5
Hub	BRMz8	Edgewise moment at the blade root with m=8
Hub-Shaft Joint	HRMxy5	Rotating low-speed shaft bending moment at the shaft tip with m=5
Main Frame. Casting	HFMxy8	Rotating (with nacelle) tower-top / yaw bearing pitch moment with m=8
Main Frame. Welded	HFMxy5	Rotating (with nacelle) tower-top / yaw bearing pitch moment with m=5
Main Frame-Tower Joint	TTMyz5	Rotating (with nacelle) tower-top / yaw bearing pitch moment with m=5
Tower Top	TTMyz5	Rotating (with nacelle) tower-top / yaw bearing pitch moment with m=5
Tower Bottom	TBMyz5	Tower base pitching (or fore-aft) moment with m=5

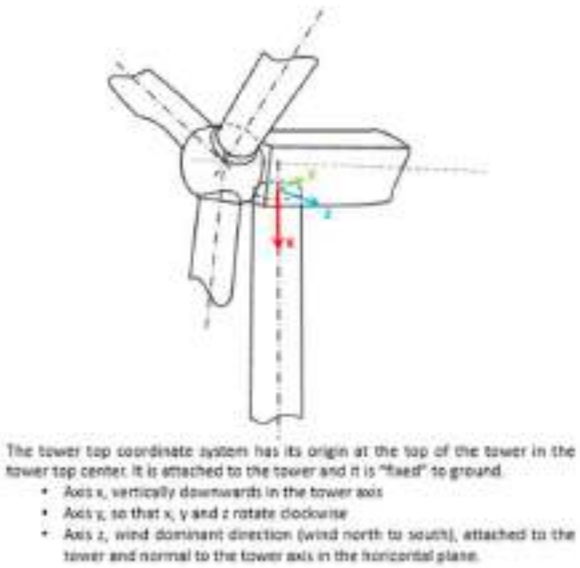

Figure 5.17: Tower-top/yaw coordinate system

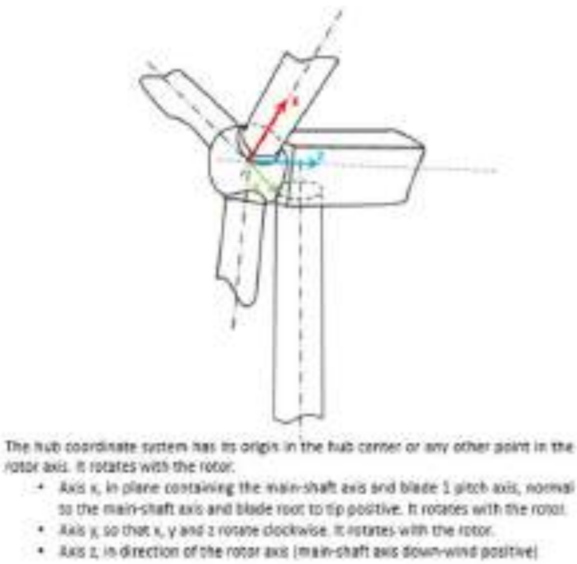

Figure 5.18: Rotating hub/shaft coordinate system

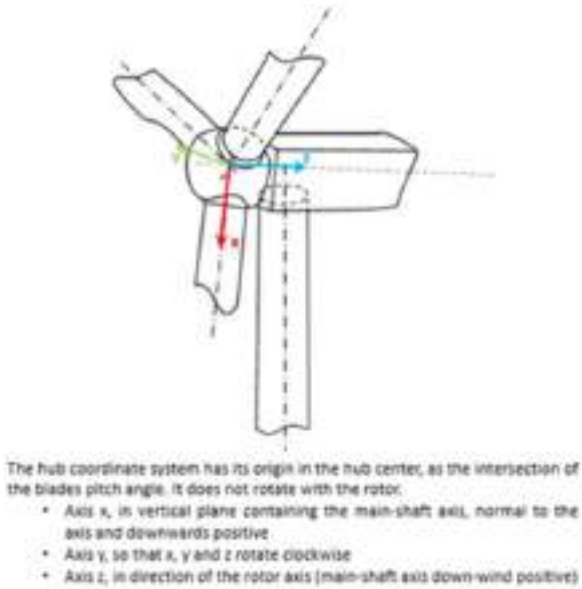

Figure 5.19: Hub Fixed/Nacelle coordinate system

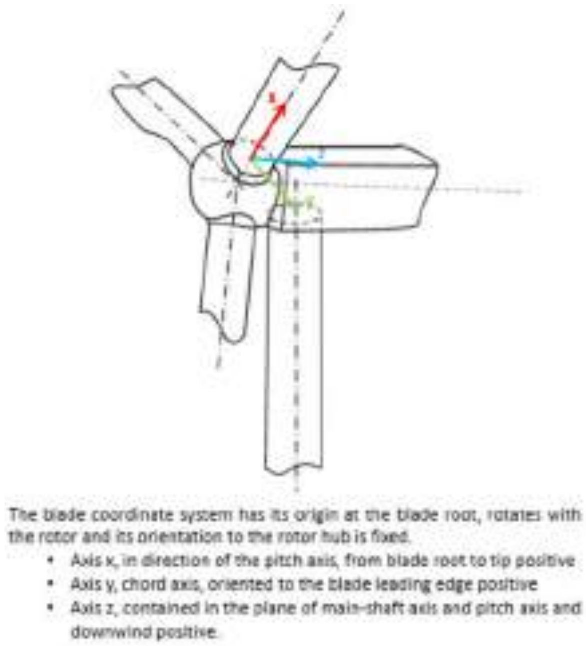

Figure 5.20: Blade coordinate system

LTE factors for GoldWind GW106 2500 kW HH 90m wind turbines at the Penonomé II WF are listed from Table 5.7:

Table 5.7: Critical components loads for GoldWind GW106 2500 kW HH 90m at Penonomé II WF.

	LTE factor per Component								
Wind Turbine	**Blade Root. Composite**	**Blade Root. Joint**	**Hub**	**Hub-Shaft Joint**	**Main Frame. Casting**	**Main Frame. Welded**	**Main Frame. Tower Joint**	**Tower Top**	**Tower Bottom**
WTG001	1.5	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG002	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG003	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG004	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG005	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG006	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG007	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG008	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG009	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG010	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG011	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG012	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG013	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG014	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG015	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG016	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0

Table 5.7: Critical components loads for GoldWind GW106 2500 kW HH 90m at Penonomé II WF.

	LTE factor per Component								
Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG017	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG018	1.5	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG019	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG020	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG021	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG022	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG023	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG024	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG025	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG026	1.6	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG027	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG028	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG029	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG030	1.6	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG031	1.6	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG032	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG033	1.6	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0

Table 5.7: Critical components loads for GoldWind GW106 2500 kW HH 90m at Penonomé II WF.

	LTE factor per Component								
Wind Turbine	**Blade Root. Composite**	**Blade Root. Joint**	**Hub**	**Hub-Shaft Joint**	**Main Frame. Casting**	**Main Frame. Welded**	**Main Frame. Tower Joint**	**Tower Top**	**Tower Bottom**
WTG034	1.6	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG035	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG036	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG037	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG038	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG039	1.6	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG040	1.6	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG041	1.6	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG042	1.6	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG043	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG044	1.6	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG045	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG046	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG047	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG048	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG054	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG055	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0

Table 5.7: Critical components loads for GoldWind GW106 2500 kW HH 90m at Penonomé II WF.

	LTE factor per Component								
Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG056	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG057	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG058	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG059	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG060	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG061	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG062	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG063	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG064	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG065	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG066	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG067	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG068	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG069	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG070	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG071	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG109	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0

Table 5.7: Critical components loads for GoldWind GW106 2500 kW HH 90m at Penonomé II WF.

	LTE factor per Component								
Wind Turbine	**Blade Root. Composite**	**Blade Root. Joint**	**Hub**	**Hub-Shaft Joint**	**Main Frame. Casting**	**Main Frame. Welded**	**Main Frame. Tower Joint**	**Tower Top**	**Tower Bottom**
WTG110	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG111	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG112	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG093	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG094	1.5	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG095	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG096	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG097	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG098	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG099	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG100	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG101	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG102	1.5	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG103	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG104	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG105	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG106	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0

Table 5.7: Critical components loads for GoldWind GW106 2500 kW HH 90m at Penonomé II WF.

	LTE factor per Component								
Wind Turbine	**Blade Root. Composite**	**Blade Root. Joint**	**Hub**	**Hub-Shaft Joint**	**Main Frame. Casting**	**Main Frame. Welded**	**Main Frame. Tower Joint**	**Tower Top**	**Tower Bottom**
WTG107	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG108	1.6	1.5	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WF	1.5	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
Min WF	1.6	1.6	1.8	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0

5.6 Damage per wind sector and energy production and damage contribution per load case

5.6.1 Damage per wind sector and energy production.

According to the estimated energy production obtained with the OpenWind tool after the wind resource analysis and the LTE factors per wind sector calculated on the LTE analysis, different rose maps of wind, energy and damage per energy for each WT and component have been created (see Appendix B – Lifetime And Production Roses Per Wind Turbine and Component)

As an example, in Figure 5.21 is shown the rose map with the wind probability energy and damage per sector in percentage for the WTG01 at the Blade root composite. Furthermore, a ratio between the damage and the estimated energy production per sector has been calculated.

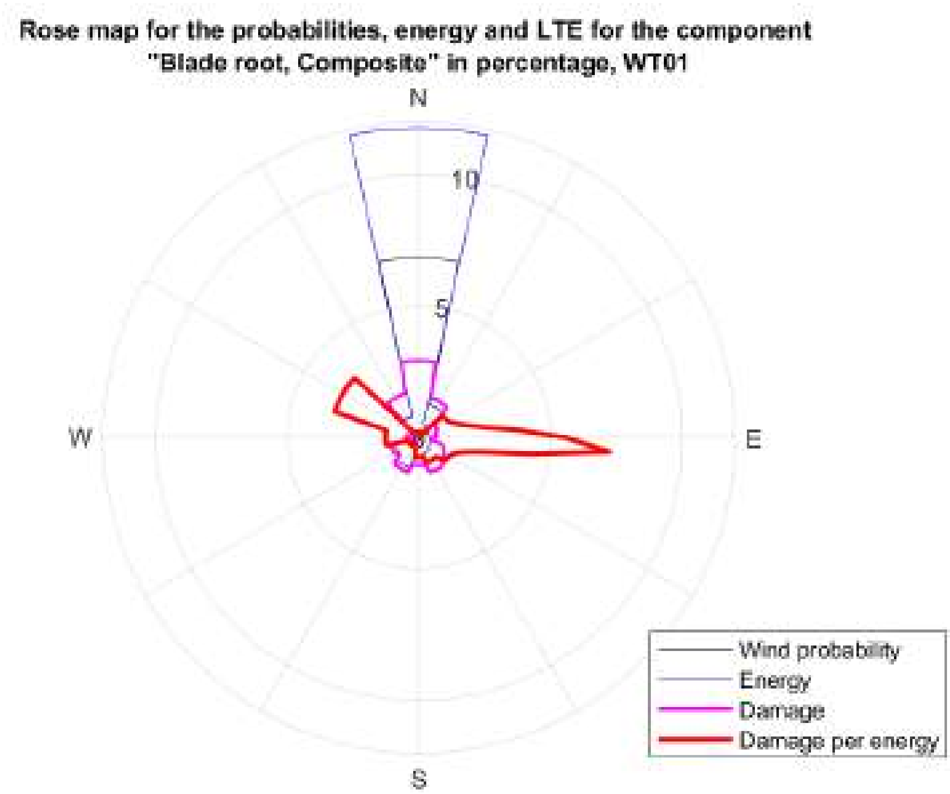

Figure 5.21: Example Rose map for the probabilities, energy and LTE.

6. LTE RESULTS PER MAIN COMPONENT

When taking into account LTE factors in Table 5.7 the following time frames regarding Lifetime Extension (LTE) are shown for Penonomé II wind turbines (refer to Table 6.2 for a summary) by considering an average availability of each wind turbine (see Table 6.1) and a certification lifetime of 20 years. The availability has been calculated [16] excluding the months that are not representative.

Blade Root Composite expected lifetime in Table 6.2 is only valid considering that the blade quality is according the design specifications.

Table 6.1: Availability of each wind turbines at Penonomé II Wind Farm

Wind turbine	Availability [%]	Wind turbine	Availability [%]	Wind turbine	Availability [%]
WTG001	92.7	**WTG030**	95.7	**WTG064**	95.3
WTG002	93.8	**WTG031**	96.0	**WTG065**	95.8
WTG003	95.6	**WTG032**	94.8	**WTG066**	94.9
WTG004	96.4	**WTG033**	95.6	**WTG067**	94.3
WTG005	96.1	**WTG034**	95.6	**WTG068**	95.2
WTG006	91.9	**WTG035**	94.4	**WTG069**	94.3
WTG007	94.7	**WTG036**	94.6	**WTG070**	93.3
WTG008	96.0	**WTG037**	94.8	**WTG071**	96.0
WTG009	96.7	**WTG038**	95.2	**WTG109**	96.8
WTG010	96.6	**WTG039**	95.6	**WTG110**	96.3
WTG011	95.8	**WTG040**	95.9	**WTG111**	96.8
WTG012	95.6	**WTG041**	95.6	**WTG112**	97.1
WTG013	96.8	**WTG042**	95.2	**WTG093**	96.4
WTG014	96.8	**WTG043**	95.6	**WTG094**	96.0
WTG015	94.9	**WTG044**	95.6	**WTG095**	96.6
WTG016	94.2	**WTG045**	96.7	**WTG096**	95.5
WTG017	94.2	**WTG046**	93.9	**WTG097**	94.5
WTG018	95.4	**WTG047**	95.9	**WTG098**	95.8
WTG019	94.7	**WTG048**	96.5	**WTG099**	95.0
WTG020	94.2	**WTG054**	95.6	**WTG100**	96.3
WTG021	95.8	**WTG055**	95.1	**WTG101**	95.2
WTG022	93.6	**WTG056**	96.6	**WTG102**	95.7
WTG023	96.0	**WTG057**	95.2	**WTG103**	95.1
WTG024	96.2	**WTG058**	94.3	**WTG104**	94.5
WTG025	95.2	**WTG059**	96.6	**WTG105**	95.7
WTG026	96.5	**WTG060**	95.8	**WTG106**	94.8
WTG027	96.2	**WTG061**	96.5	**WTG107**	96.2
WTG028	95.9	**WTG062**	95.1	**WTG108**	96.0
WTG029	96.8	**WTG063**	95.1	Average	95.5

Table 6.2: Lifetime P50-values in years per component for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite[1]	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG001	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG002	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG003	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG004	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG005	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG006	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG007	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG008	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG009	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG010	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG011	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG012	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG013	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG014	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG015	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG016	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG017	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0

[1] Blade Root Composite expected lifetime is only valid considering that the blade quality is according the design specifications.

Table 6.2: Lifetime P50-values in years per component for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite[1]	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG018	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG019	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG020	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG021	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG022	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG023	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG024	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG025	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG026	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG027	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG028	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG029	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG030	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG031	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG032	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG033	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG034	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG035	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0

Table 6.2: Lifetime P50-values in years per component for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite[1]	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG036	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG037	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG038	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG039	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG040	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG041	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG042	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG043	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG044	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG045	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG046	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG047	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG048	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG054	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG055	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG056	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG057	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG058	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0

Table 6.2: Lifetime P50-values in years per component for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite[1]	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG059	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG060	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG061	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG062	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG063	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG064	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG065	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG066	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG067	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG068	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG069	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG070	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG071	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG109	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG110	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG111	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG112	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG093	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0

Table 6.2: Lifetime P50-values in years per component for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite[1]	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG094	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG095	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG096	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG097	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG098	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG099	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG100	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG101	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG102	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG103	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG104	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG105	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG106	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG107	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG108	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WF	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
Min WF	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0

Figure 6.1:P50 Lifetime at Blade root composite

Figure 6.2: P50 Lifetime at Blade root Joint

Figure 6.3: P50 Lifetime at Hub

Figure 6.4: P50 Lifetime at Hub-Shaft joint

Figure 6.5: P50 Lifetime at main frame casting

Figure 6.6: P50 Lifetime at main frame welded

Figure 6.7: P50 Lifetime at main frame tower joint

Figure 6.8: P50 Lifetime at Tower top

Figure 6.9: P50 Lifetime at tower bottom

Figure 6.10: P50 Minimum Lifetime per WT

7. UNCERTAINTIES CALCULATIONS

According to ANSI/UL 4143 [1], the RUL (Remaining Useful Life) can be derived by measurements and several assumptions either in load analysis or statistical analysis (e.g. analysis of the SCADA data), and therefore, a certain uncertainty exists in the RUL determination. The uncertainty of the determined LTE factors considers contributions from the characterization of the uncertainties from external conditions (wind speed, turbulence intensity, wind shear, inflow angle and air density) and the wind turbine modelling uncertainties. The operational conditions are reviewed to determine if the design levels are exceeded or not and corrections are applied on DELs only in case of exceedance.

With the site-specific uncertainties and the wind turbine modelling uncertainties, which are assumed to be stochastic and independent, an overall uncertainty for each LTE factor is calculated by means of the sensitivity of the LTE factors in regard to each of the parameters. The sensitivity factors are obtained using the slope (change in LTE factor for a given change in the parameter under revision) and are specific for each loads station or component. The sensitivity is critical for many of the LTE uncertainties as it is connected with the inverse of the Wöhler exponents on the S-N curves. This connection means that moderate variations on the load levels (DELs) may derive into significant variations on the theoretical cycles. This effect is particularly significant for cast (m=8) and even more for composites (m=10).

The use of operational wind plant data together with proper crosschecks with the meteorological mast data and the calculated wind data obtained with OpenWind tool allows for partly reducing some of the uncertainty elements. The existence and quality of a well-documented source of data is critical for the robustness of the results.

The use of clusters, grouping wind turbines under single calculations, also reduces uncertainties when considering the results valid for the average values, see Ref. [17]. This approximation is considered adequate for lifetime extension analysis when the values are conservatively taken (WF value in P90).

The sensitivities for each loads station and Wöhler exponent come from the changes in LTE factors for different changes on the wind speed distributions per wind sector. UL obtains the different sensitivity factors by running different simulations with the same turbine model changing the parameter whose sensitivity is analyzed. At least five different simulations to obtain the slope for each Loads Station are systematically carried out per each wind turbine and wind sector. The sensitivity factors are calculated for the wind speed, wind shear, wind turbulence intensity, upflow and density. The IAM sensibility is analyzed too, by the analysis of the impact of several inputs in the IAM generation and how these inputs impact on the lifetime of each wind turbine component.

Each sensitivity factor is multiplied for the respective uncertainty to obtain the uncertainty for the LTE factors on each Load Station/Component. It should be considered that not all the wind parameters have the same sensitivity on the LTE calculation. For example, the LTE factor determination is very sensitive to wind speed and wind turbulence intensity on some Loads Stations as it is linked with the inverse of the S-N curve slope. This link evidences the need to reduce uncertainties in order to achieve sufficiently robust results.

Analysis of an individual wind turbine, without proper information, will get an uncertainty level in wind distribution that is not acceptable from LTE analysis point of view (uncertainties over 100%). In order to get this individual analysis with acceptable uncertainty met-mast data and operational data are required. Anyway, the compilation of the results in the statistical value of the wind farm, for example the average value per component, allows to reduce uncertainty in the values by individual uncertainties stacking-up process.

Sensitivities has been calculated for each wind turbine and per wind direction.

Considering that the different uncertainty contributions (wind speed, turbulence intensity, wind shear, air density and WT model, see Table 7.1) are independent, and after multiplying each one for the respective sensitivity factor, a quadratic sum is applied to obtain the overall uncertainty for the LTE factors. When applying those LTE factors per component and considering normal distributions, the respective P-values are obtained (considering the S-N curves are set to 97.5% for the material properties and the P-values reflect the year when this 97.5% level is reached). The uncertainties values are shown in Table 7.2 whereas the P90 values of lifetime extension for the wind turbines are shown in Table 7.3.

Blade Root Composite expected lifetime in Table 7.3 is only valid considering that the blade quality is according the design specifications.

Table 7.1:Uncertainty contribution of Wind conditions, inspections and aero elastic model at Penonomé II Wind Farm

External conditions	Uncertainty [%]
Wind speed	6.10%
TI	15.13%
Shear	15.52%
Air density	4.06%
Upflow	3.32%
Inspections	0.99%
Aero model	5.44%

The WF results have been calculated according to the standard of the European Accreditation for uncertainty calculation [18]. Basically the P50 of the wind farm is obtained as an average value of the values of the wind turbine per component, and the P90 value for the wind farm has been calculated considering the WF P50 value per component, and the WF uncertainty per component as an stack-up process of individual wind turbines uncertainties as is described in [18], considering proper correlation between them.

Table 7.2: Uncertainties values per component and WT for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG001	26.8%	13.1%	27.7%	61.0%	72.1%	62.5%	62.4%	62.4%	60.8%
WTG002	26.7%	13.1%	27.7%	61.0%	72.1%	62.5%	62.4%	62.4%	60.8%
WTG003	26.7%	13.0%	27.5%	61.2%	72.1%	62.5%	62.5%	62.5%	60.9%
WTG004	26.6%	12.9%	27.4%	61.2%	72.1%	62.5%	62.5%	62.5%	60.9%
WTG005	26.6%	13.0%	27.5%	61.1%	72.1%	62.5%	62.5%	62.5%	60.9%
WTG006	26.7%	13.0%	27.8%	60.9%	72.1%	62.5%	62.5%	62.5%	60.9%
WTG007	26.6%	13.0%	27.8%	60.9%	72.1%	62.5%	62.5%	62.5%	60.9%
WTG008	26.6%	13.0%	27.9%	60.8%	72.1%	62.5%	62.5%	62.5%	60.9%
WTG009	27.6%	13.6%	28.5%	60.9%	72.1%	62.5%	62.5%	62.5%	61.0%
WTG010	26.9%	13.2%	28.2%	60.9%	72.1%	62.5%	62.5%	62.5%	61.0%
WTG011	26.8%	13.2%	28.1%	60.9%	72.1%	62.5%	62.5%	62.5%	61.0%
WTG012	26.8%	13.1%	28.0%	60.9%	72.1%	62.6%	62.5%	62.5%	61.0%
WTG013	26.7%	13.1%	27.7%	61.0%	72.1%	62.6%	62.5%	62.5%	61.0%
WTG014	26.7%	13.0%	27.7%	61.0%	72.1%	62.6%	62.5%	62.5%	61.0%
WTG015	26.7%	13.0%	27.8%	60.9%	72.1%	62.6%	62.5%	62.5%	61.0%
WTG016	26.7%	13.0%	27.9%	60.9%	72.1%	62.6%	62.5%	62.5%	61.0%
WTG017	26.7%	13.0%	27.8%	61.0%	72.1%	62.6%	62.5%	62.5%	61.0%
WTG018	26.9%	13.1%	27.9%	60.9%	72.1%	62.4%	62.4%	62.4%	60.8%

Table 7.2: Uncertainties values per component and WT for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG019	26.9%	13.1%	27.6%	61.3%	72.1%	62.5%	62.4%	62.4%	60.8%
WTG020	27.0%	13.2%	27.7%	61.3%	72.1%	62.5%	62.4%	62.4%	60.9%
WTG021	27.0%	13.2%	27.7%	61.3%	72.1%	62.5%	62.4%	62.4%	60.9%
WTG022	26.9%	13.1%	27.5%	61.5%	72.1%	62.5%	62.4%	62.4%	60.9%
WTG023	26.8%	13.1%	27.4%	61.5%	72.1%	62.5%	62.4%	62.4%	60.9%
WTG024	26.9%	13.2%	27.3%	61.6%	72.1%	62.5%	62.5%	62.5%	60.9%
WTG025	26.8%	13.2%	27.8%	60.8%	72.1%	62.4%	62.4%	62.4%	60.9%
WTG026	27.1%	13.3%	27.8%	61.1%	72.1%	62.5%	62.5%	62.5%	60.9%
WTG027	26.9%	13.3%	27.8%	61.2%	72.1%	62.5%	62.5%	62.5%	61.0%
WTG028	26.9%	13.3%	27.9%	61.0%	72.1%	62.5%	62.5%	62.5%	61.0%
WTG029	27.0%	13.3%	27.9%	61.1%	72.1%	62.6%	62.5%	62.5%	61.0%
WTG030	27.0%	13.3%	27.9%	61.1%	72.1%	62.5%	62.5%	62.5%	61.0%
WTG031	26.9%	13.3%	27.8%	61.1%	72.1%	62.5%	62.5%	62.5%	61.0%
WTG032	26.9%	13.3%	27.8%	60.9%	72.1%	62.4%	62.4%	62.4%	60.7%
WTG033	27.0%	13.3%	27.9%	60.8%	72.1%	62.4%	62.4%	62.4%	60.7%
WTG034	27.0%	13.3%	27.9%	60.8%	72.1%	62.4%	62.4%	62.4%	60.7%
WTG035	27.0%	13.3%	27.8%	61.0%	72.1%	62.5%	62.4%	62.4%	60.7%
WTG036	27.0%	13.3%	27.8%	61.0%	72.1%	62.5%	62.5%	62.5%	60.8%

Table 7.2: Uncertainties values per component and WT for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG037	27.1%	13.3%	28.0%	61.0%	72.1%	62.5%	62.5%	62.5%	60.8%
WTG038	27.2%	13.3%	27.9%	61.1%	72.1%	62.5%	62.5%	62.5%	60.8%
WTG039	27.2%	13.3%	27.7%	61.3%	72.1%	62.5%	62.5%	62.5%	60.8%
WTG040	27.0%	13.3%	27.7%	61.2%	72.1%	62.5%	62.5%	62.5%	60.8%
WTG041	26.8%	13.2%	27.7%	61.0%	72.1%	62.5%	62.5%	62.5%	60.9%
WTG042	27.0%	13.3%	27.8%	61.1%	72.1%	62.5%	62.5%	62.5%	60.9%
WTG043	26.9%	13.3%	27.6%	61.1%	72.1%	62.5%	62.5%	62.5%	60.9%
WTG044	26.8%	13.3%	27.7%	61.1%	72.1%	62.5%	62.5%	62.5%	61.0%
WTG045	26.8%	13.3%	27.4%	61.3%	72.1%	62.5%	62.5%	62.5%	61.0%
WTG046	26.7%	13.3%	27.4%	61.2%	72.1%	62.5%	62.5%	62.5%	61.0%
WTG047	26.7%	13.3%	27.6%	61.1%	72.1%	62.5%	62.5%	62.5%	61.0%
WTG048	26.6%	13.2%	27.2%	61.5%	72.1%	62.5%	62.5%	62.5%	61.0%
WTG054	27.0%	13.4%	27.6%	61.2%	72.1%	62.6%	62.5%	62.5%	60.8%
WTG055	27.2%	13.5%	27.7%	61.3%	72.1%	62.6%	62.6%	62.6%	60.8%
WTG056	27.0%	13.4%	27.7%	61.1%	72.1%	62.5%	62.5%	62.5%	60.8%
WTG057	26.9%	13.3%	27.6%	61.1%	72.1%	62.5%	62.5%	62.5%	60.8%
WTG058	26.8%	13.3%	27.7%	60.9%	72.1%	62.5%	62.5%	62.5%	60.8%
WTG059	26.7%	13.3%	27.7%	60.9%	72.1%	62.5%	62.5%	62.5%	60.8%

Table 7.2: Uncertainties values per component and WT for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG060	26.6%	13.2%	27.5%	61.0%	72.1%	62.5%	62.5%	62.5%	60.8%
WTG061	26.8%	13.3%	27.2%	61.5%	72.2%	62.6%	62.6%	62.6%	60.8%
WTG062	26.8%	13.3%	27.6%	61.1%	72.1%	62.6%	62.6%	62.6%	60.8%
WTG063	26.9%	13.4%	27.7%	61.0%	72.1%	62.6%	62.6%	62.6%	60.9%
WTG064	26.8%	13.3%	27.5%	61.2%	72.2%	62.6%	62.6%	62.6%	60.8%
WTG065	26.8%	13.3%	27.2%	61.5%	72.2%	62.6%	62.6%	62.6%	60.8%
WTG066	26.7%	13.3%	27.4%	61.2%	72.2%	62.6%	62.6%	62.6%	60.8%
WTG067	26.8%	13.3%	27.5%	61.1%	72.2%	62.6%	62.6%	62.6%	60.8%
WTG068	26.6%	13.2%	27.1%	61.5%	72.2%	62.6%	62.6%	62.6%	60.8%
WTG069	26.7%	13.2%	27.1%	61.6%	72.2%	62.6%	62.6%	62.6%	60.8%
WTG070	26.8%	13.3%	27.5%	61.3%	72.2%	62.6%	62.6%	62.6%	60.9%
WTG071	26.7%	13.3%	27.5%	61.2%	72.2%	62.6%	62.6%	62.6%	60.9%
WTG109	26.5%	13.2%	27.2%	61.5%	72.1%	62.6%	62.5%	62.5%	61.1%
WTG110	26.8%	13.3%	27.4%	61.5%	72.1%	62.5%	62.5%	62.5%	61.1%
WTG111	26.9%	13.3%	27.5%	61.5%	72.1%	62.6%	62.5%	62.5%	61.1%
WTG112	26.8%	13.3%	27.6%	61.2%	72.1%	62.6%	62.6%	62.6%	61.1%
WTG093	26.8%	13.3%	27.6%	61.3%	72.2%	62.6%	62.6%	62.6%	61.1%
WTG094	26.7%	13.3%	27.5%	61.4%	72.2%	62.6%	62.6%	62.6%	61.2%

Table 7.2: Uncertainties values per component and WT for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG095	26.7%	13.2%	27.5%	61.5%	72.2%	62.6%	62.6%	62.6%	61.2%
WTG096	26.7%	13.2%	27.3%	61.6%	72.1%	62.6%	62.6%	62.6%	61.1%
WTG097	26.6%	13.3%	27.4%	61.4%	72.2%	62.7%	62.6%	62.6%	61.2%
WTG098	26.7%	13.4%	27.6%	61.2%	72.2%	62.6%	62.6%	62.6%	61.1%
WTG099	26.7%	13.4%	27.6%	61.2%	72.2%	62.6%	62.6%	62.6%	61.2%
WTG100	26.8%	13.3%	27.7%	61.1%	72.2%	62.6%	62.6%	62.6%	61.1%
WTG101	26.9%	13.3%	27.8%	61.1%	72.1%	62.6%	62.6%	62.6%	61.1%
WTG102	26.9%	13.3%	27.8%	61.3%	72.2%	62.6%	62.6%	62.6%	61.1%
WTG103	27.0%	13.3%	27.8%	61.3%	72.2%	62.6%	62.6%	62.6%	61.1%
WTG104	28.9%	14.3%	29.3%	61.1%	72.0%	62.5%	62.5%	62.5%	61.2%
WTG105	26.9%	13.3%	27.5%	61.4%	72.1%	62.6%	62.6%	62.6%	61.0%
WTG106	26.6%	13.1%	27.1%	61.6%	72.1%	62.6%	62.5%	62.5%	61.0%
WTG107	26.6%	13.2%	27.3%	61.4%	72.1%	62.6%	62.5%	62.5%	61.0%
WTG108	26.6%	13.2%	27.5%	61.1%	72.1%	62.6%	62.5%	62.5%	61.0%
WF	18.0%	8.9%	18.6%	41.1%	48.4%	42.0%	42.0%	42.0%	40.9%

Table 7.3: Lifetime P90-values in years per component and WT for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite[1]	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG001	21.0	26.4	22.9	21.1	15.3	20.8	20.1	20.1	18.8
WTG002	21.0	26.4	22.8	20.9	14.8	20.6	19.8	19.8	18.8
WTG003	20.6	25.9	22.7	21.3	14.4	20.2	19.4	19.4	18.4
WTG004	20.6	25.9	22.8	21.2	14.4	20.1	19.4	19.4	18.5
WTG005	20.8	26.2	22.9	21.1	14.5	20.2	19.6	19.6	18.5
WTG006	21.8	27.4	23.5	20.2	14.9	21.0	20.2	20.2	19.4
WTG007	21.0	26.6	22.8	19.2	14.4	20.3	19.6	19.6	18.8
WTG008	20.6	26.1	22.3	18.2	14.1	19.9	19.3	19.3	18.6
WTG009	20.1	25.9	22.0	18.0	12.5	18.4	17.8	17.8	17.3
WTG010	20.4	26.1	22.1	18.0	13.2	19.2	18.6	18.6	18.1
WTG011	20.6	26.2	22.3	17.8	13.4	19.4	18.9	18.9	18.4
WTG012	20.6	26.3	22.6	18.4	13.5	19.6	19.0	19.0	18.4
WTG013	20.4	25.8	22.5	19.4	13.4	19.4	18.8	18.8	18.2
WTG014	20.6	26.0	22.6	19.4	13.5	19.6	19.0	19.0	18.4
WTG015	21.1	26.8	23.0	19.0	13.7	20.0	19.4	19.4	18.9
WTG016	21.1	27.0	23.1	18.9	13.7	20.1	19.5	19.5	18.9
WTG017	21.0	26.8	23.2	19.0	13.6	20.0	19.4	19.4	18.9

[1] Blade Root Composite expected lifetime is only valid considering that the blade quality is according the design specifications.

Table 7.3: Lifetime P90-values in years per component and WT for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite[1]	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG018	20.4	25.7	22.0	19.7	14.6	20.1	19.3	19.3	18.1
WTG019	20.7	26.0	22.7	22.4	14.7	20.4	19.5	19.5	18.3
WTG020	20.8	26.1	22.7	22.0	14.4	20.3	19.5	19.5	18.3
WTG021	20.6	25.8	22.6	22.1	14.4	20.2	19.3	19.3	18.1
WTG022	21.1	26.4	23.4	23.8	15.1	20.8	20.0	20.0	18.6
WTG023	20.8	25.9	23.1	24.1	15.2	20.8	19.9	19.9	18.4
WTG024	20.8	25.9	23.2	24.1	15.4	20.9	20.1	20.1	18.6
WTG025	21.3	26.6	23.1	20.2	15.3	21.2	20.5	20.5	19.3
WTG026	21.0	26.3	23.1	21.3	14.4	20.5	19.8	19.8	18.8
WTG027	21.3	26.7	23.5	21.7	15.0	21.0	20.3	20.3	19.3
WTG028	21.1	26.4	23.1	20.4	14.4	20.6	19.9	19.9	19.2
WTG029	21.2	26.8	23.5	21.0	14.4	20.5	19.8	19.8	19.0
WTG030	21.3	26.8	23.5	21.3	14.6	20.8	20.1	20.1	19.2
WTG031	21.1	26.5	23.3	21.2	14.7	20.8	20.1	20.1	19.2
WTG032	21.3	26.6	23.1	20.6	15.8	21.6	20.8	20.8	19.3
WTG033	21.2	26.7	22.8	20.0	15.7	21.3	20.6	20.6	19.0
WTG034	21.3	26.7	22.8	19.9	15.5	21.3	20.5	20.5	19.0
WTG035	21.4	26.8	23.1	21.1	15.4	21.4	20.5	20.5	19.1

Table 7.3: Lifetime P90-values in years per component and WT for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite[1]	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG036	21.3	26.5	23.1	21.1	15.0	21.0	20.3	20.3	18.8
WTG037	21.2	26.7	22.9	20.2	14.6	20.8	19.9	19.9	18.7
WTG038	21.1	26.6	22.9	20.8	14.3	20.5	19.8	19.8	18.4
WTG039	21.1	26.6	23.2	22.1	14.7	20.6	19.9	19.9	18.4
WTG040	21.2	26.5	23.1	22.0	14.8	20.9	20.0	20.0	18.6
WTG041	21.3	26.6	23.1	21.0	15.2	21.2	20.4	20.4	19.0
WTG042	21.4	26.7	23.4	21.4	15.1	21.3	20.6	20.6	19.2
WTG043	21.2	26.5	23.3	21.8	15.5	21.3	20.6	20.6	19.2
WTG044	21.3	26.6	23.4	21.6	15.4	21.4	20.7	20.7	19.5
WTG045	21.1	26.2	23.5	22.9	15.4	21.4	20.7	20.7	19.3
WTG046	21.9	27.0	24.3	23.4	16.2	22.4	21.6	21.6	20.2
WTG047	21.5	26.6	23.8	22.0	15.5	21.9	21.2	21.2	20.0
WTG048	21.5	26.6	24.2	24.8	15.9	22.1	21.3	21.3	20.0
WTG054	21.6	27.0	24.0	22.3	15.1	21.7	20.9	20.9	19.6
WTG055	22.3	28.1	24.8	22.9	15.3	21.9	21.1	21.1	19.7
WTG056	21.9	27.2	24.1	22.1	15.4	22.0	21.2	21.2	19.7
WTG057	22.3	27.6	24.5	22.5	16.3	22.8	21.9	21.9	20.4
WTG058	22.5	27.8	24.4	21.8	16.5	23.2	22.4	22.4	20.8

Table 7.3: Lifetime P90-values in years per component and WT for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite[1]	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG059	21.8	27.0	23.7	21.2	16.2	22.8	22.0	22.0	20.4
WTG060	22.2	27.5	24.3	22.2	16.1	23.1	22.2	22.2	20.7
WTG061	21.8	26.8	24.3	24.3	15.3	22.5	21.7	21.7	20.1
WTG062	21.8	27.0	24.1	22.0	15.1	22.3	21.5	21.5	20.2
WTG063	21.7	27.0	23.9	21.0	14.7	21.9	21.1	21.1	20.1
WTG064	21.6	27.0	24.1	22.2	14.8	21.9	21.2	21.2	20.0
WTG065	21.6	26.8	24.3	24.2	14.9	21.9	21.2	21.2	19.9
WTG066	21.7	27.0	24.1	22.8	15.1	22.1	21.4	21.4	20.1
WTG067	21.7	27.1	24.2	22.1	15.2	22.1	21.4	21.4	20.3
WTG068	21.6	26.9	24.5	24.3	15.3	22.3	21.5	21.5	20.3
WTG069	21.7	27.0	24.7	24.9	15.6	22.4	21.6	21.6	20.4
WTG070	22.3	27.9	25.0	23.5	15.6	22.4	21.8	21.8	20.6
WTG071	21.5	26.8	24.1	22.1	15.1	21.8	21.1	21.1	20.1
WTG109	21.5	26.6	24.2	24.7	15.9	22.0	21.3	21.3	20.0
WTG110	21.5	26.7	24.2	24.1	15.2	21.5	20.8	20.8	19.6
WTG111	21.2	26.5	23.9	23.5	14.5	20.9	20.2	20.2	19.2
WTG112	21.0	26.3	23.6	21.6	14.3	20.6	20.0	20.0	19.3
WTG093	21.3	26.7	24.0	22.0	14.4	20.7	20.1	20.1	19.4

Table 7.3: Lifetime P90-values in years per component and WT for GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite[1]	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG094	21.2	26.7	23.9	22.4	14.4	20.8	20.2	20.2	19.5
WTG095	21.2	26.6	23.9	22.9	14.2	20.6	20.0	20.0	19.3
WTG096	21.4	26.8	24.3	24.1	14.3	20.8	20.2	20.2	19.4
WTG097	21.9	27.3	24.9	23.8	15.5	22.1	21.5	21.5	20.6
WTG098	21.9	27.5	24.5	21.9	15.2	21.8	21.2	21.2	20.6
WTG099	22.1	27.6	24.7	22.1	15.3	22.0	21.4	21.4	20.7
WTG100	21.4	26.9	23.9	20.7	14.3	20.9	20.4	20.4	19.8
WTG101	21.5	27.3	24.0	20.6	13.9	20.5	20.0	20.0	19.4
WTG102	21.1	26.8	23.7	21.0	13.4	19.8	19.3	19.3	18.8
WTG103	20.9	26.6	23.6	20.9	13.0	19.6	19.0	19.0	18.6
WTG104	20.7	27.1	23.3	18.5	10.0	17.0	16.6	16.6	16.4
WTG105	21.5	26.7	24.0	23.3	14.9	21.5	20.8	20.8	19.7
WTG106	21.8	27.0	24.6	25.2	15.6	22.1	21.4	21.4	20.1
WTG107	21.4	26.6	24.0	23.7	15.2	21.6	20.9	20.9	19.8
WTG108	21.4	26.7	23.7	21.8	14.9	21.5	20.7	20.7	19.8
WF	24.9	28.5	27.8	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
Min WF	20.1	25.7	22.0	17.8	10.0	17.0	16.6	16.6	16.4

Figure 7.1:P90 Lifetime at Blade root. composite

Figure 7.2: P90 Lifetime at Blade root. Joint

Figure 7.3: P90 Lifetime at Hub

Figure 7.4: P90 Lifetime at Hub-Shaft joint

Figure 7.5: P90 Lifetime at main frame. casting

Figure 7.6: P90 Lifetime at main frame. Welded

Figure 7.7: P90 Lifetime at main frame. tower joint

Figure 7.8: P90 Lifetime at Tower top

Figure 7.9: P90 Lifetime at Tower bottom

Figure 7.10: P90 Minimum Lifetime per WT

8. ESTIMATION AND ANALYSIS OF THE PRODUCTION EXTENDING THE WF LIFE

The purpose of this section is to evaluate the possibilities to ensure safe operation of the most critical mechanical components identified in the wind turbines by recurrent inspection (as far as possible) in order to reduce costs, thus optimizing the O&M of the assets, under a specific target time frame. Based on the assessments to support a 30-year useful economic life on the assets, the results show that lifetime expectations can be increased to 30 years in some of the components, but it is not possible to guarantee that lifetime in blade composite or blade bolted joint.

UL strongly recommends including corrosion-related inspections and components' treatment and protection in the O&M strategy. Including in the current maintenance plan the following LTE management plan (based on LTE calculations and the specific corrosion issues and environment effects on Penonomé II wind farm) ensures that he probability of failure is significantly reduced for the addressed components.

The components that are addressed belong to a selection of mechanical components which are estimated to be the most safety critical.

According to the results shown from Table 6.2 for a P50 scenario and from Table 7.3 for a P90 scenario it can be summarize:

- P50 scenario
  - All the wind turbines reach 30 years in all the components.
- P90 scenario
  - The estimated lifetime expectation for the different components are the following: Blade root-composite (20.1-22.5 years), blade root-joint (25.7-28.1 years), hub (22.0-25.0 years), Hub-Shaft joint (17.8-25.2 years), Main Frame-Casing (10.0-16.5 years), Main Frame-Welded (17.0-23.2 years), Main Frame-Tower joint (16.6-22.4 years), Tower top (16.6-22.4 years) and Tower bottom (16.4-20.8 years).

8.1 Recommended Inspections Program

The Recommended Inspection Program is focused on the critical structural components for life extension, and it is based on recurrent inspection and non-destructive testing, by which the probability of serious and costly failures can be significantly reduced. However, the preferable interval and technique may vary between the components since the possibility to detect the damage and the time scale for the damage evolution varies between the components. In this particular case and due to the dynamic nature of the operation of a wind turbine. Fatigue is the most dominant damage mechanism. Optimal inspection intervals are obviously such that the time between two inspections are maximized and at the same time safe operation of the component is ensured. The recommended interval inspection is four years for the hub and one year for the blade root (composite & bolted joints).

Table 8.1: Aging Management Plan Summary [8.1]

Component	Failure Mode	Inspection	Intervals
Blade Overview including Tip	Fatigue	Visual Inspection (binoculars, high resolution camera, climbing robot, drones rope access etc.)	One year
	Corrosion		
Blade Root. Bolted Joints	Fatigue	Tap testing of all rotor bolts Spot checks of the bolts preload are recommended.	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
	Fatigue and Corrosion	NDT (Ultrasonic analysis, magnetic particles testing or penetrating liquids)	Four years
Rotor Hub	Fatigue and Corrosion	NDT (Ultrasonic analysis, magnetic particles testing or penetrating liquids)	Four years
		Visual inspection	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
Hub to shaft bolted joint	Fatigue	Tap testing of all rotor bolts Spot checks of the bolts preload are recommended.	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
	Fatigue and Corrosion	NDT (Ultrasonic analysis. Magnetic particles testing or penetrating liquids)	Four years
Main frame	Fatigue	Visual inspection	One year
		NDT (Ultrasonic analysis. Magnetic particles testing or penetrating liquids)	Four years
Steel tower	Fatigue and Corrosion	Visual inspection of the tower welds Tap testing of all tower bolts. Spot checks of the bolts preload is recommended.	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
	Fatigue and Corrosion	NDT of the tower welds (magnetic particle testing)	Four years
Nacelle components	Corrosion	Installation of a filter in the nacelle	Once. Replaced or cleaned at maintenance interval
		Visual inspection	One year

The effect of corrosion issues is of secondary importance on the lifetime of the wind farm when compared to the fatigue damage mechanism. This means that the corrosion, as secondary damage mechanism, can create initiation sites for fatigue processes that would otherwise not take place. As mentioned above, the fatigue is the most dominant damage mechanism; therefore, the corrosion was not considered in the LTE calculations. UL strongly recommends considering the corrosion as a damage mechanism of secondary importance as well as a worsening factor for the fatigue damage mechanism. Therefore, regular visual inspections and proper surface treatments are to be considered for all components showing corrosion issues.

[8.1] The analysis is based on the assumption that actual O&M will prevail as it is with an additional special care given to the corrosion issues.

UL strongly recommends taking the corrosion and environment effects into account when establishing a maintenance plan.

8.2 Structural Components Inspection Cost Analysis

It is initially considered that the O&M contract will be reaming as actual status for the target frame of 30 years.

The total cost for one day of inspection by a trained inspection engineer is 800 EUR. This cost could potentially be minimized by coordination with other inspection activities. such the standard periodical inspection performed according to an O&M contract. When taking this coordination into account and assuming each inspection is done independently, the following cost can be assumed to reach the target frame of 30 years. Costs only consider the inspections previously explained. No repair cost is considered. Prices consider that visual inspections for different components are done simultaneously.

Table 8.2: Aging management plan scheduled cost GoldWind GW106 2500 kW HH 90m at Penonomé II WF

Component	Program Inspections	P	Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	Year 26-30
Blade Overview including Tip[1]	Yearly visual inspection NDT (not included in the cost calculations)	P50	0 €	60,000 €	60,000 €	60,000 €	60,000 €	60,000 €
		P90	0 €	60,000 €	60,000 €	60,000 €	70,304 €	73,760 €
Blade root, Joint (metallic parts)	Yearly bolts tap testing. Preload test Yearly visual inspection NDT (every 4 years)	P50	0 €	0 €	0 €	0 €	0 €	0 €
		P90	0 €	0 €	0 €	0 €	0 €	33,600 €
Rotor Hub	NDT Yearly visual inspection	P50	0 €	0 €	0 €	0 €	0 €	0 €
		P90	0 €	0 €	0 €	0 €	5,160 €	17,200 €
Hub-Shaft joint	Yearly visual inspection. Yearly tap testing & Preload test of bolts NDT (every 4 years)	P50	0 €	0 €	0 €	0 €	0 €	0 €
		P90	0 €	0 €	0 €	2,040 €	33,240 €	51,600 €
Main Frame (casting) Main Frame (welded)	NDT (performed together)	P50	0 €	0 €	0 €	0 €	0 €	0 €
		P90	0 €	0 €	3,360 €	33,280 €	34,400 €	34,400 €
Main Frame - Tower joint	NDT (every 4 years)	P50	0 €	0 €	0 €	0 €	0 €	0 €
		P90	0 €	0 €	0 €	760 €	15,360 €	17,200 €
Tower	NDT(every 4 years) Bolts yearly tap testing. Preload test Yearly visual inspection	P50	0 €	0 €	0 €	0 €	0 €	0 €
		P90	0 €	0 €	0 €	6,907 €	39,573 €	40,133 €
		Sum P50	0 €	0 €	0 €	0 €	0 €	0 €
		Sum P90	0 €	0 €	3,360 €	42,987 €	138,037 €	207,893 €

NOTE: The above figures are rough estimates, and variations may occur. The costs refer to total cost unless otherwise stated.

[1] Blade inspection include tip problems but it doesn't include the blade bushing issue which should be covered by a monitoring system.

In the case of visual inspection of the blade root composite, if damage is found, then NDT is recommended. The total cost for NDTs examination(Ref. [19]) is about 15.000 EUR for a three-blade wind turbine. This cost could certainly be reduced if this approach is introduced on a larger scale (meaning performing the inspection at all turbines); thus, 10.000 EUR should not be unrealistic.

For metallic parts, the recommended NDT test are Ultrasonic analysis (Ref. [20]), magnetic particles testing (Ref. [21]) or penetrating liquids (Ref. [22]) in all cases the aim of these test is detect defects in an incipient state of damage on the components. Ultrasonic tests have the capacity to detect internal defects whereas the magnetic particles and penetrating liquids detect superficial defects.

For the surface treatments for the corrosion issues, the working time was estimated to be 1 day per turbine with 2 experienced technicians and 2000 EUR of materials. This work was estimated to be done once before year 20 in order to bring the components to a better condition related to the corrosion issues that the turbines experience.

Inspection costs can be reduced if the activities are well-planned. This estimation has considered the following:

- Blade root composite:
  - Visual Inspection (binoculars, high resolution camera, TSR robot, rope access, etc.) in order to detect cracks or lightning strikes on the blades with 2 inspections per day with 1 specialized technician.
  - NDT (infrared test) every 4 years at 2 turbines per day with 2 specialized technicians to detect internal defects in the composite.
- Blade root joint:
  - Yearly bolt tap test and preload test: 2 inspections per day with 1 specialized technician in order to detect regular level of preload in all the bolts of the joint. Additionally, if a re-tightening process is performed, then a reference could be stated by Ultrasonic (US) test in each bolt, and this preload level could be quantified in further US inspections.
  - NDT every 4 years at 2 turbines per day with 2 specialized technicians to detect possible cracks. Is possible to apply ultrasonic, magnetic particles and or penetrating liquids test.
  - Surface treatment only once before year 20 with 2000 EUR materials per turbine for the surface treatment at 1 day per turbine with 2 technicians
- Hub: one visual inspection every year and an NDT every 4 years to detect cracks or internal damage in the component.

In the event of damaged bolts, a small CAPEX is expected. This CAPEX can be estimated based on the following assumptions.

- Cost per Bolt, Nut, and Wash: around 50€
- Total Cost of Materials per Repair: around 350 €
- Cost of Replacement (Man Power) per Repair: 700 €
- Total Cost per Repairs: 350€ + 700 € = 1050€/Turbine

NOTE: Cost of energy lost due to 4 hours of turbine stop is not taken into account.

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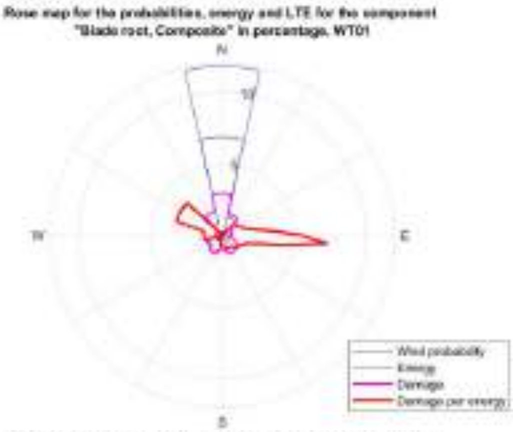
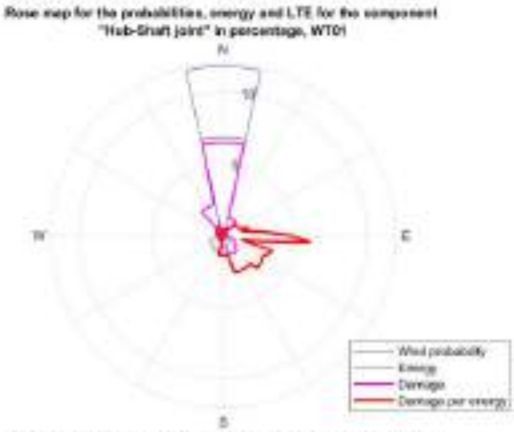
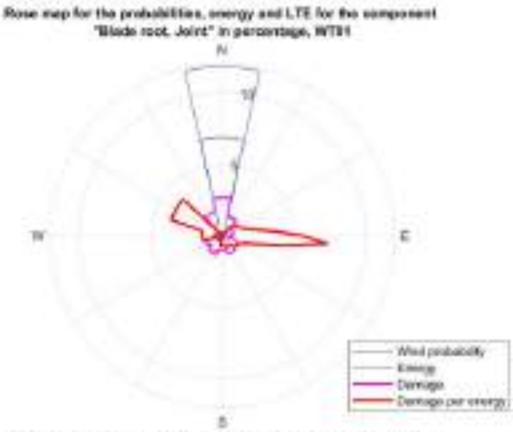
APPENDIX A - WIND SITE CONDITIONS

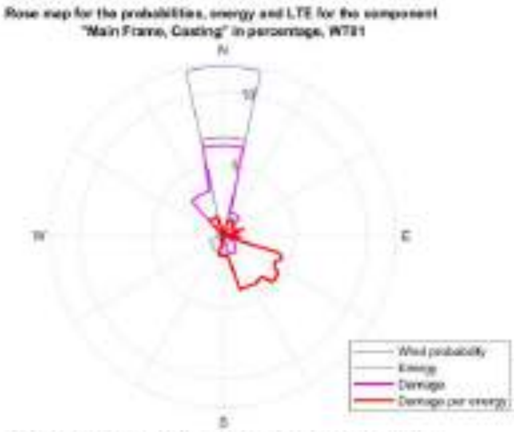
Electronic source of UL Openwind model.

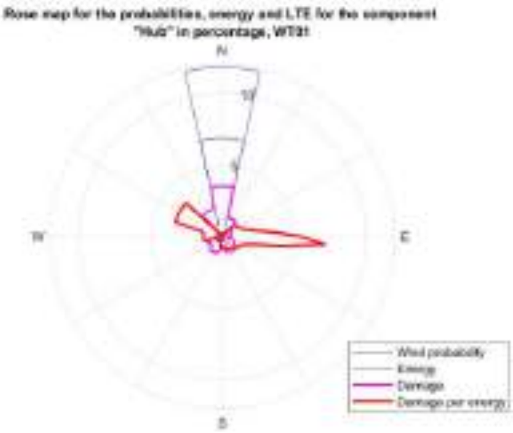
APPENDIX B – LIFETIME AND PRODUCTION ROSES PER WIND TURBINE AND COMPONENT

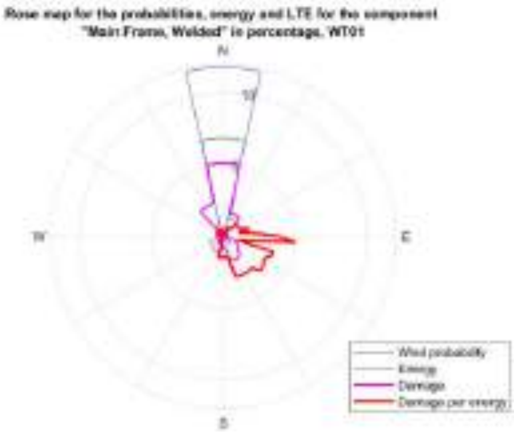




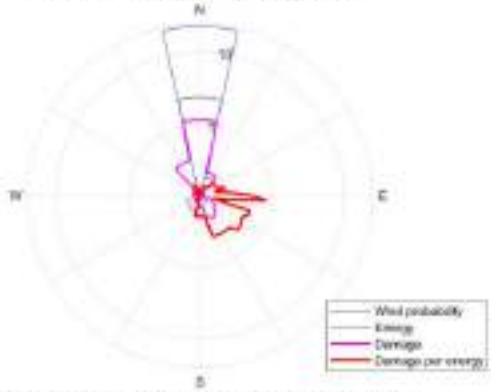




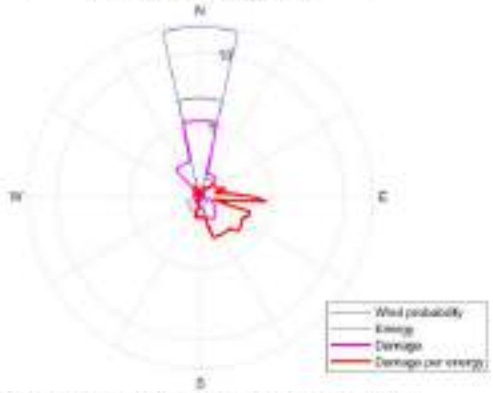




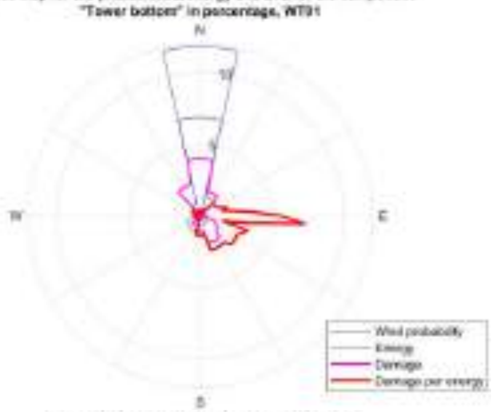
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT01



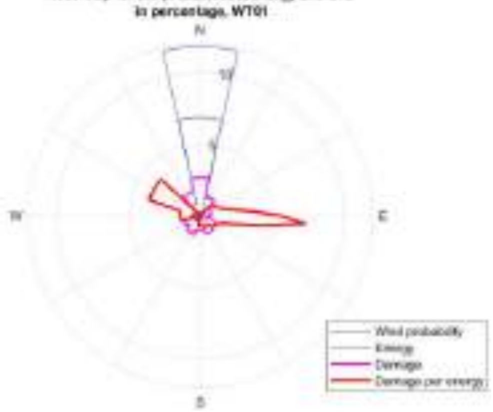
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT01



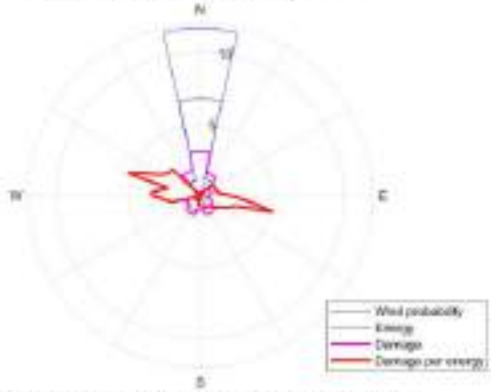
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT01



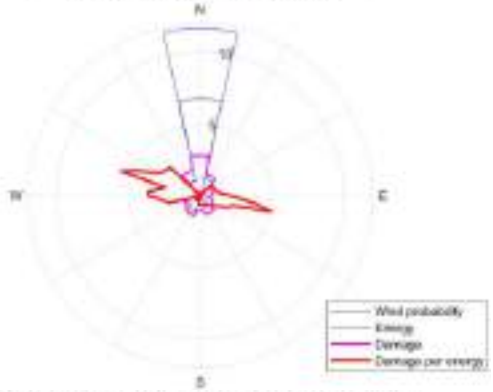
Rose map for the probabilities, energy and LTE in percentage, WT01



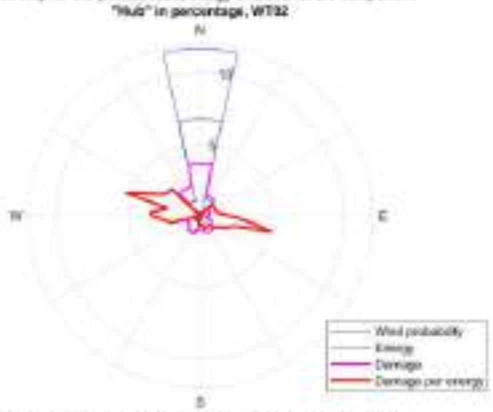
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT02



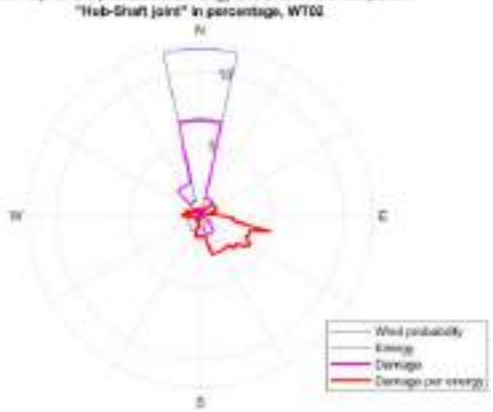
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT02



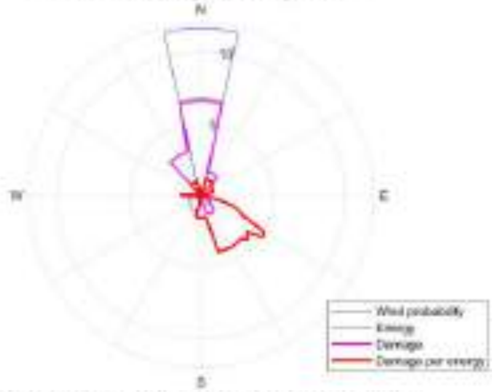
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT02



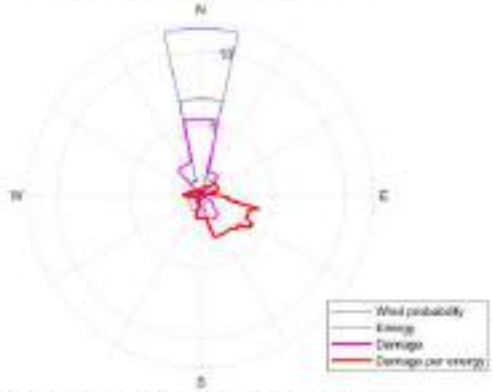
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT02



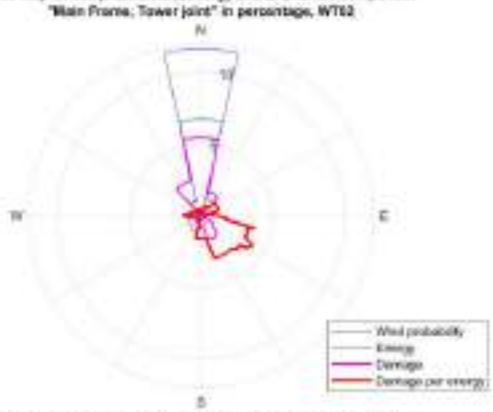
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT02



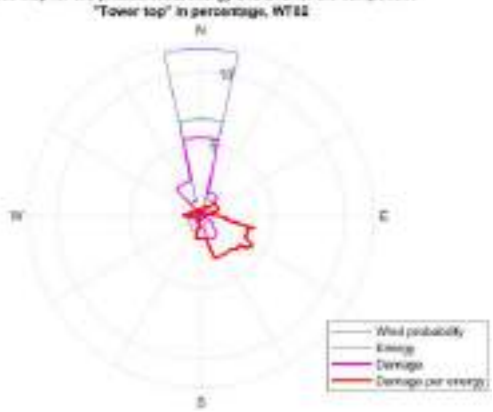
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT02

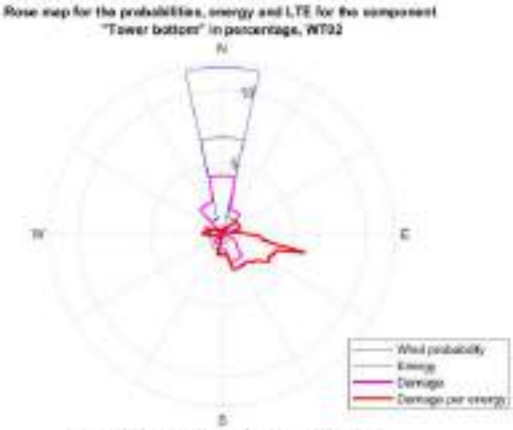


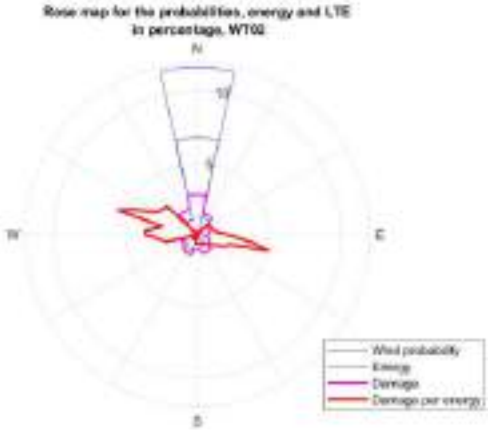
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT02



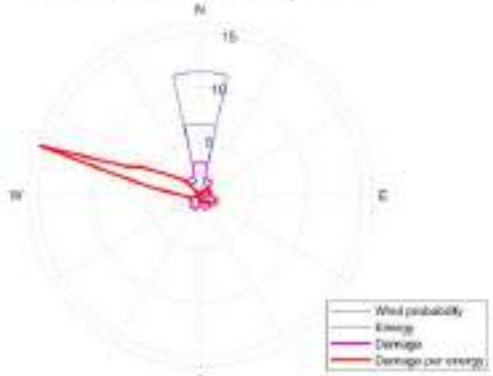
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT02



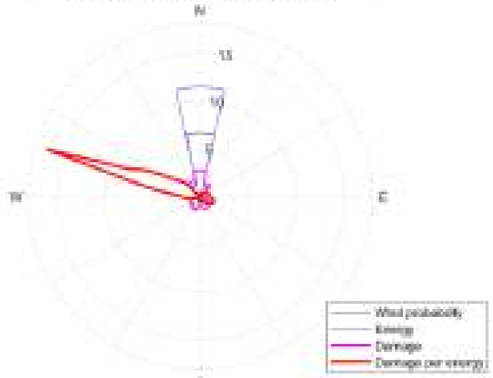

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT02
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT02
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT03



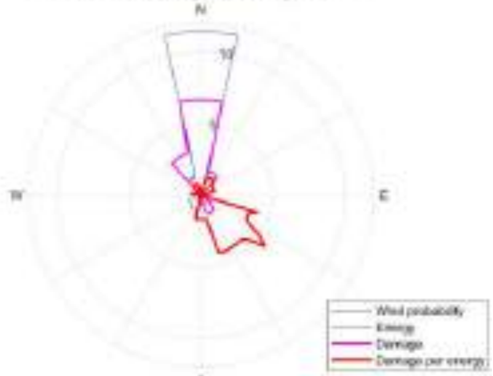
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT03



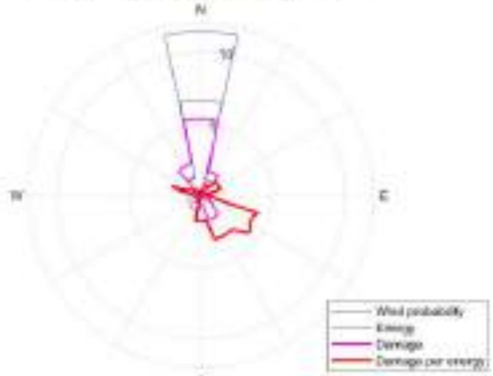
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT03

Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT03

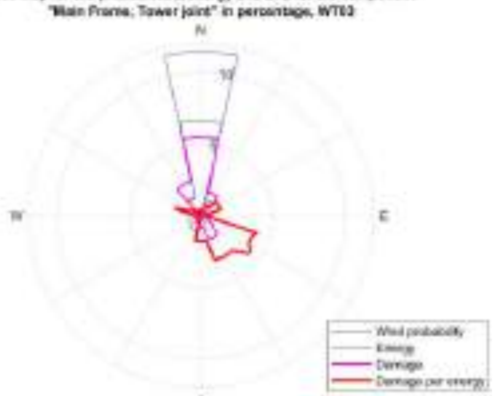
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT03



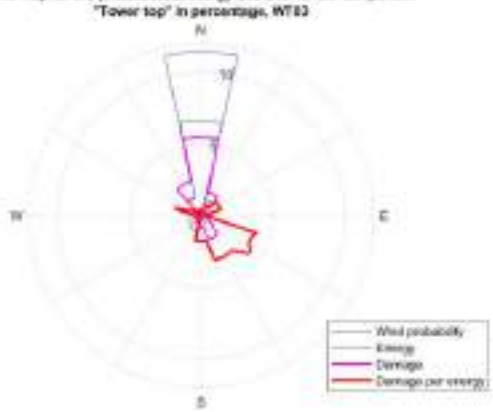
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT03



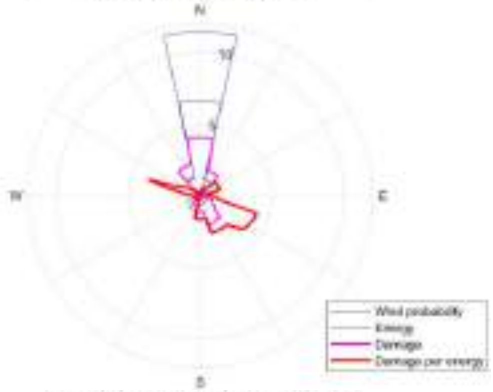
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT03



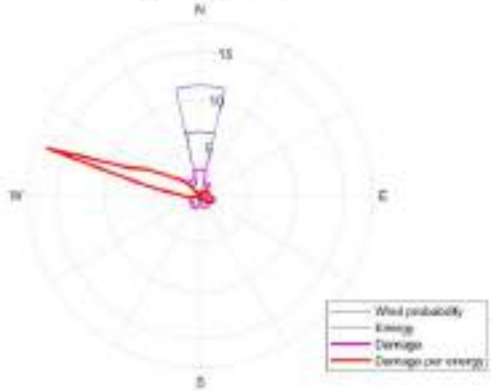
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT03



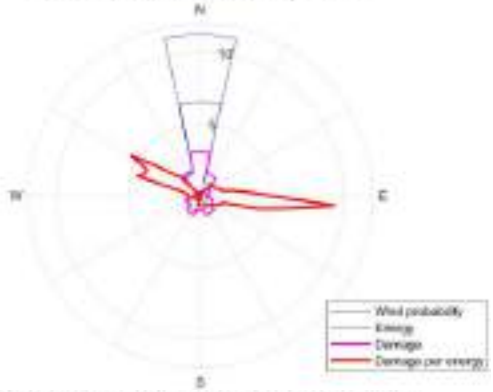
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT03



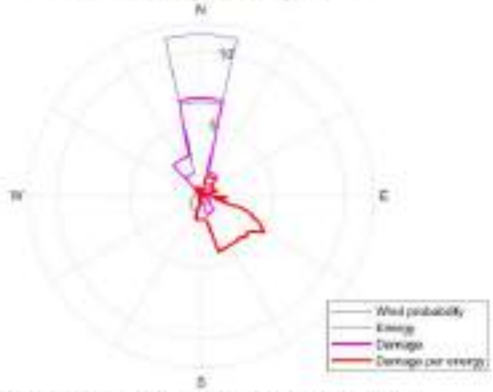
Rose map for the probabilities, energy and LTE in percentage, WT03



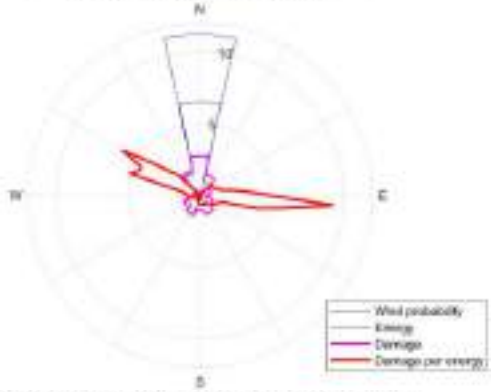
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT04



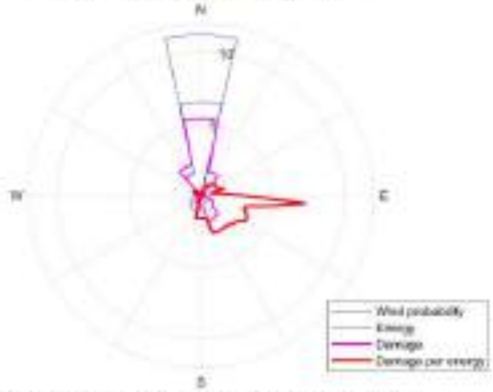
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT04



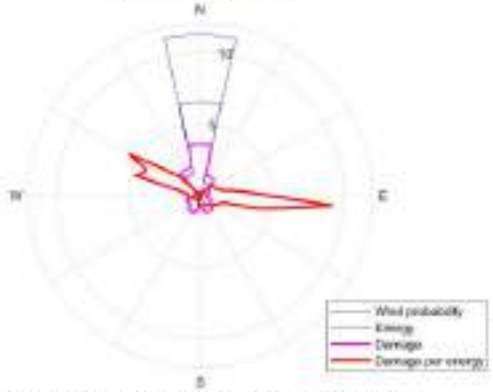
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT04



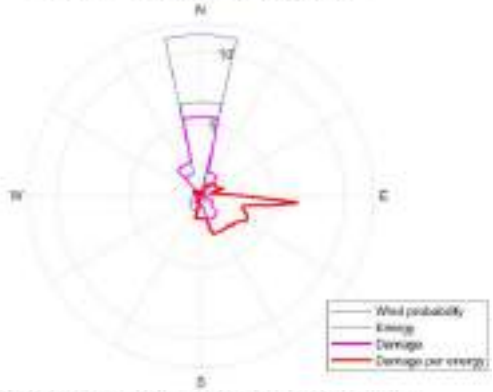
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT04



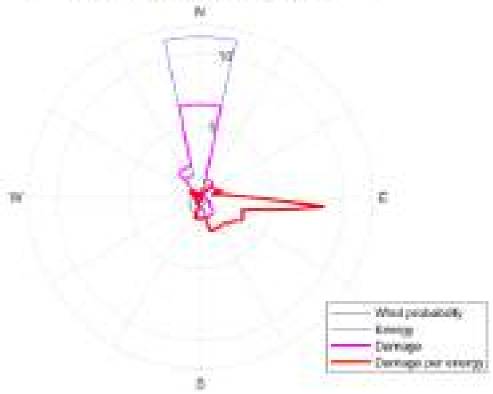
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT04



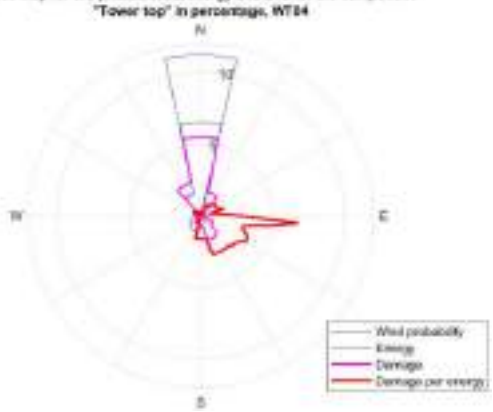
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT04

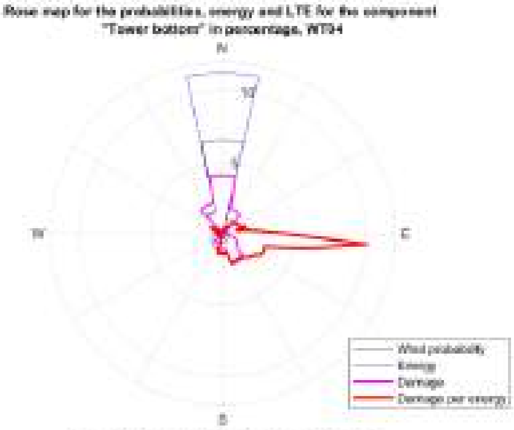


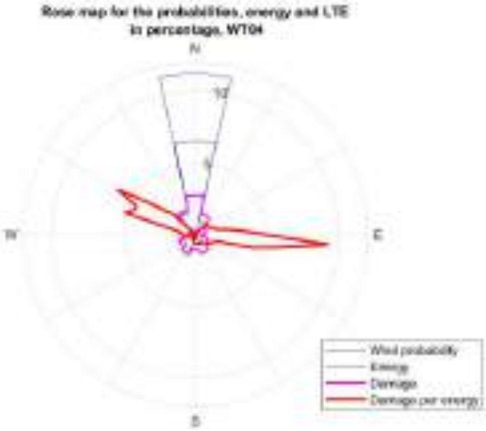
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT04

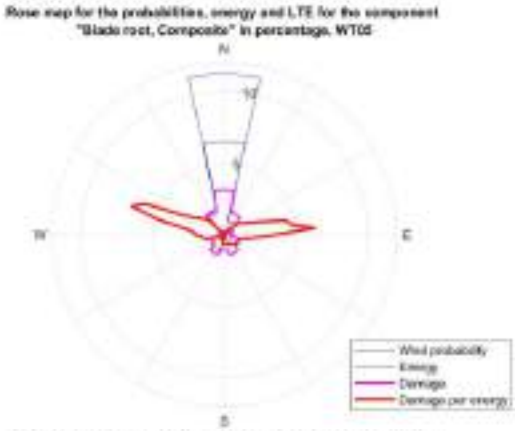


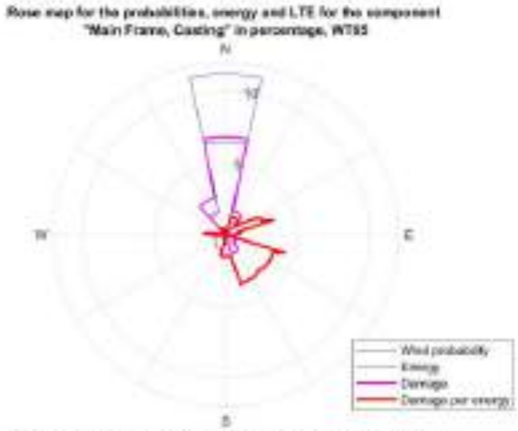
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT04

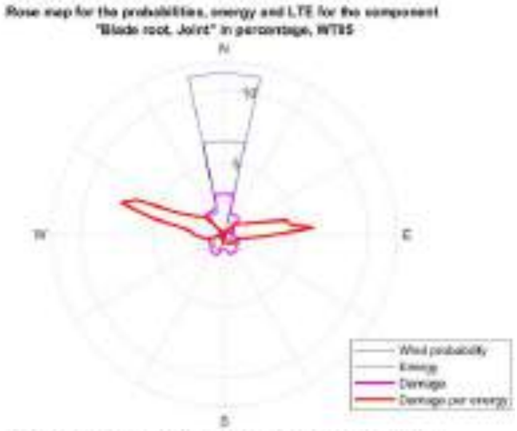


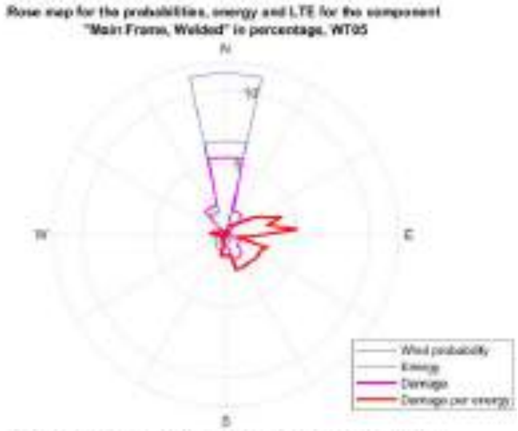

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT04
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

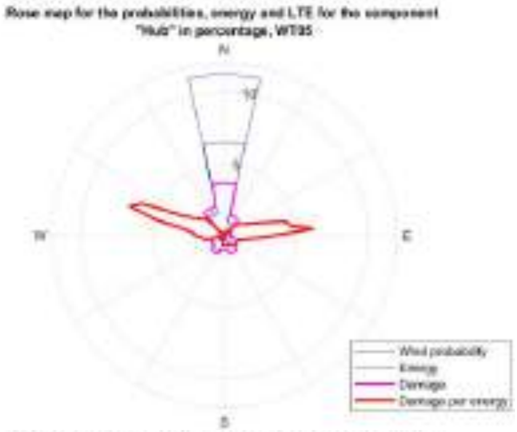

Rose map for the probabilities, energy and LTE in percentage, WT04
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

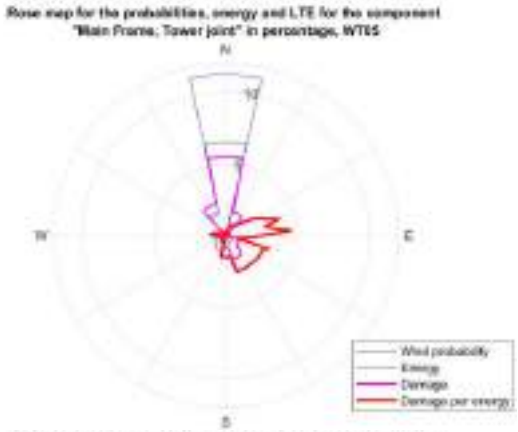

Rose map for the probabilities, energy and LTE for the component
"Blade root, Composite" in percentage, WT05
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

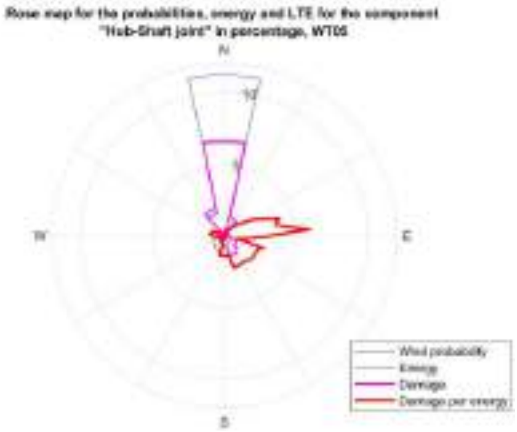

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Casting" in percentage, WT05
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

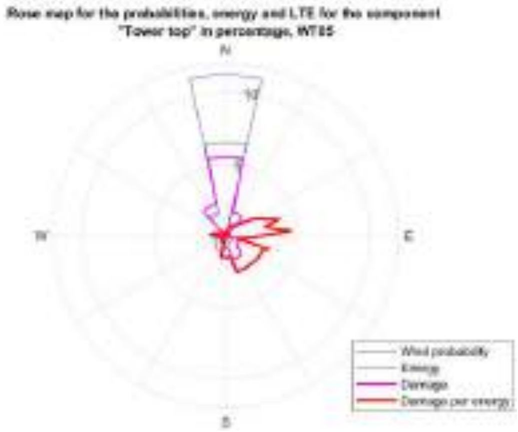

Rose map for the probabilities, energy and LTE for the component
"Blade root, Joint" in percentage, WT05
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

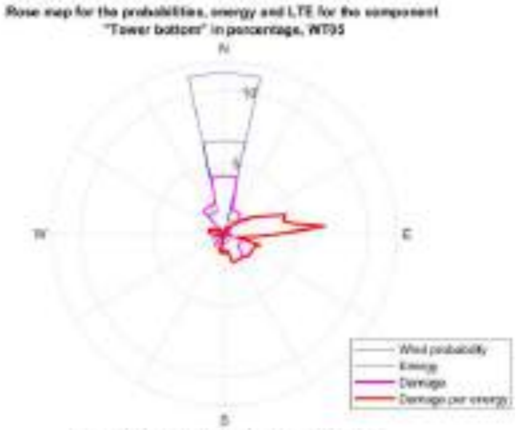

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Welded" in percentage, WT05
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

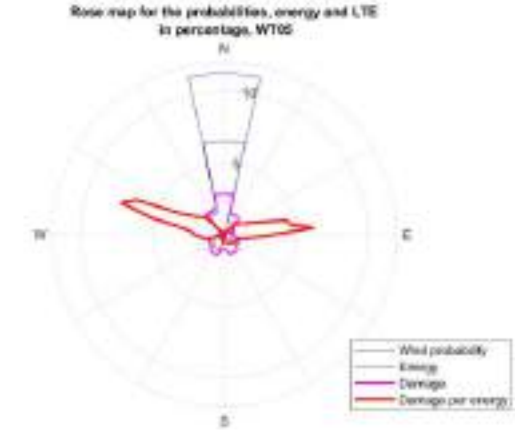

Rose map for the probabilities, energy and LTE for the component
"Hub" in percentage, WT05
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Main Frame; Tower joint" in percentage, WT05
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

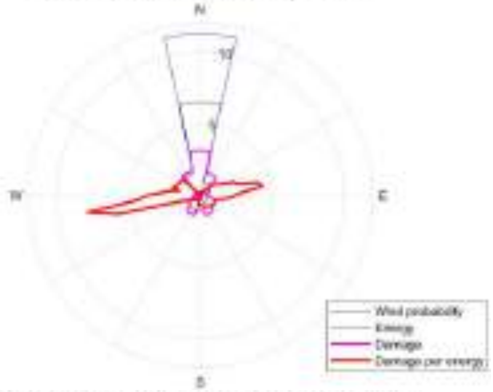

Rose map for the probabilities, energy and LTE for the component
"Hub-Shaft joint" in percentage, WT05
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Tower top" in percentage, WT05
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

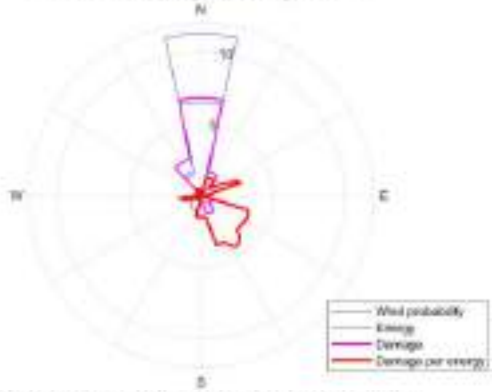

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT05
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT05
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

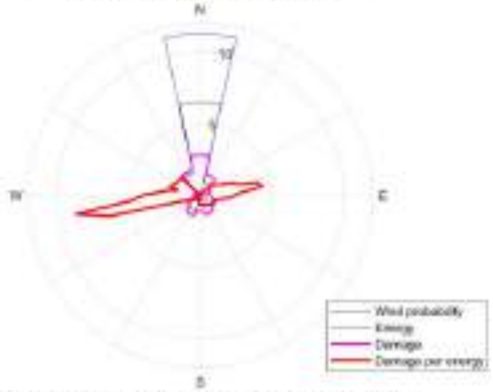
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT06



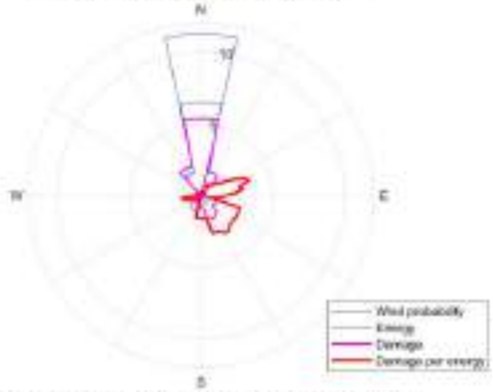
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT06



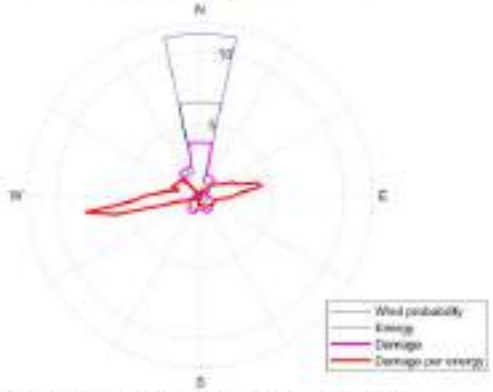
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT06



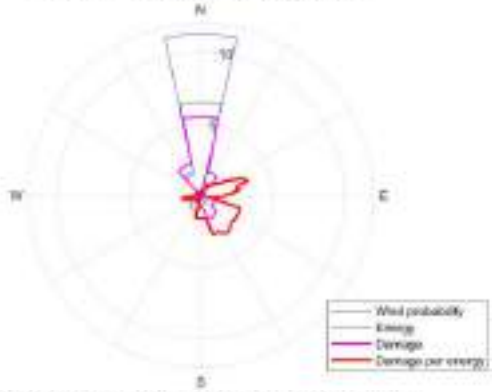
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT06



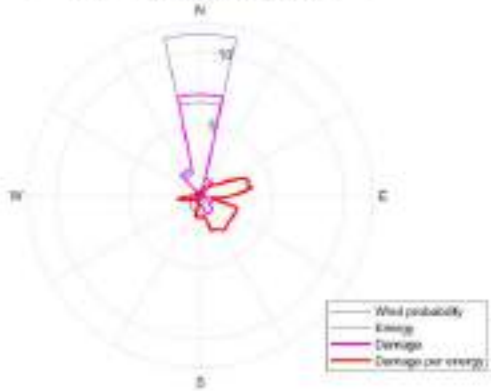
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT06



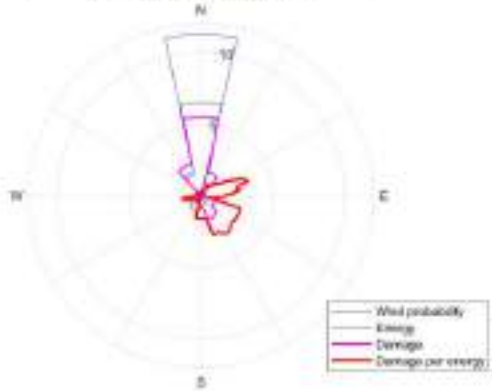
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT06



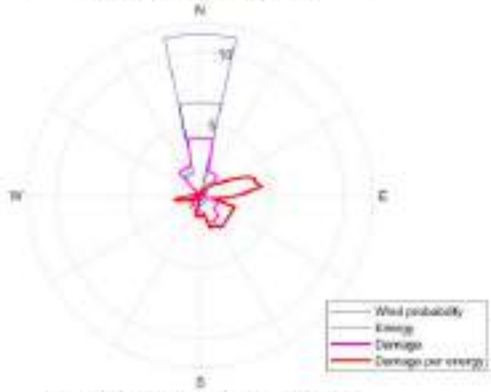
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT06



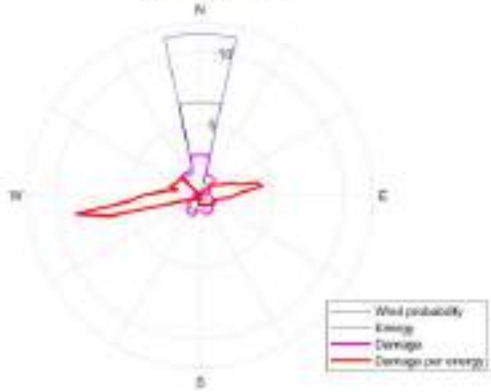
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT06



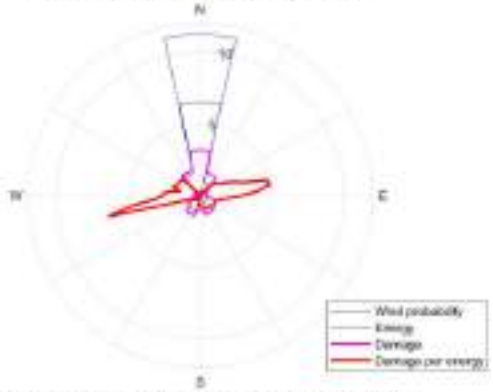
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT06



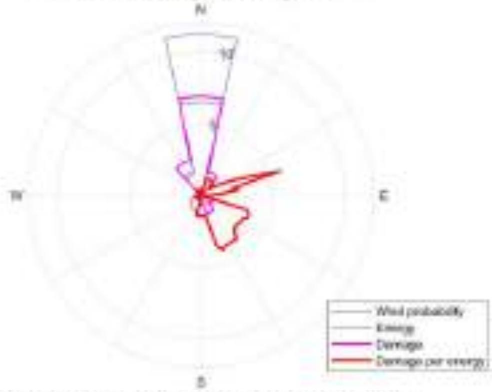
Rose map for the probabilities, energy and LTE in percentage, WT06



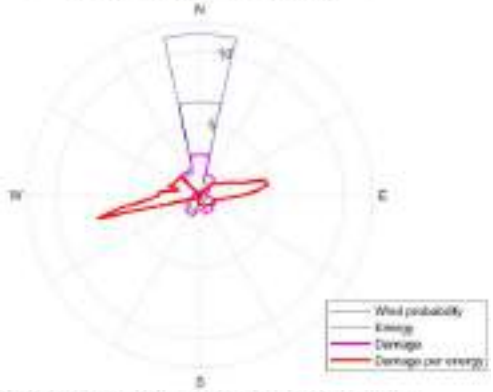
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT07



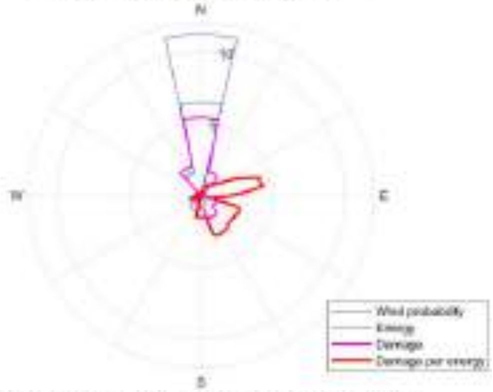
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT07



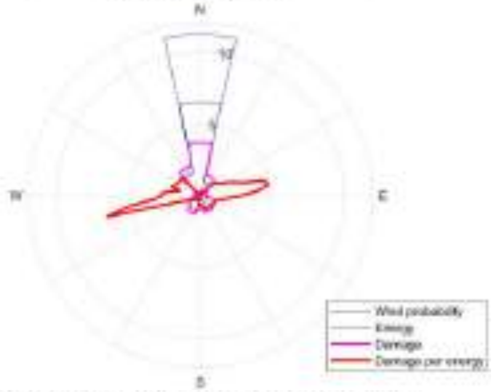
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT07



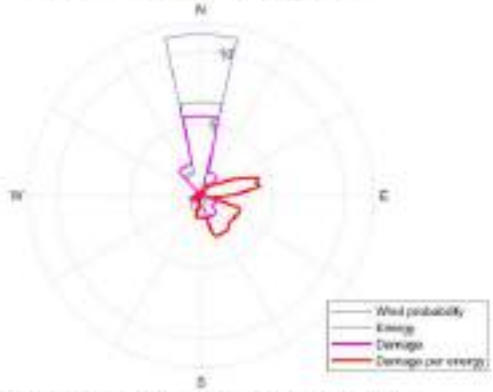
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT07



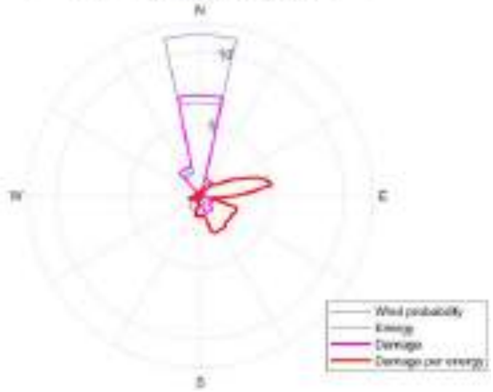
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT07



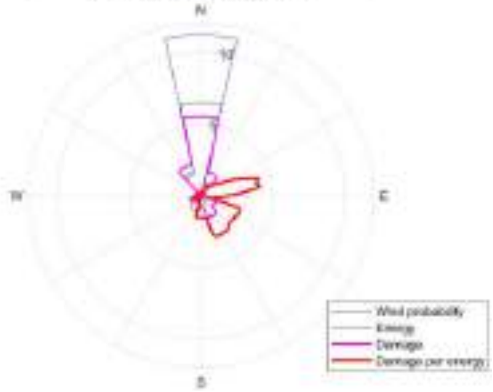
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT07

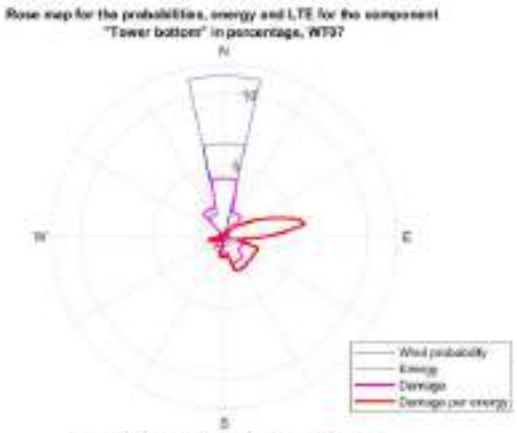


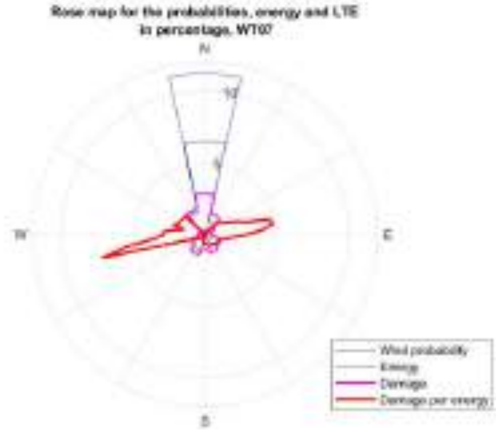
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT07

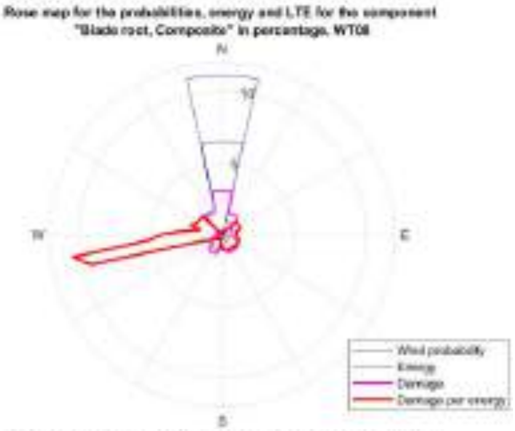


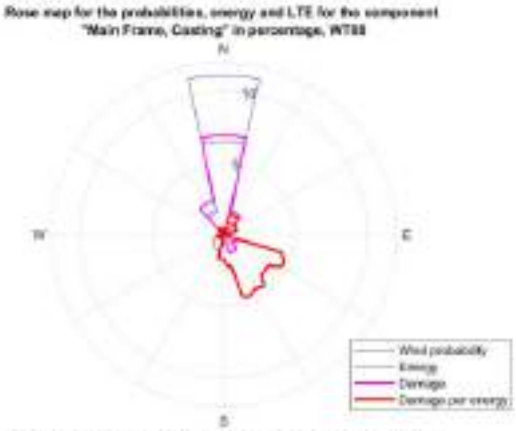
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT07

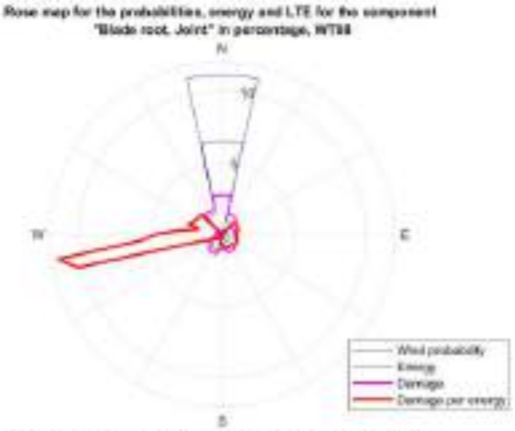


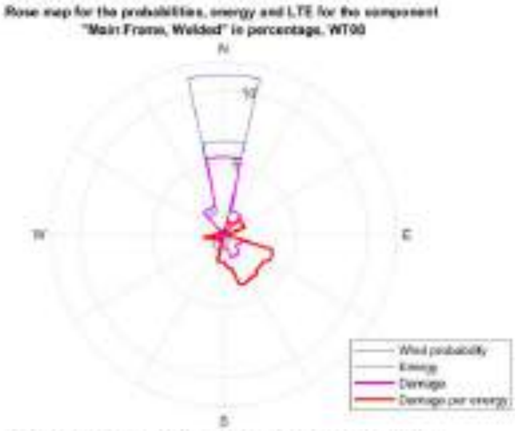

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT07
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

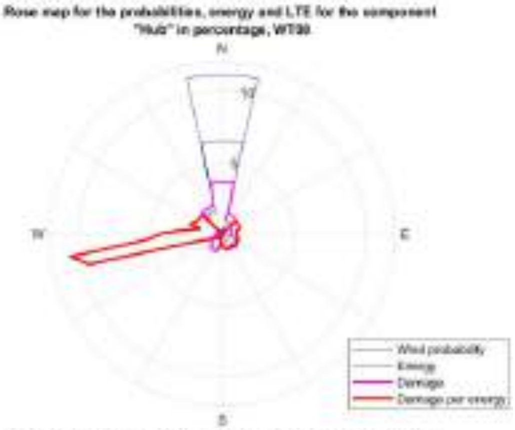

Rose map for the probabilities, energy and LTE
in percentage, WT07
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

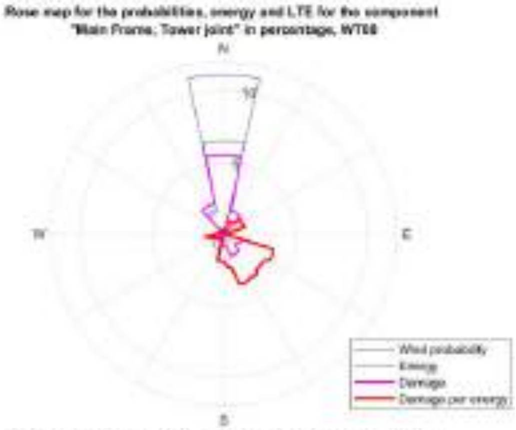

Rose map for the probabilities, energy and LTE for the component
"Blade root, Composite" in percentage, WT08
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

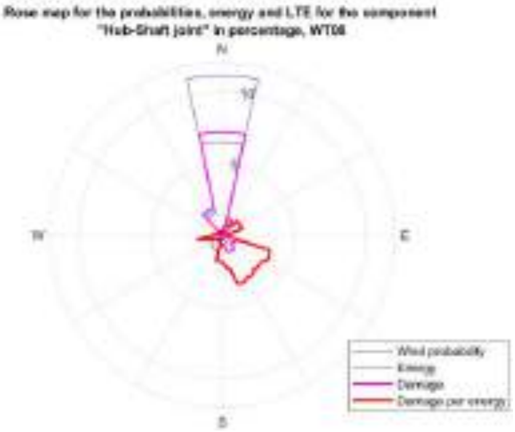

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Casting" in percentage, WT08
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

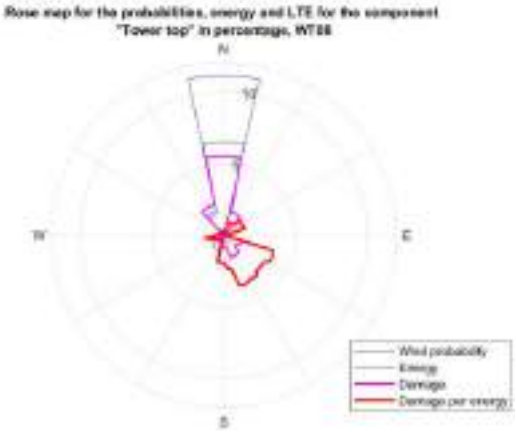

Rose map for the probabilities, energy and LTE for the component
"Blade root, Joint" in percentage, WT08
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

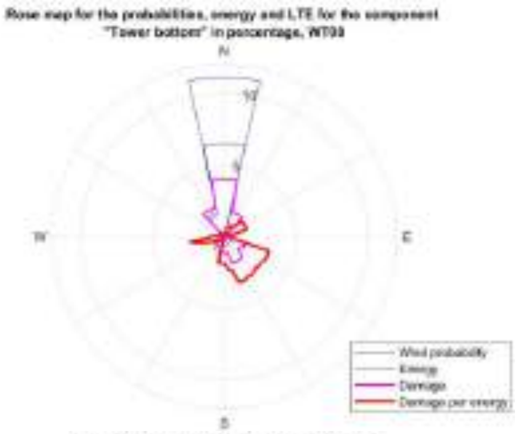

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Welded" in percentage, WT08
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

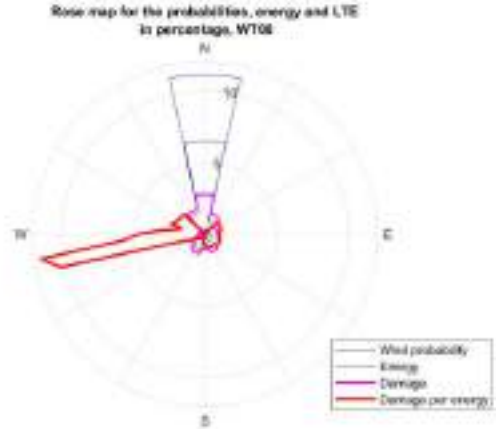

Rose map for the probabilities, energy and LTE for the component
"Hub" in percentage, WT08
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Main Frame; Tower joint" in percentage, WT08
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

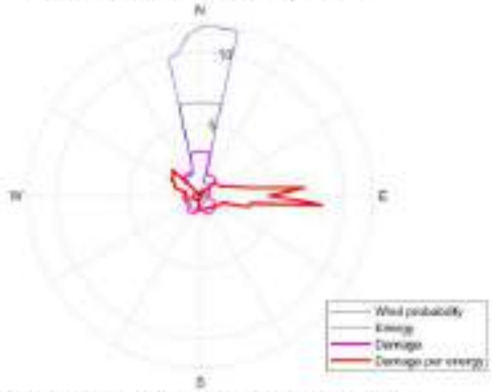

Rose map for the probabilities, energy and LTE for the component
"Hub-Shaft joint" in percentage, WT08
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Tower top" in percentage, WT08
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

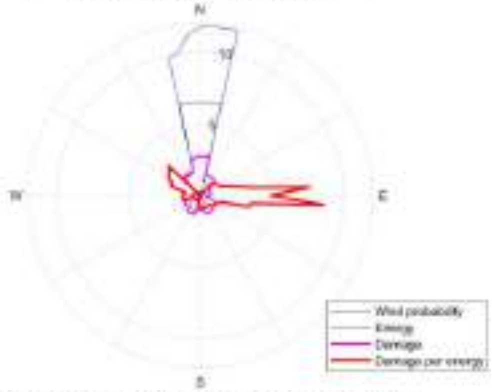

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT03
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT06
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

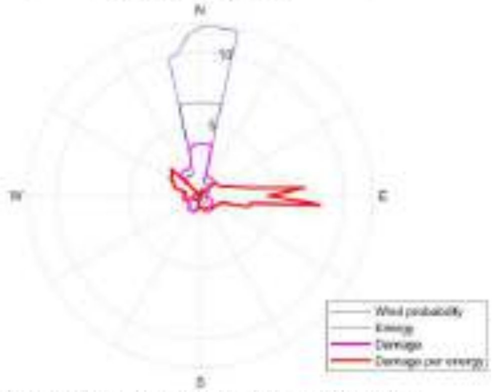
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT09



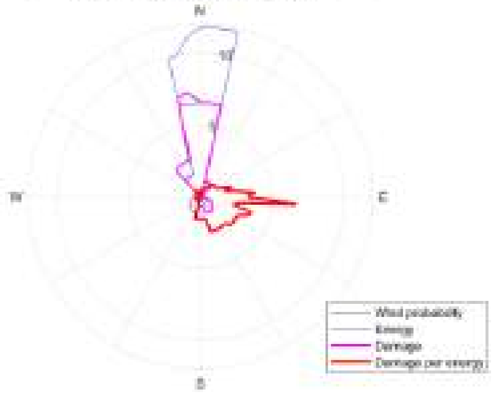
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT09



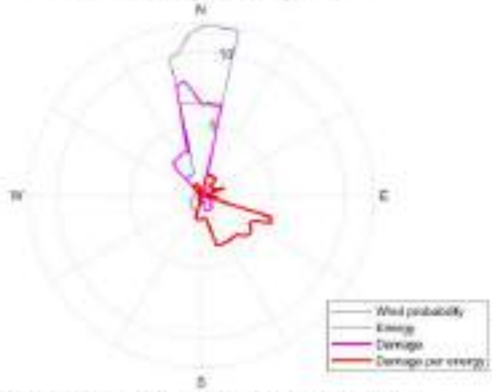
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT09



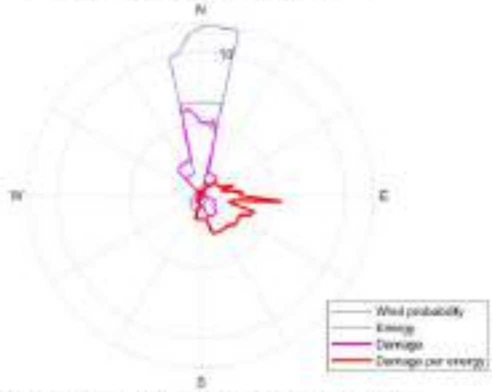
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT09



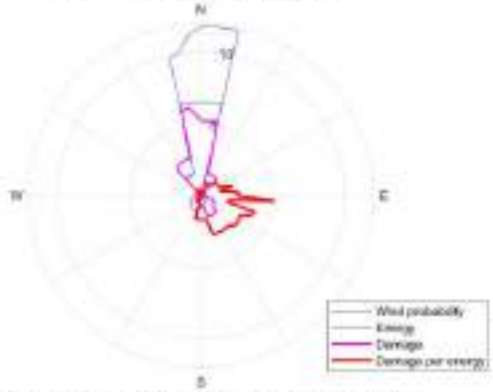
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT09



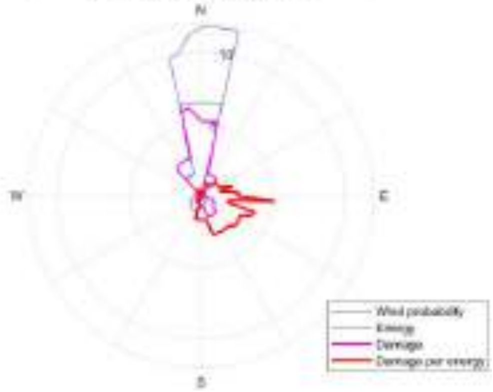
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT09

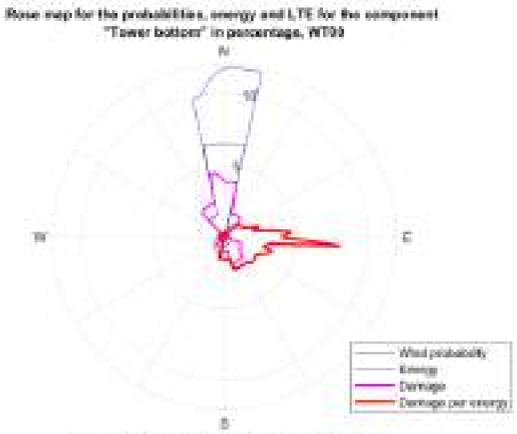


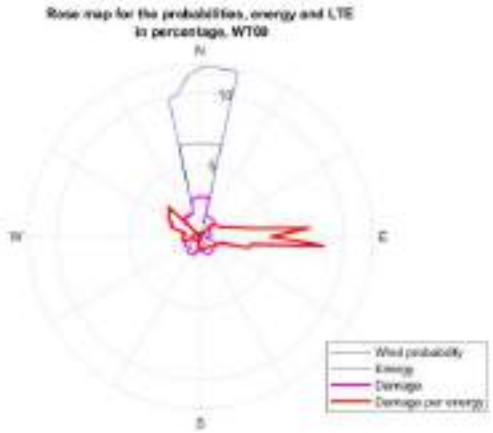
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT09



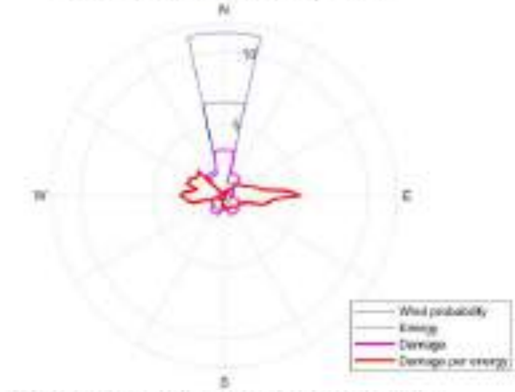
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT09



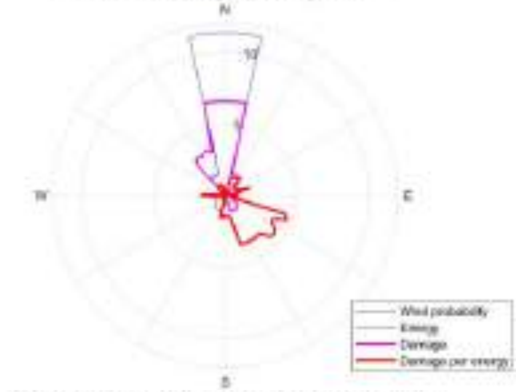

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT08
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT08
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

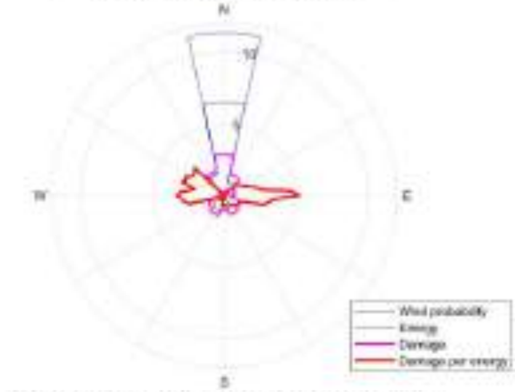
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT10



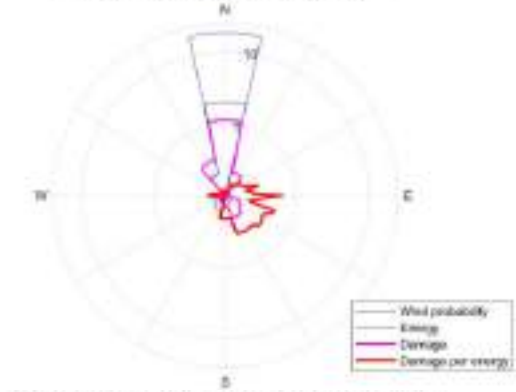
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT10



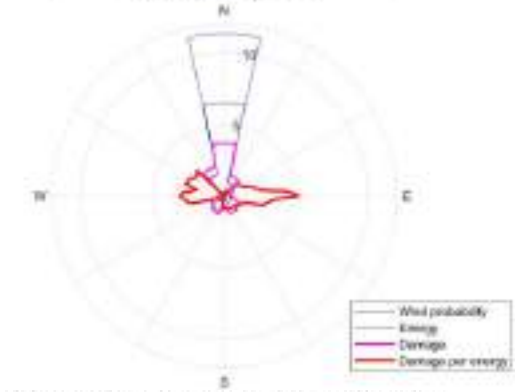
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT10



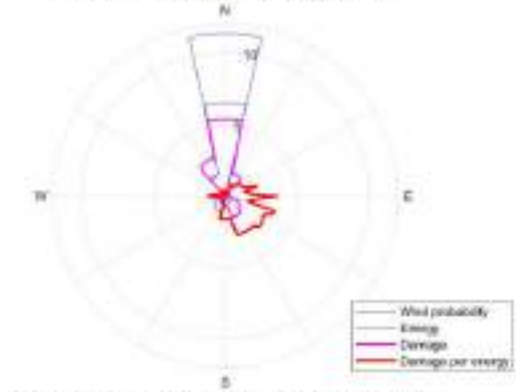
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT10



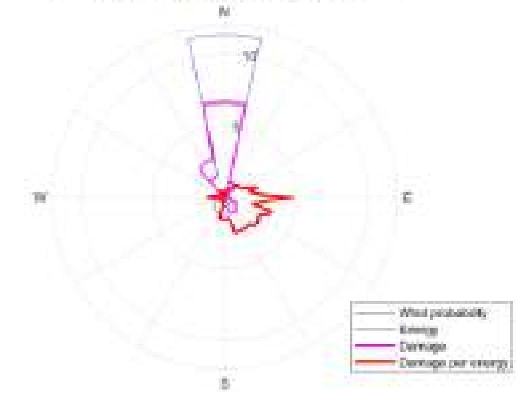
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT10



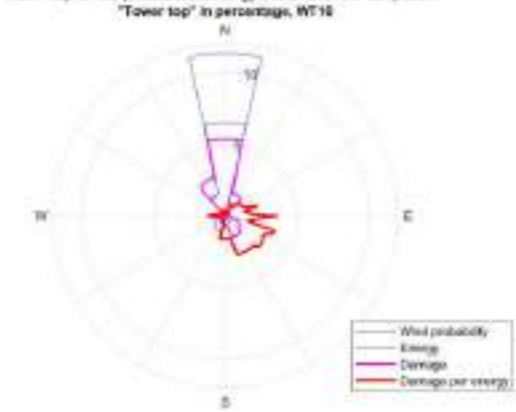
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT10

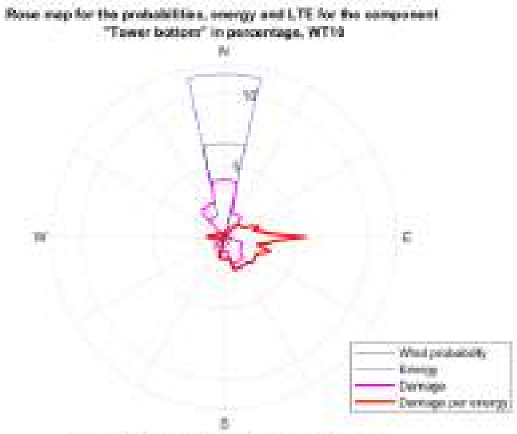


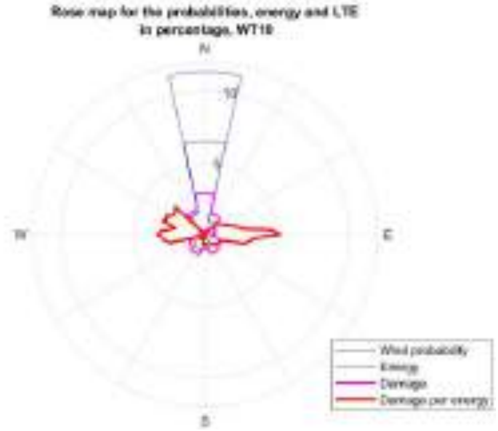
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT10



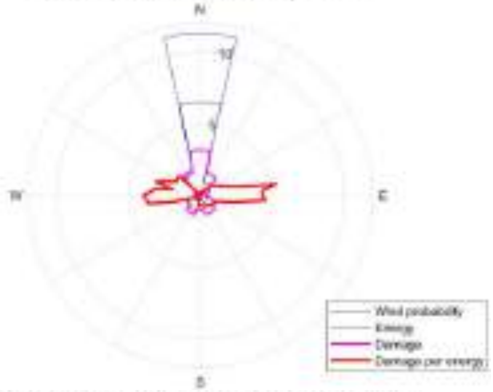
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT10



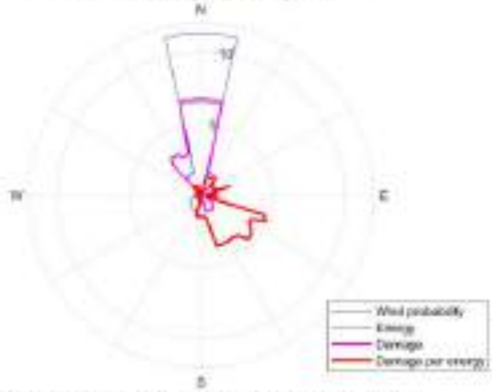

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT10
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT10
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

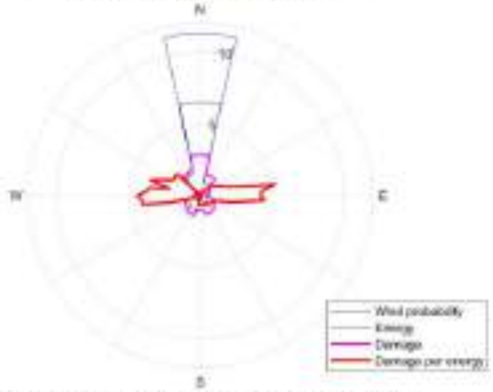
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT11



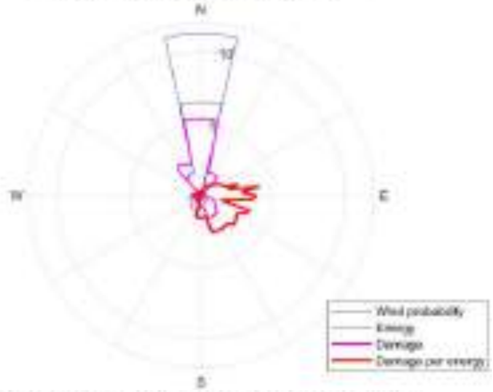
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT11



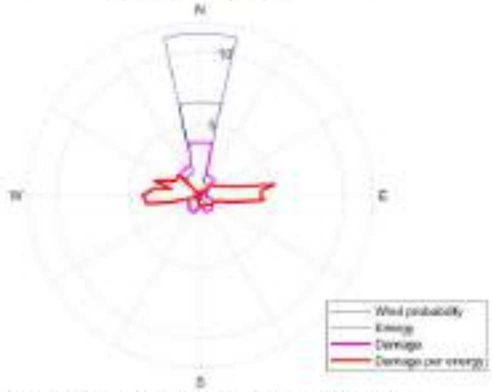
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT11



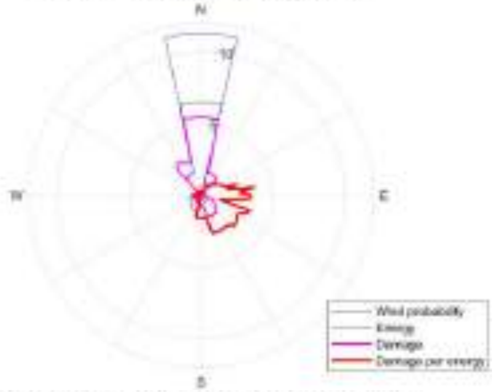
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT11



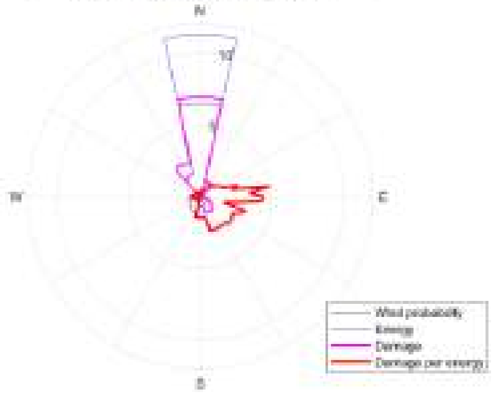
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT11



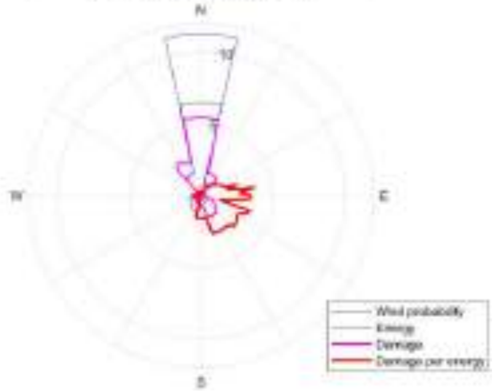
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT11

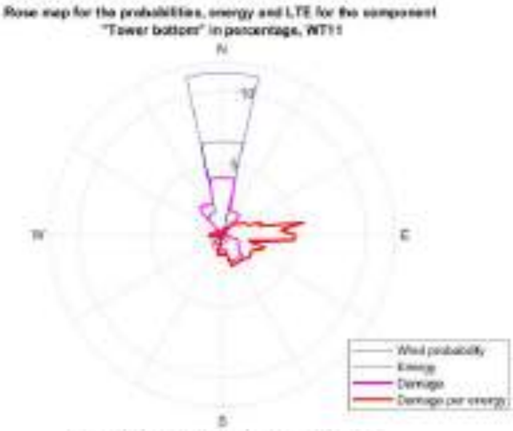


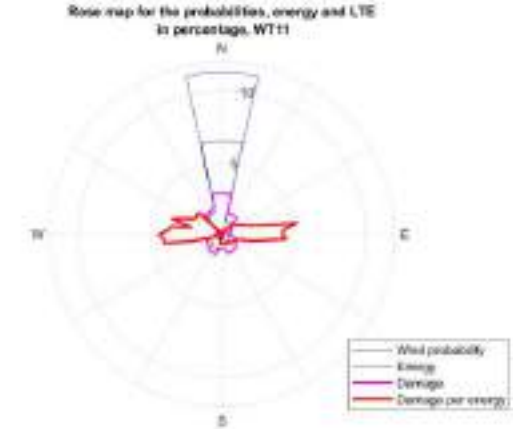
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT11



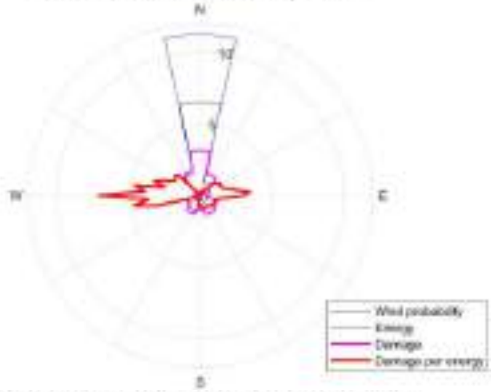
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT11



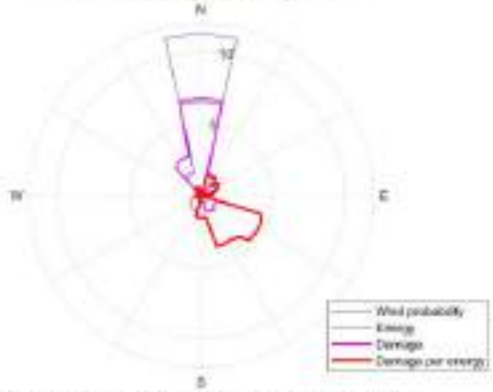

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT11
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT11
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

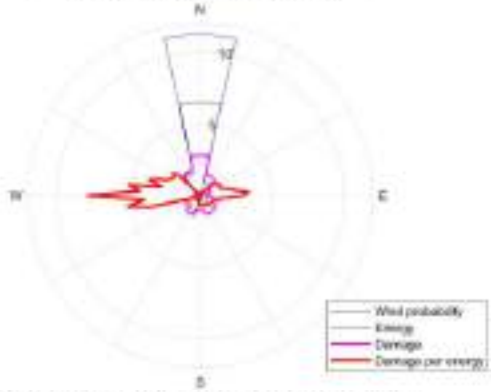
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT12



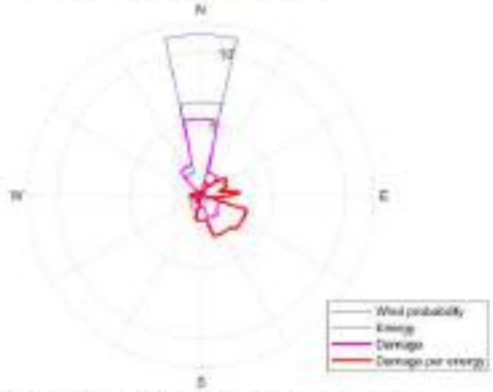
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT12



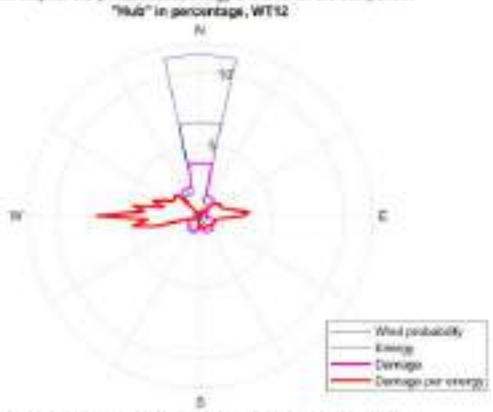
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT12



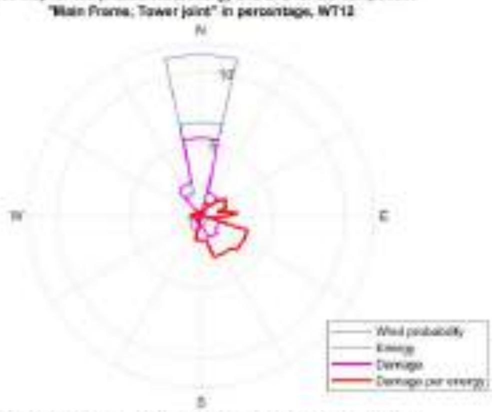
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT12



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT12

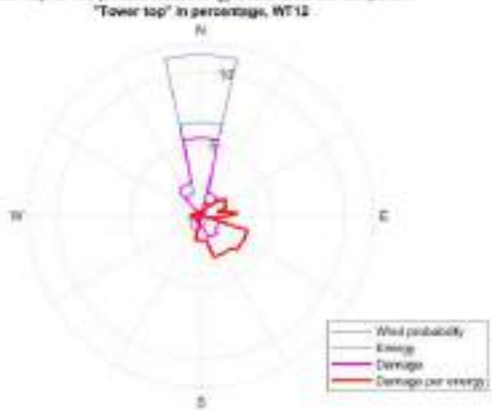


Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT12

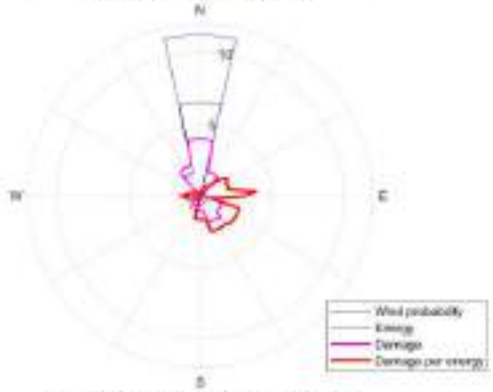


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT12

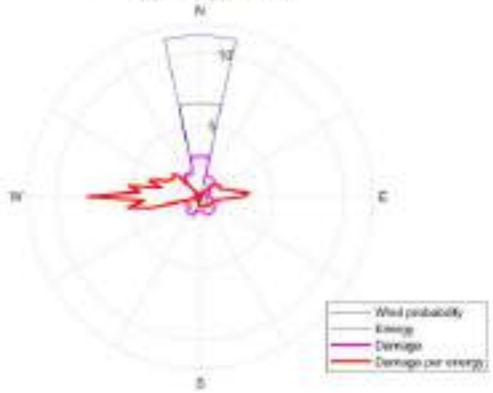
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT12



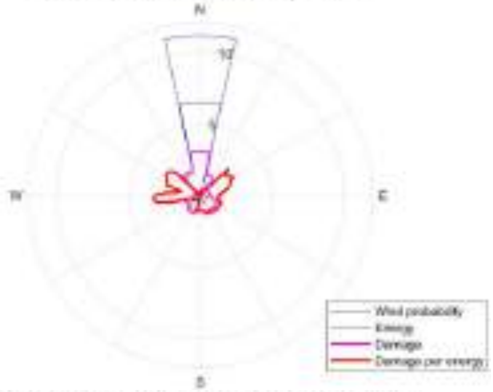
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT12



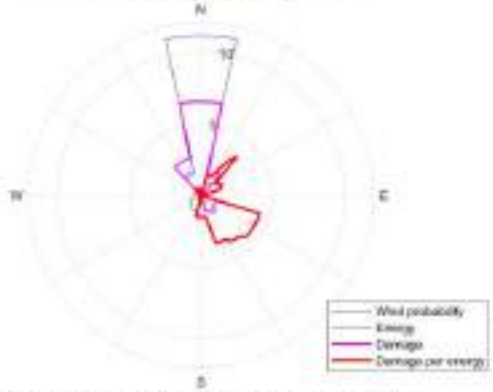
Rose map for the probabilities, energy and LTE in percentage, WT12



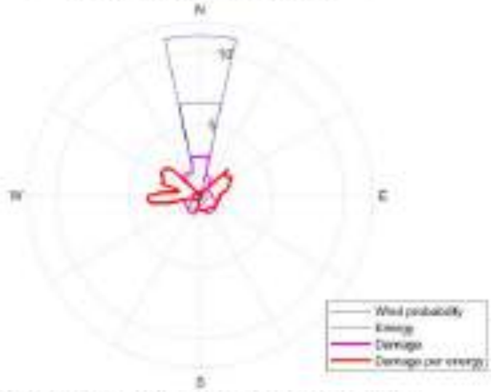
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT13



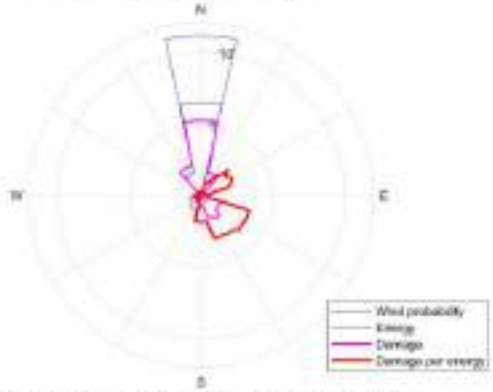
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT13



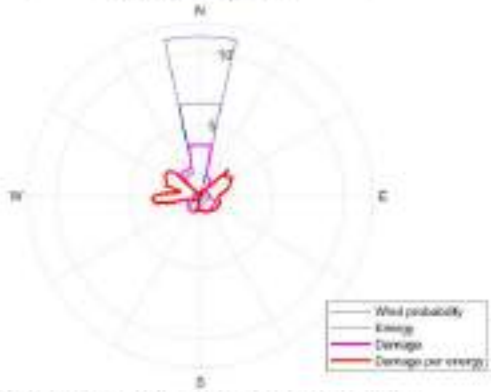
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT13



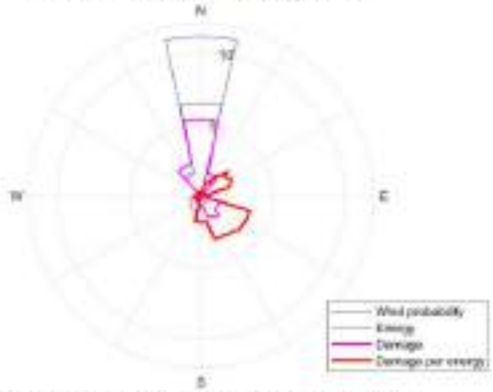
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT13



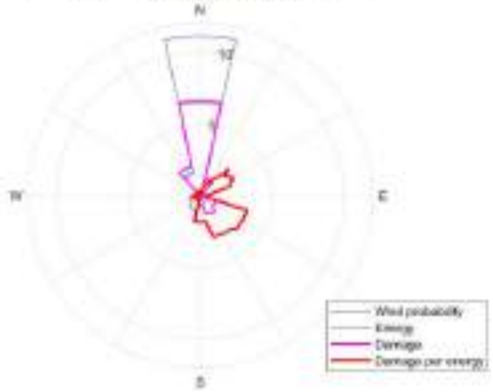
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT13



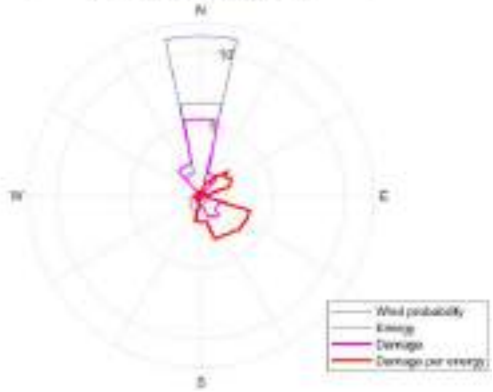
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT13



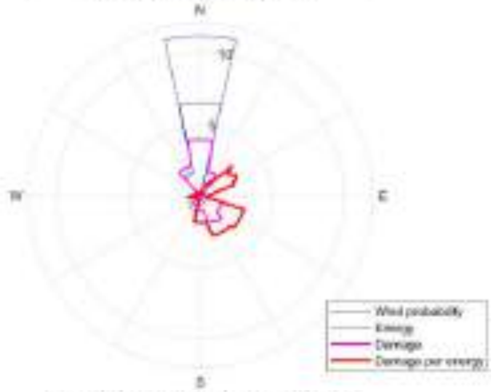
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT13



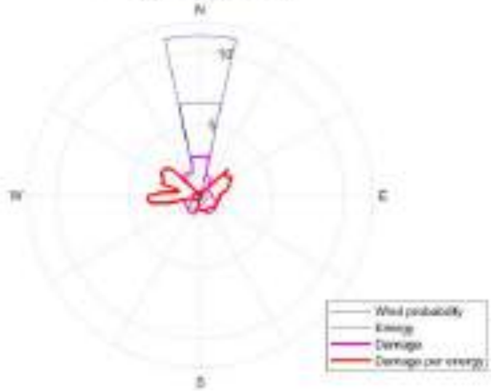
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT13



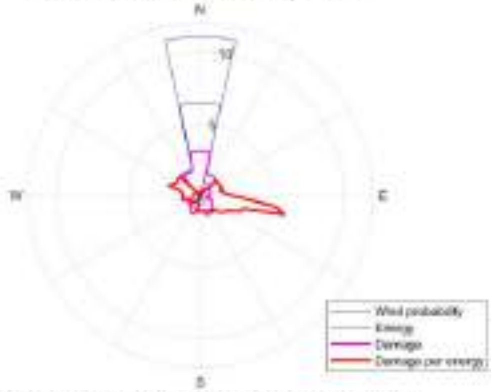
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT13



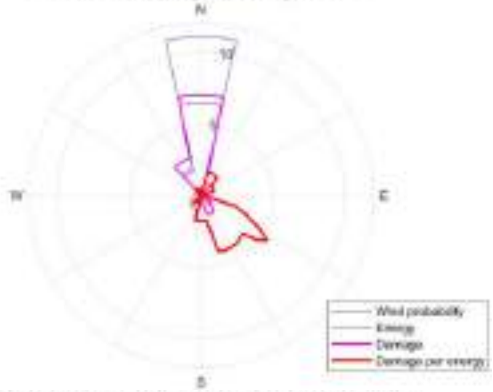
Rose map for the probabilities, energy and LTE in percentage, WT13



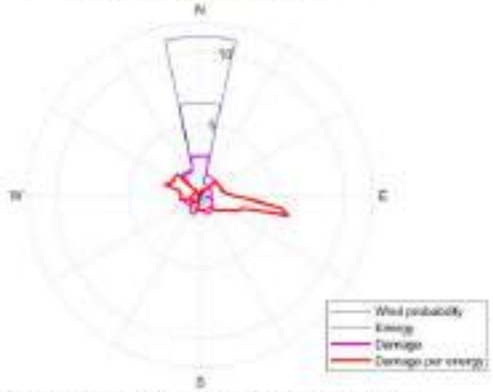
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT14



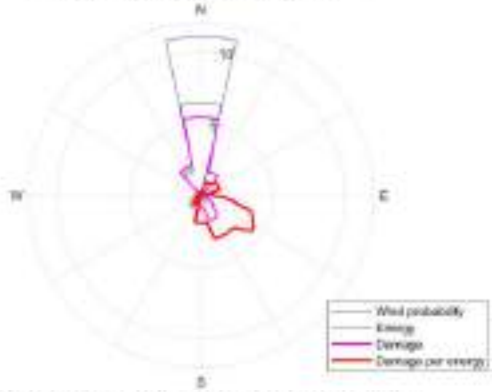
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT14



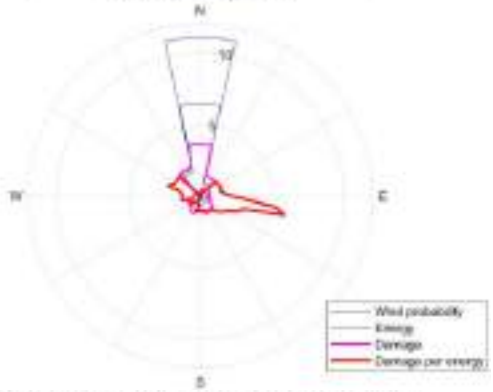
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT14



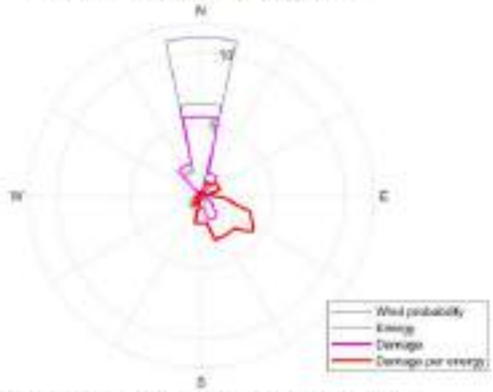
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT14



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT14

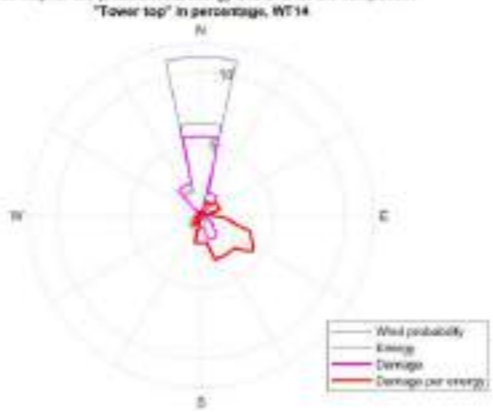


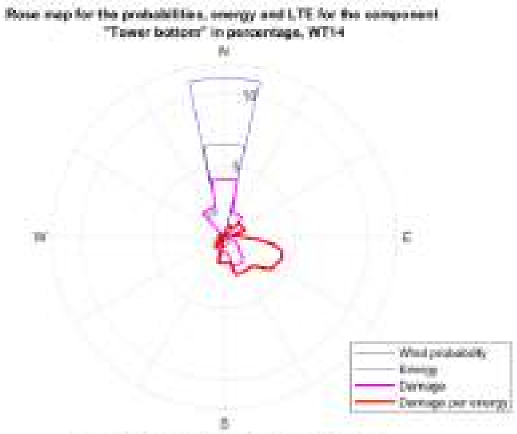
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT14

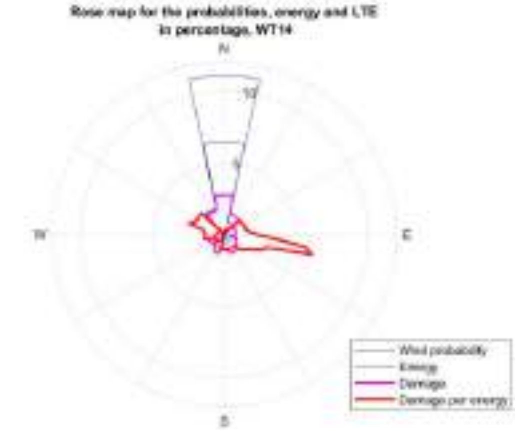


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT14

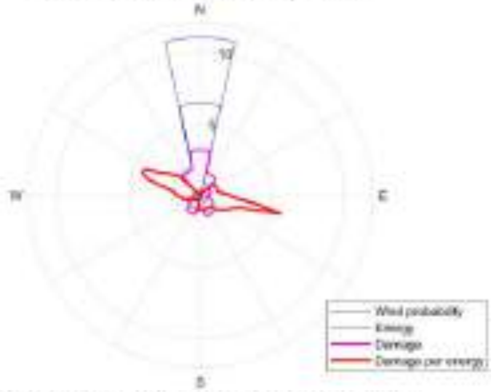
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT14



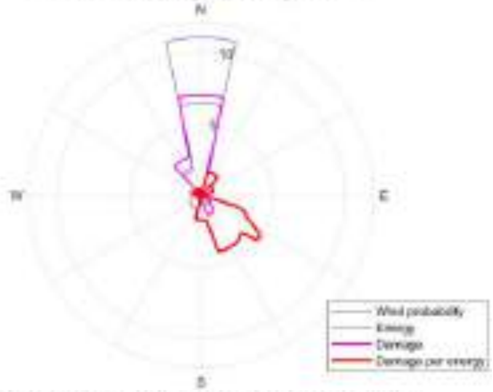

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT14
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT14
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

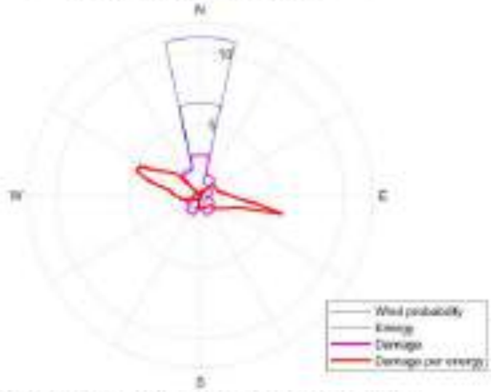
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT15



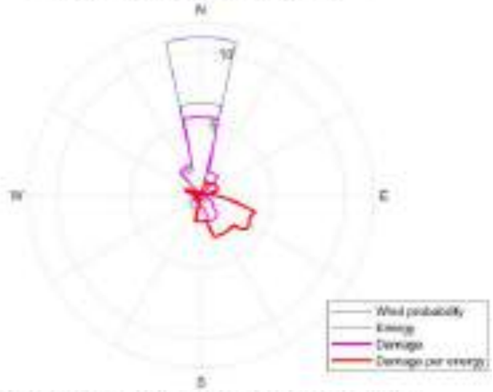
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT15



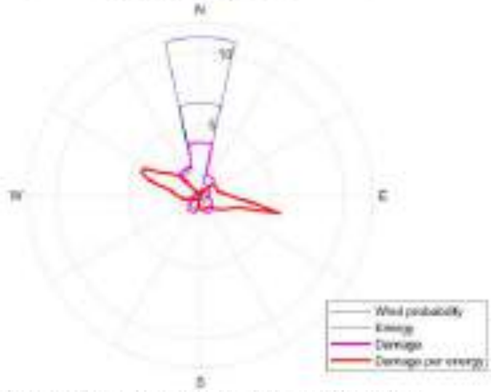
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT15



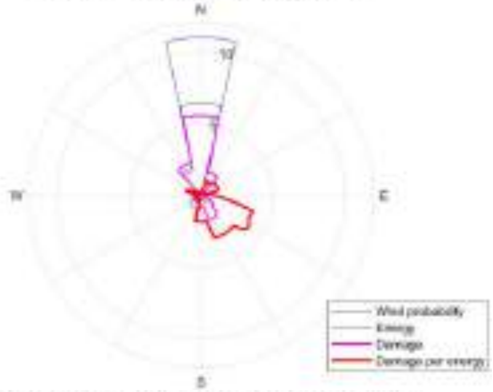
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT15



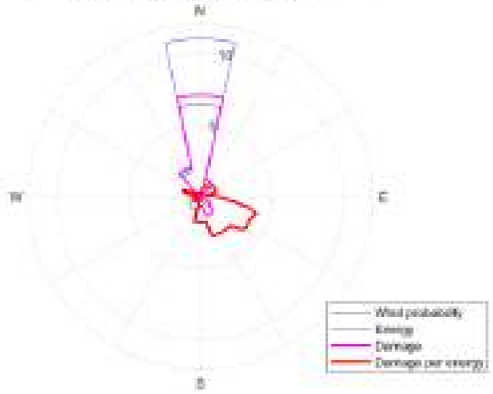
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT15



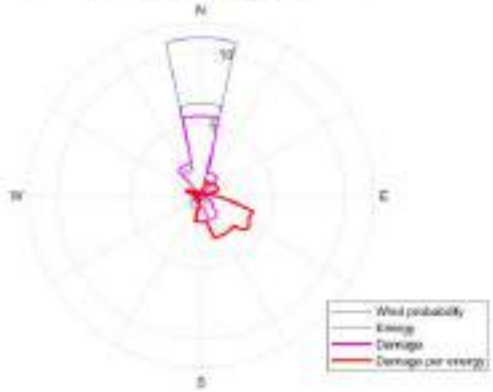
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT15



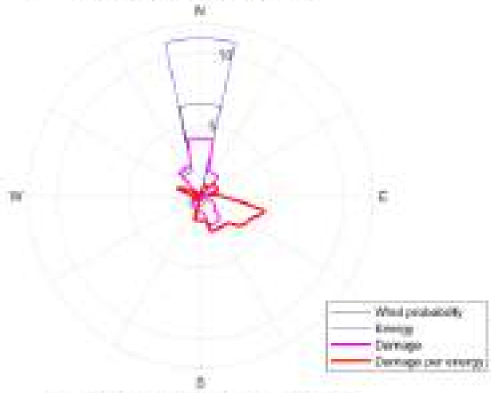
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT15



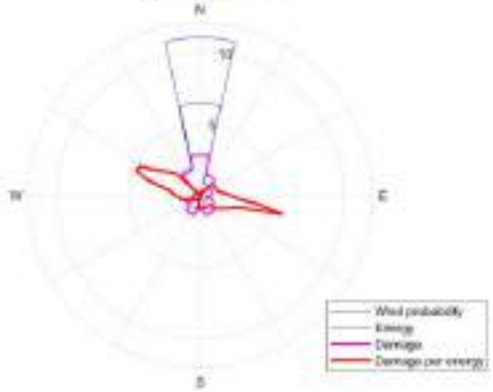
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT15



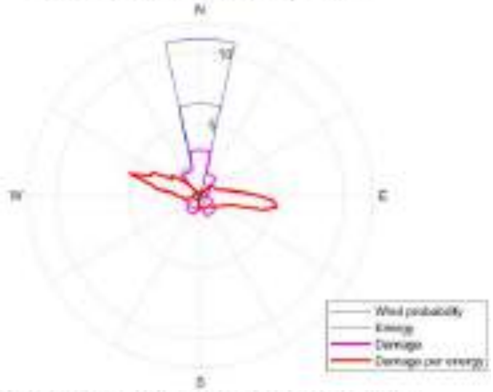
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT15



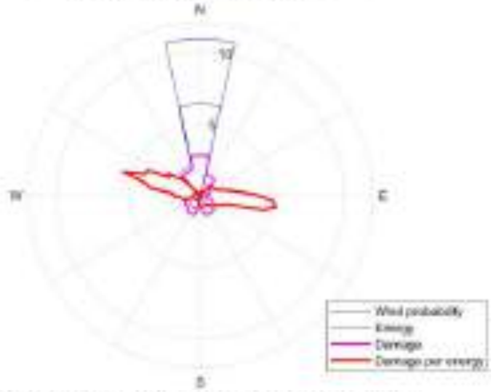
Rose map for the probabilities, energy and LTE in percentage, WT15



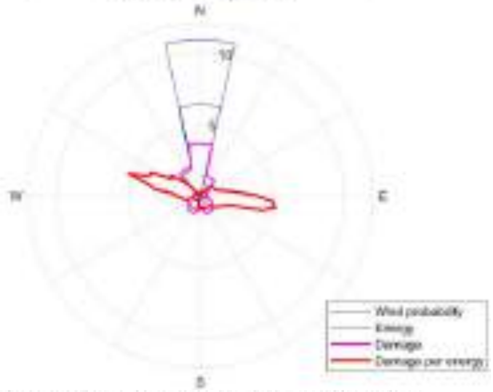
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT16



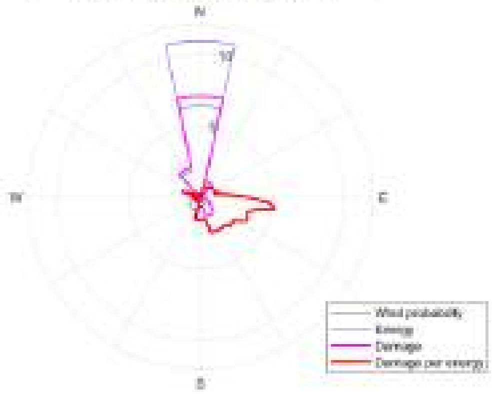
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT16



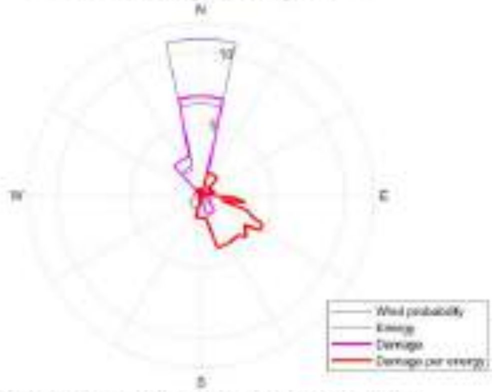
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT16



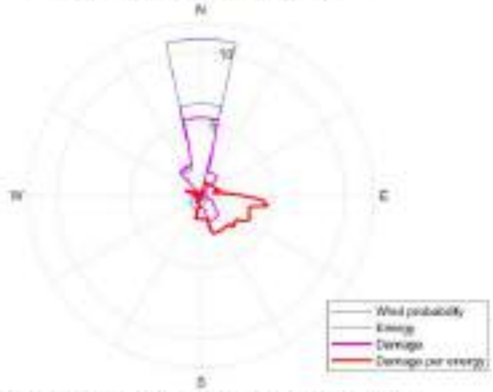
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT16



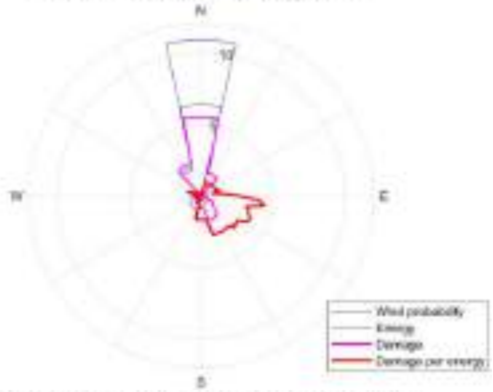
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT16



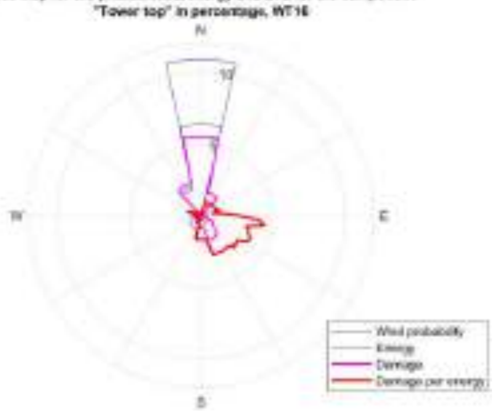
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT16

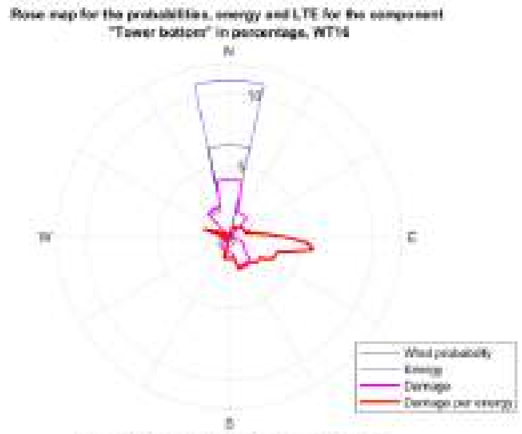


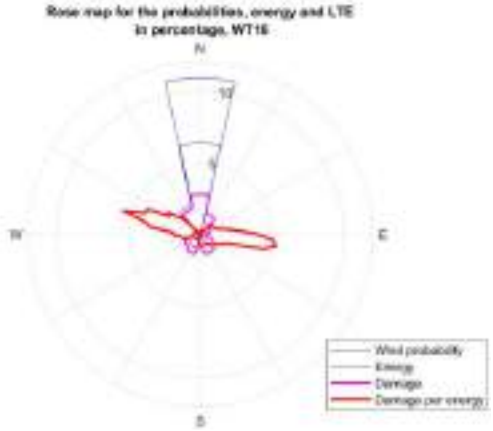
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT16



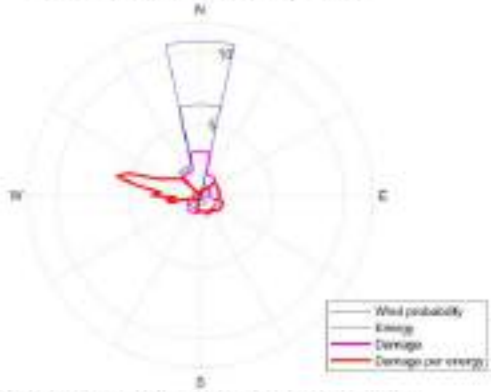
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT16



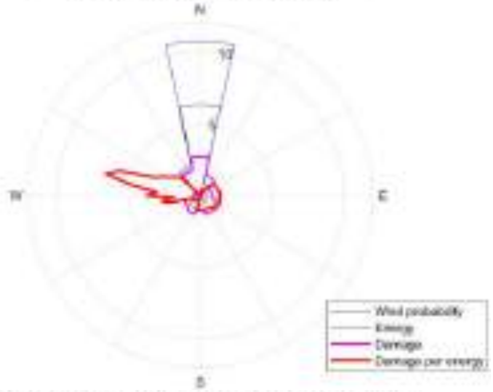

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT16
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT16
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

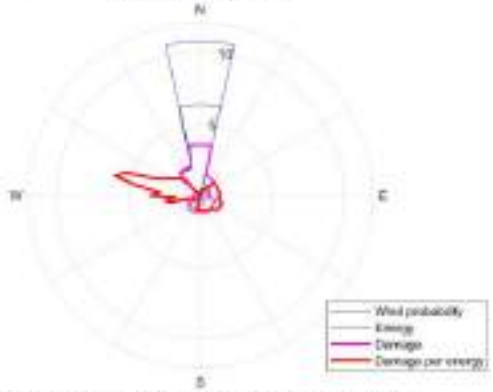
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT17



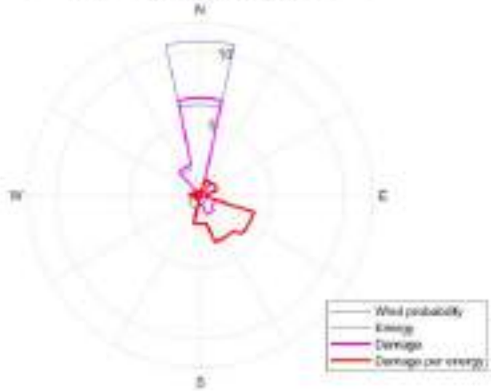
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT17



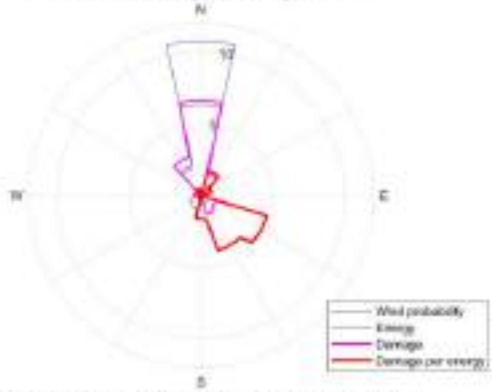
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT17



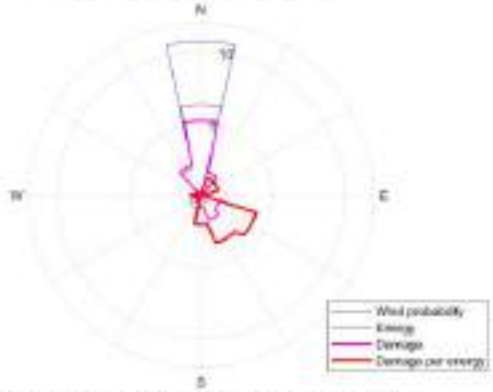
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT17



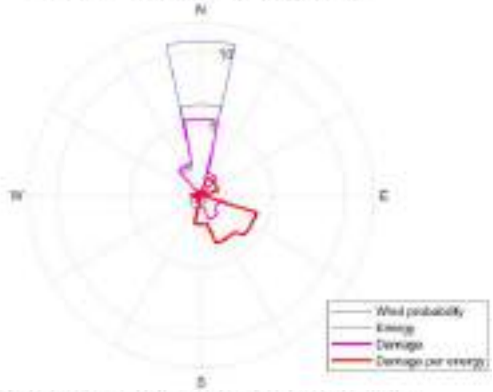
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT17



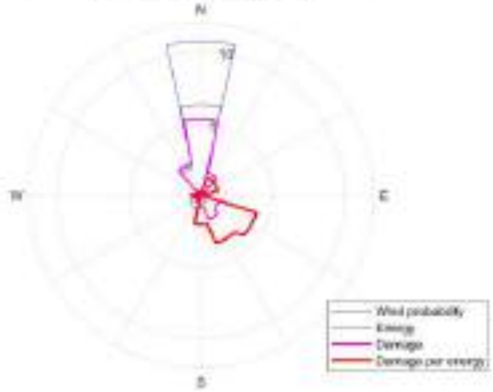
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT17



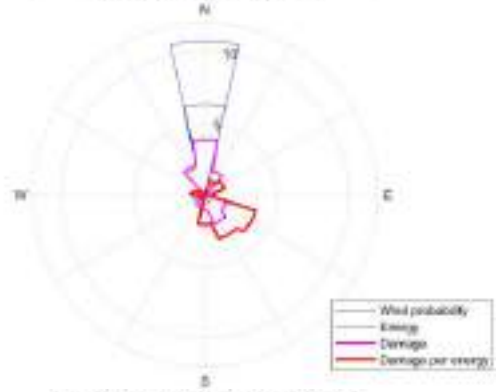
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT17



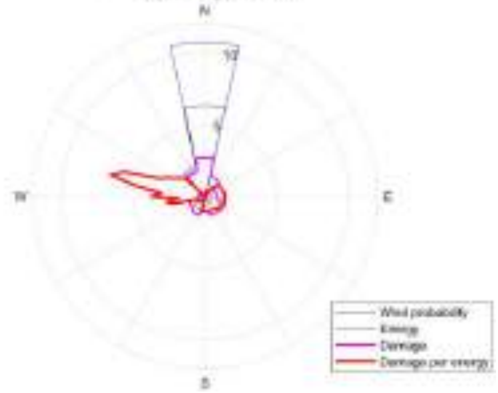
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT17



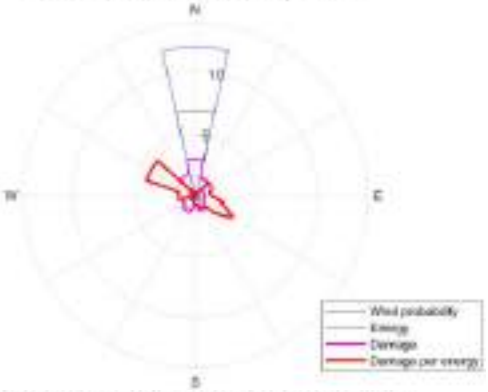
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT17



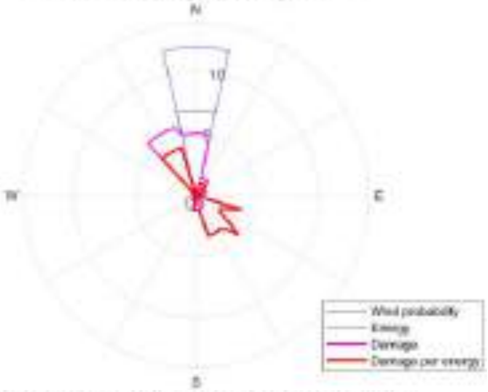
Rose map for the probabilities, energy and LTE in percentage, WT17



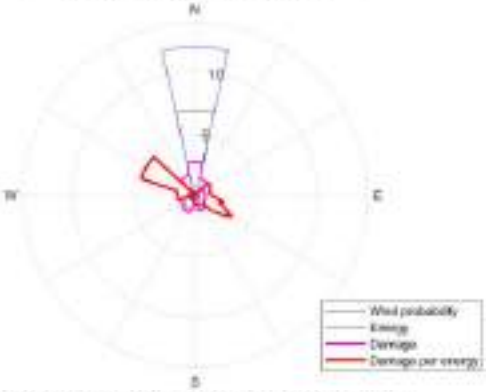
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT18



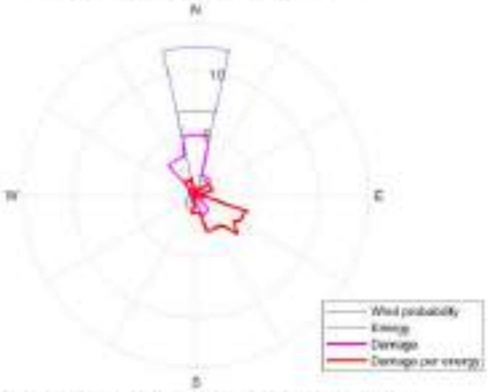
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT18



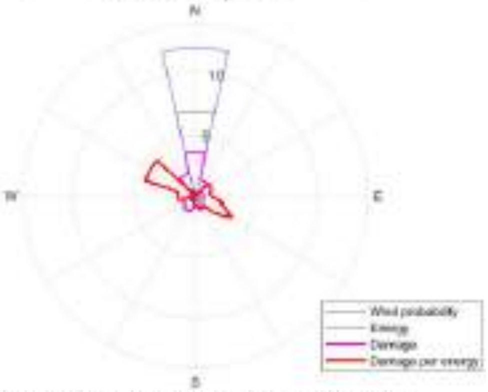
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT18



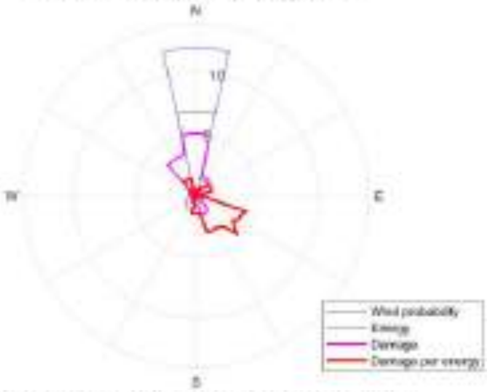
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT18



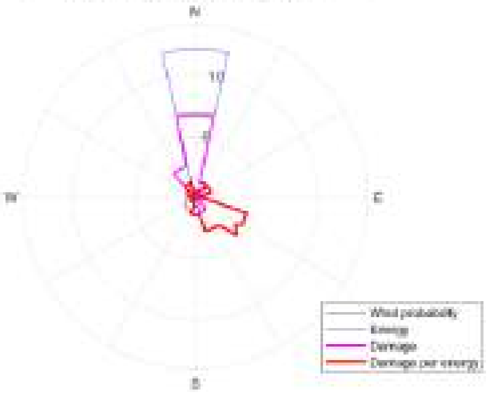
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT18



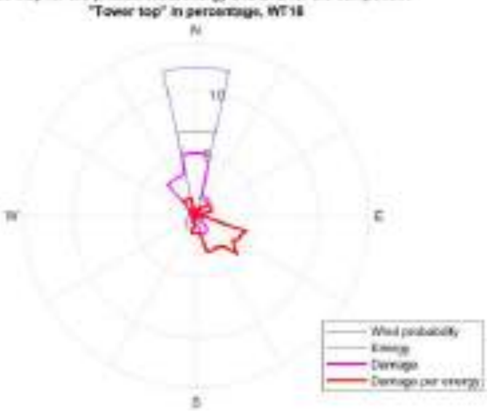
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT18

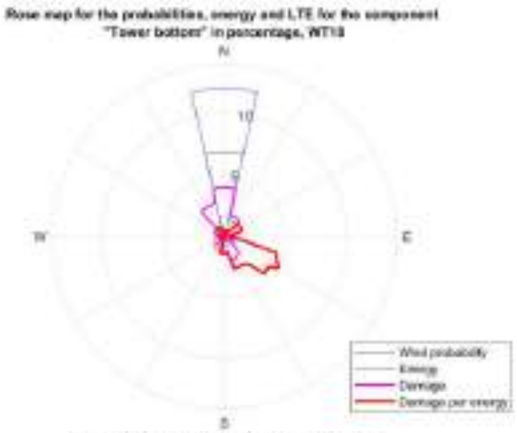


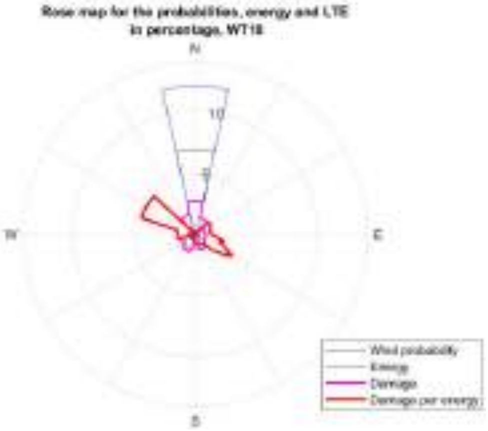
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT18

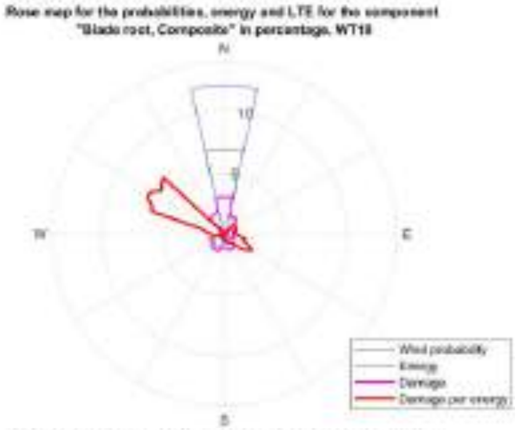


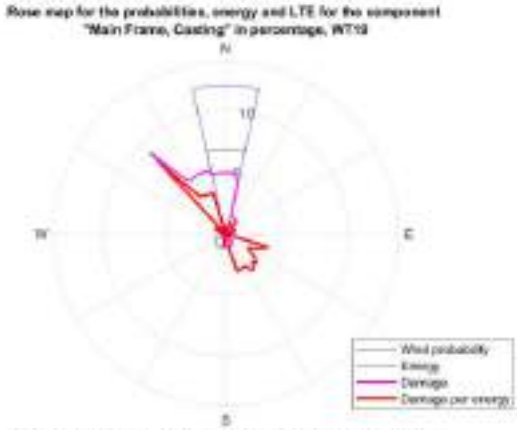
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT18

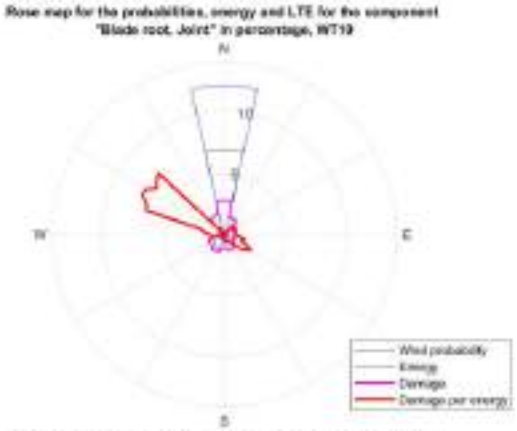


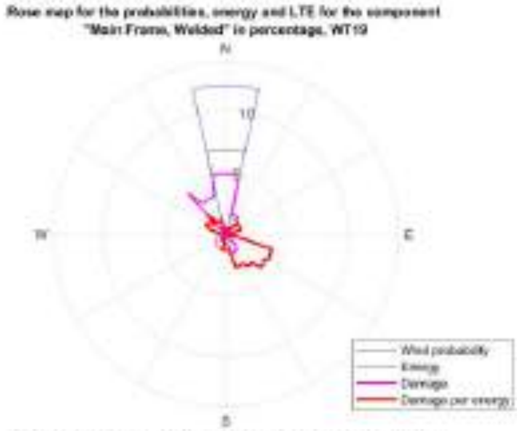

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT18
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy

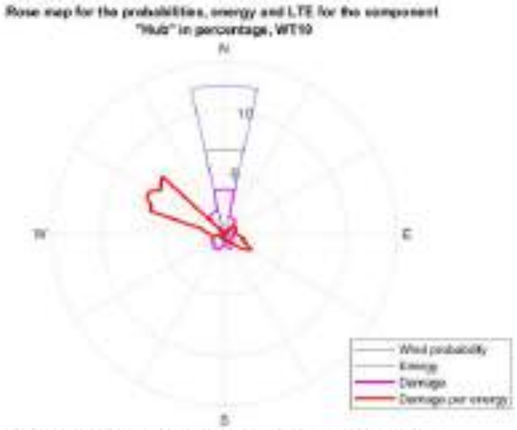

Rose map for the probabilities, energy and LTE
in percentage, WT18
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy

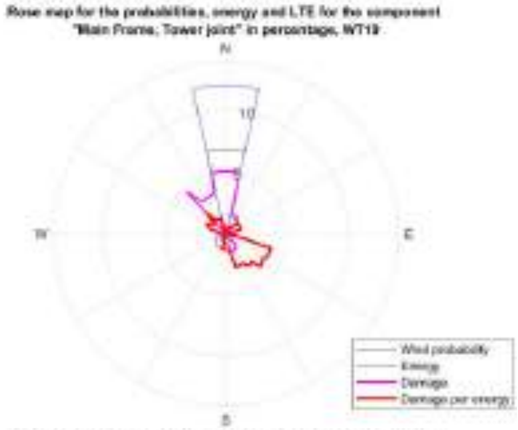

Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT19
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

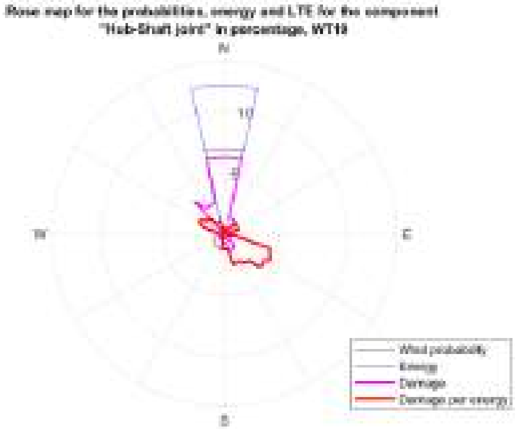

Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT19
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

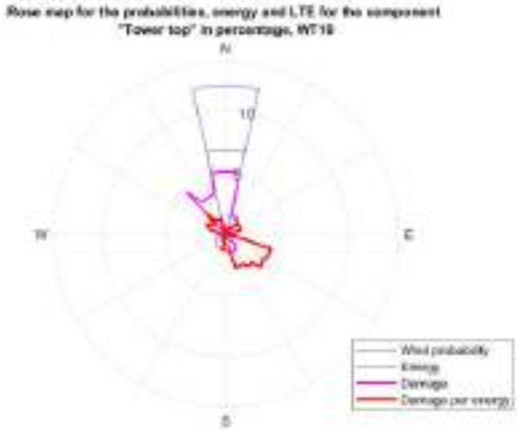

Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT19
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

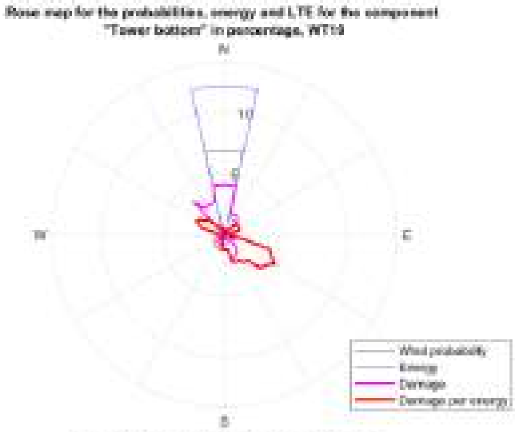

Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT19
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

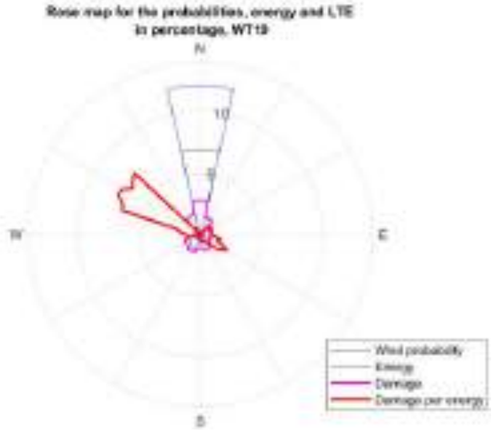

Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT19
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT19
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

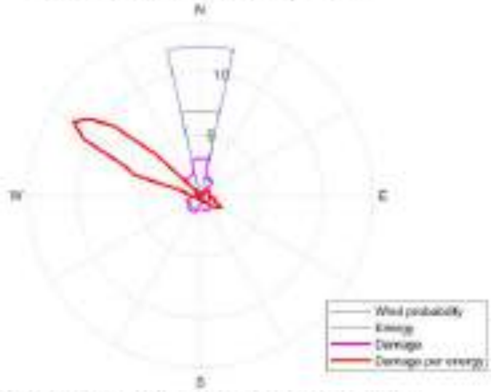

Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT19
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT19
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

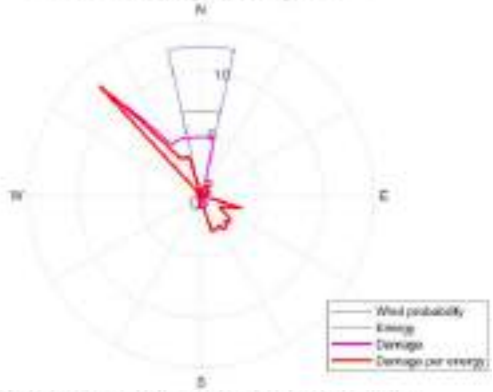

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT19
N
W
E
S
10
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT19
N
W
E
S
10
Wind probability
Energy
Damage
Damage per energy

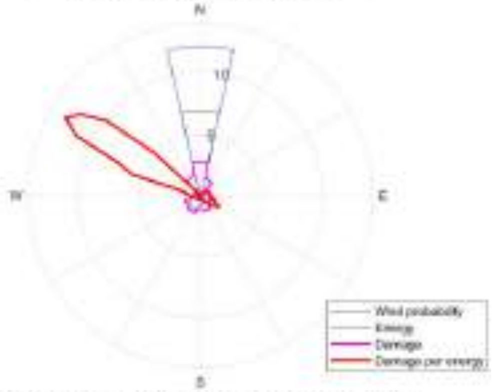
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT28



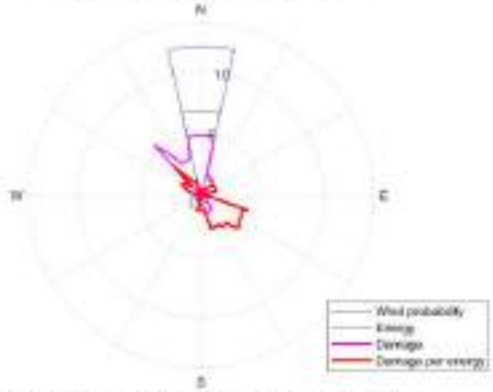
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT28



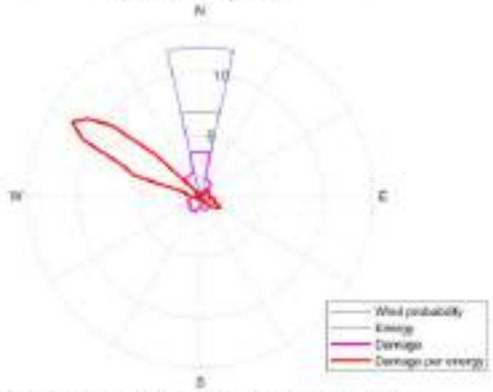
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT28



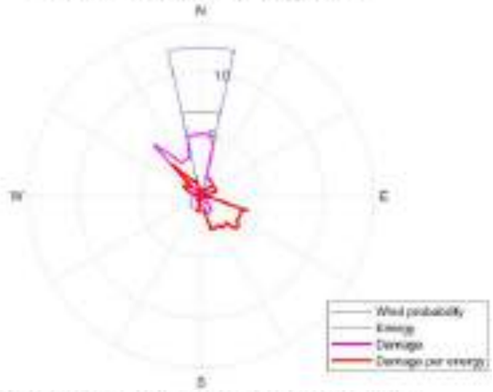
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT28



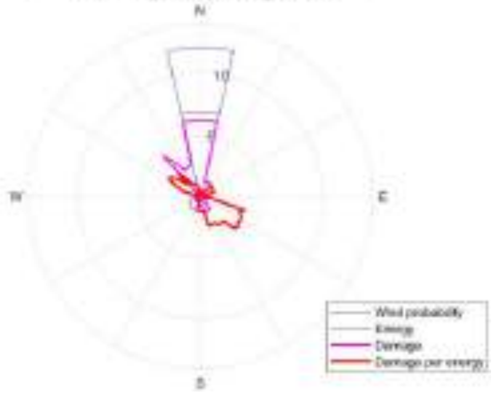
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT28



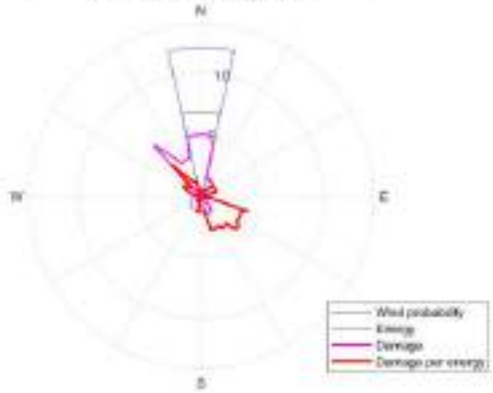
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT28



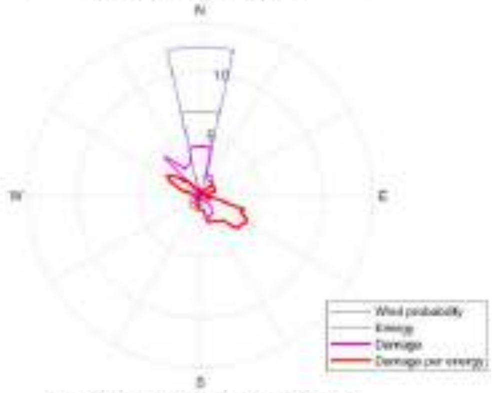
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT28



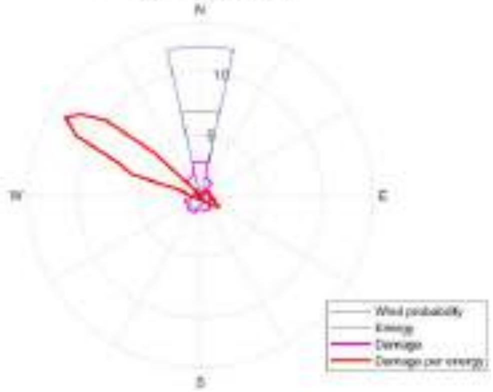
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT28

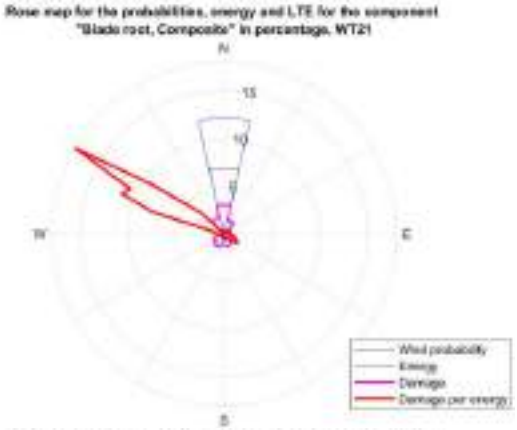


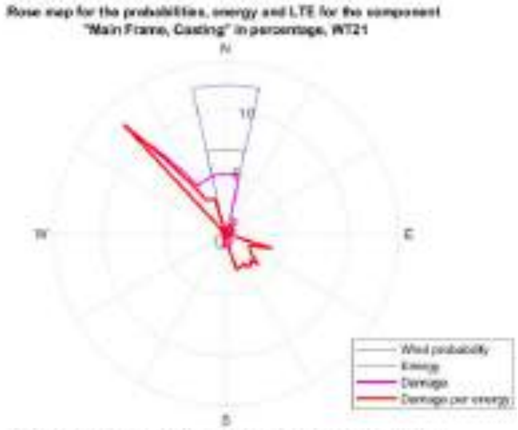
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT20

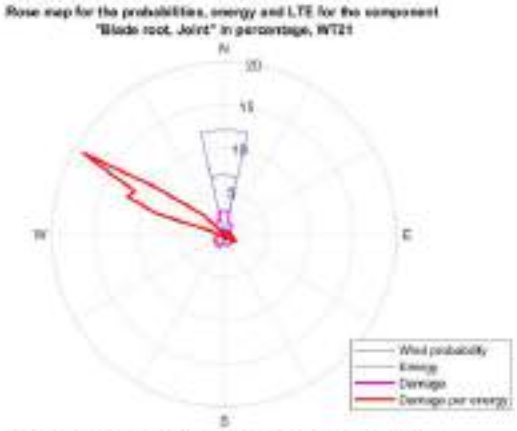


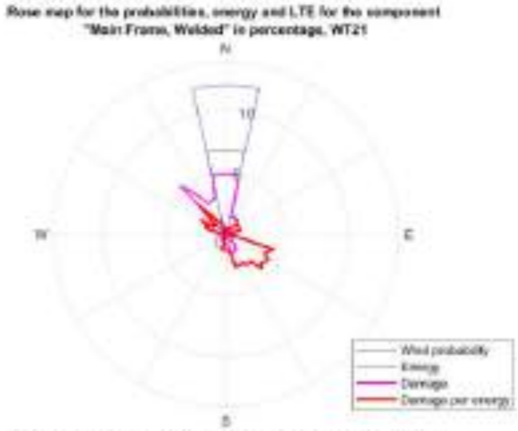
Rose map for the probabilities, energy and LTE in percentage, WT20

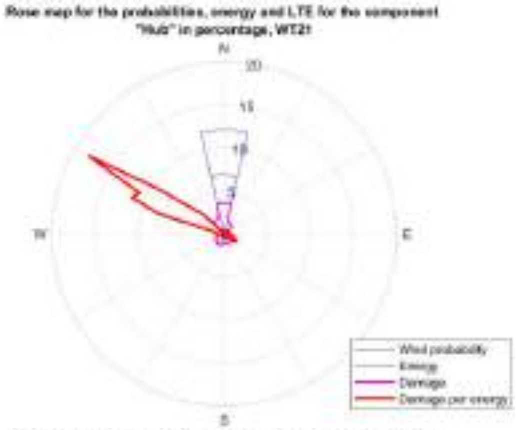


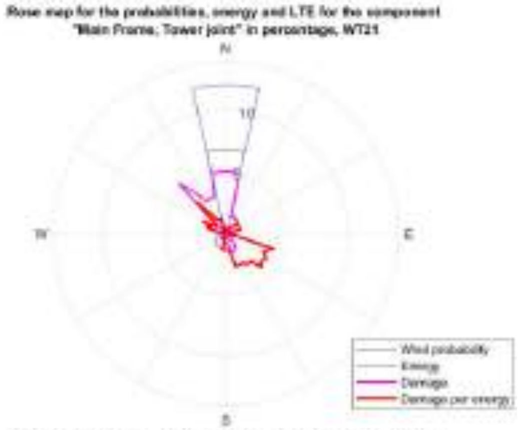

Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT21
N
15
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

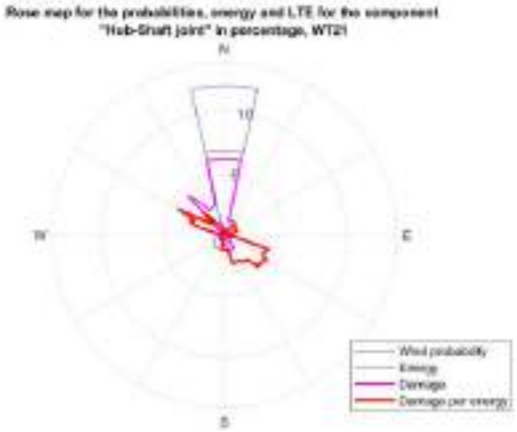

Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT21
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

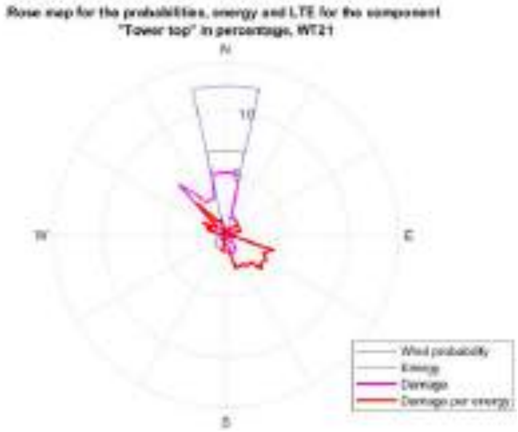

Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT21
N
20
15
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

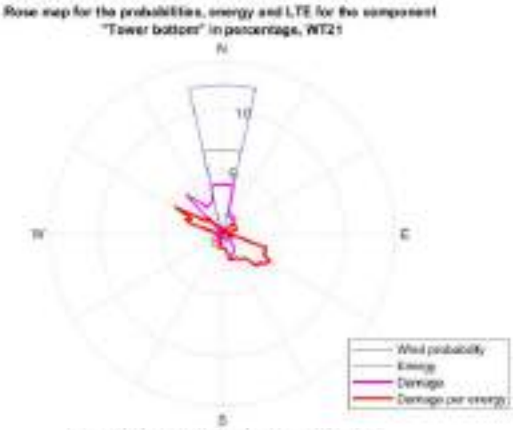

Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT21
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

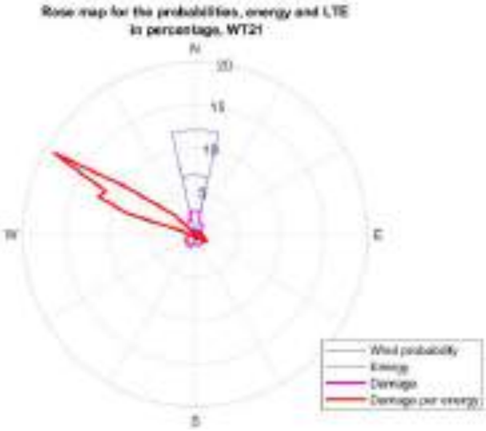

Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT21
N
20
15
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT21
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

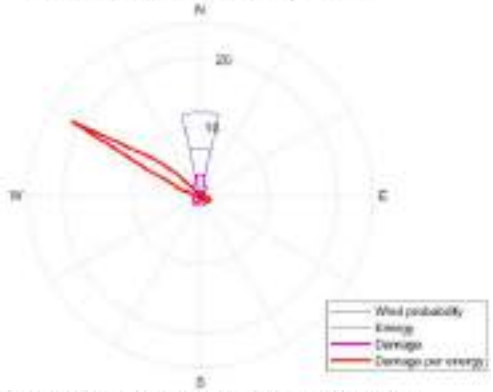

Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT21
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT21
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

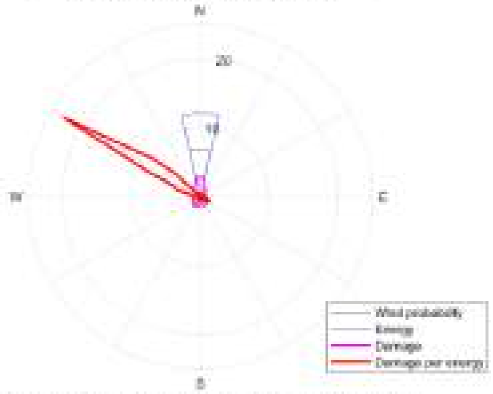

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT21
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT21
N
20
15
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

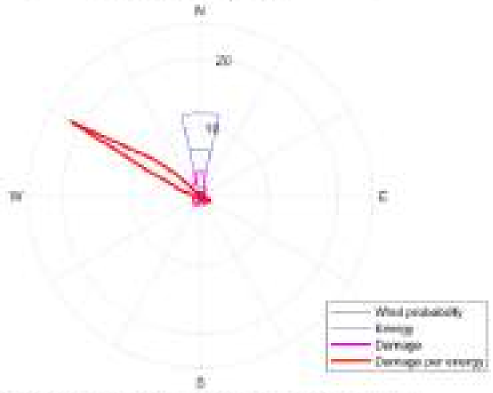
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT22



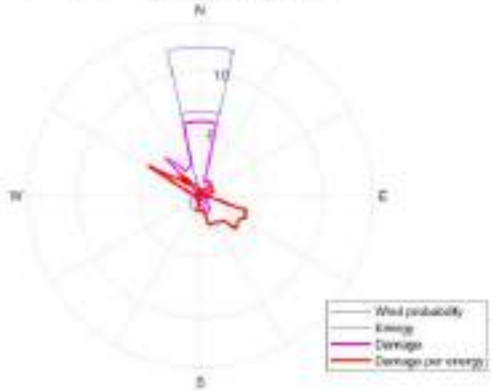
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT22



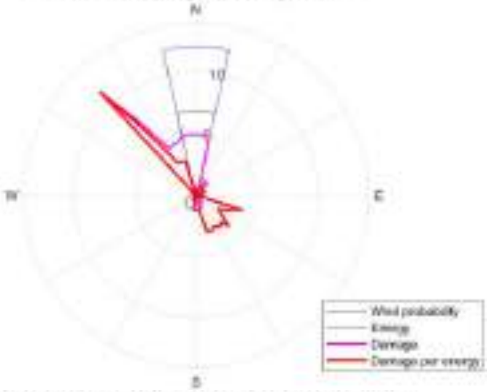
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT22



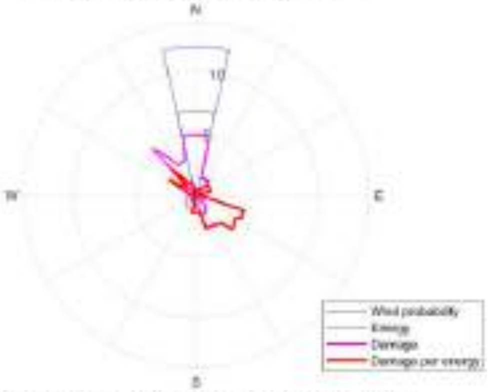
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT22



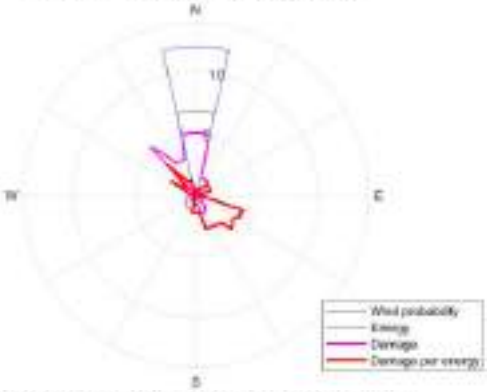
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT22



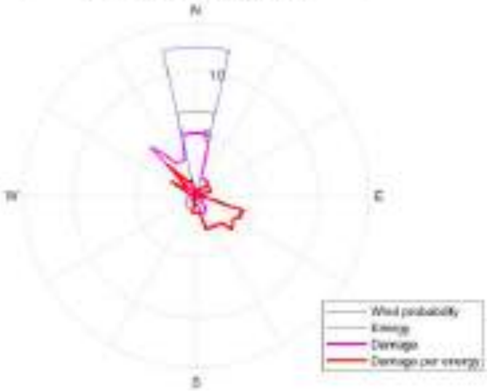
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT22

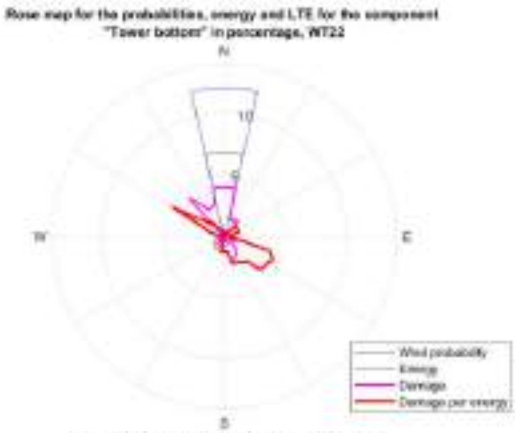


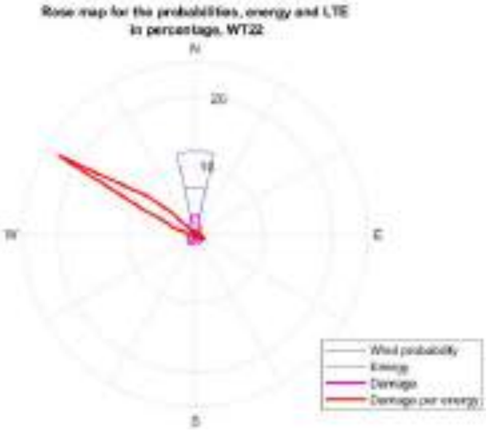
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT22



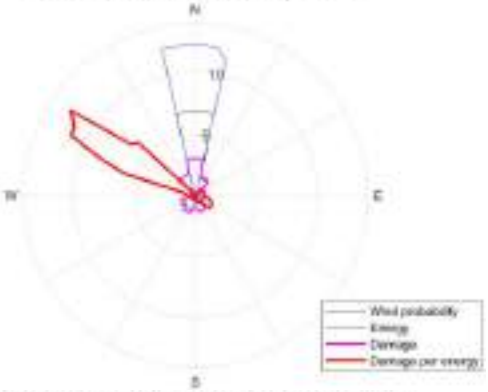
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT22



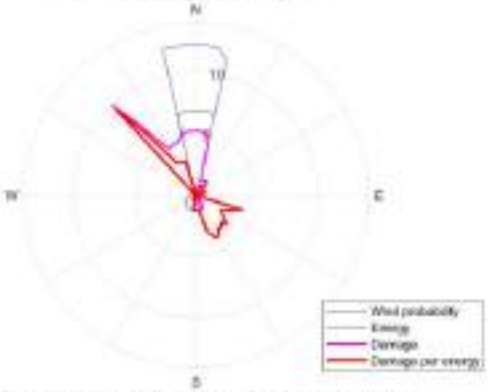

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT22
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT22
N
20
10
W
E
S
Wind probability
Energy
Damage
Damage per energy

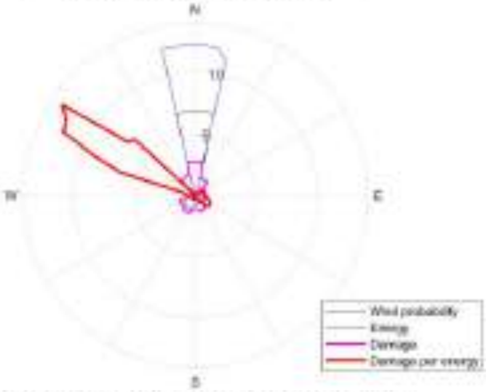
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT23



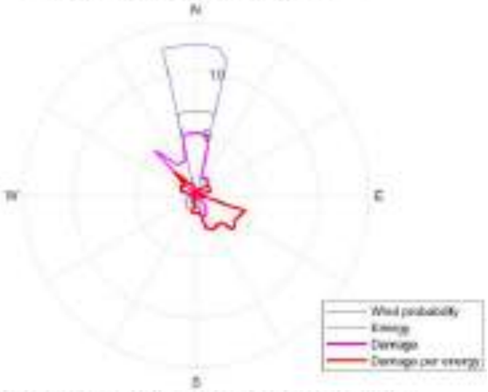
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT23



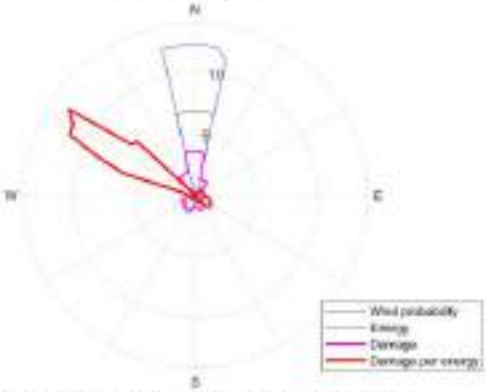
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT23



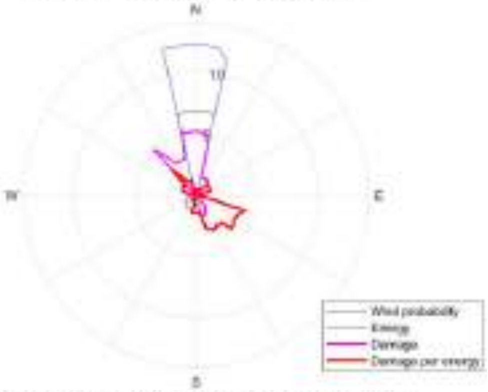
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT23



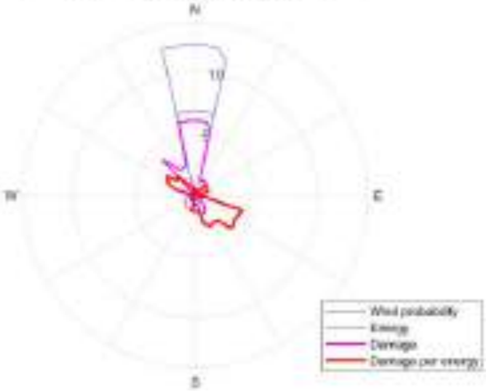
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT23



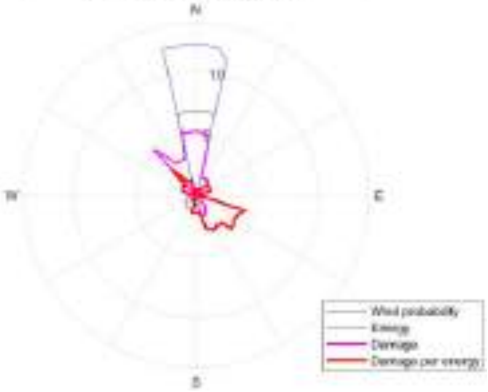
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT23

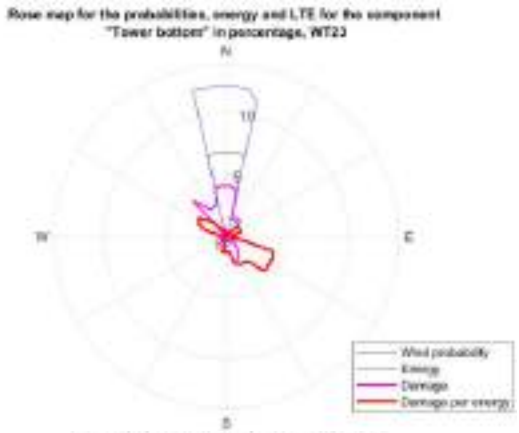


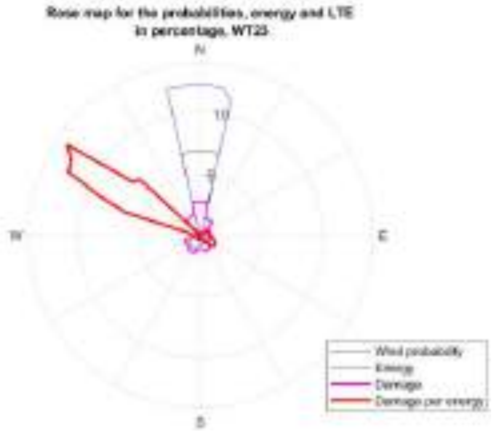
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT23



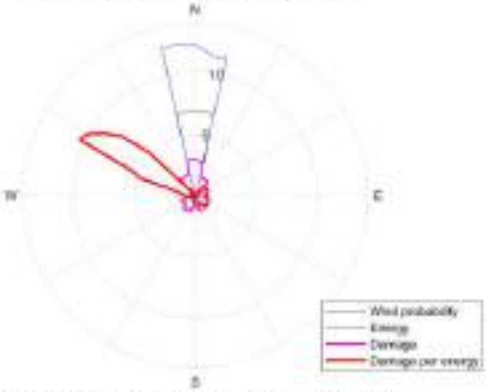
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT23



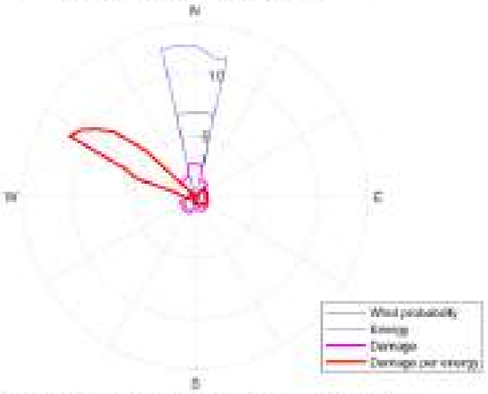

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT23
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT23
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

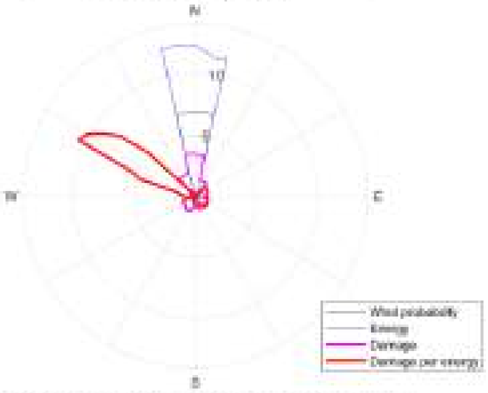
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT24



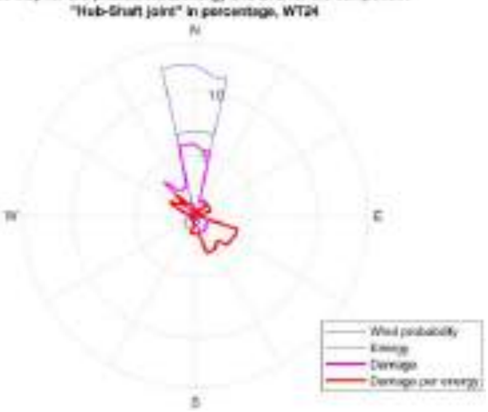
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT24



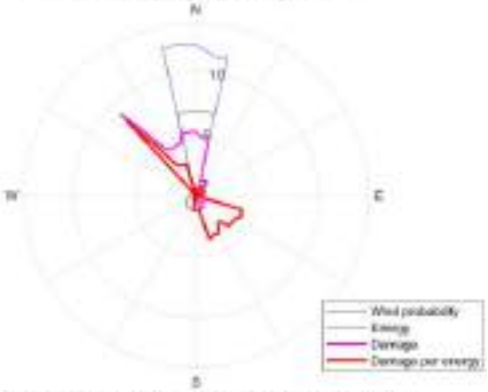
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT24



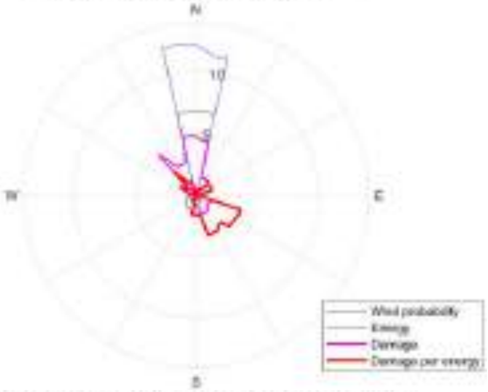
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT24



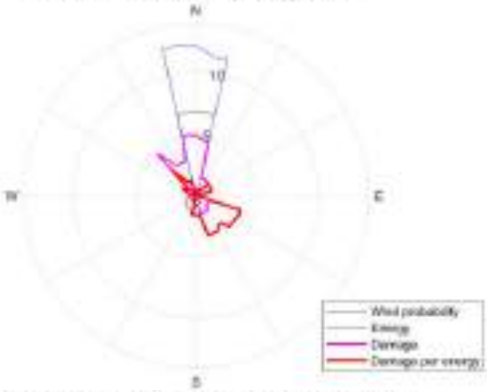
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT24



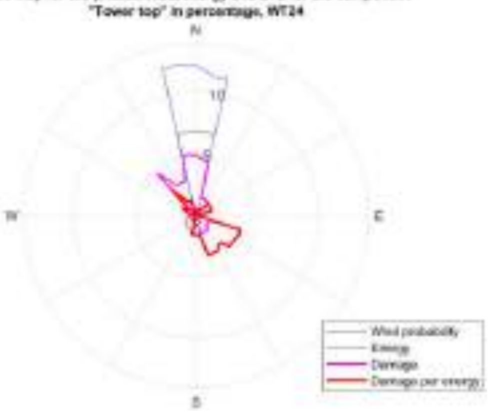
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT24

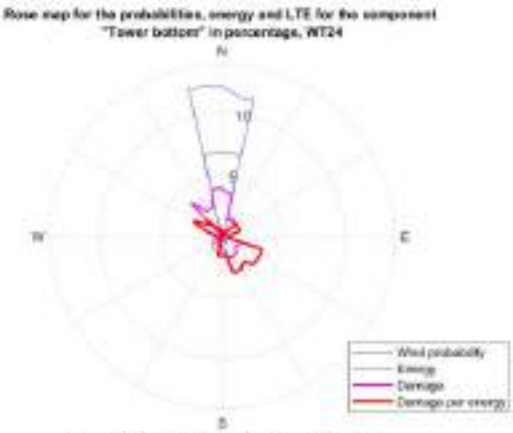


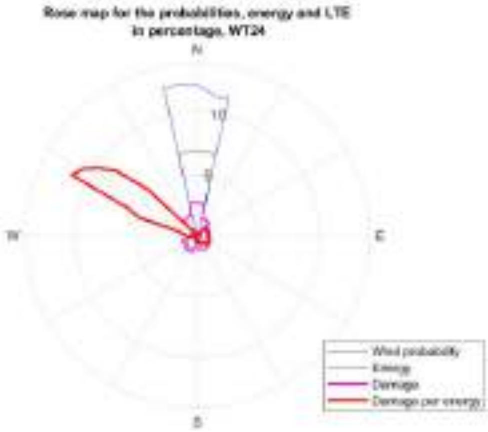
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT24



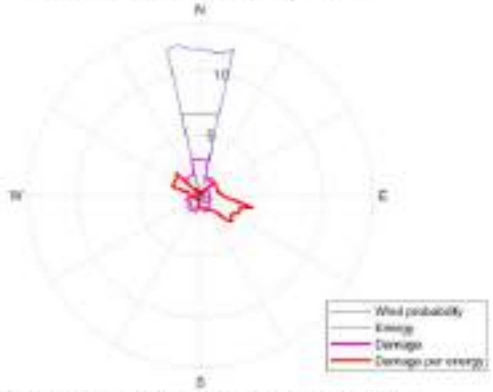
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT24



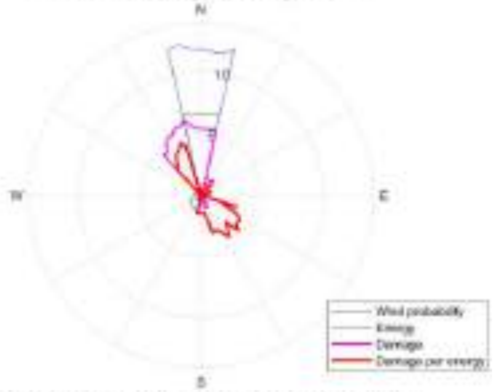

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT24
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT24
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

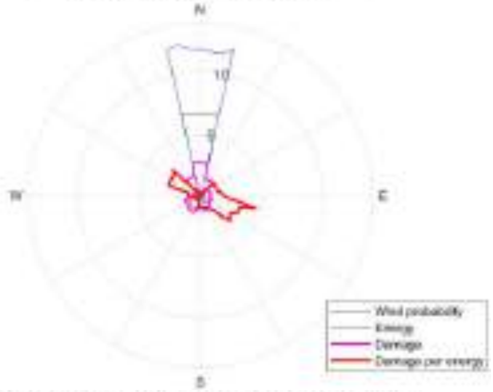
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT25



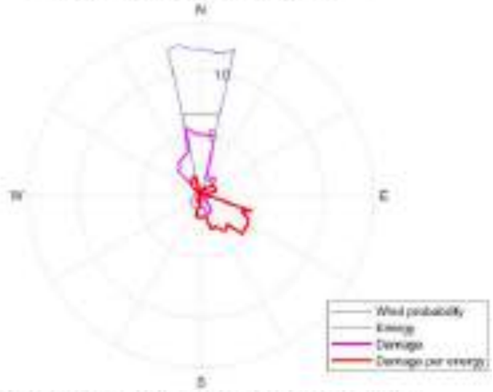
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT25



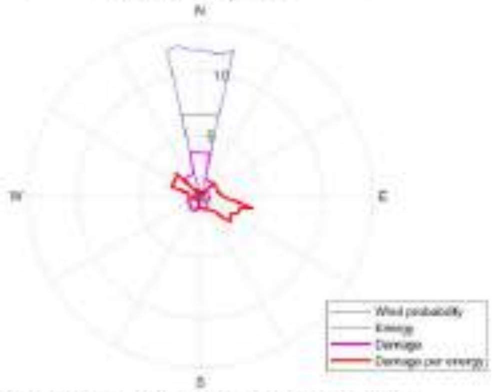
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT25



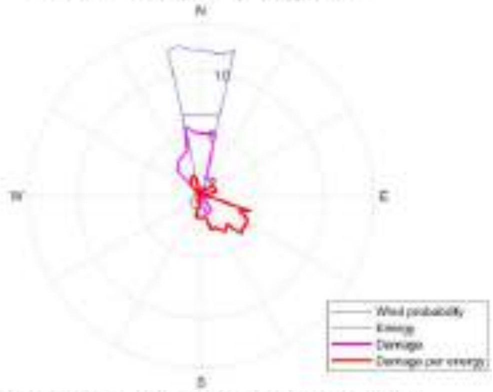
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT25



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT25

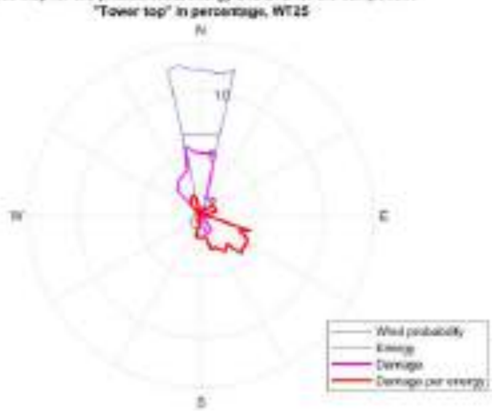


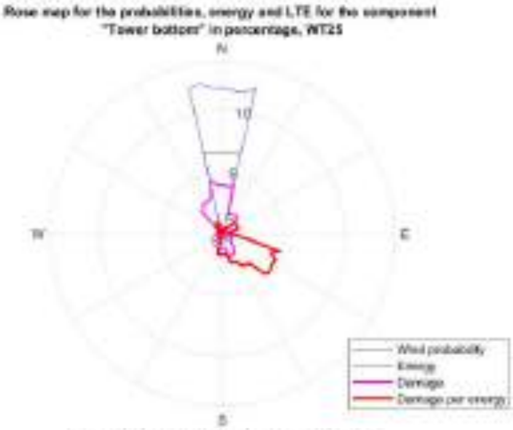
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT25

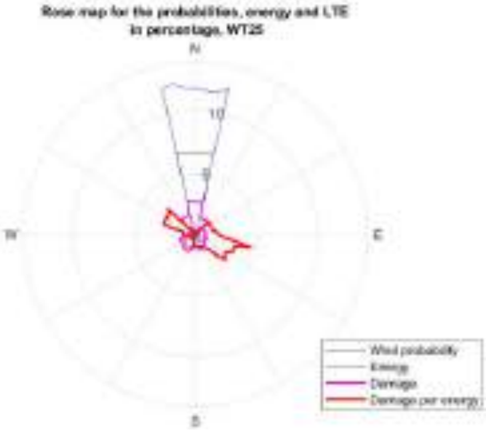


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT25

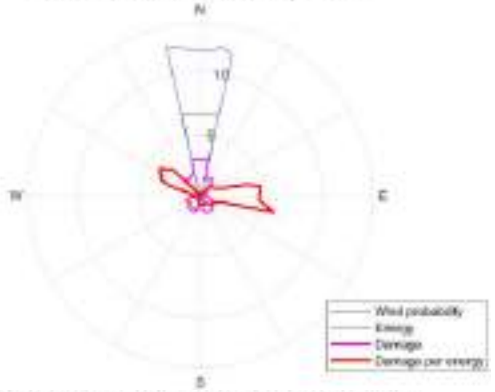
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT25



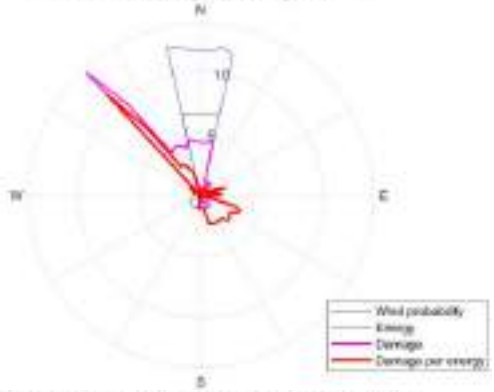

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT25
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT25
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

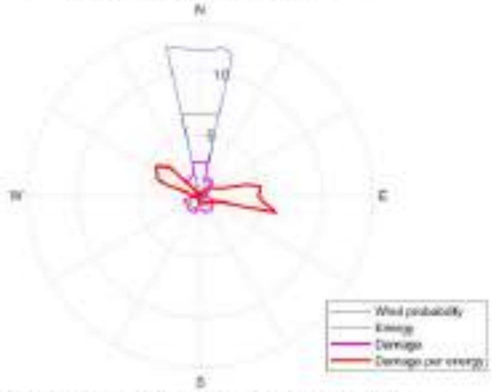
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT26



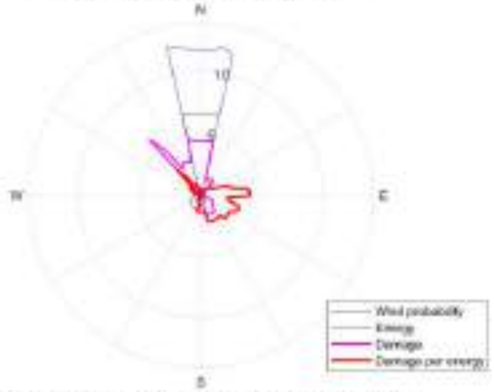
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT26



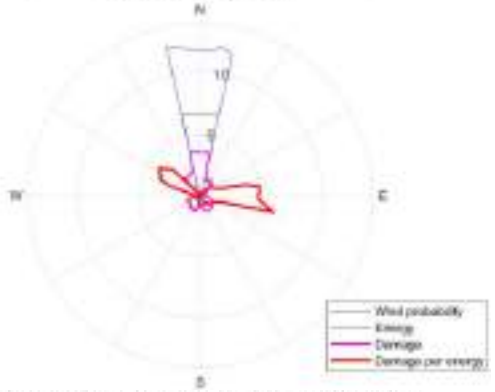
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT26



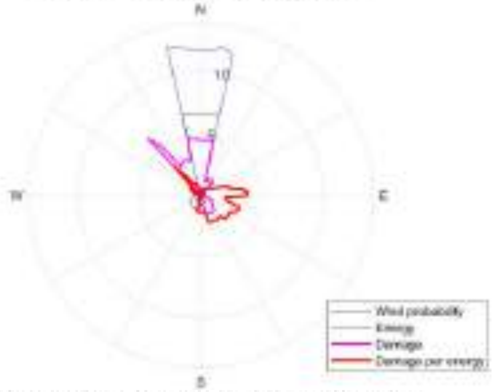
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT26



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT26



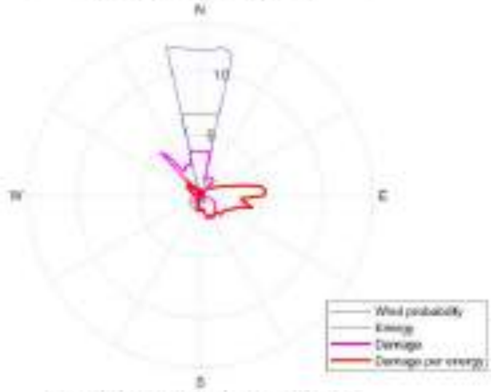
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT26



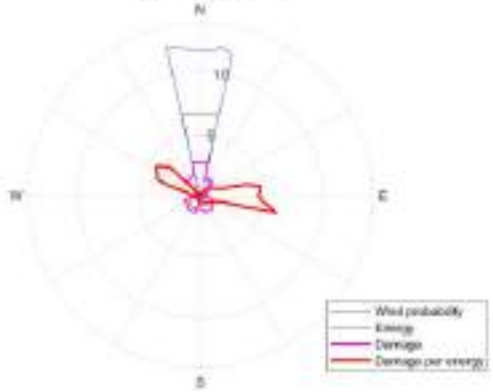
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT26

Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT26

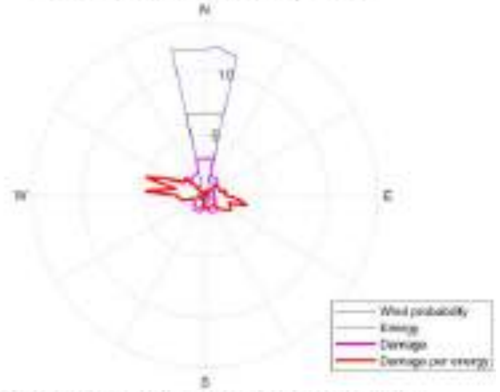
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT26



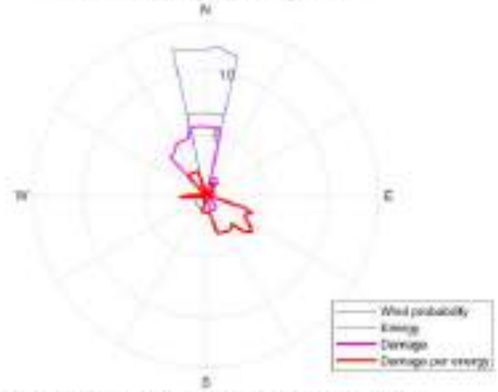
Rose map for the probabilities, energy and LTE in percentage, WT26



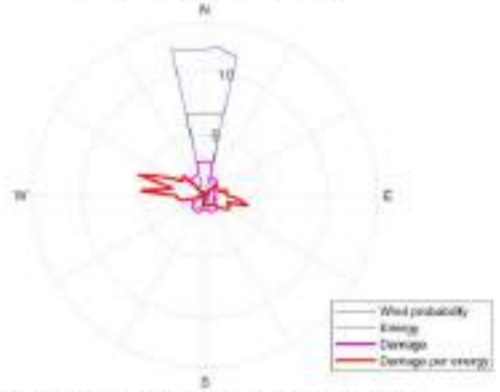
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT27



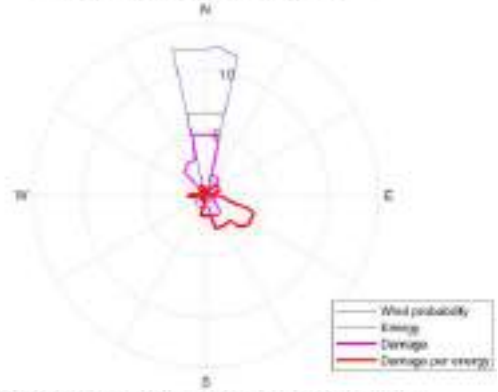
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT27



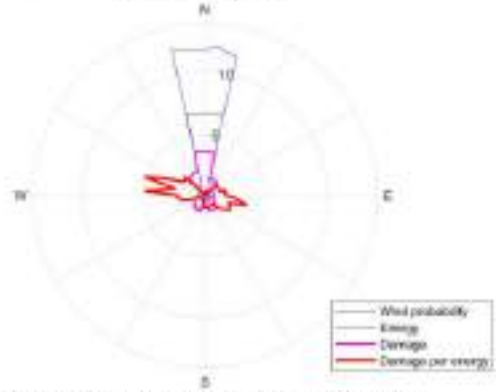
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT27



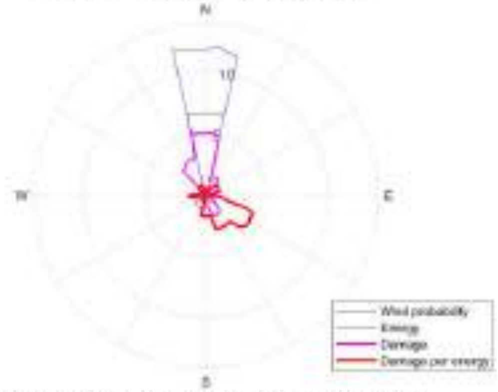
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT27



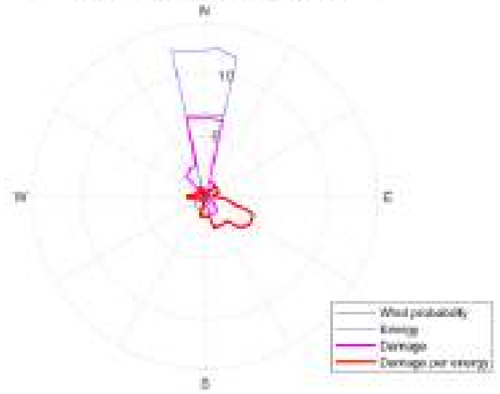
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT27



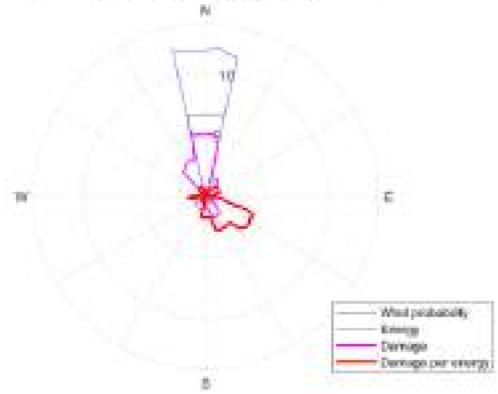
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT27



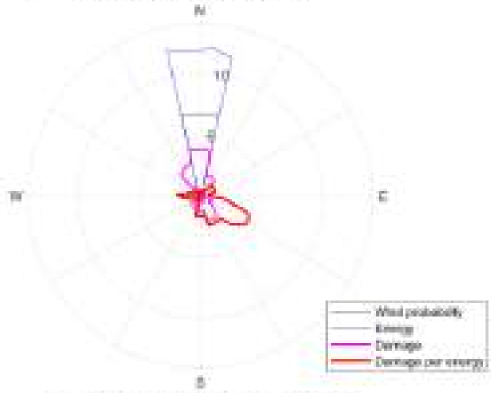
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT27



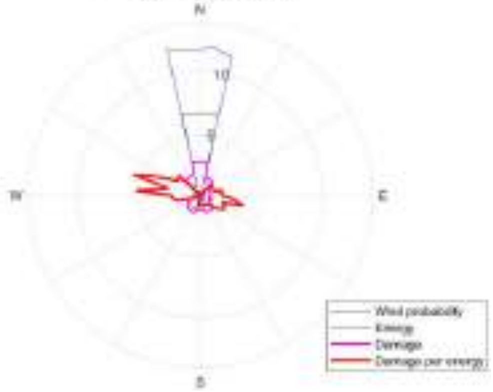
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT27



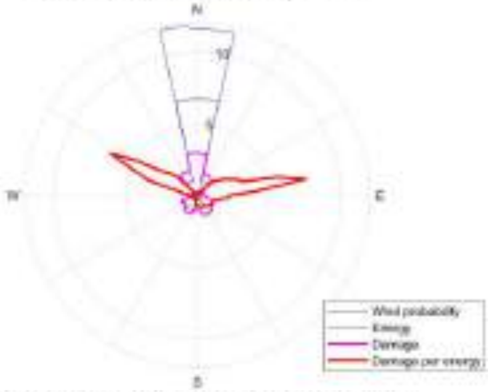
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT27



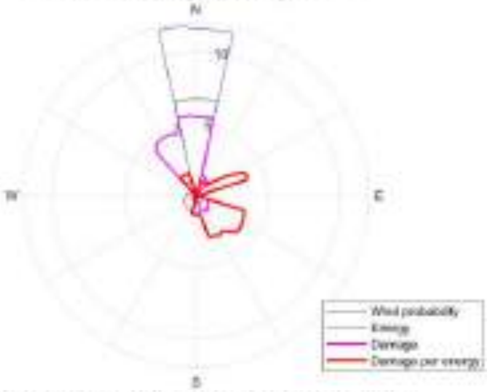
Rose map for the probabilities, energy and LTE in percentage, WT27



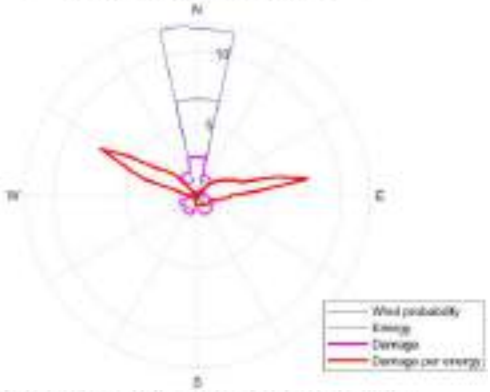
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT28



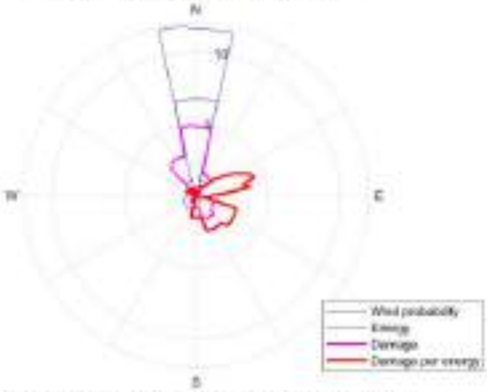
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT28



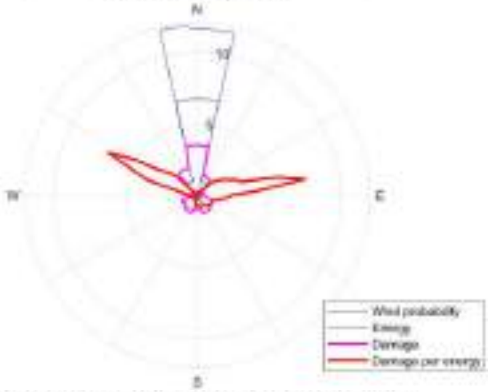
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT28



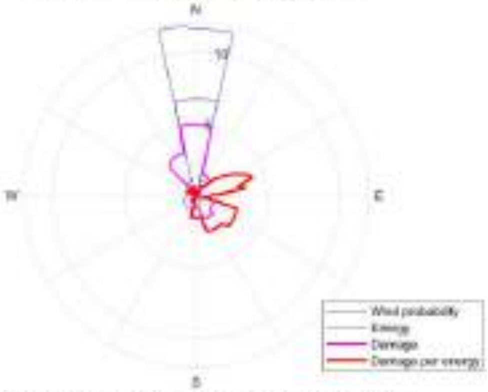
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT28



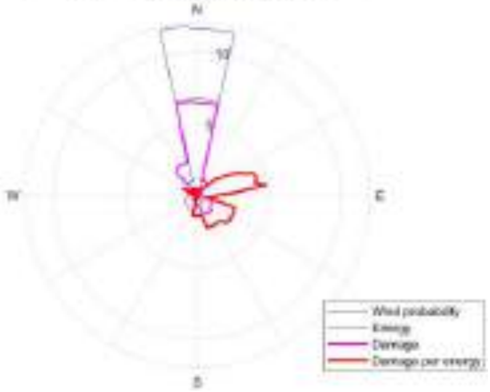
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT28



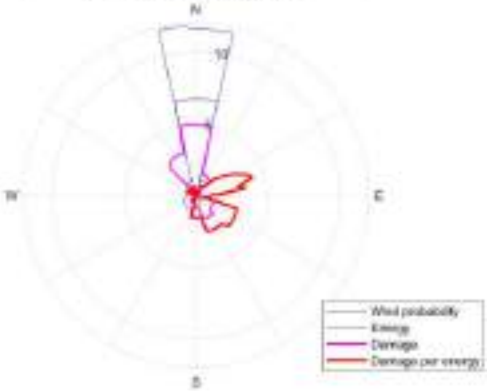
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT28

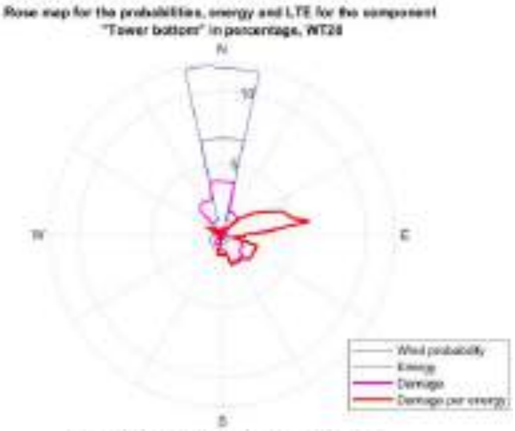


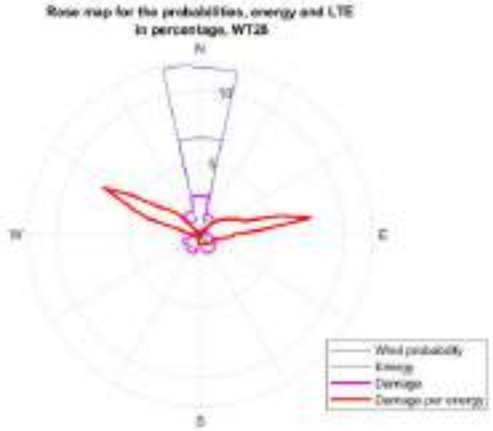
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT28



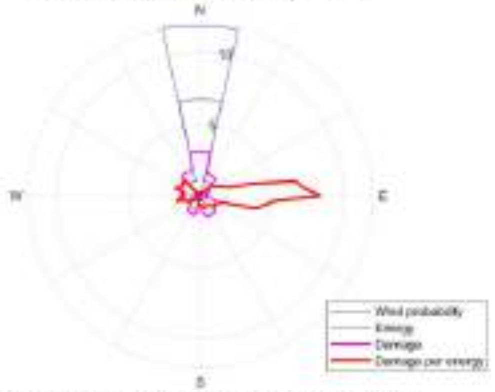
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT28



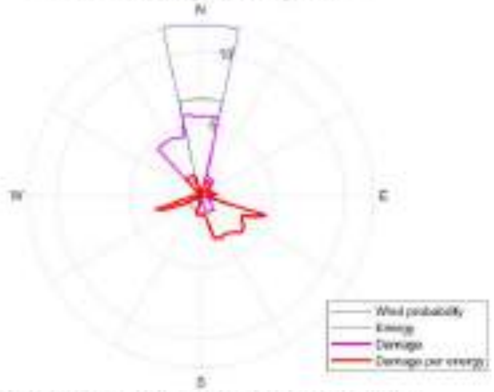

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT28
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT28
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy

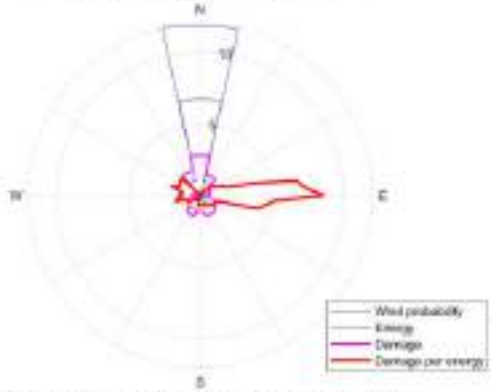
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT29



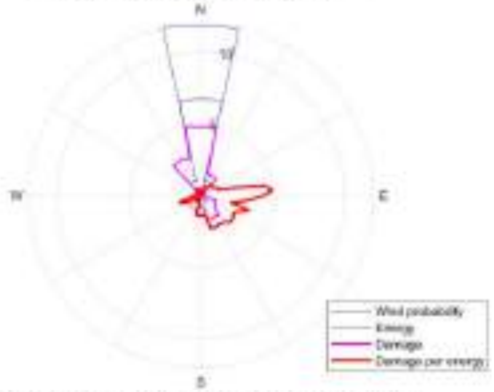
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT29



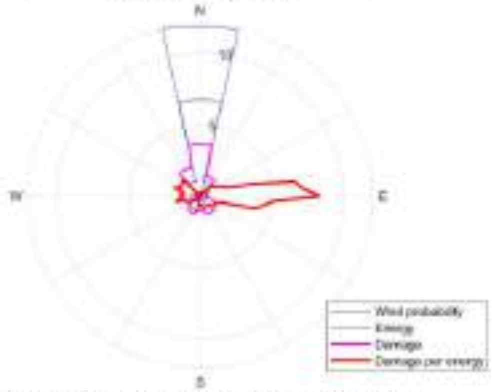
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT29



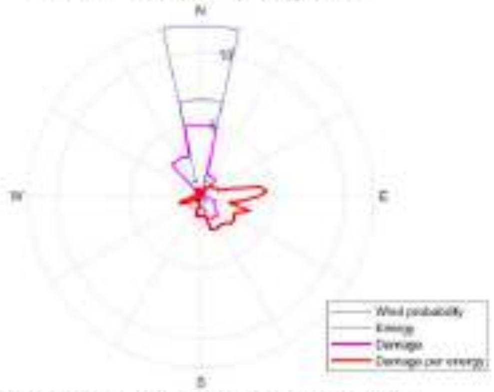
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT29



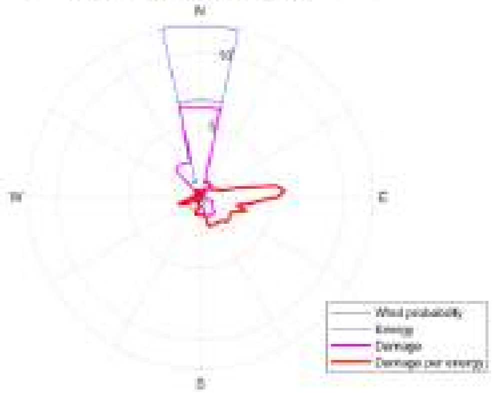
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT29



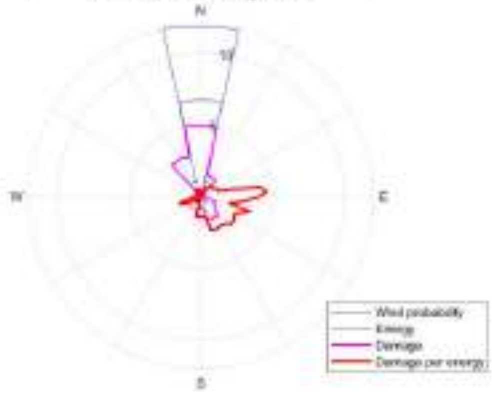
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT29



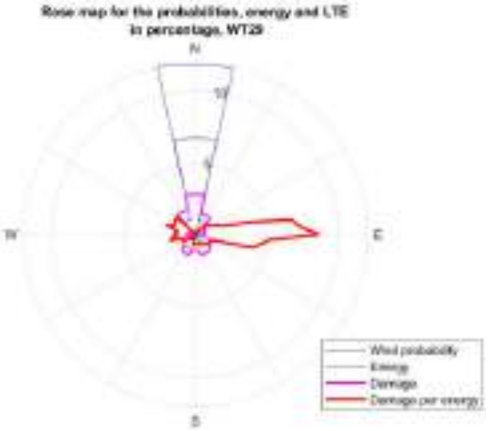
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT29



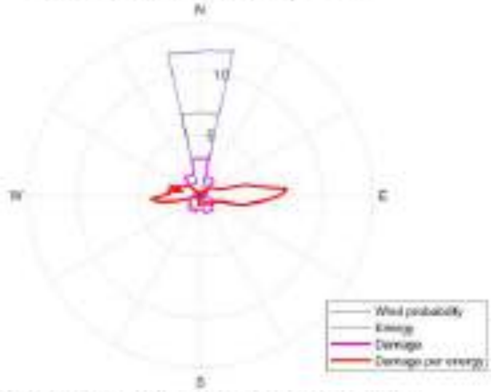
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT29



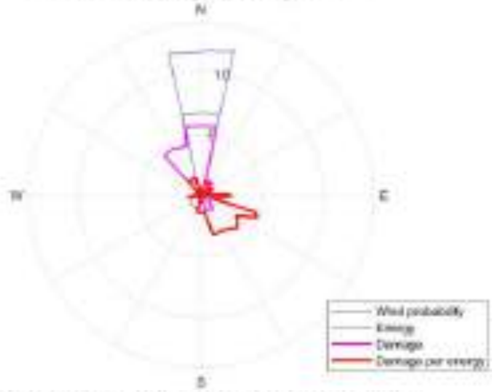

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT29
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT29
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

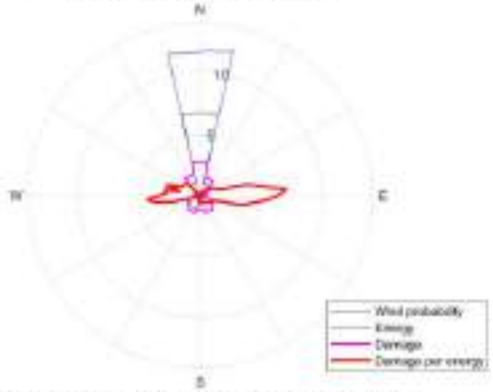
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT38



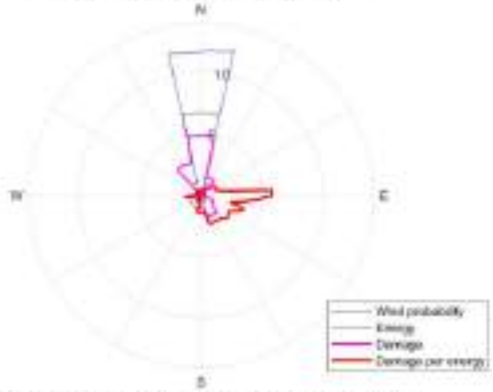
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT38



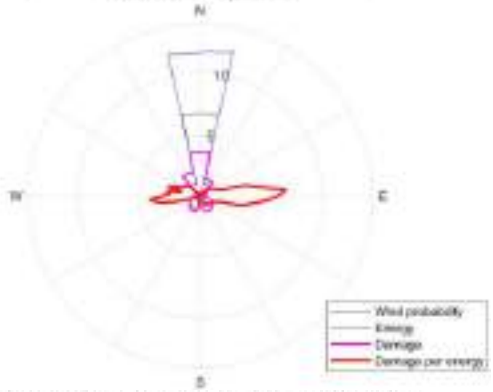
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT38



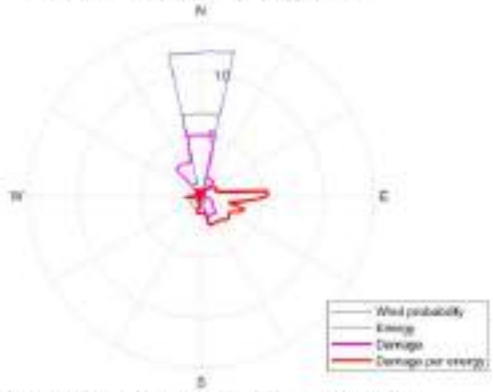
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT38



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT38

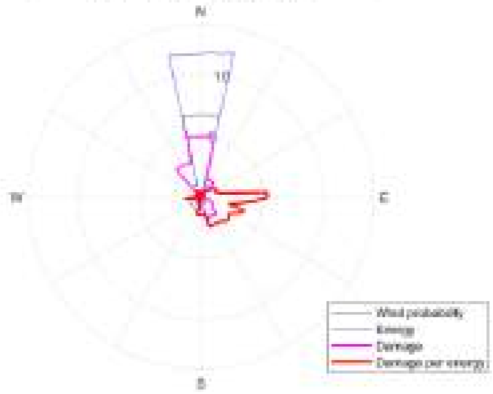


Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT38

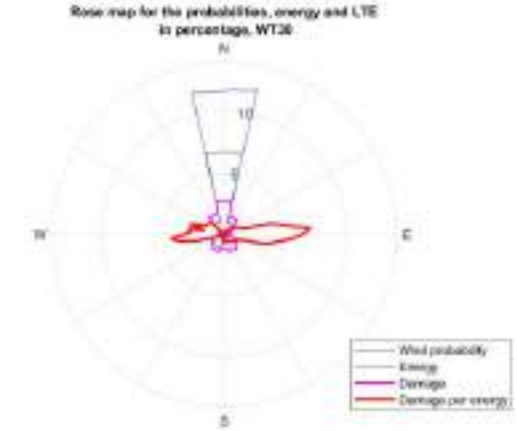


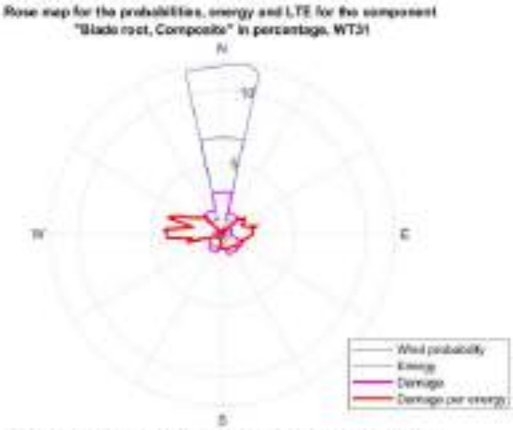
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT38

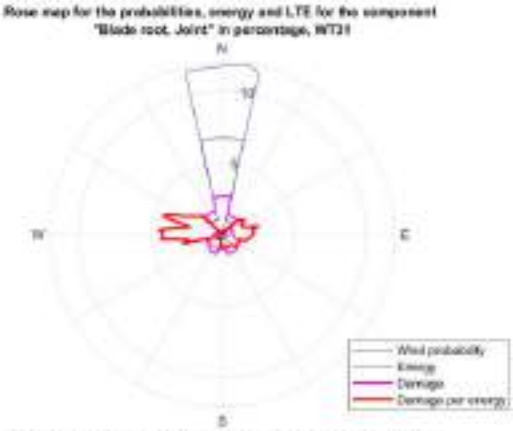
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT38

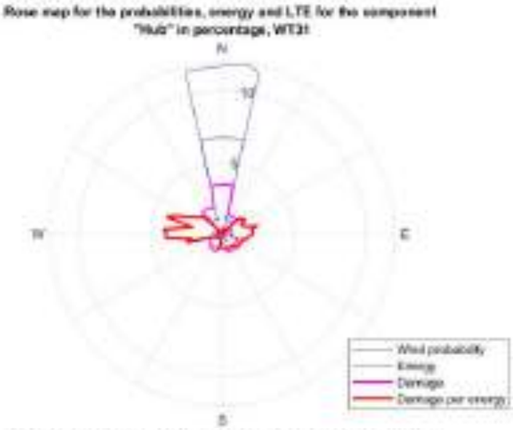


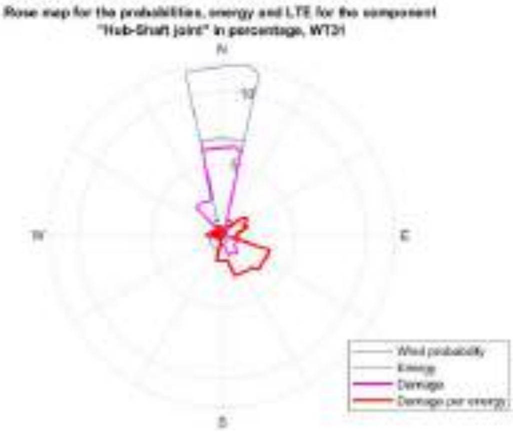

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT30
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

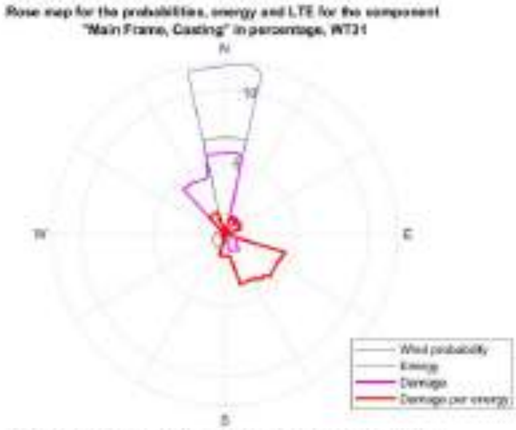

Rose map for the probabilities, energy and LTE in percentage, WT30
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

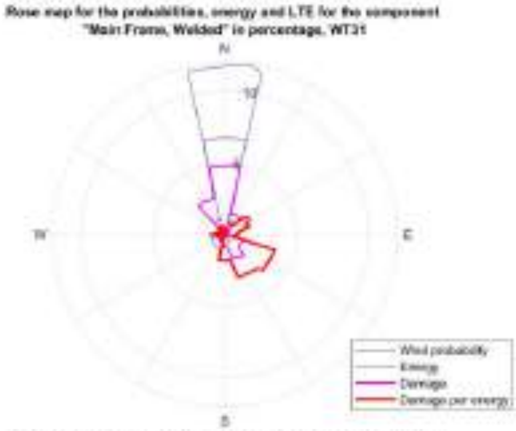

Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT31
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

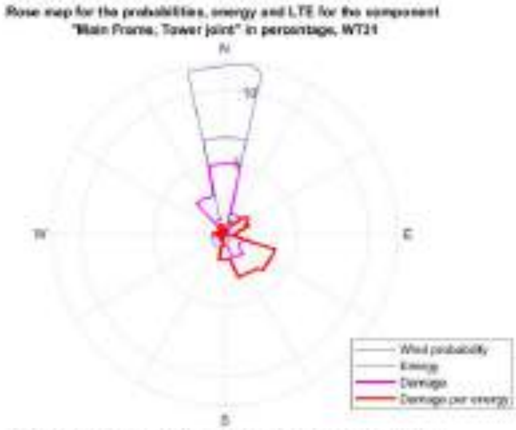

Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT31
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

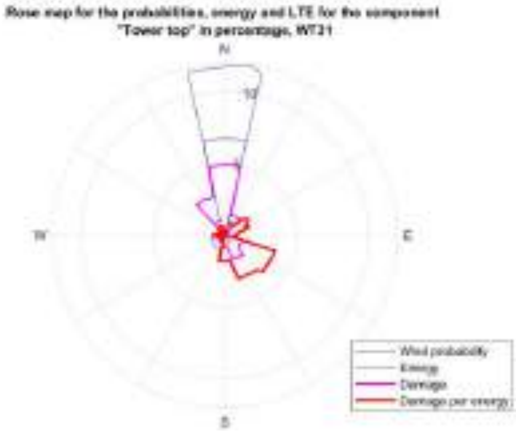

Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT31
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT31
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

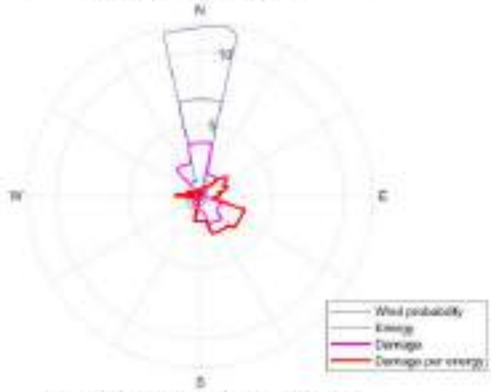

Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT31
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT31
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

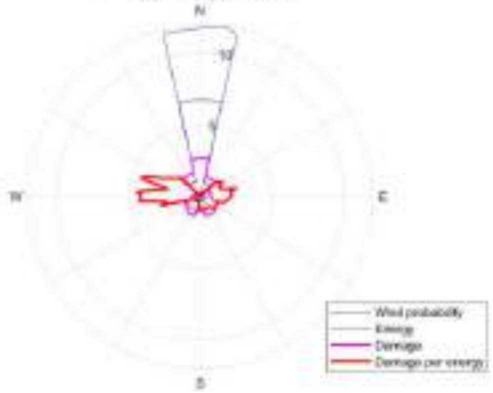

Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT31
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT31
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

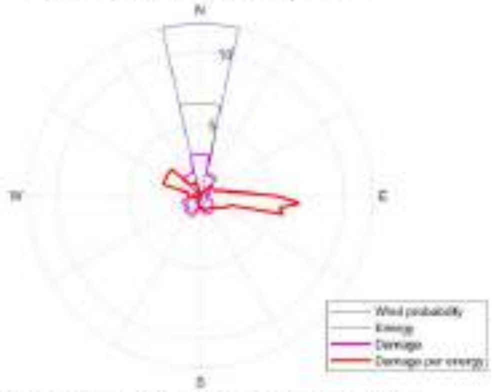
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT31



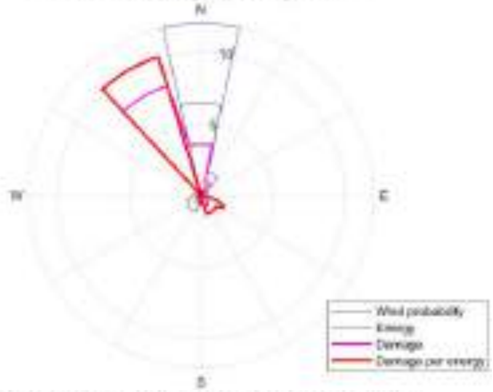
Rose map for the probabilities, energy and LTE in percentage, WT31



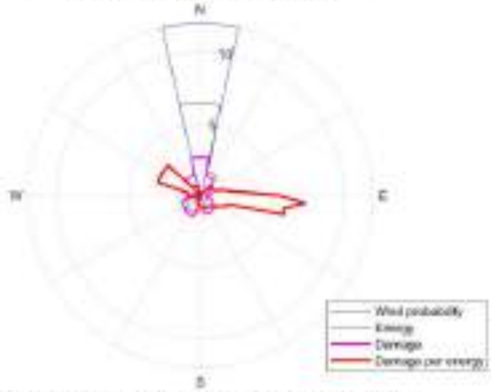
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT32



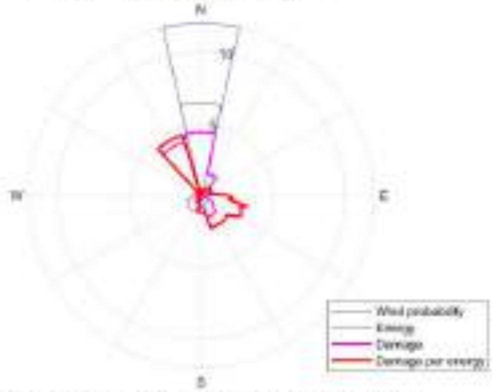
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT32



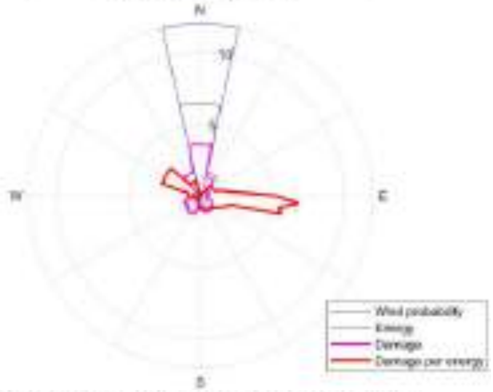
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT32



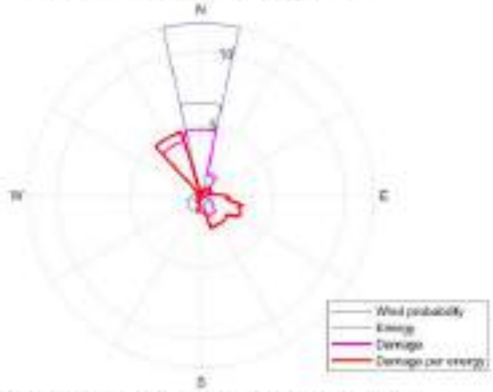
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT32



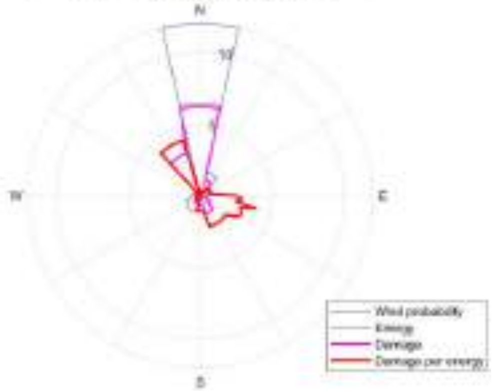
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT32



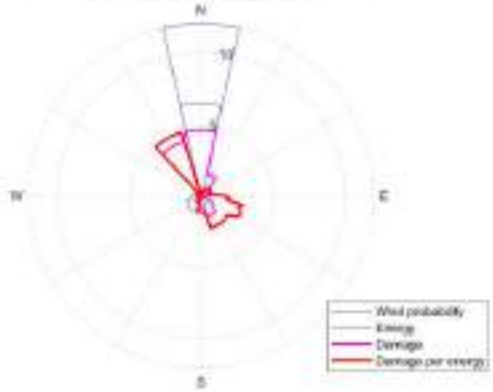
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT32

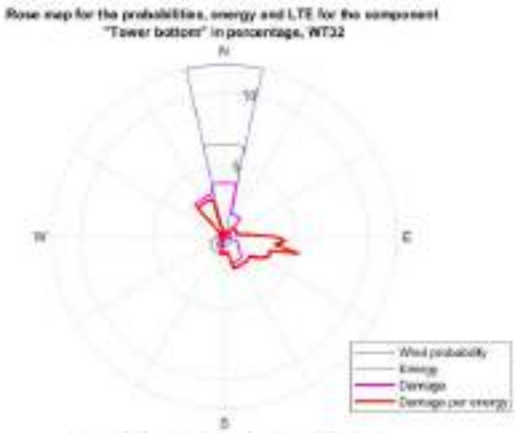


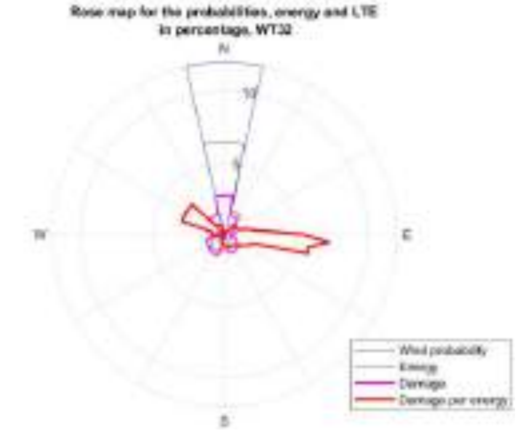
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT32



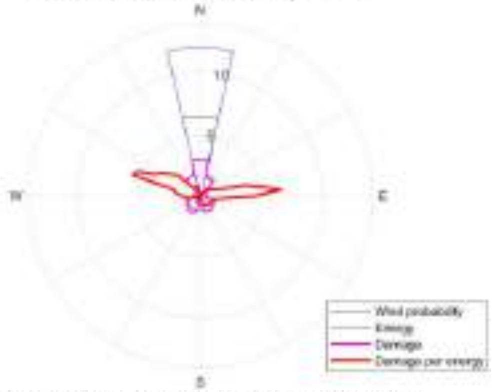
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT32



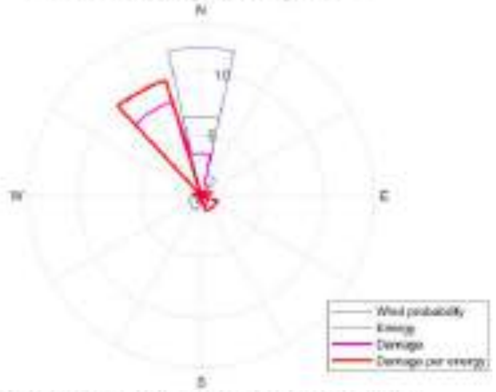

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT32
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT32
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

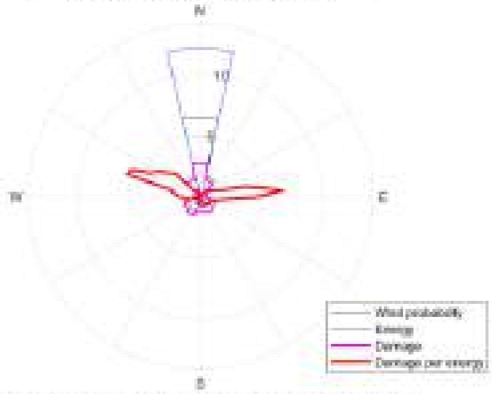
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT33



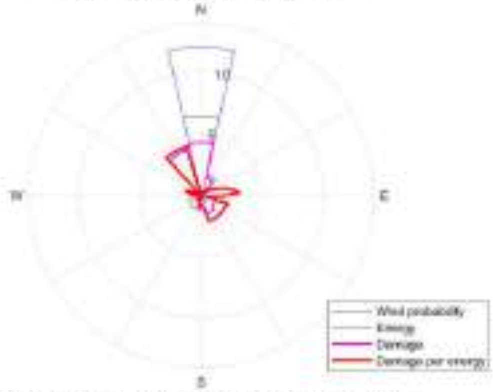
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT33



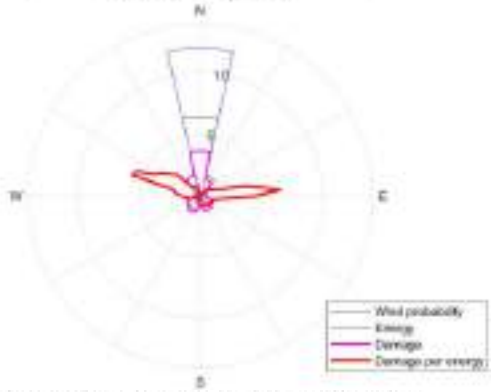
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT33



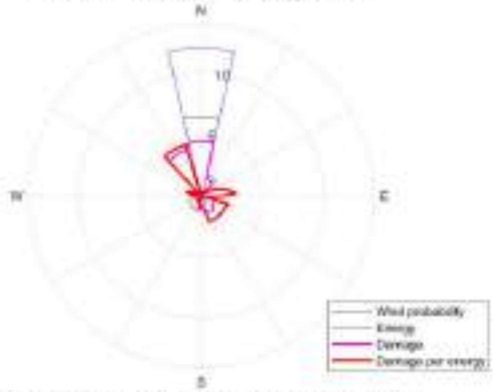
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT33



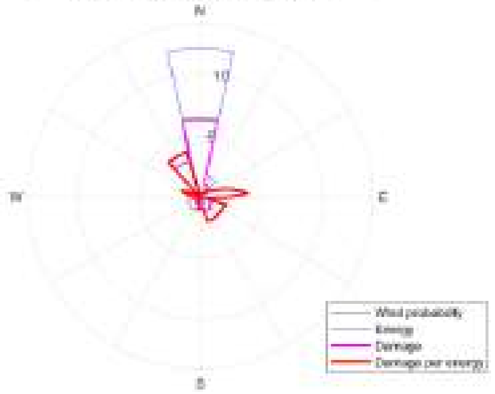
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT33



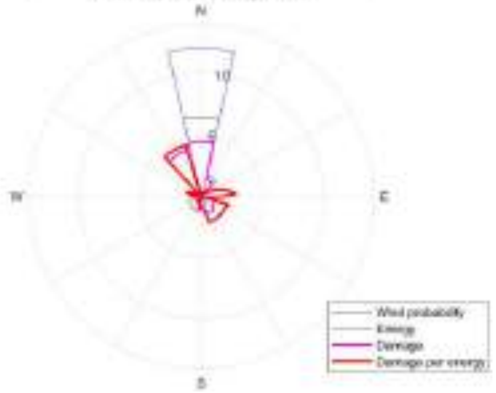
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT33



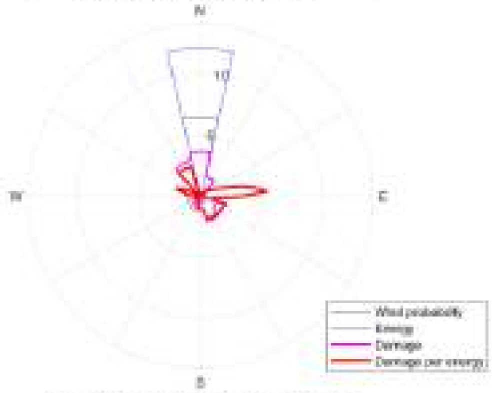
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT33



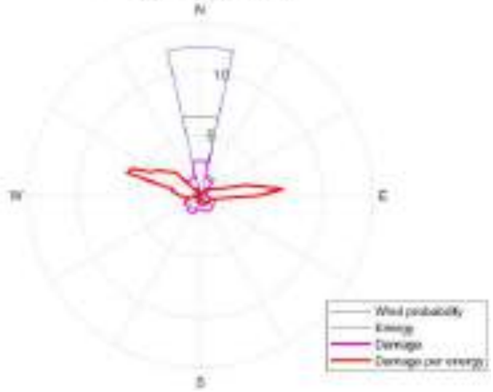
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT33



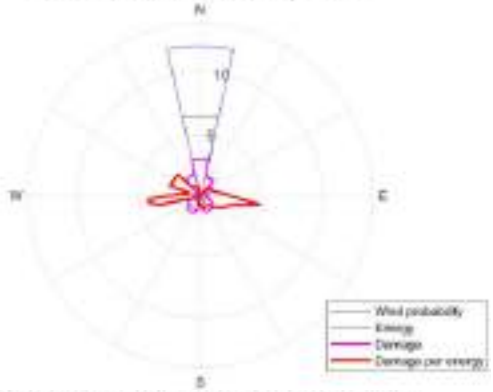
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT33



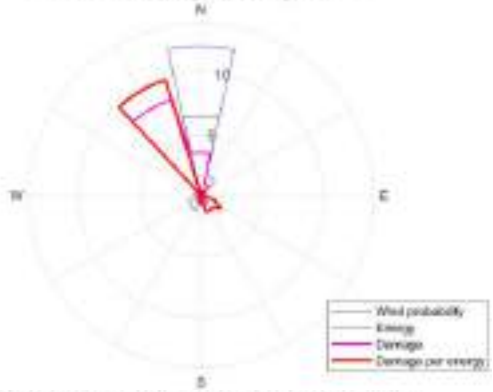
Rose map for the probabilities, energy and LTE in percentage, WT33



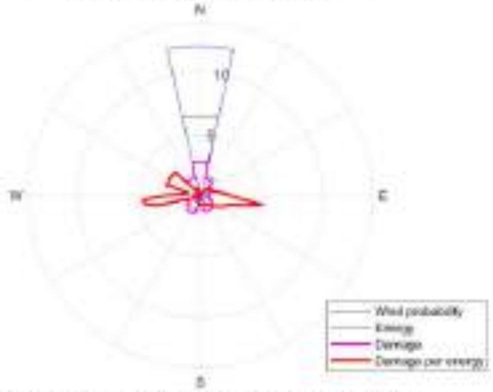
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT34



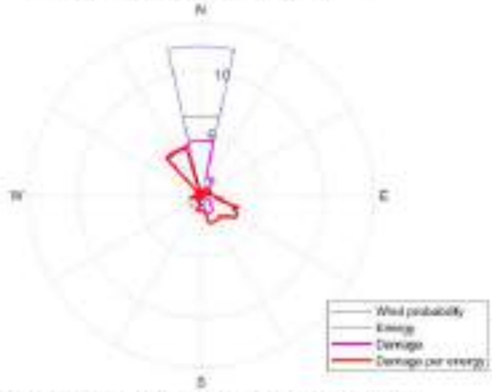
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT34



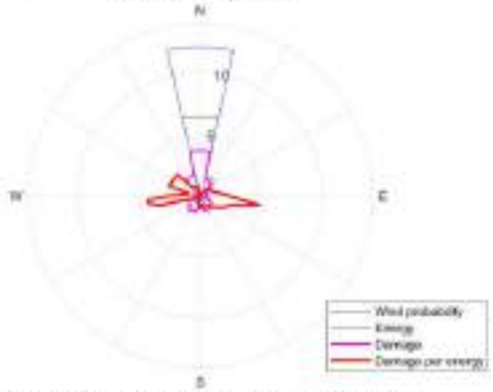
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT34



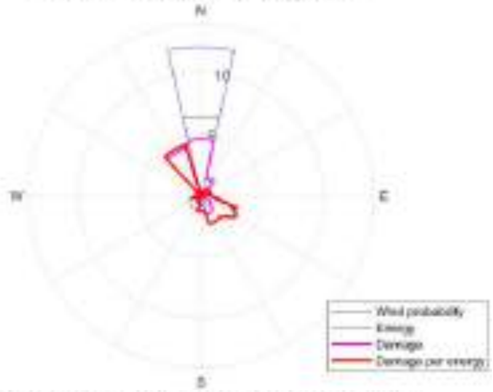
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT34



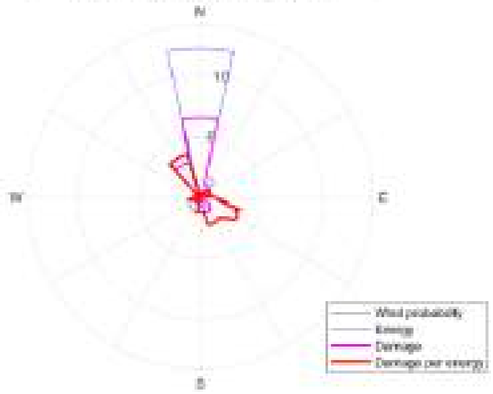
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT34



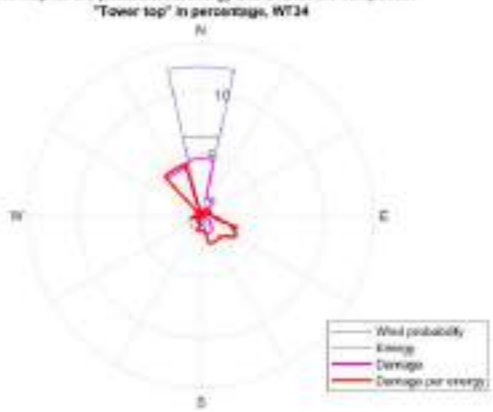
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT34

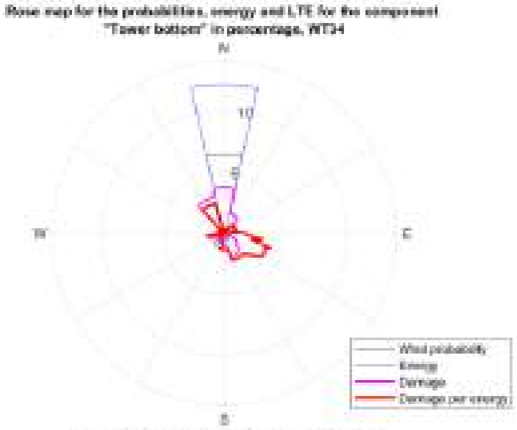


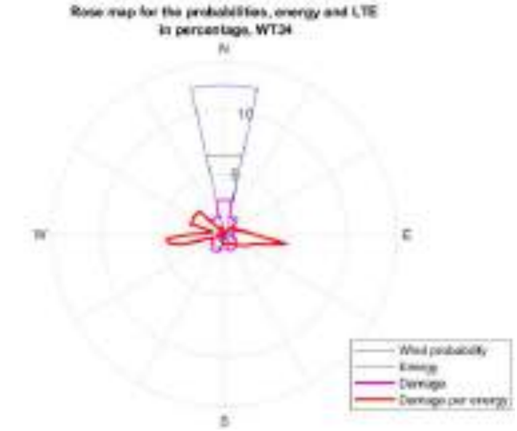
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT34



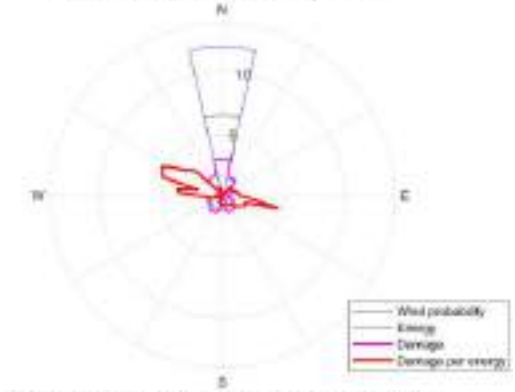
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT34



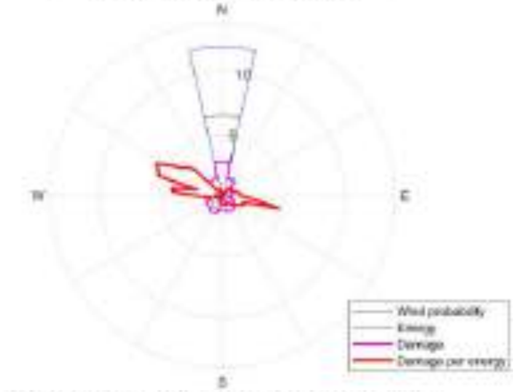

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT34
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT34
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

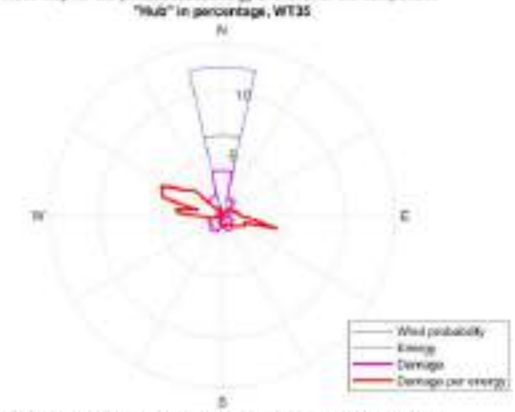
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT35



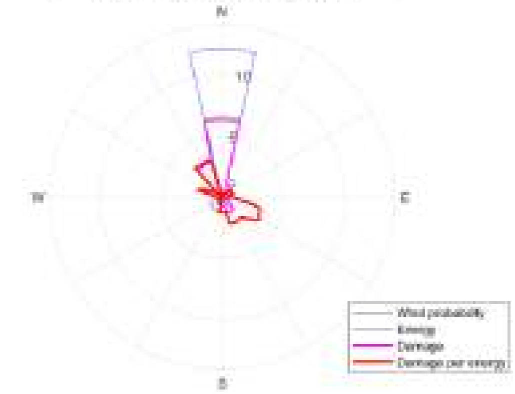
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT35



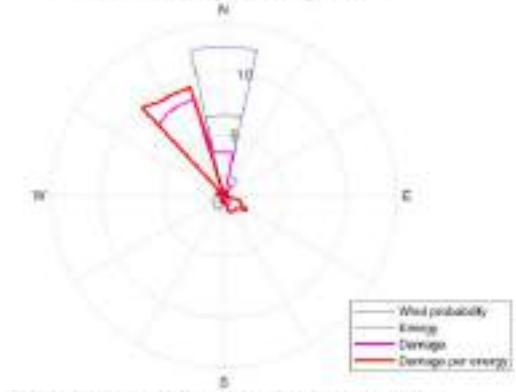
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT35



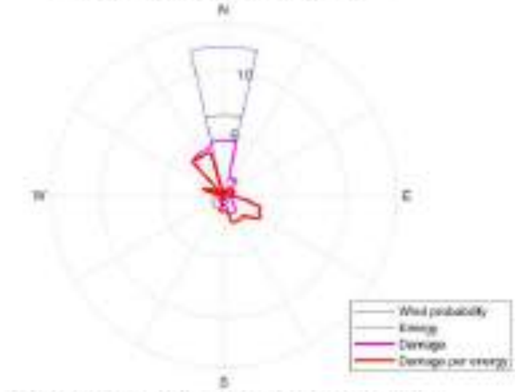
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT35



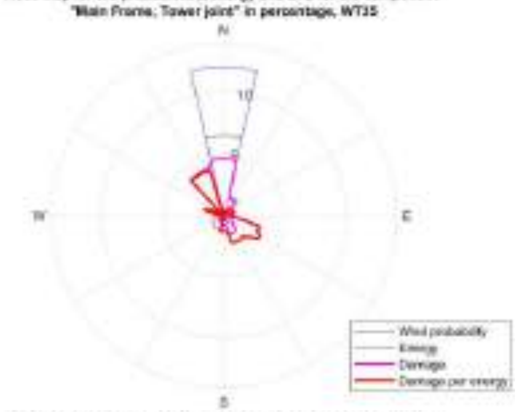
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT35



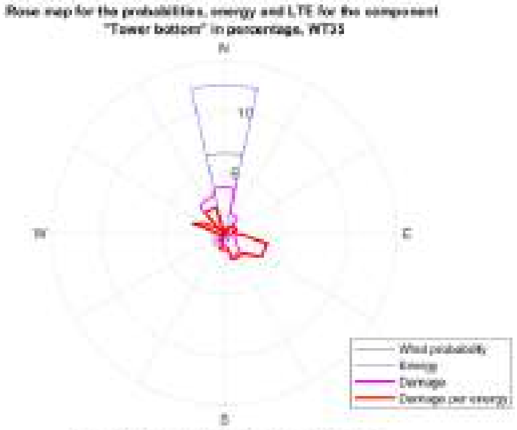
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT35

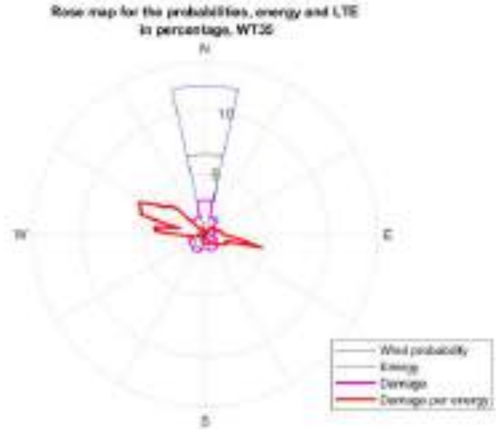


Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT35

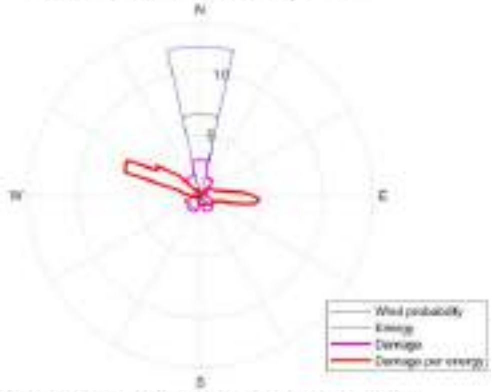


Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT35

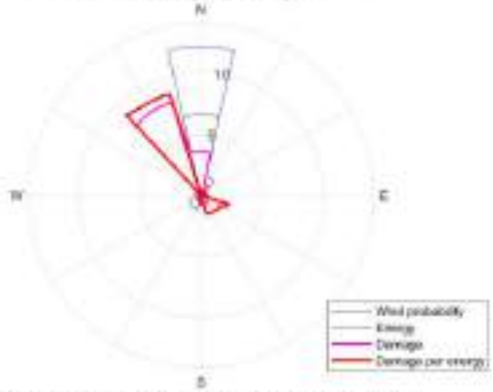

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT35
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT35
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

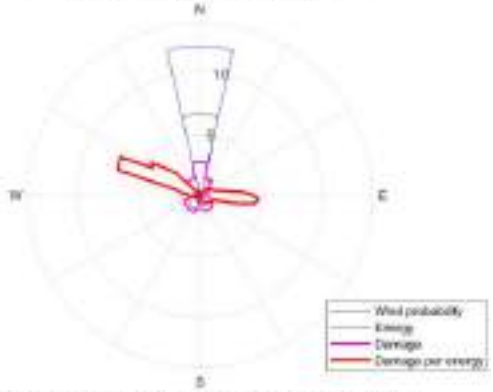
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT36



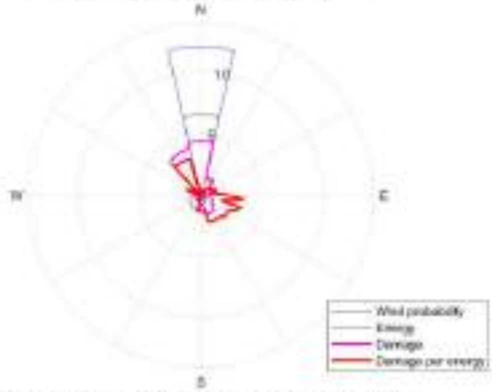
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT36



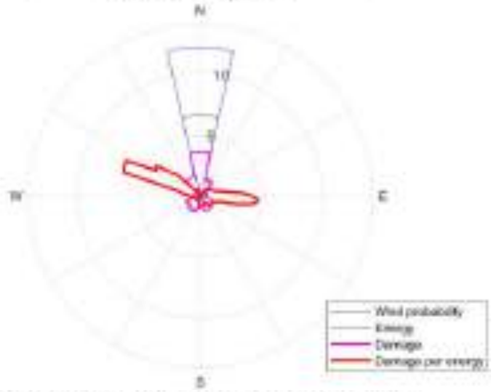
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT36



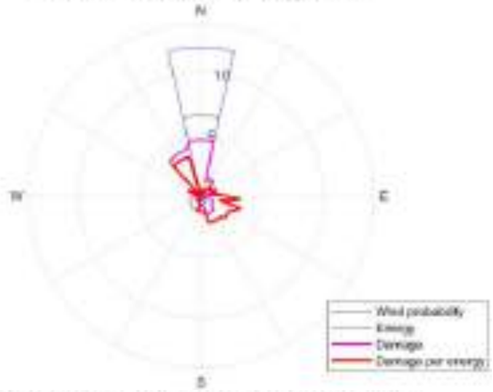
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT36



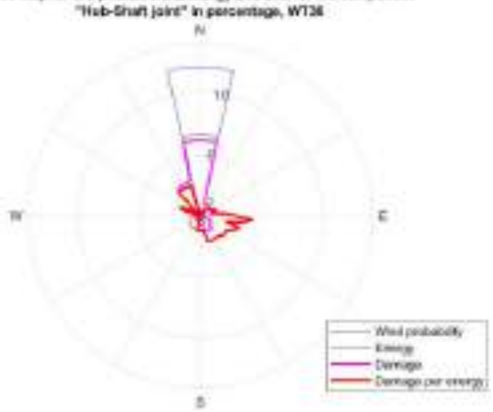
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT36



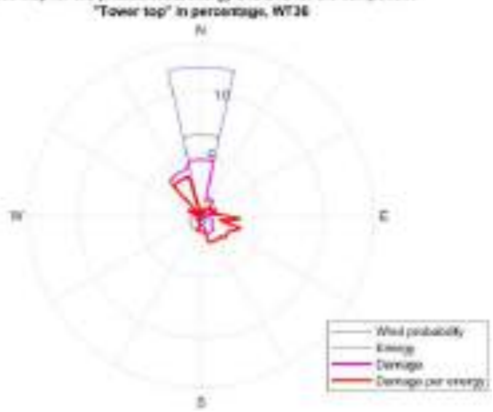
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT36



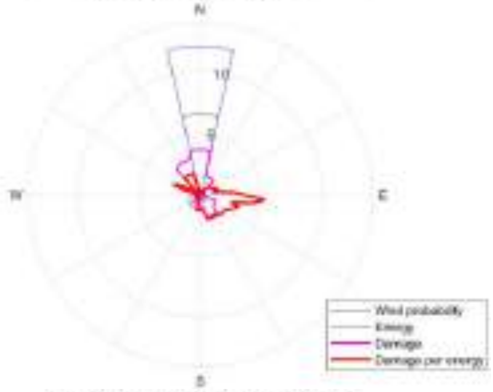
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT36



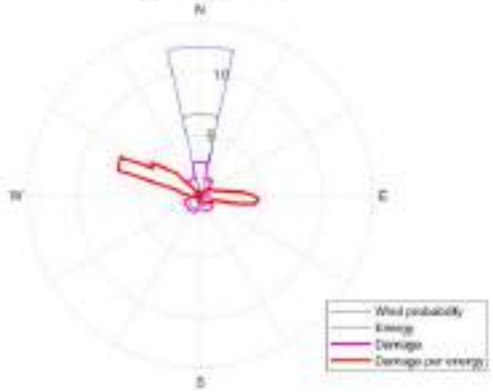
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT36



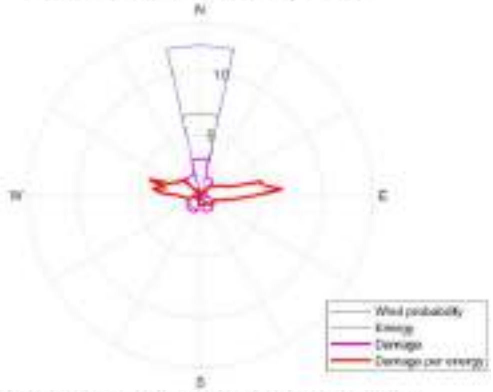
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT36



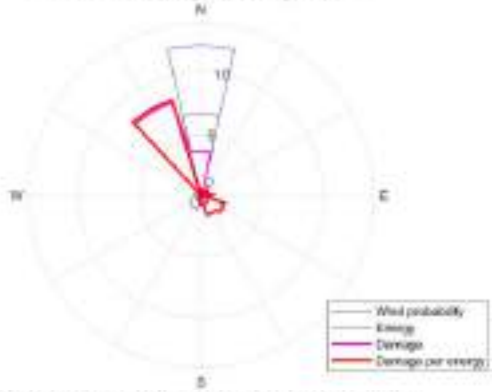
Rose map for the probabilities, energy and LTE in percentage, WT36



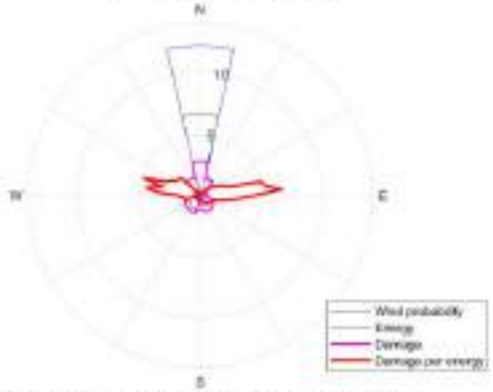
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT37



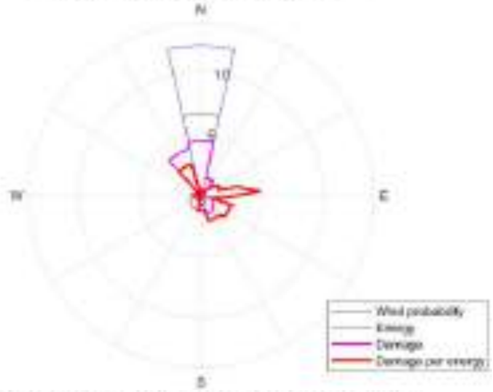
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT37



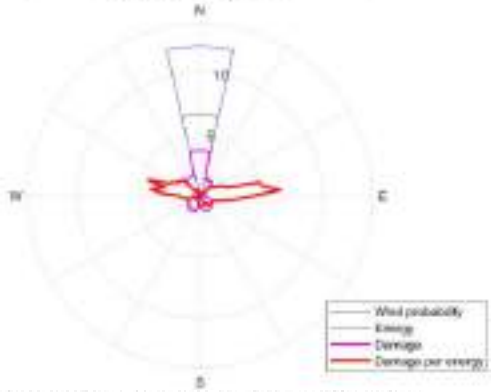
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT37



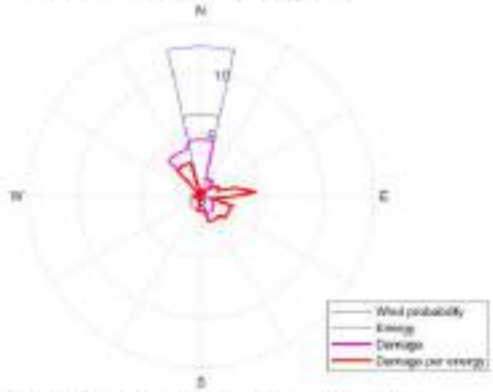
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT37



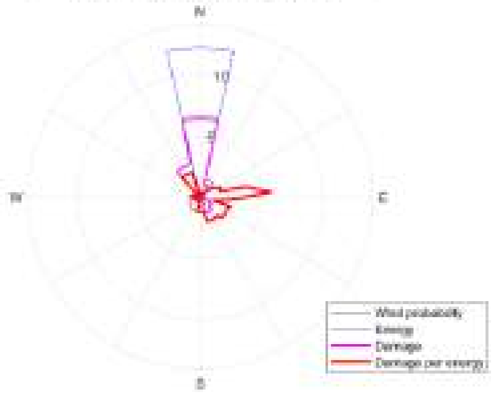
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT37



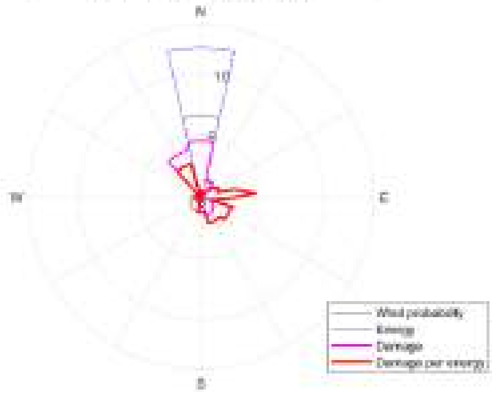
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT37



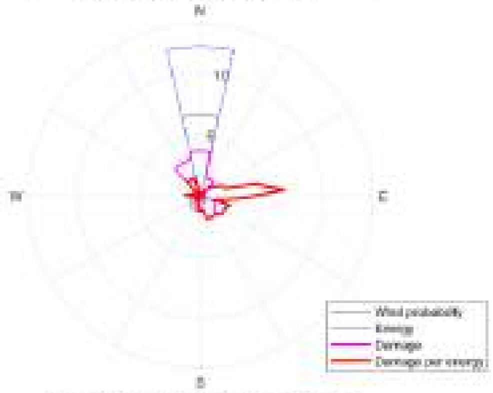
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT37



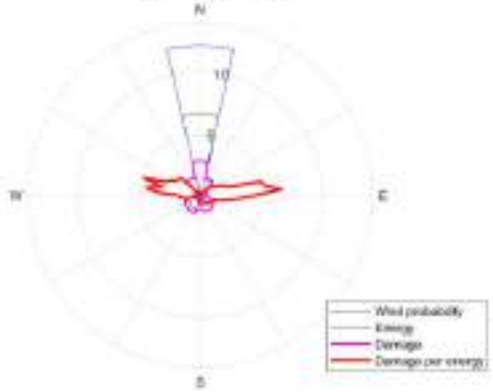
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT37



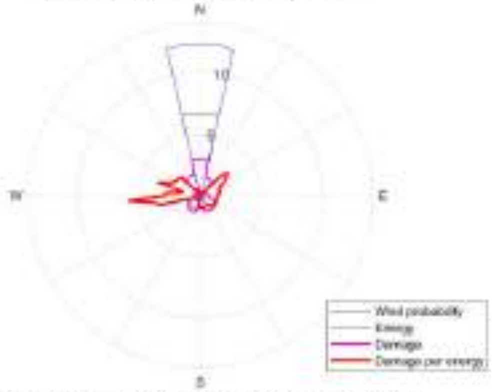
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT37



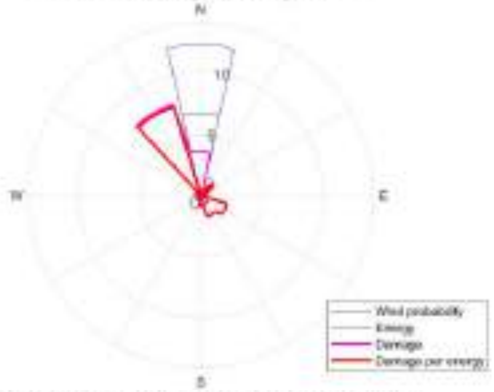
Rose map for the probabilities, energy and LTE in percentage, WT37



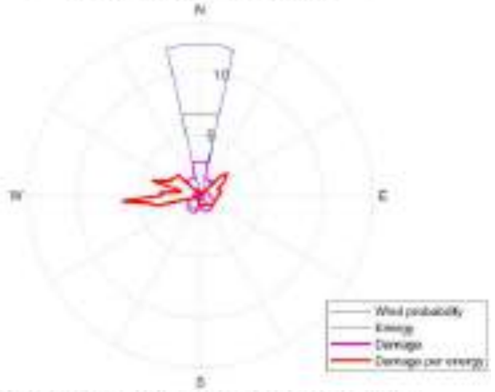
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT38



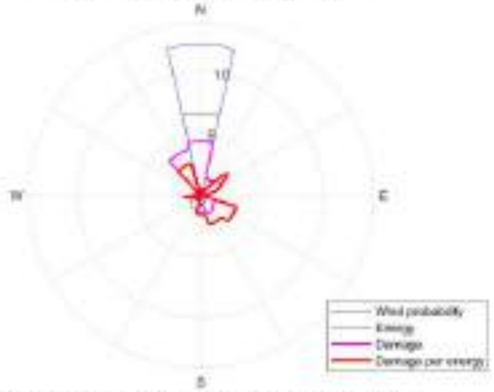
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT38



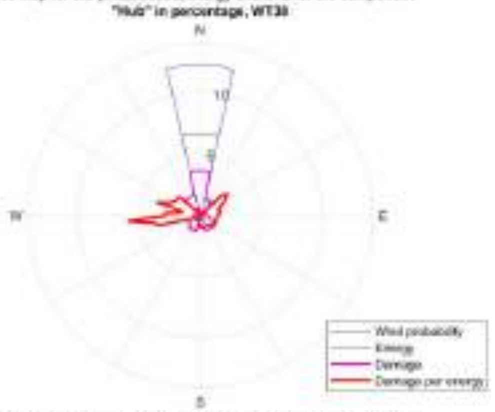
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT38



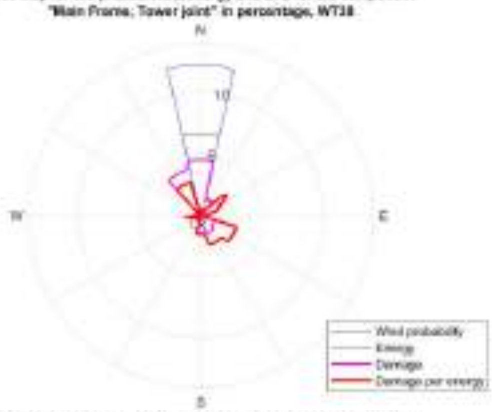
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT38



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT38

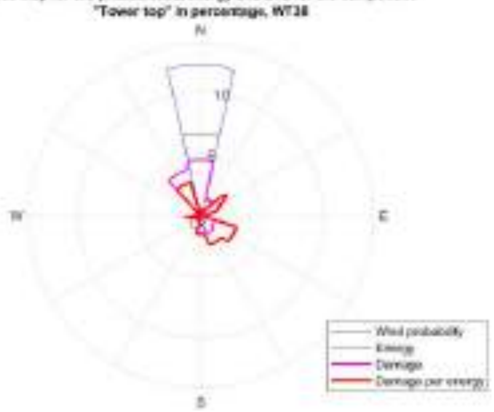


Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT38

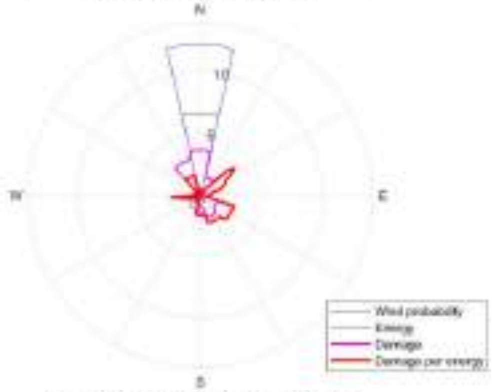


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT38

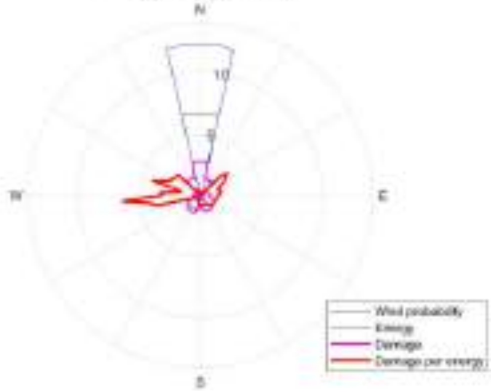
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT38



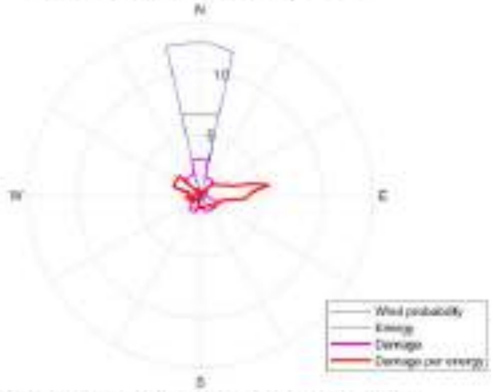
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT38



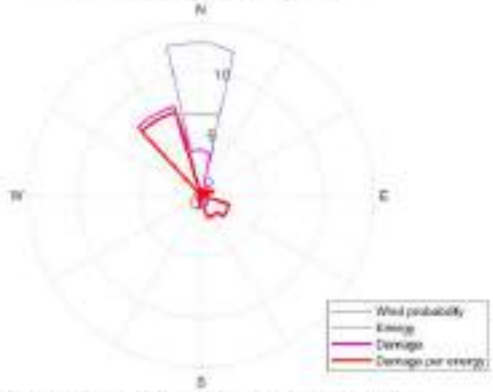
Rose map for the probabilities, energy and LTE in percentage, WT38



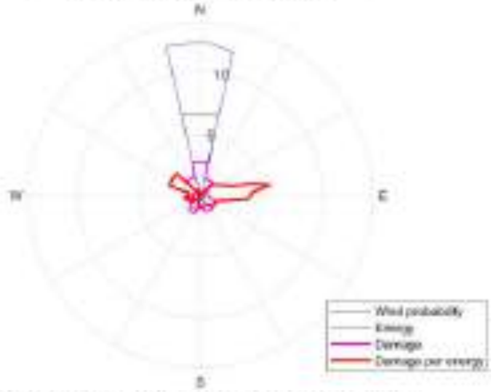
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT39



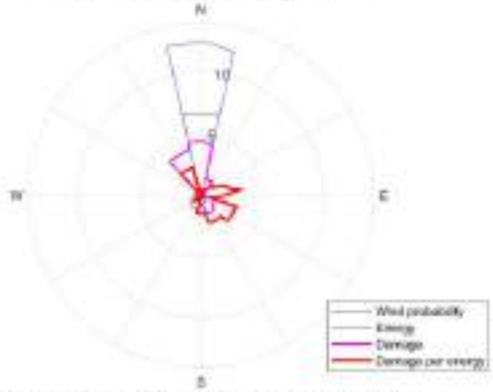
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT39



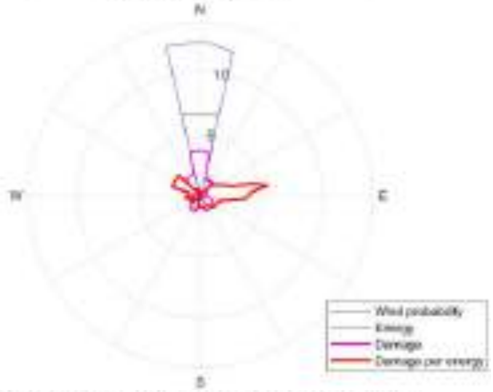
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT39



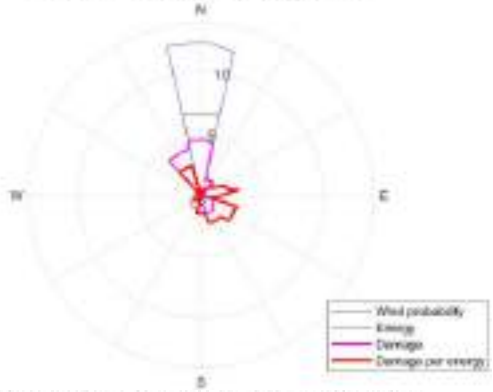
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT39



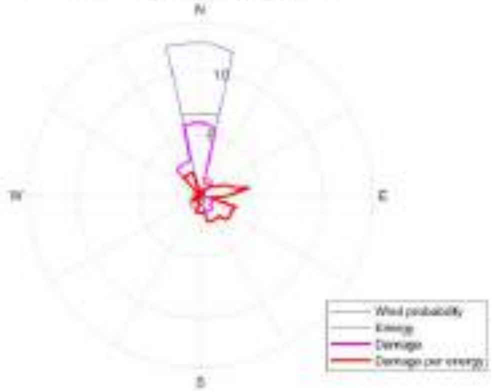
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT39



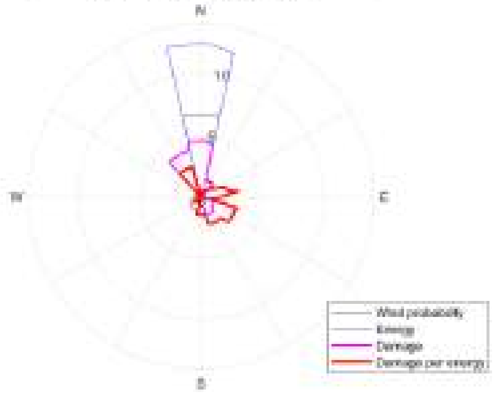
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT39



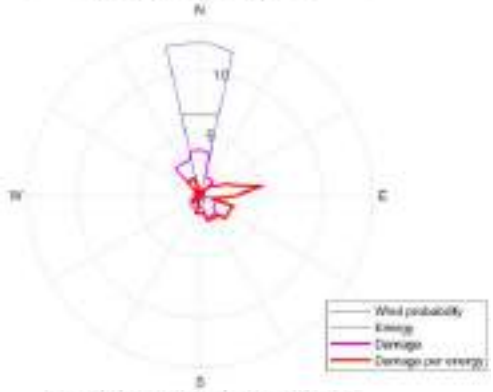
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT39



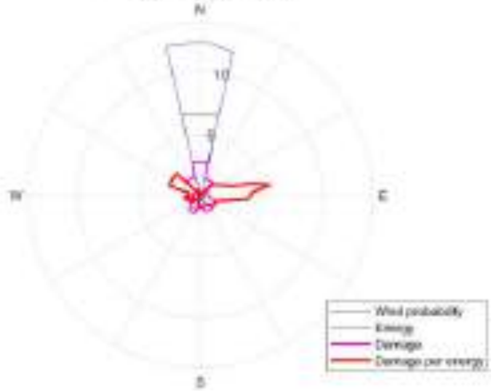
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT39



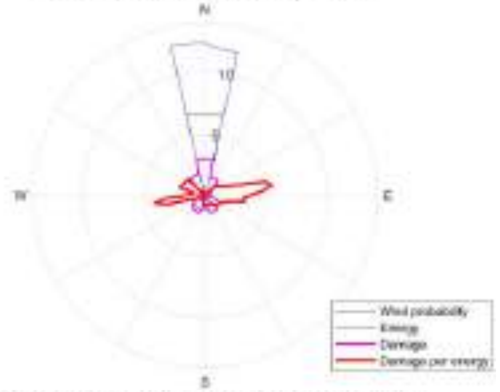
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT39



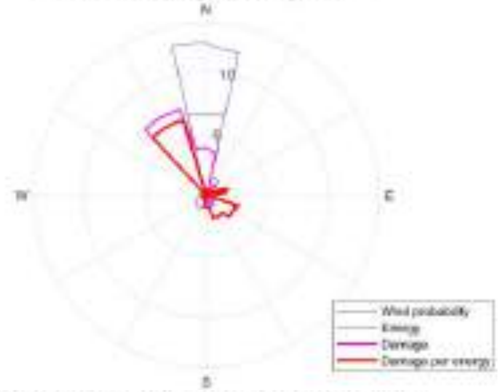
Rose map for the probabilities, energy and LTE in percentage, WT39



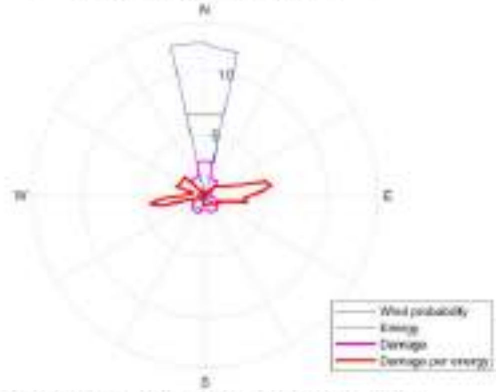
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT40



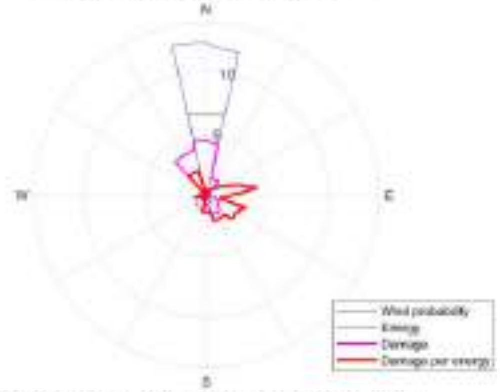
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT40



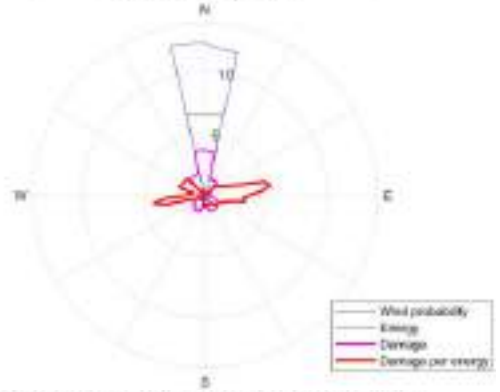
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT40



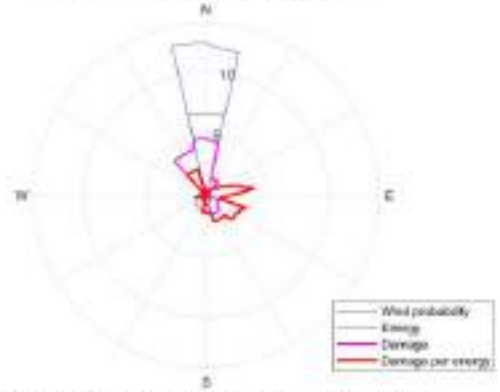
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT40



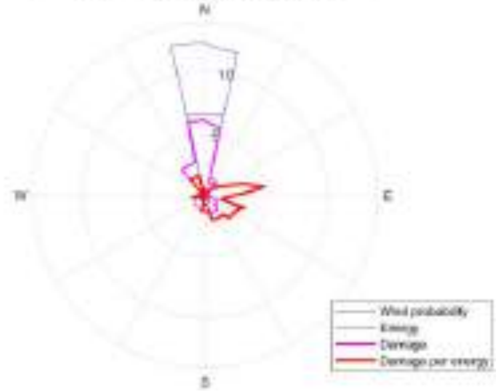
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT40



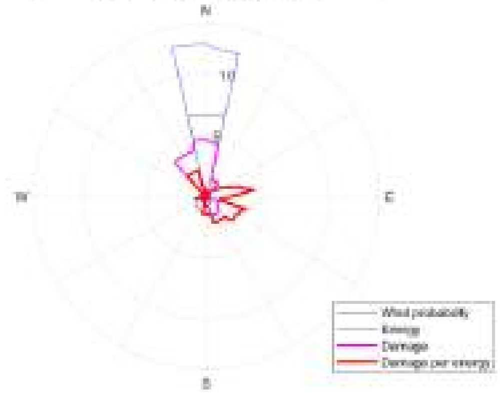
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT40



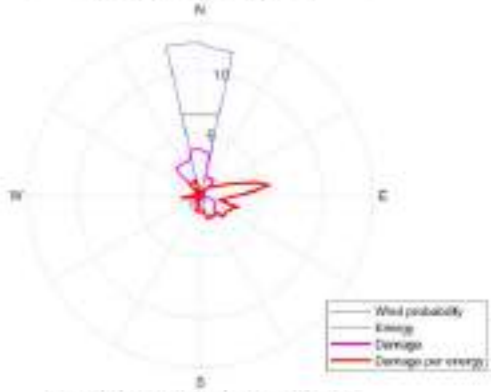
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT40



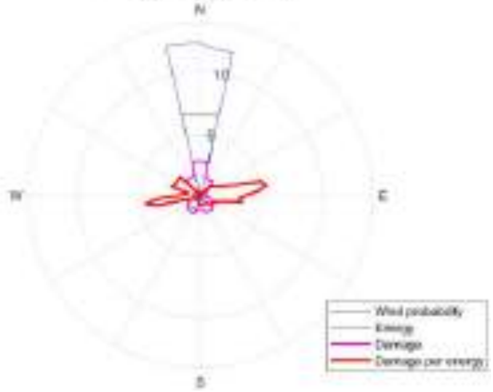
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT40



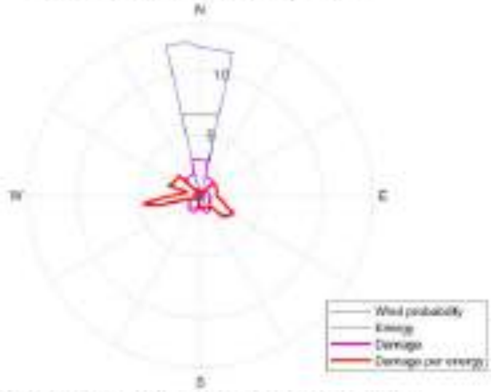
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT40



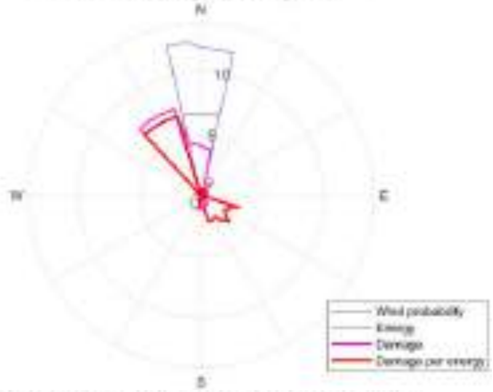
Rose map for the probabilities, energy and LTE in percentage, WT46



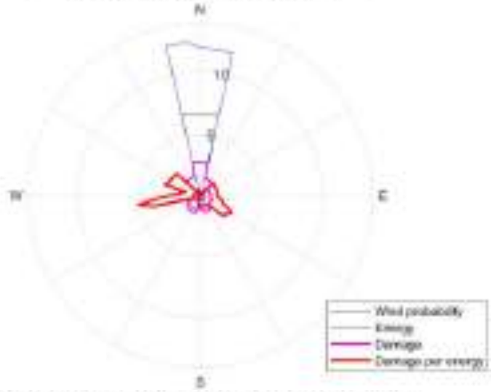
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT41



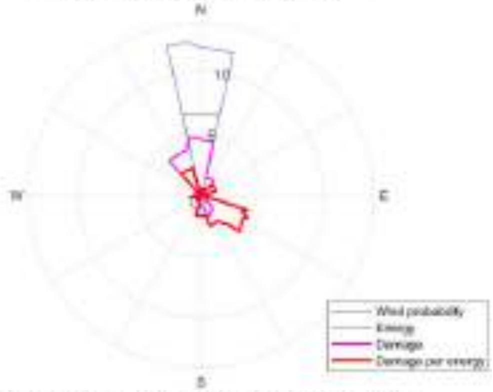
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT41



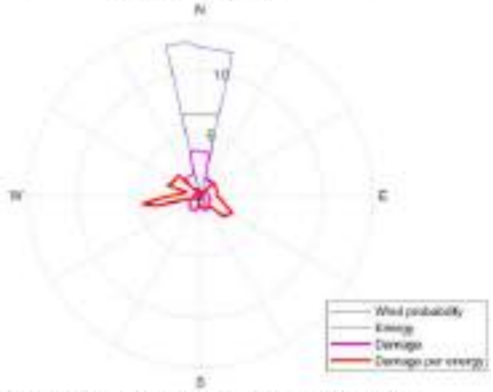
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT41



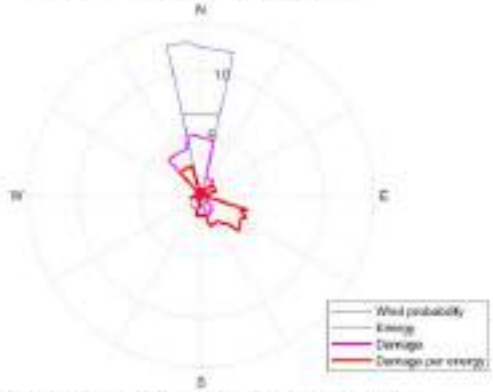
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT41



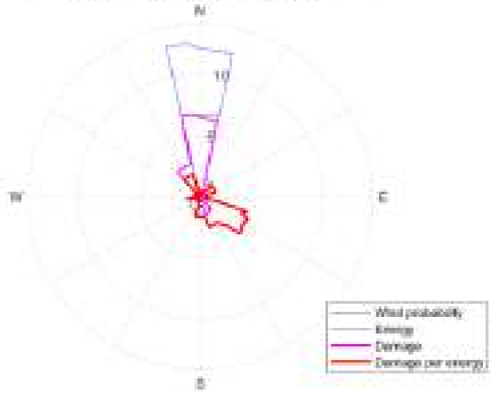
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT41



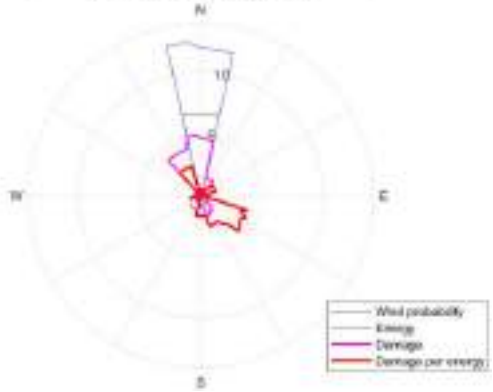
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT41

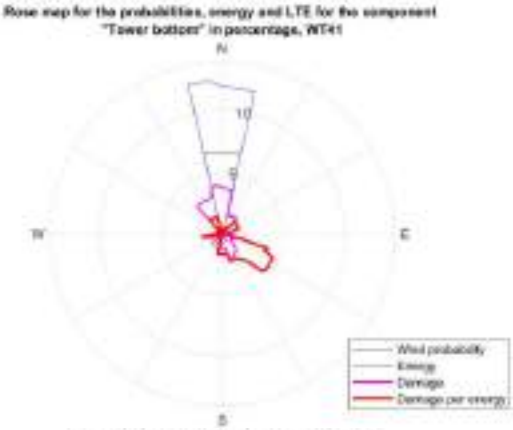


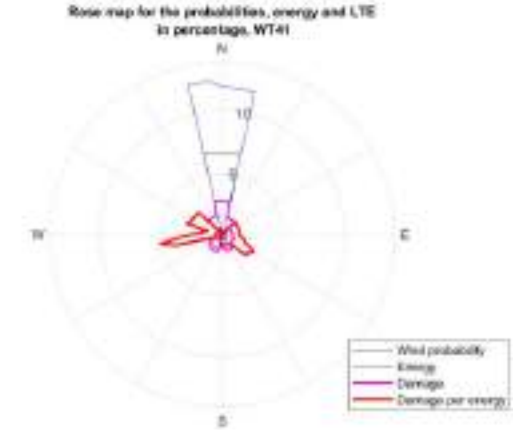
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT41



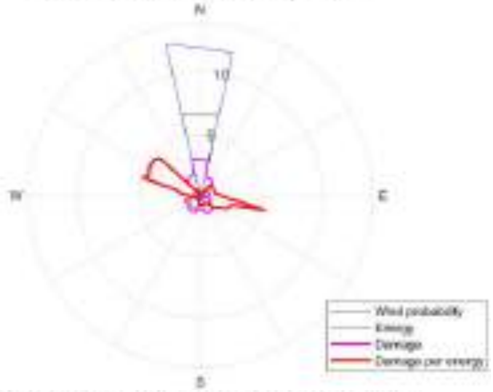
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT41



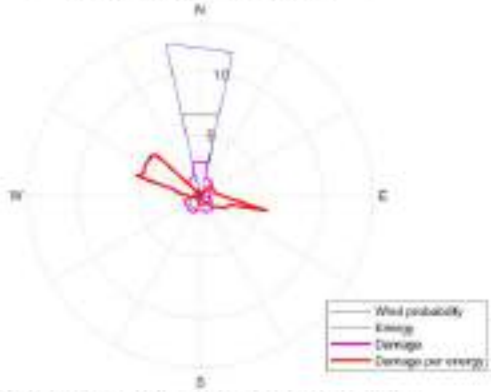

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT41
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT41
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

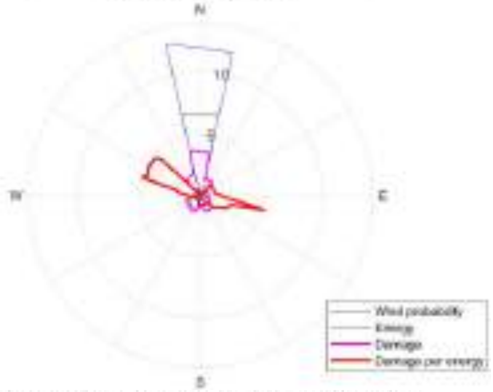
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT42



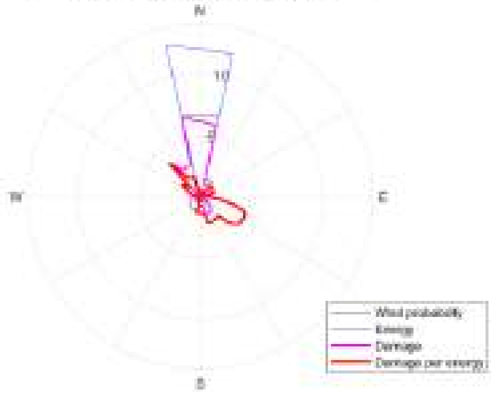
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT42



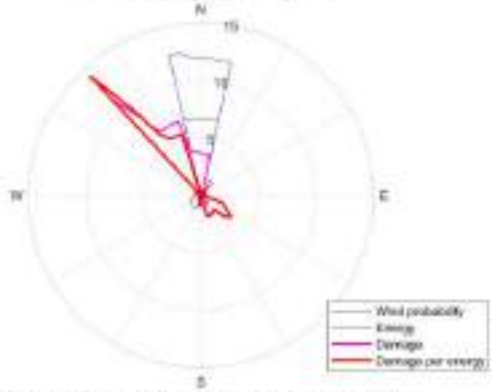
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT42



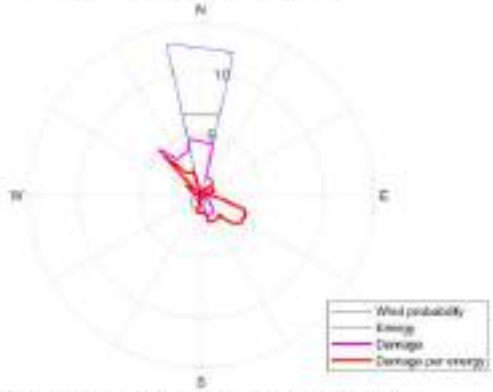
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT42



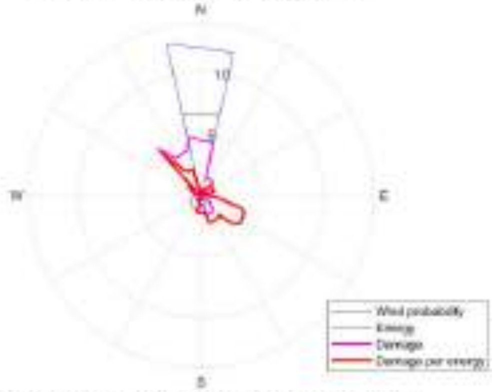
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT42



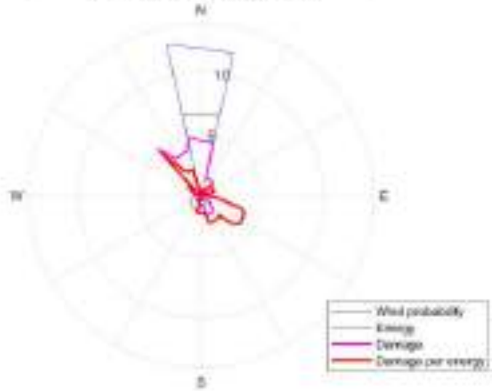
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT42

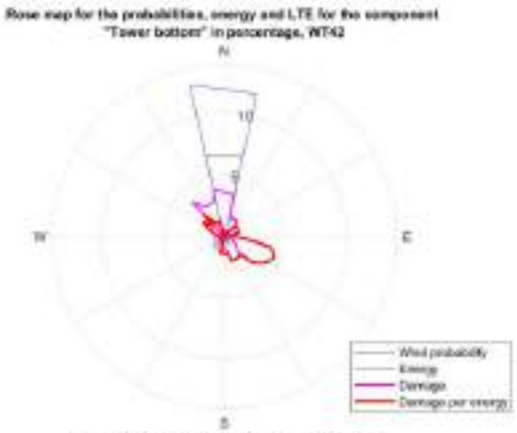


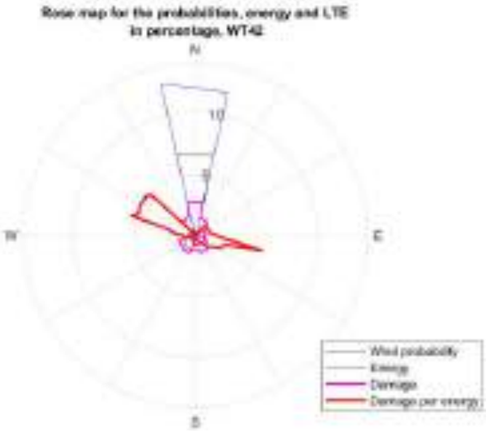
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT42



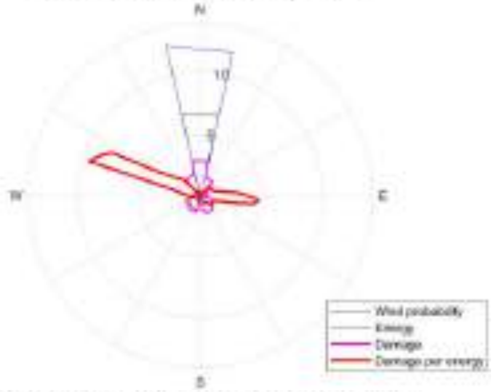
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT42



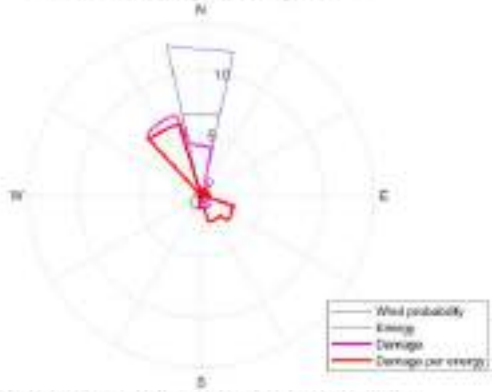

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT42
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT42
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

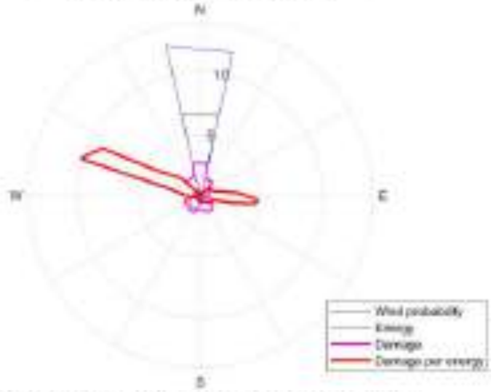
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT43



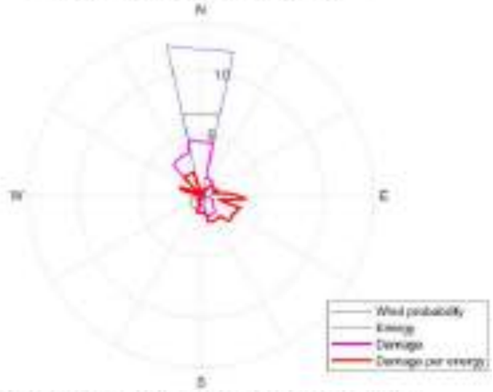
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT43



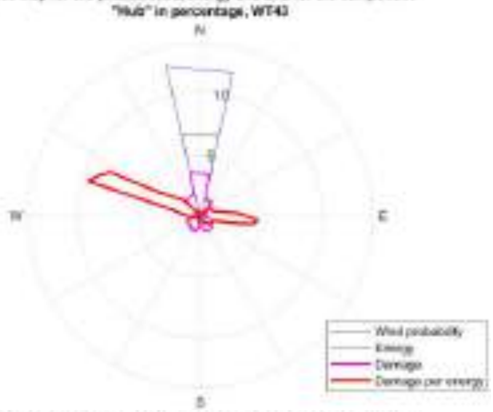
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT43



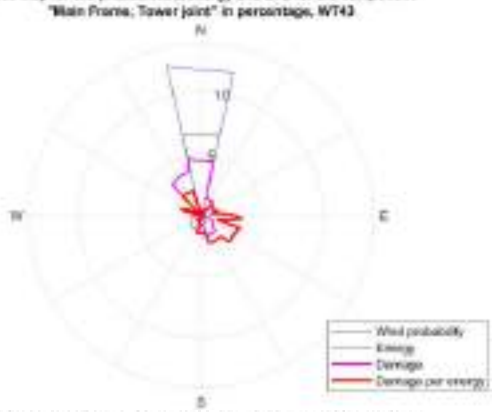
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT43



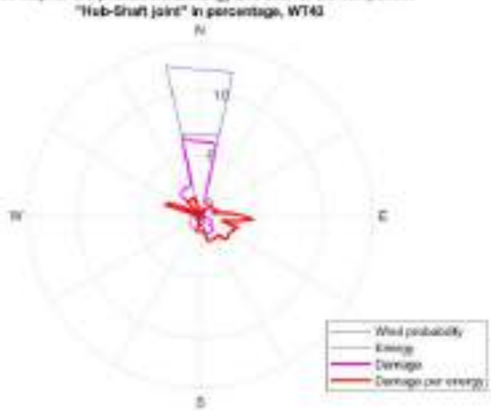
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT43



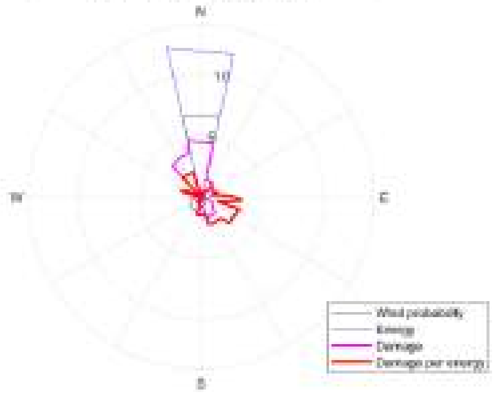
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT43

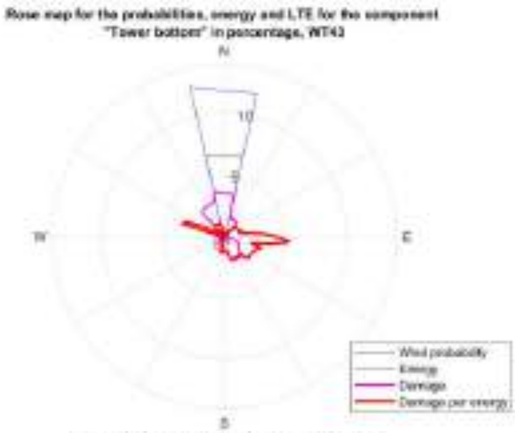


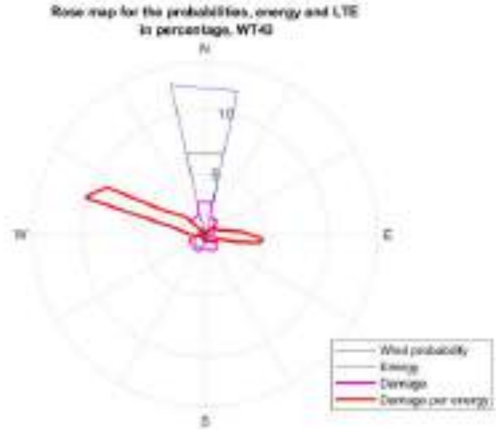
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT43



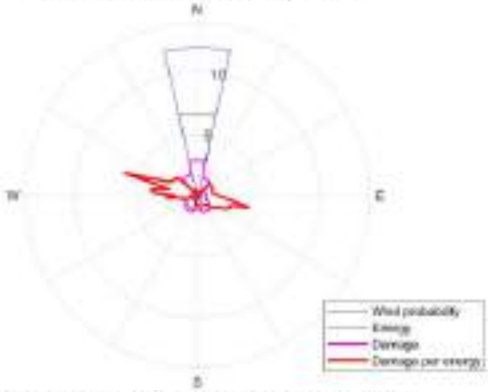
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT43



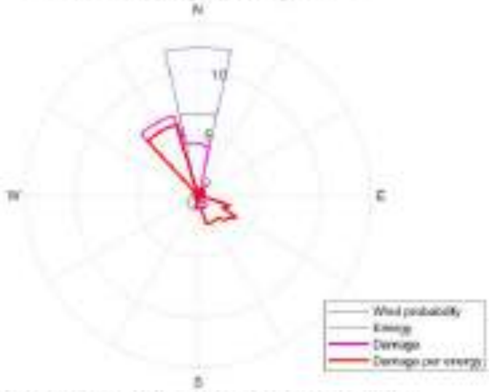

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT43
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT43
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

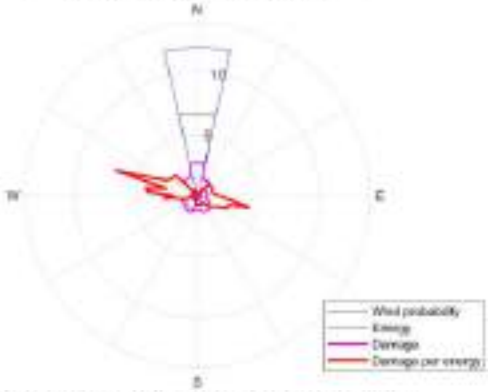
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT44



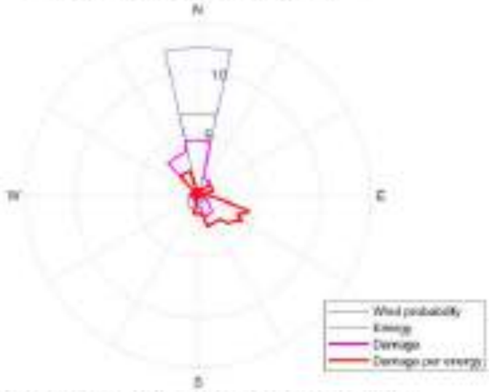
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT44



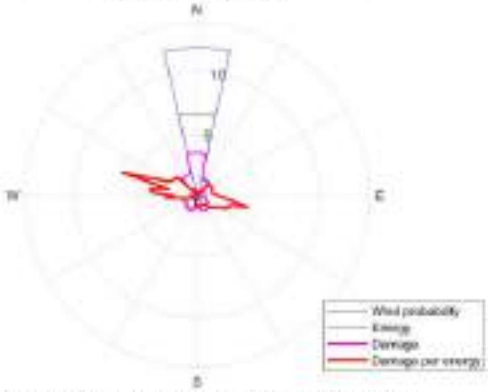
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT44



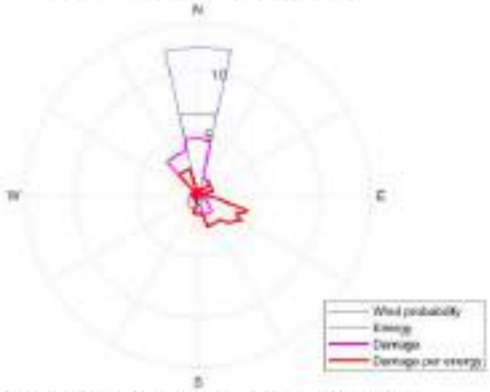
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT44



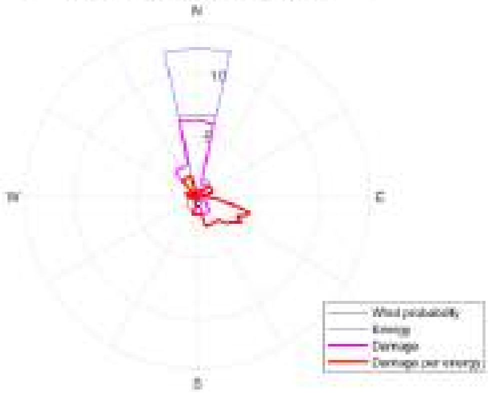
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT44



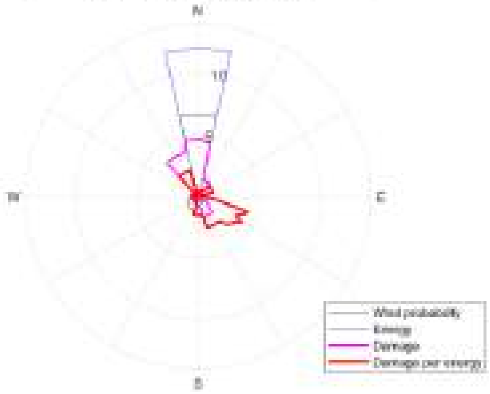
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT44

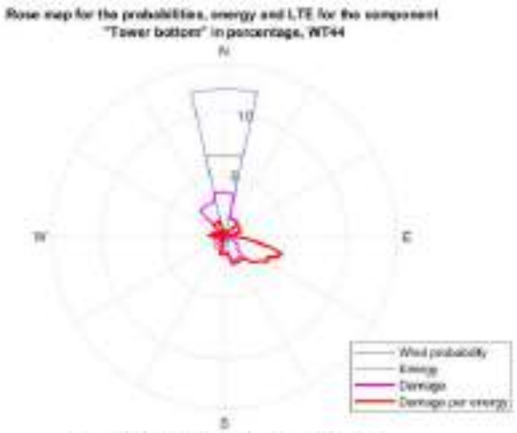


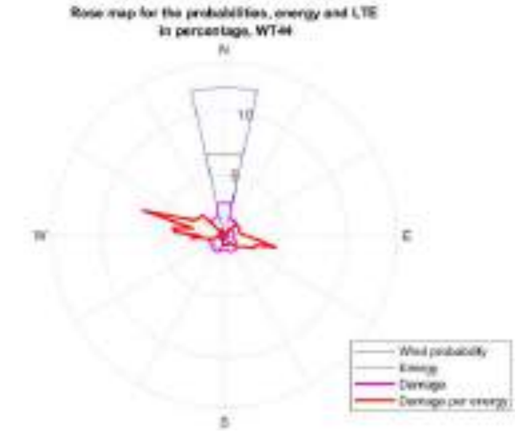
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT44



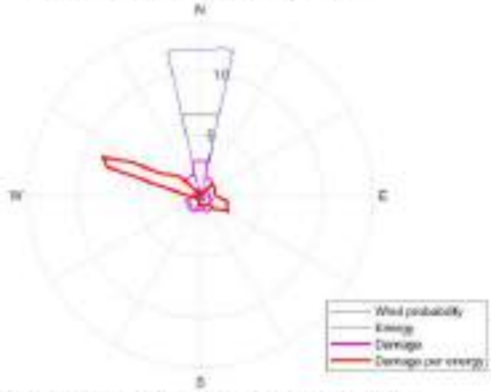
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT44



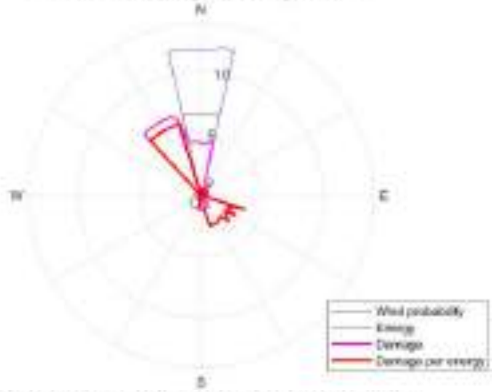

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT44
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT44
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy

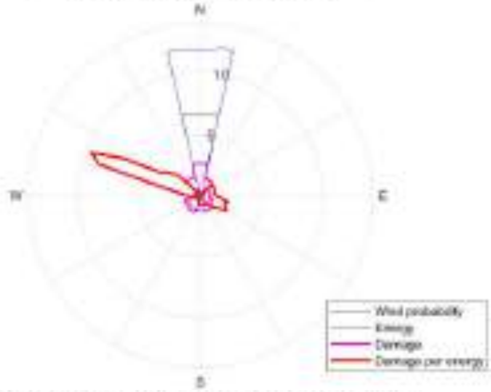
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT45



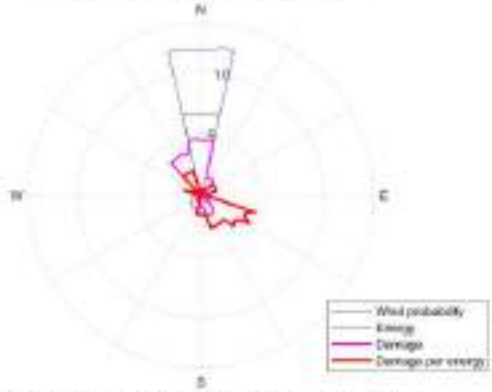
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT45



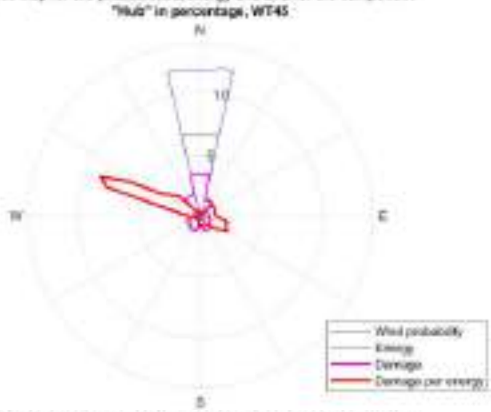
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT45



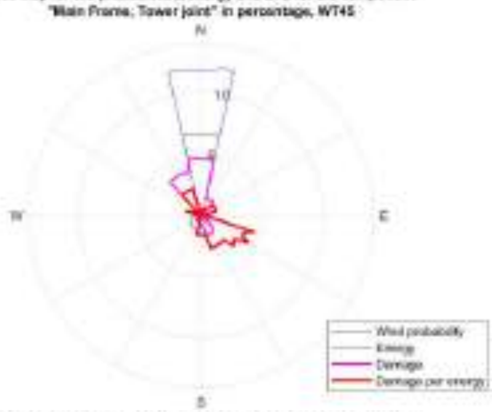
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT45



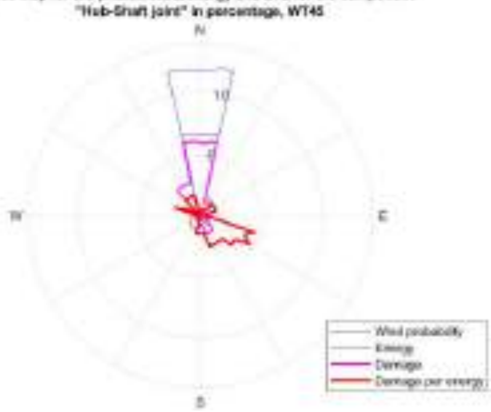
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT45



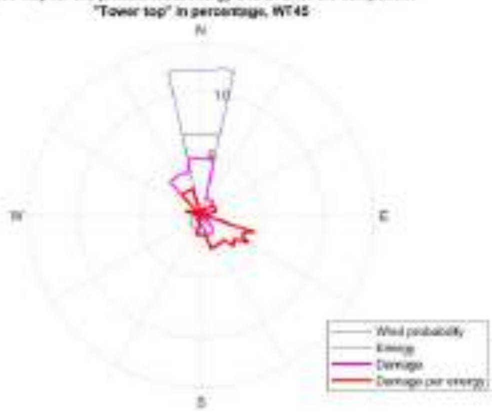
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT45

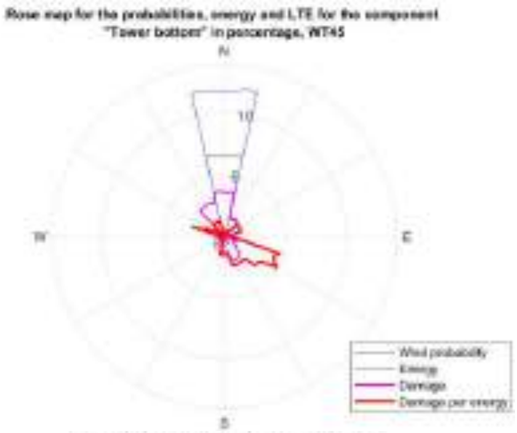


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT45



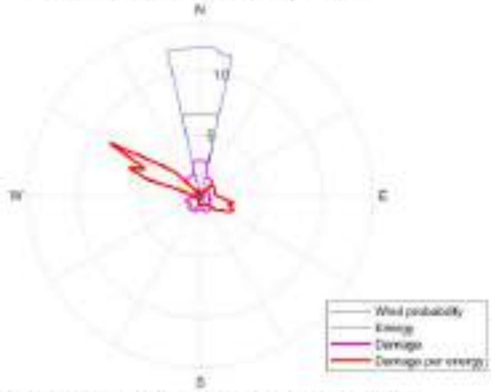
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT45



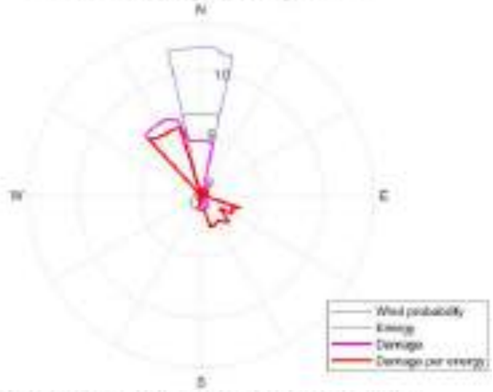

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT45
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT45
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

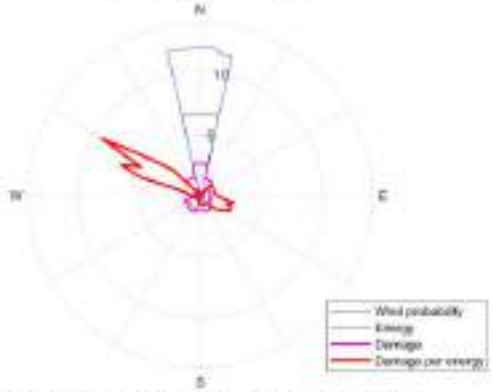
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT46



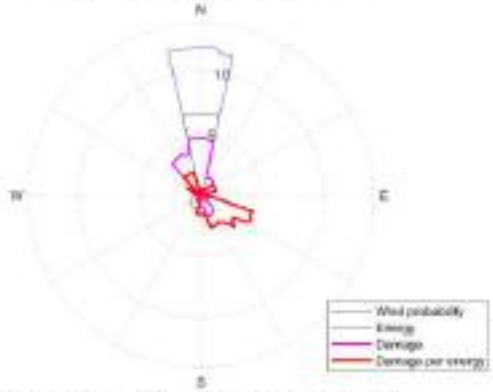
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT46



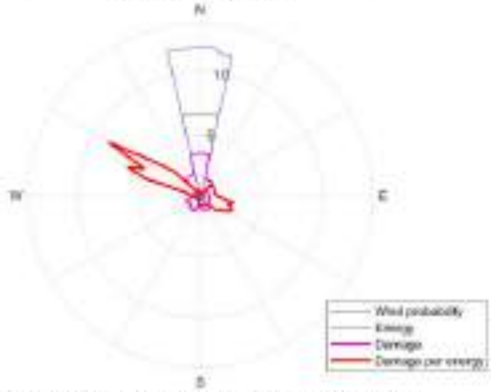
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT46



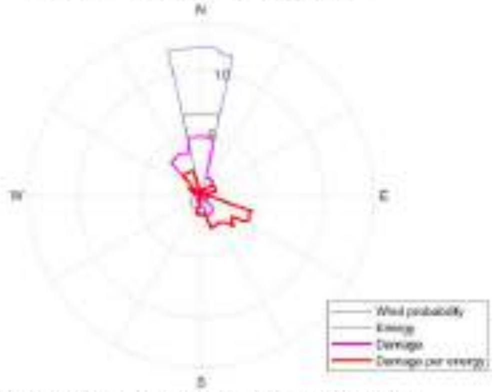
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT46



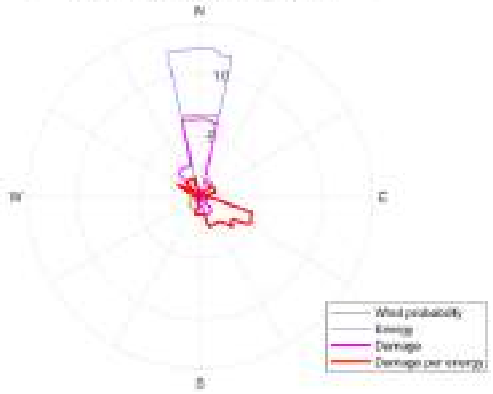
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT46



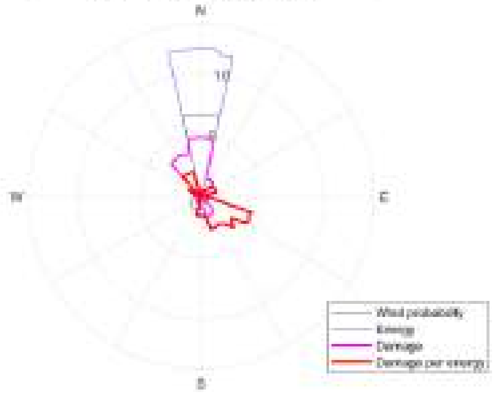
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT46



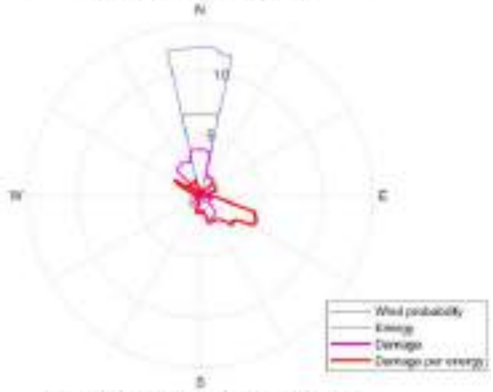
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT46



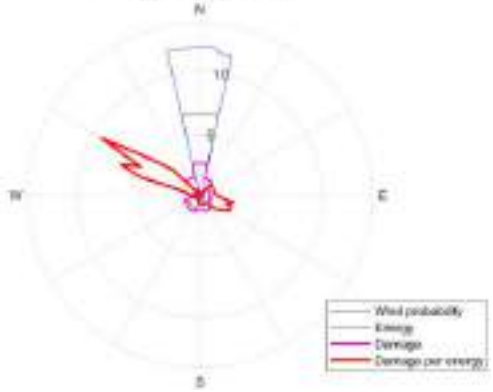
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT46



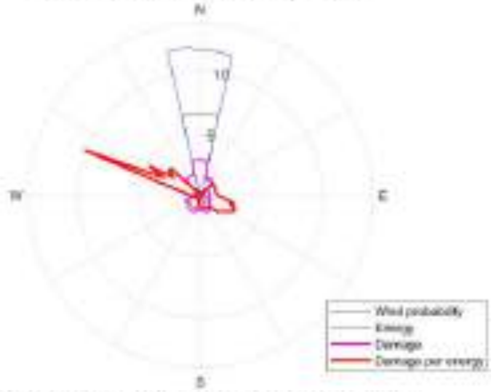
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT46



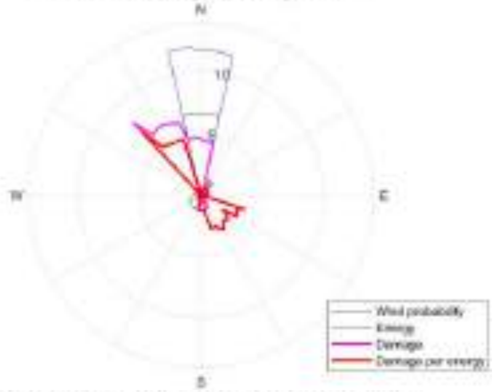
Rose map for the probabilities, energy and LTE in percentage, WT46



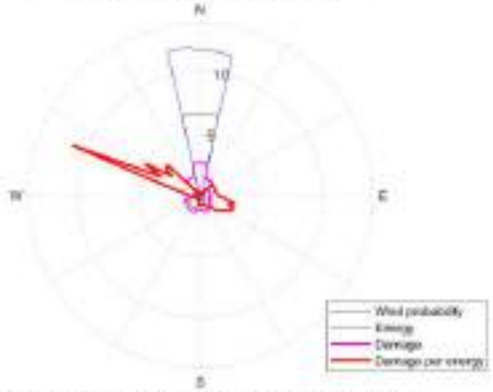
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT47



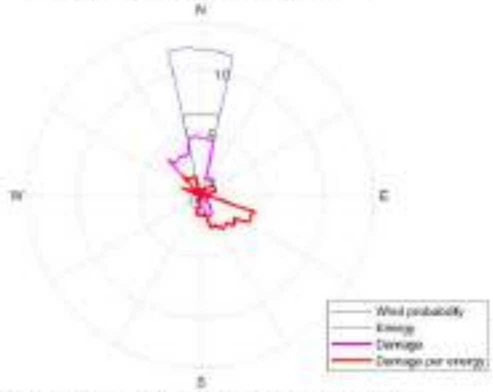
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT47



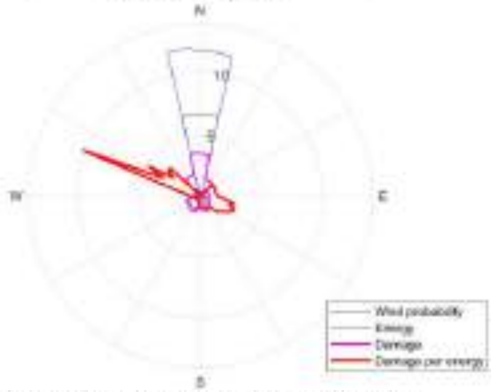
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT47



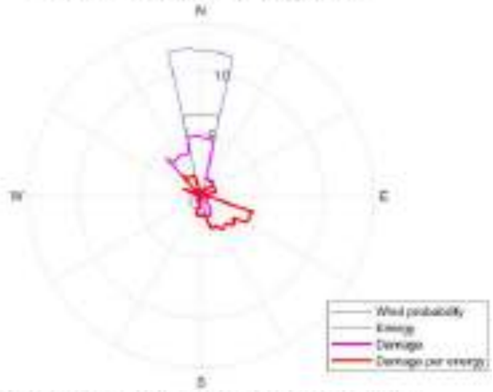
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT47



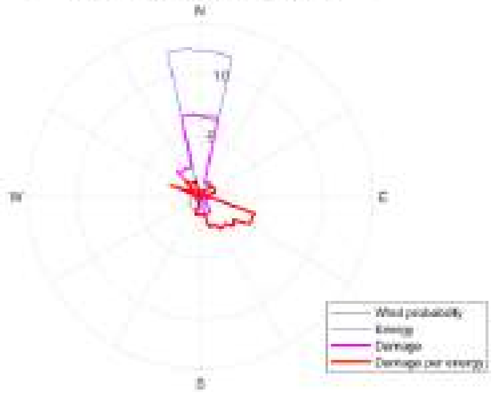
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT47



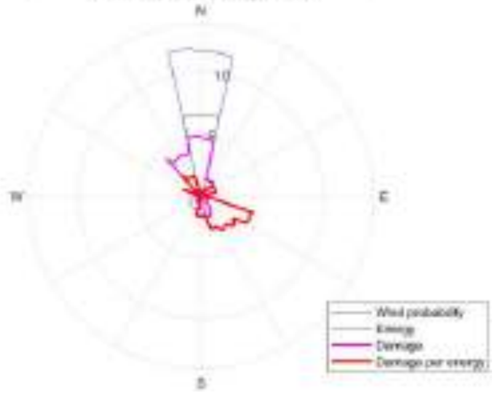
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT47



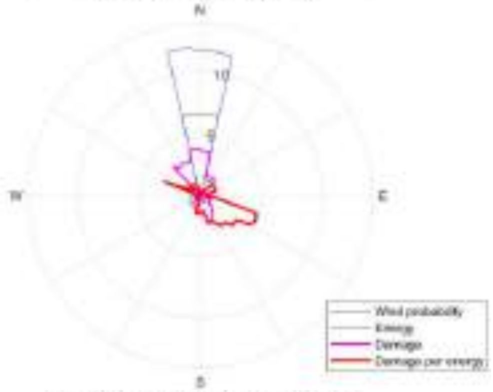
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT47



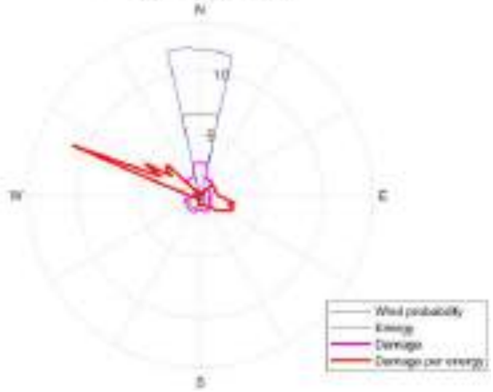
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT47



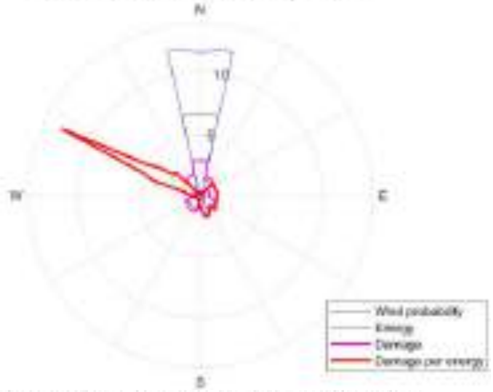
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT47



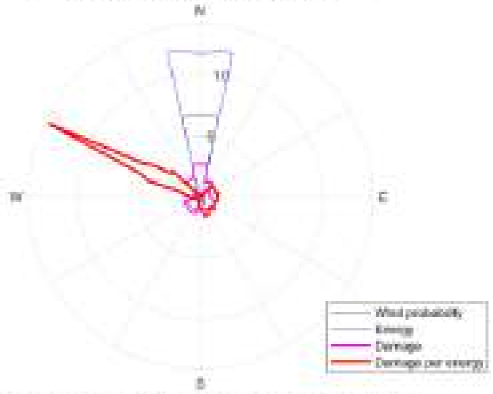
Rose map for the probabilities, energy and LTE in percentage, WT47



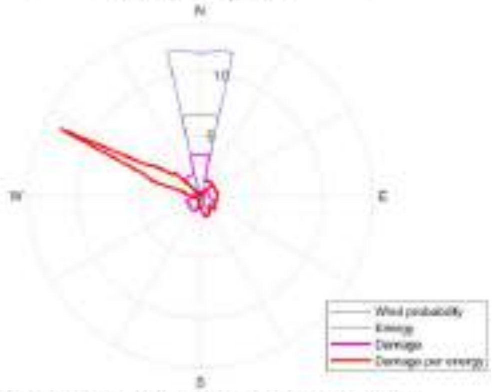
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT48



Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT48

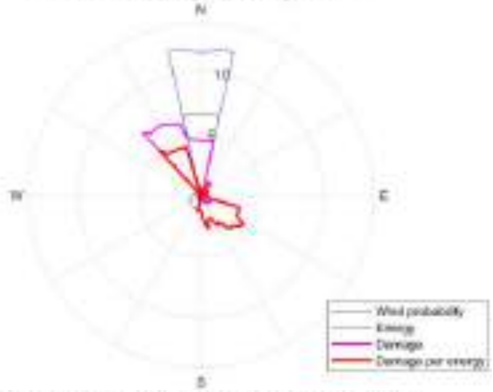


Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT48

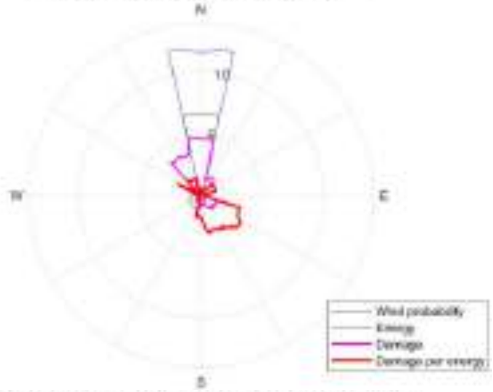


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT48

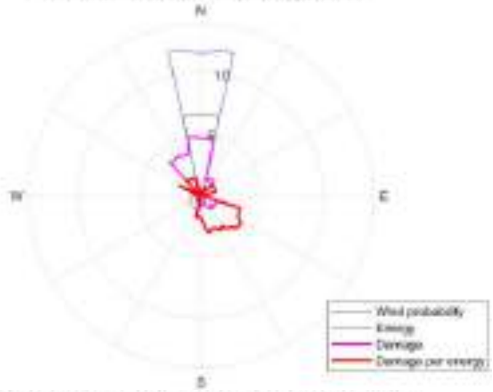
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT48



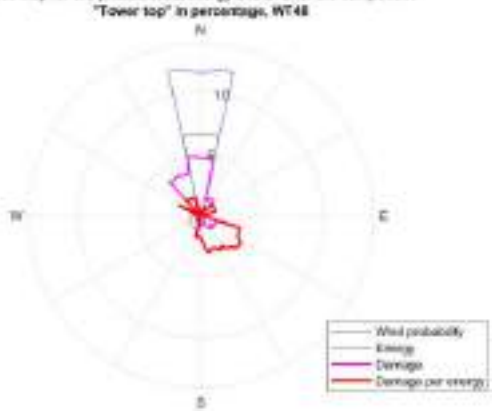
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT48

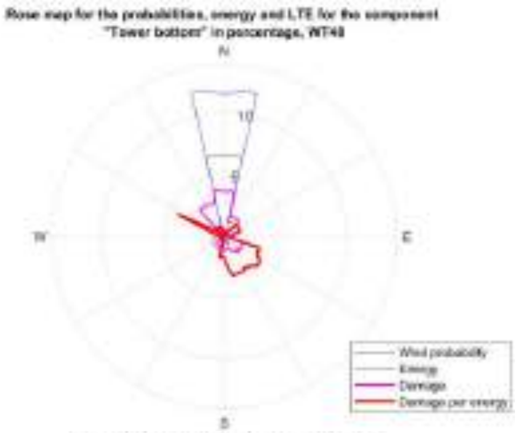


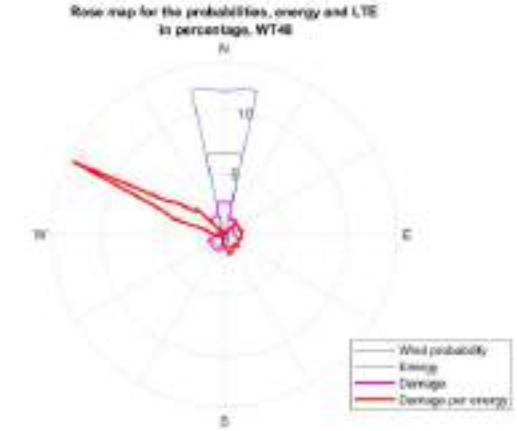
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT48



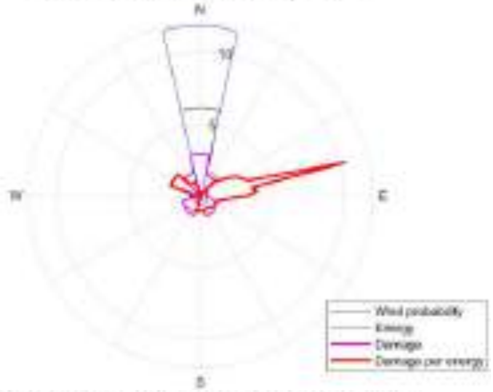
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT48



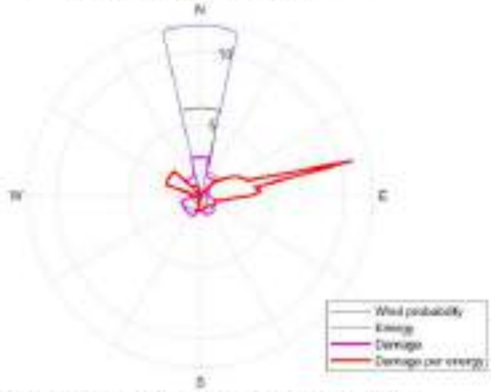

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT48
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT48
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

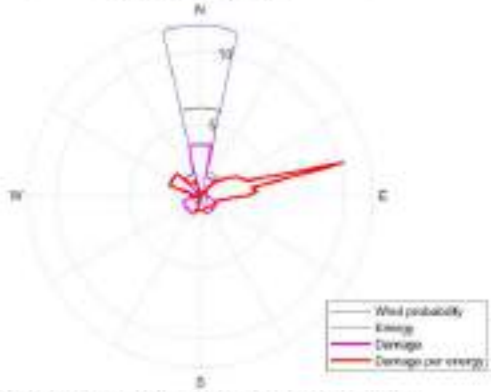
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT49



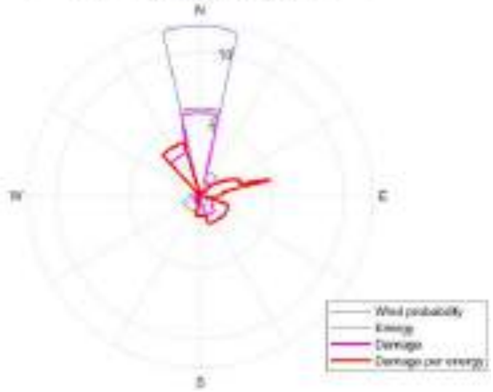
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT49



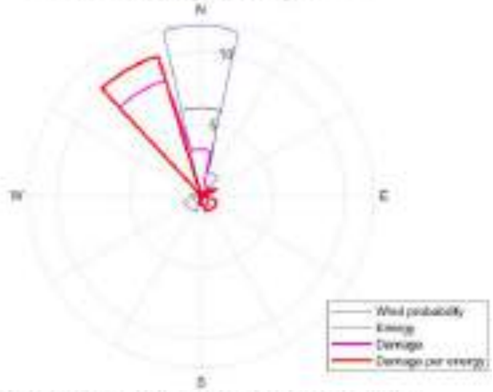
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT49



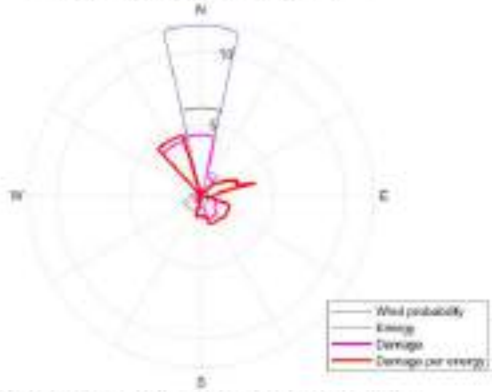
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT49



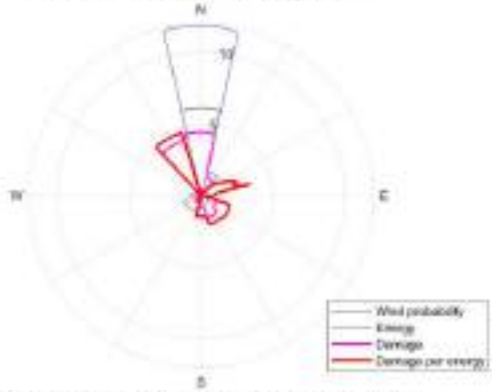
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT49



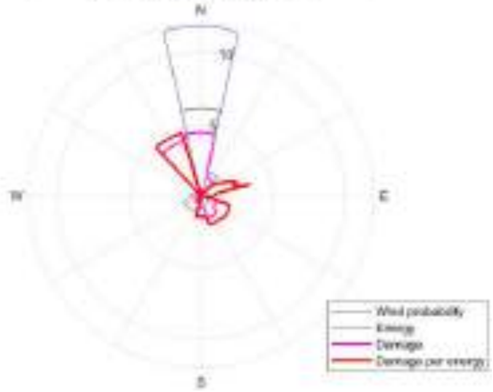
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT49

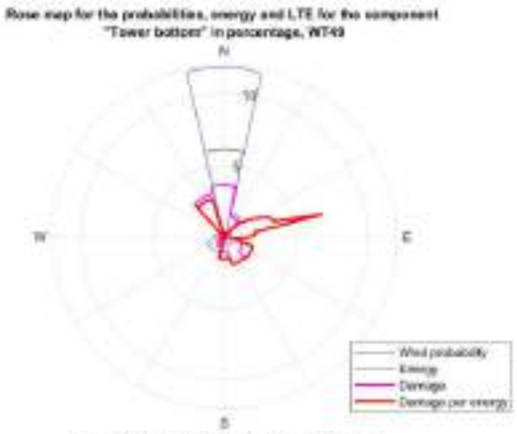


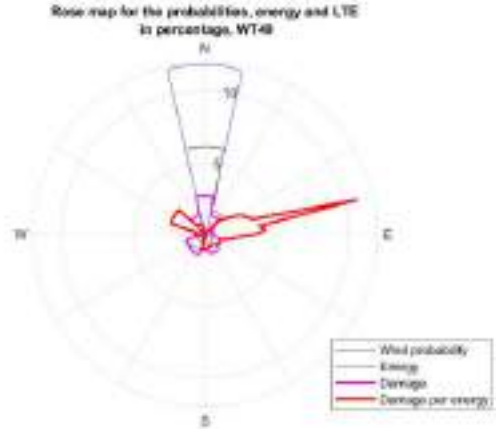
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT49



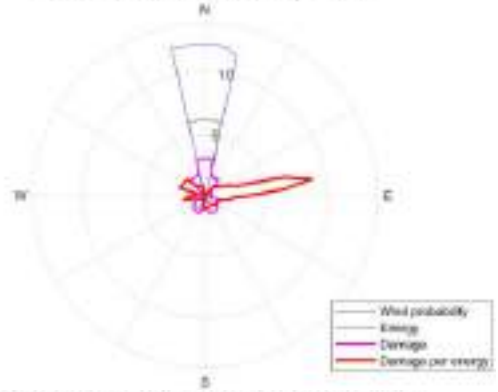
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT49



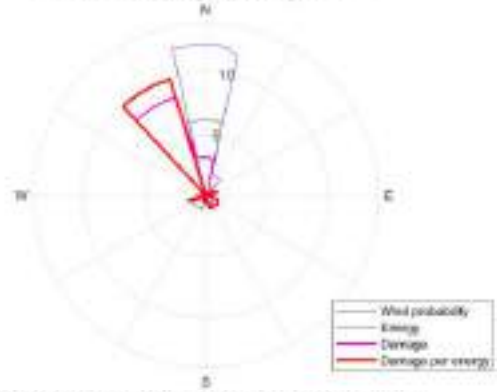

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT49
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT49
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

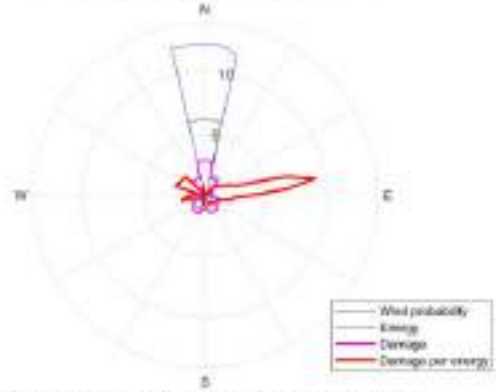
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT58



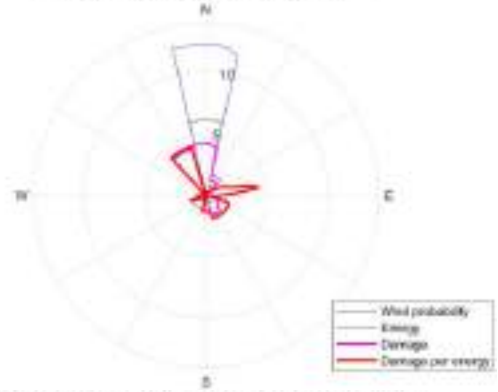
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT58



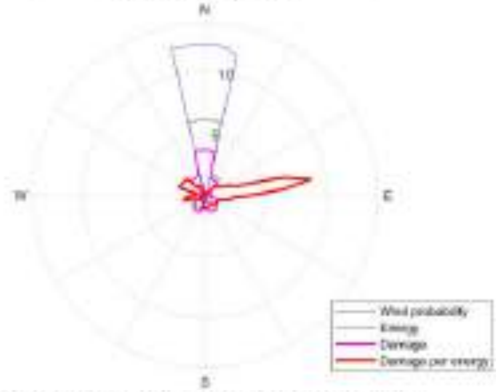
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT58



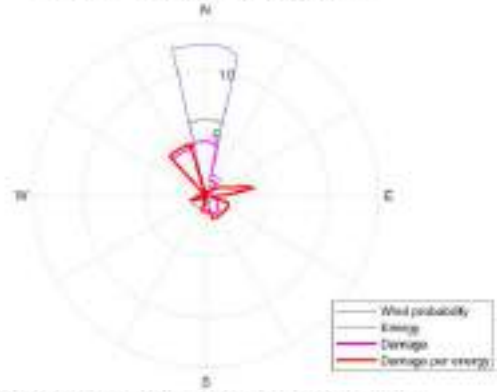
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT58



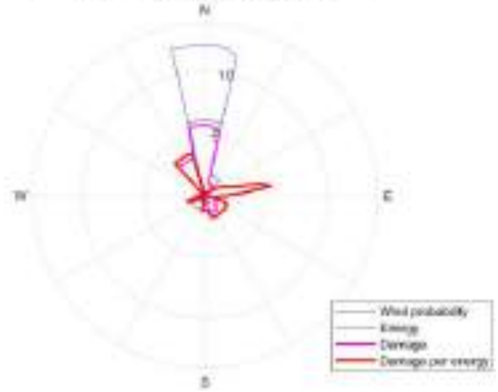
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT58



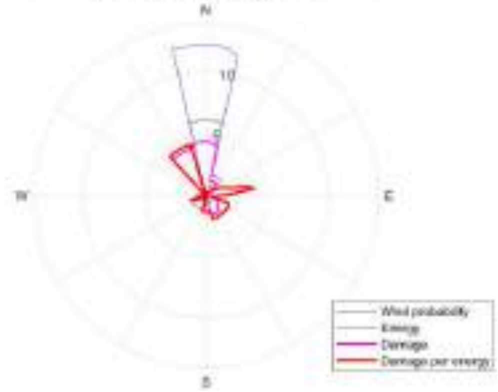
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT58



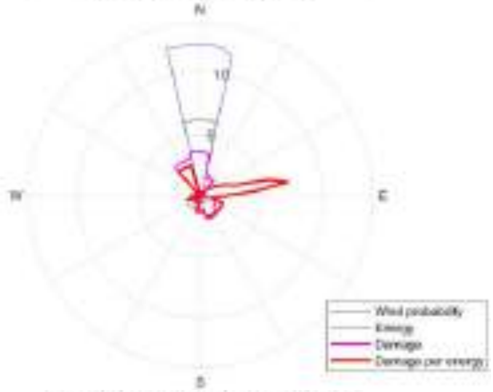
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT58



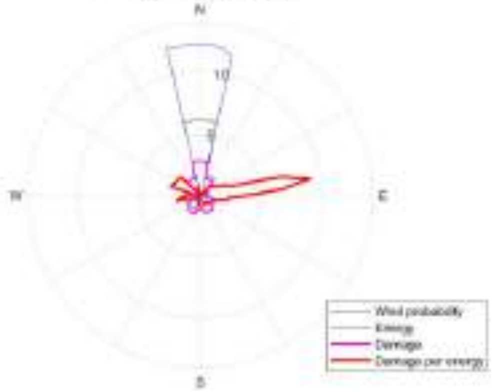
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT58



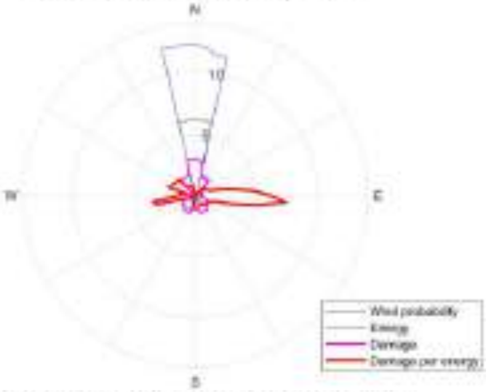
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT50



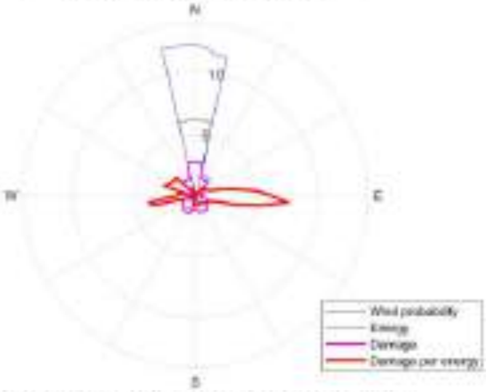
Rose map for the probabilities, energy and LTE in percentage, WT50



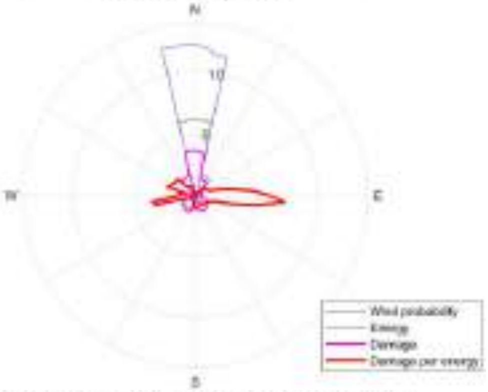
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WTS1



Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WTS1

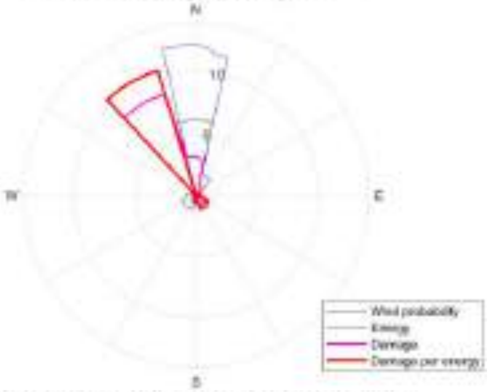


Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WTS1

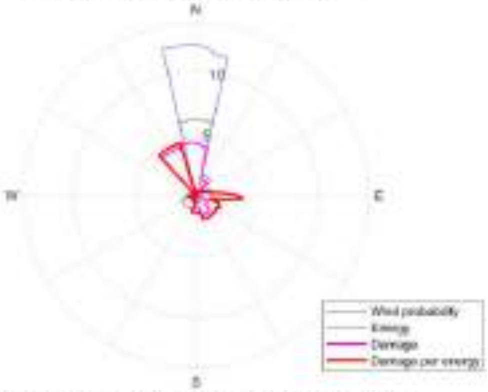


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WTS1

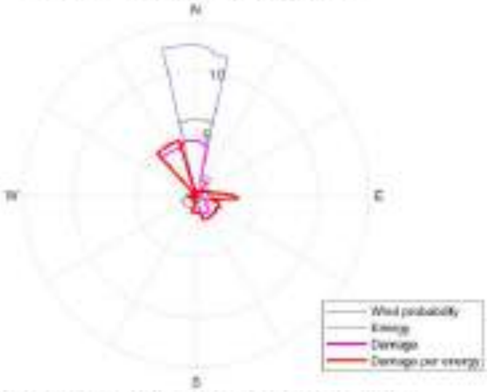
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WTS1



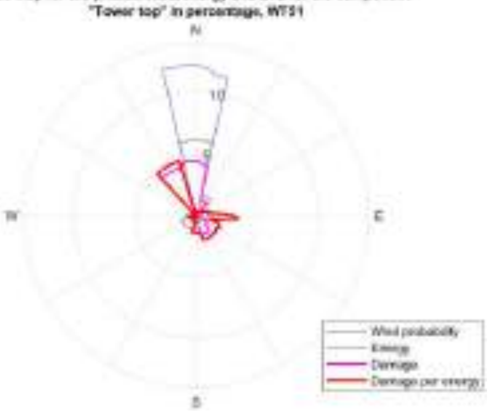
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WTS1



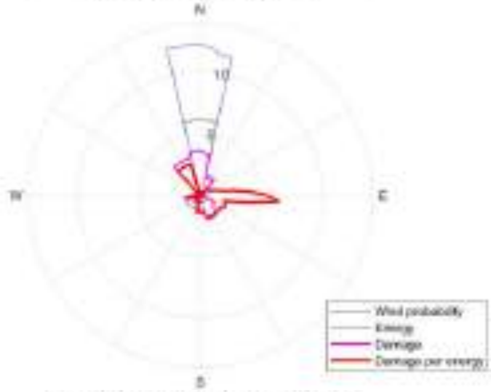
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WTS1



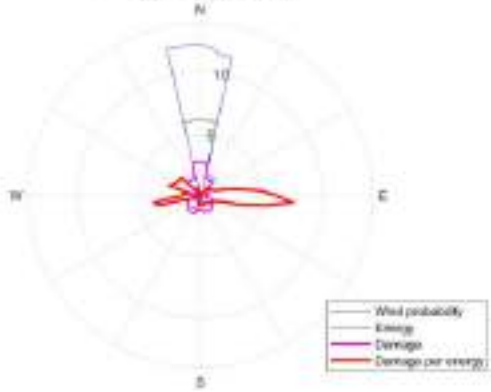
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WTS1



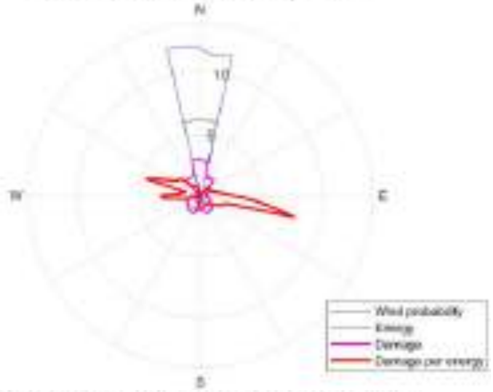
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT51



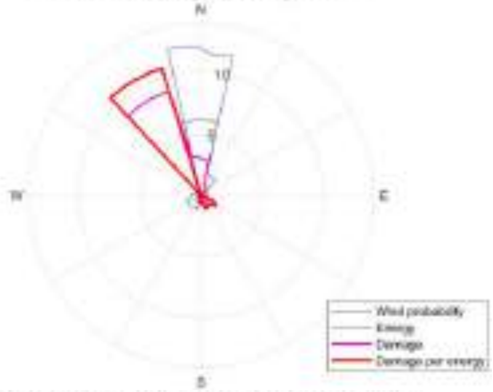
Rose map for the probabilities, energy and LTE in percentage, WT51



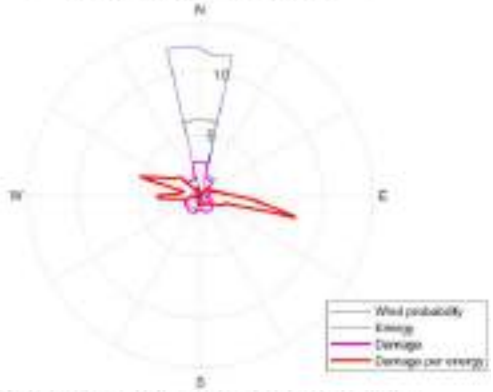
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT52



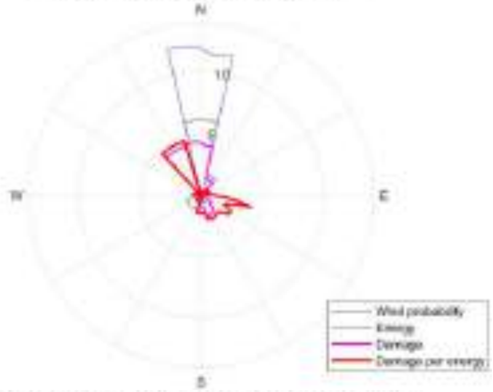
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT52



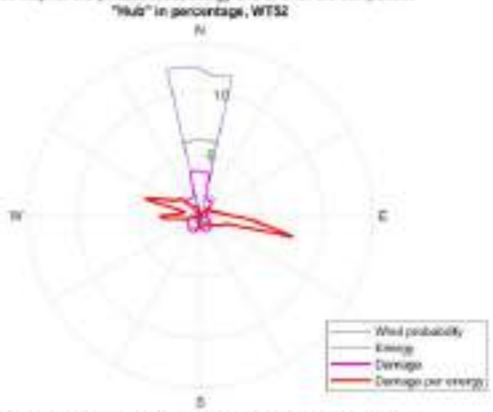
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT52



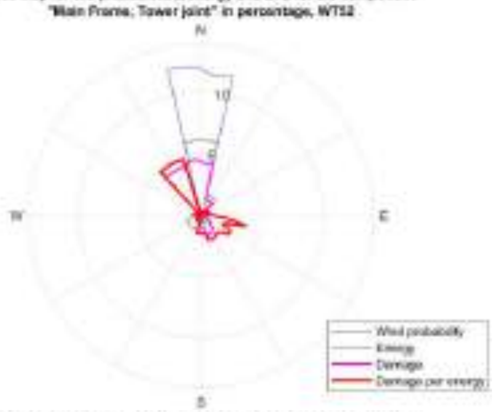
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT52



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT52

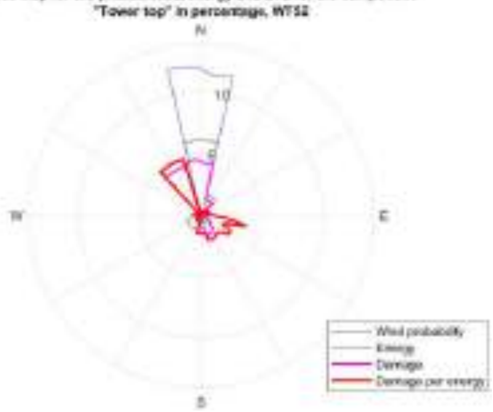


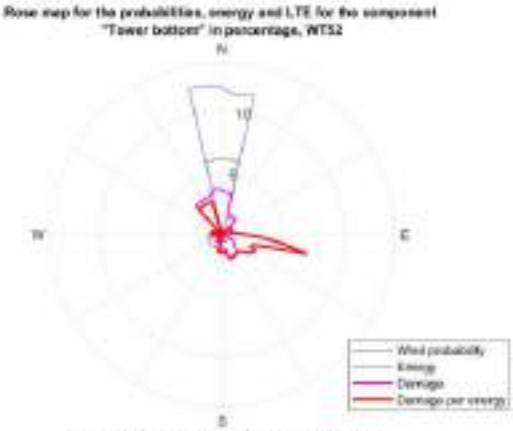
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT52

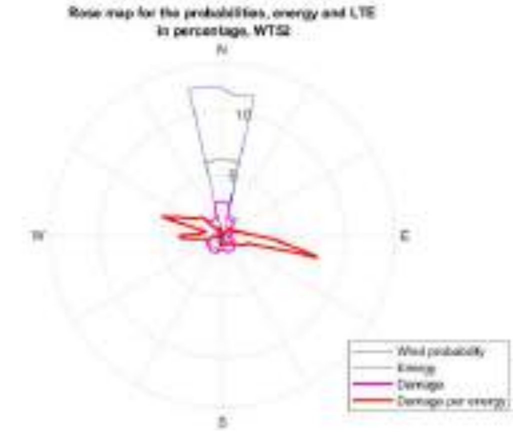


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT52

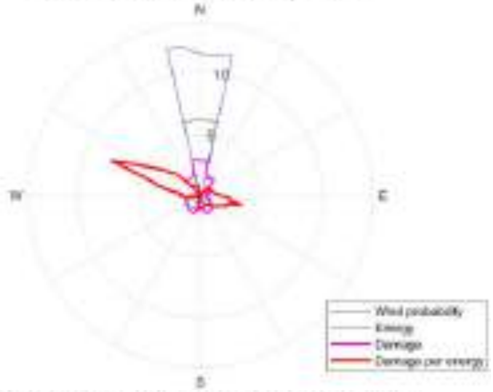
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT52



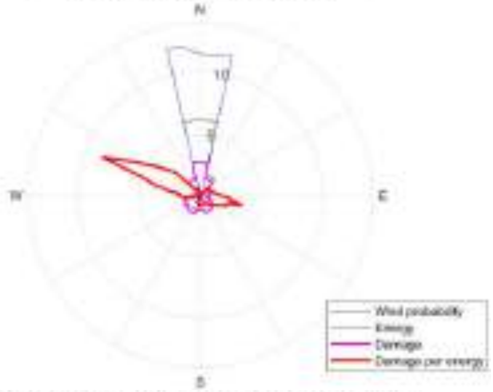

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT52
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT52
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

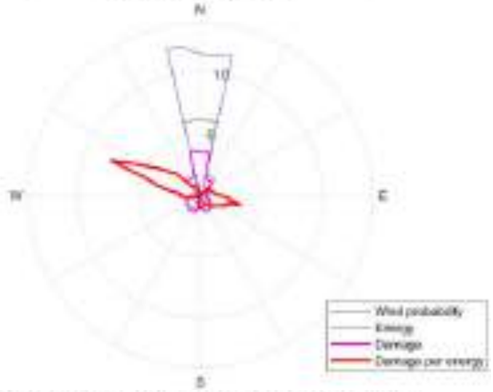
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT53



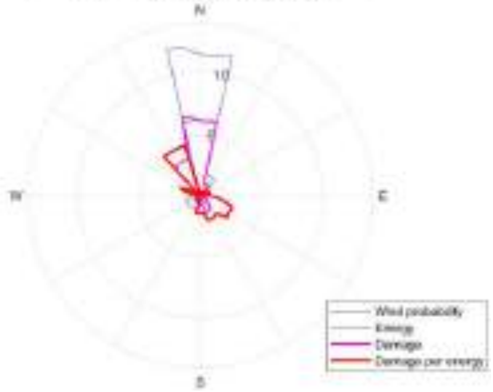
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT53



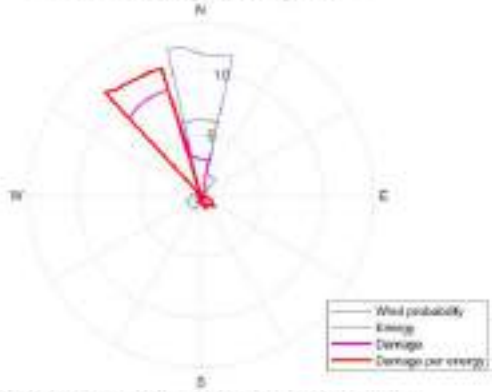
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT53



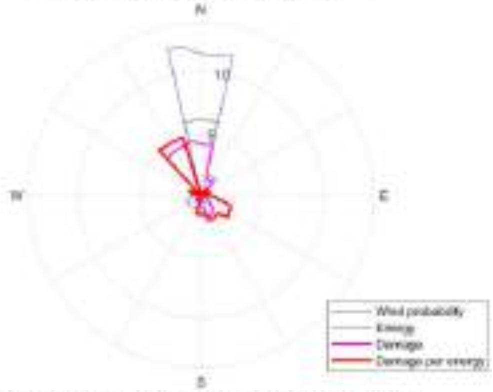
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT53



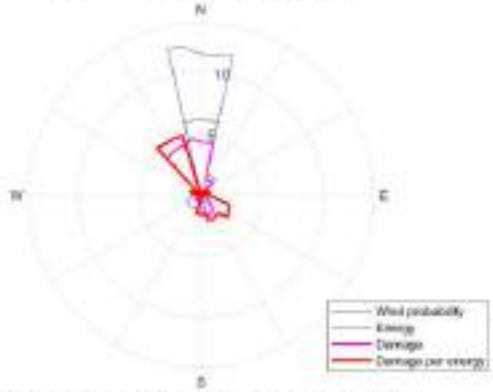
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT53



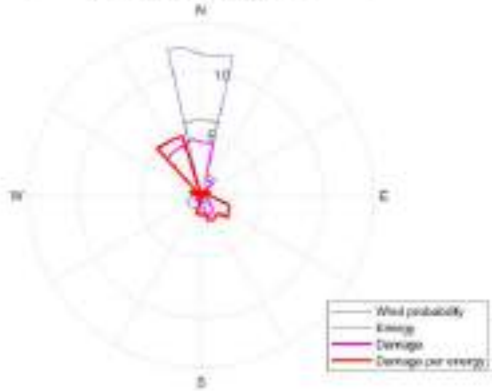
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT53

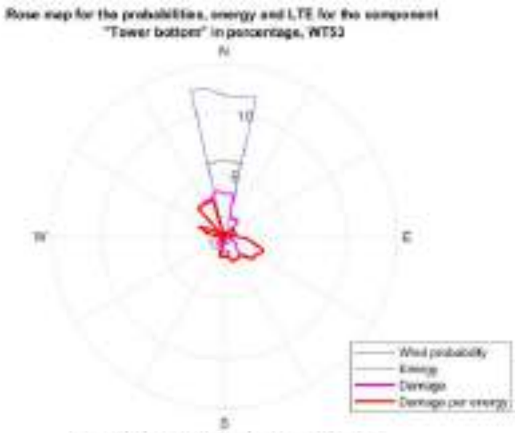


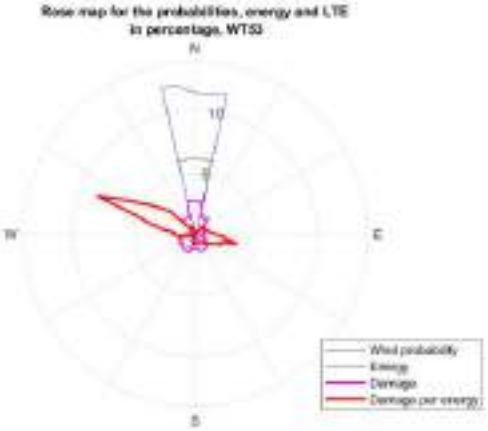
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT53



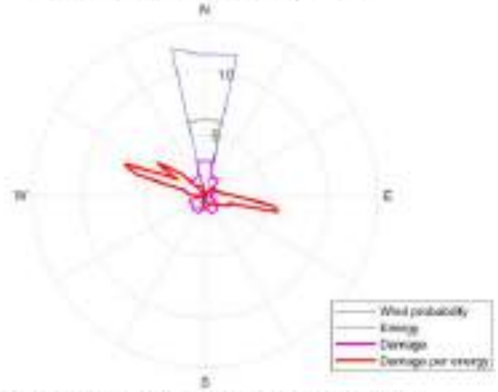
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT53



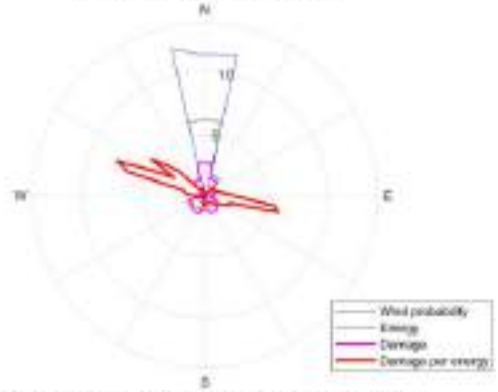

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT53
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT53
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

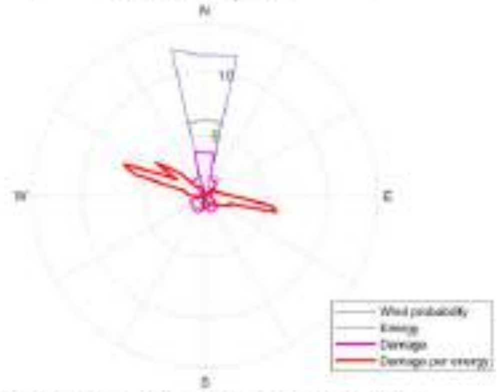
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WTS4



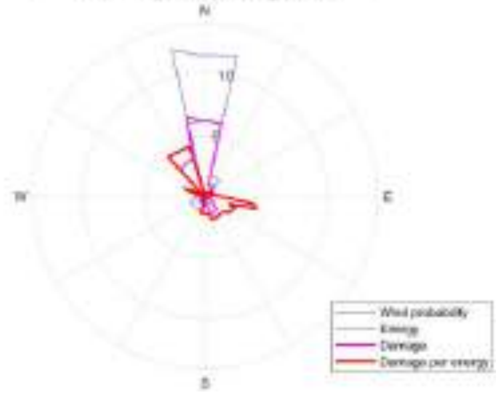
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WTS4



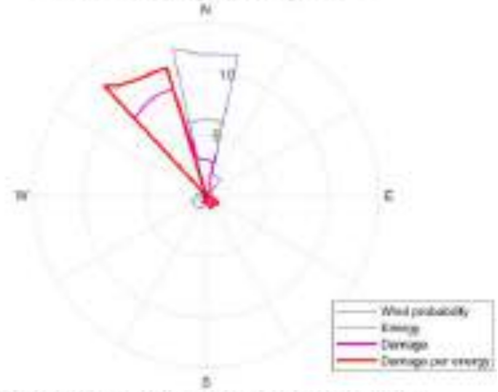
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WTS4



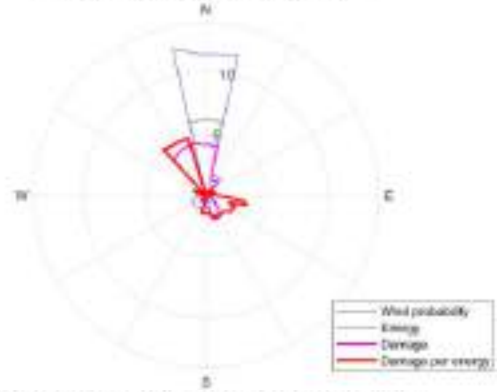
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WTS4



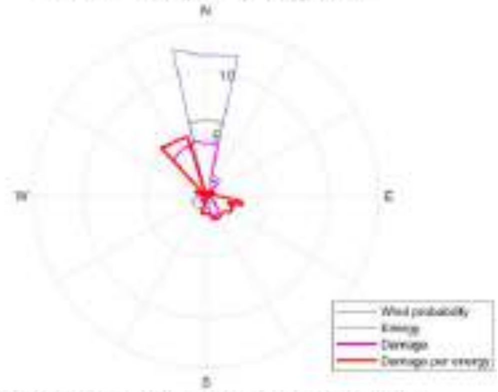
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WTS4



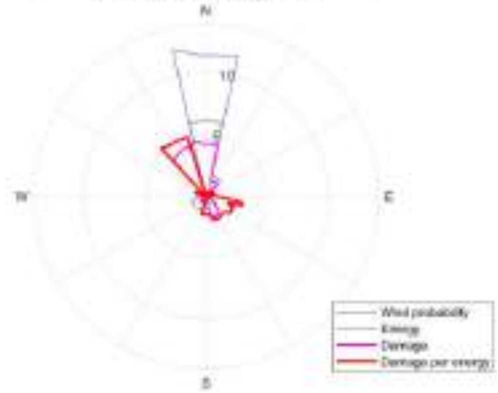
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WTS4

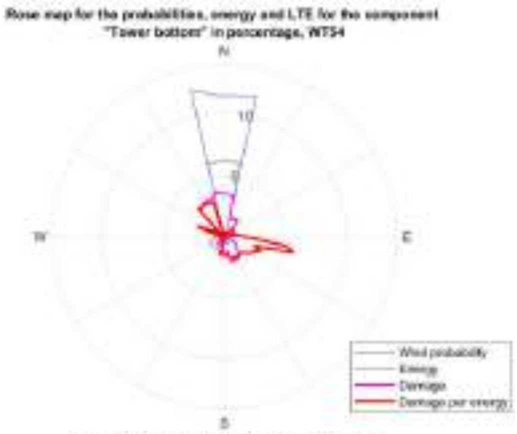


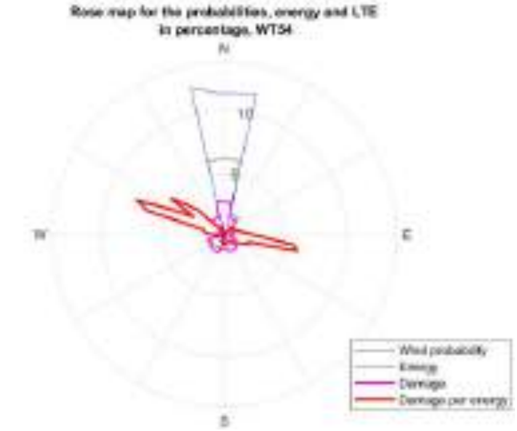
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WTS4



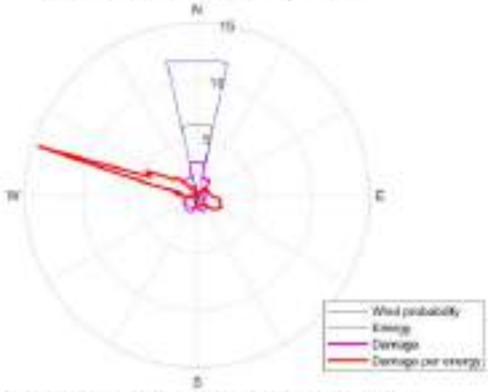
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WTS4



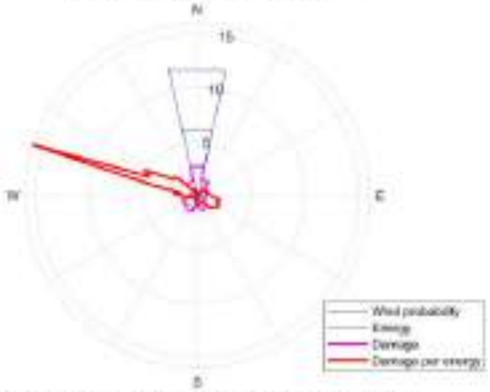

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT54
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT54
Wind probability
Energy
Damage
Damage per energy

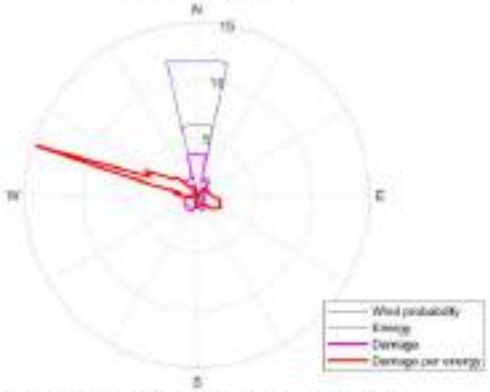
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WTS5



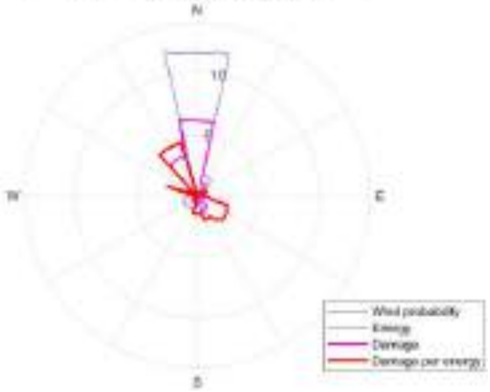
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WTS5



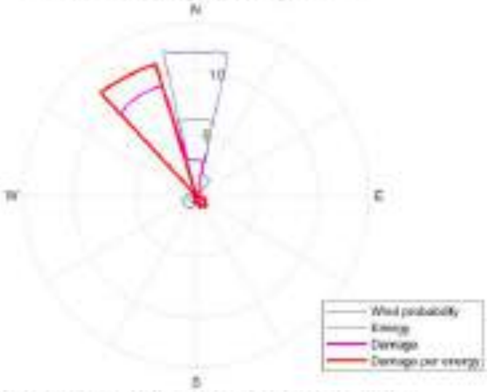
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WTS5



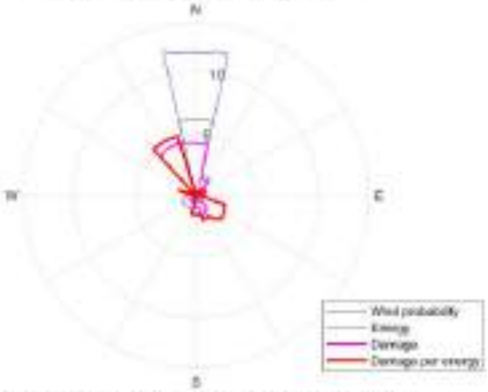
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WTS5



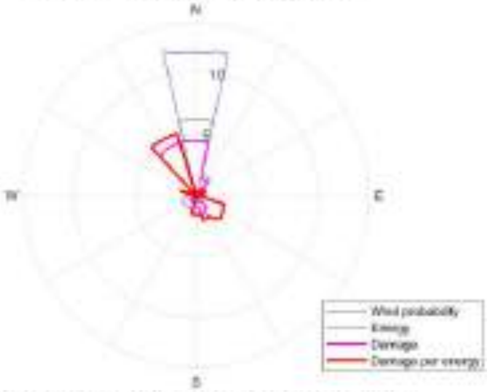
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WTS5



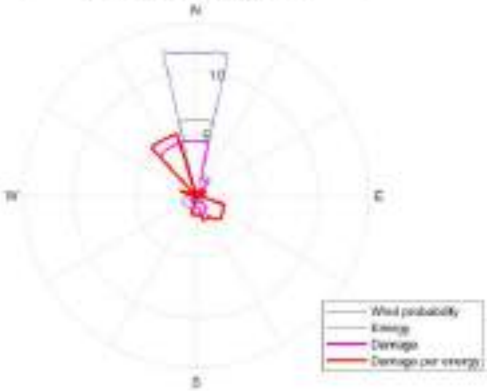
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WTS5

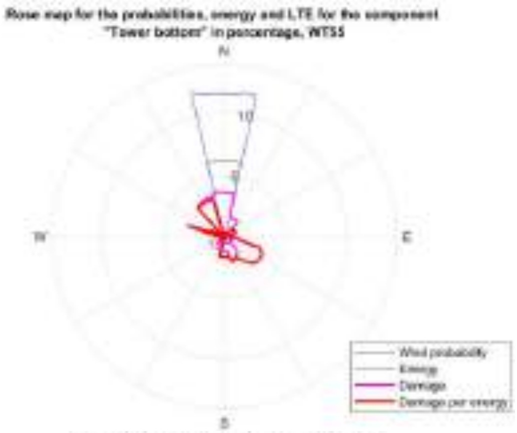


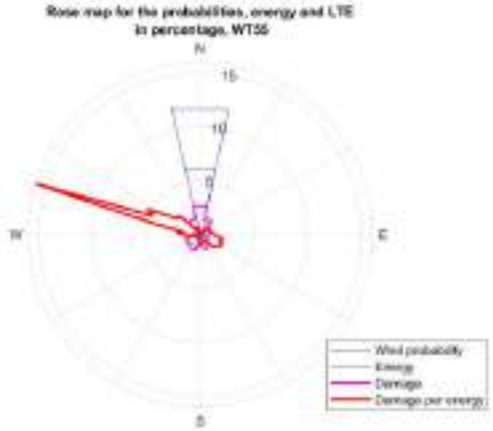
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WTS5



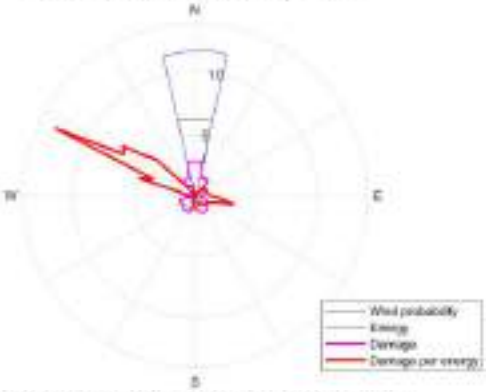
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WTS5



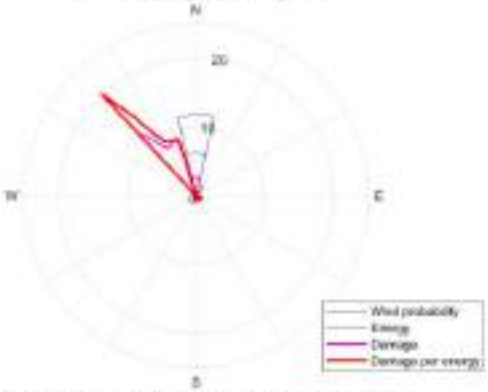

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT55
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT55
N
15
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

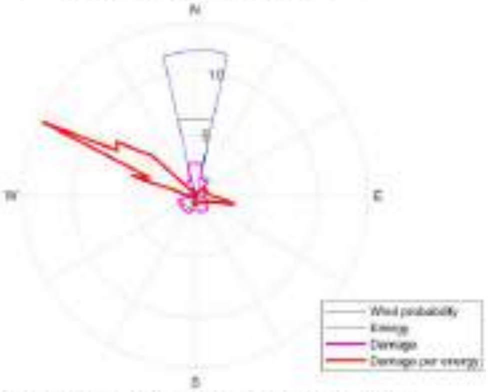
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT56



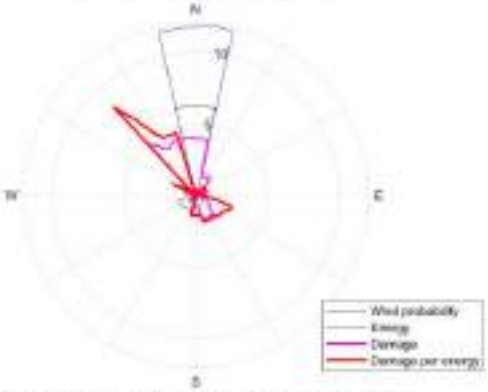
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT56



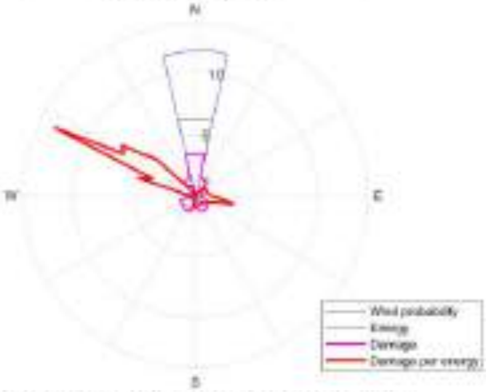
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT56



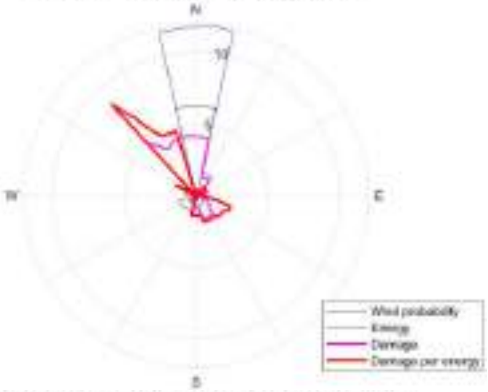
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT56



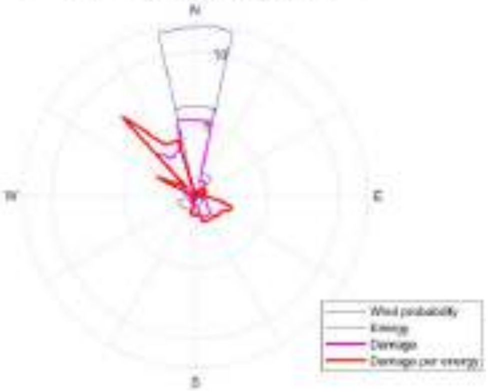
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT56



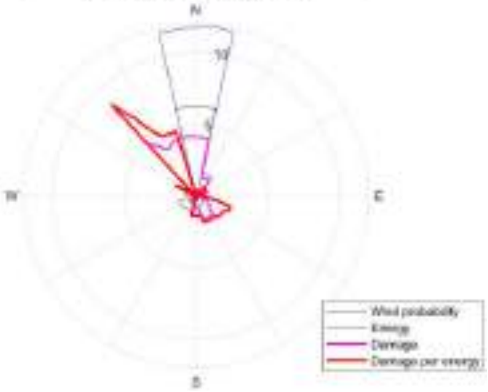
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT56

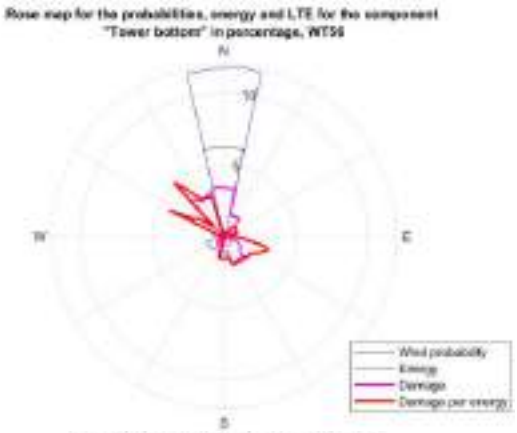


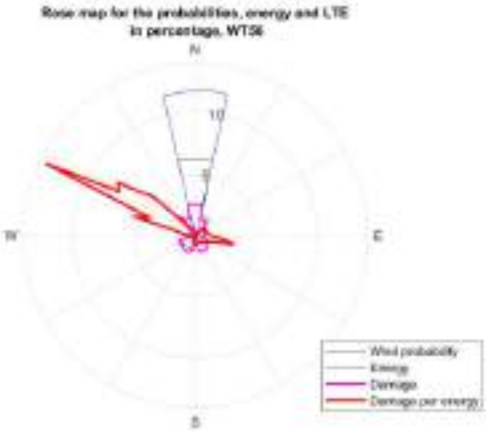
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT56



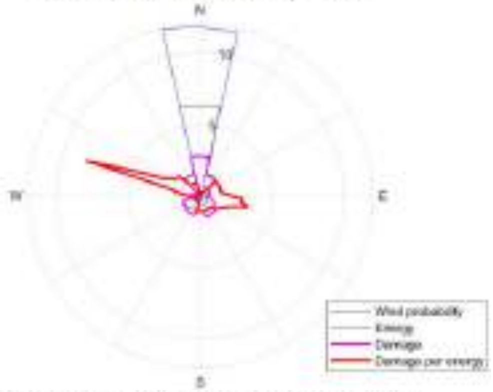
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT56



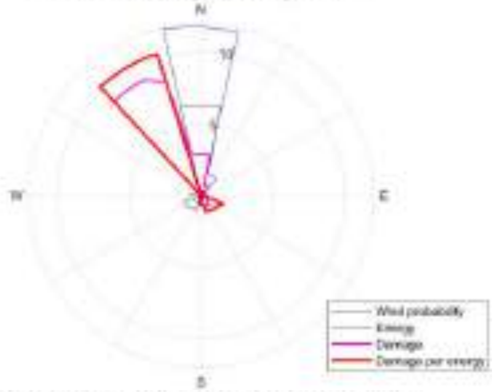

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT56
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT56
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

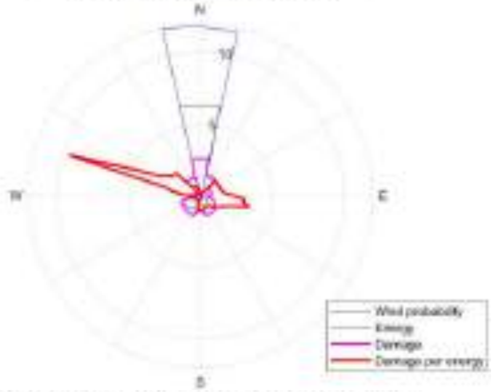
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WTS7



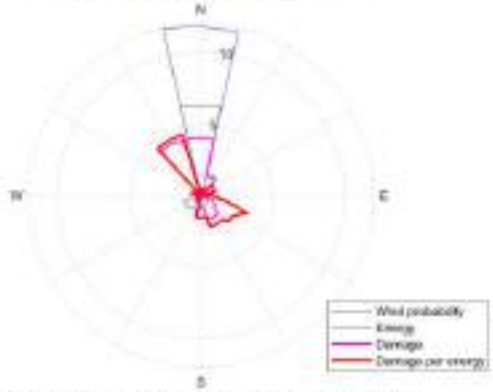
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WTS7



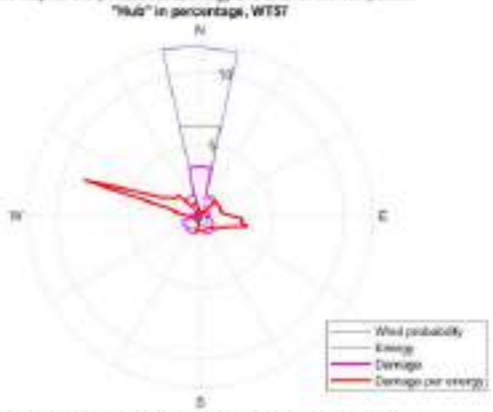
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WTS7



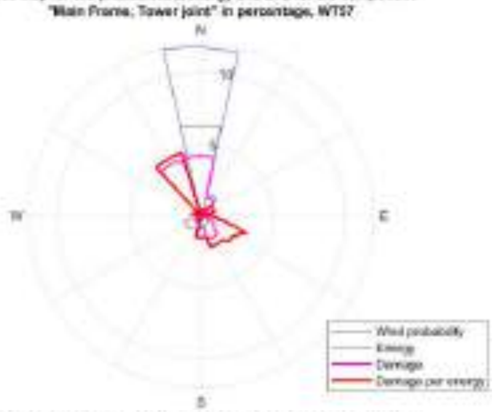
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WTS7



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WTS7

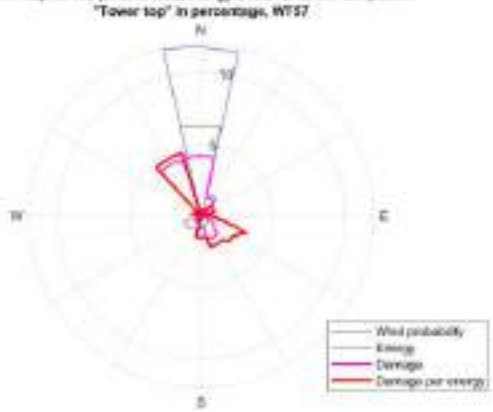


Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WTS7

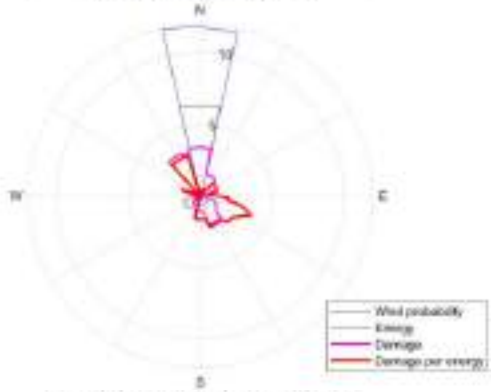


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WTS7

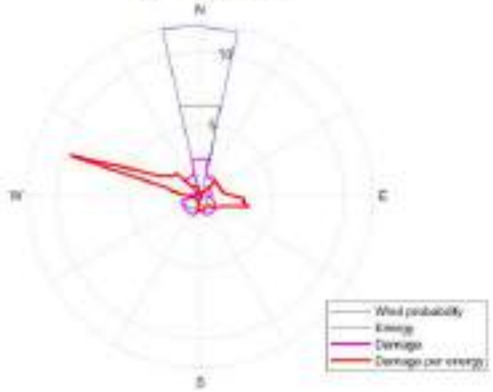
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WTS7



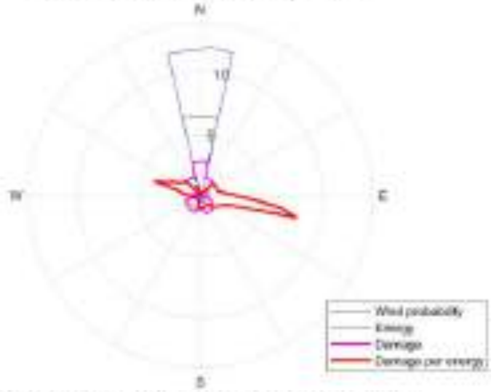
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT57



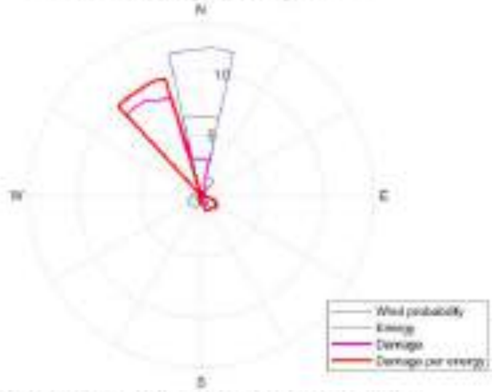
Rose map for the probabilities, energy and LTE in percentage, WT57



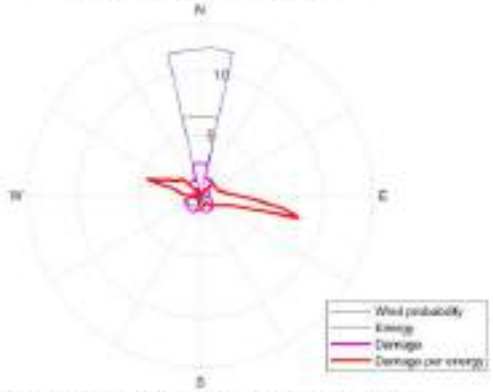
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT58



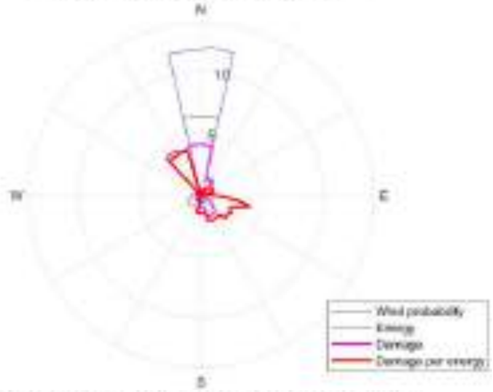
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT58



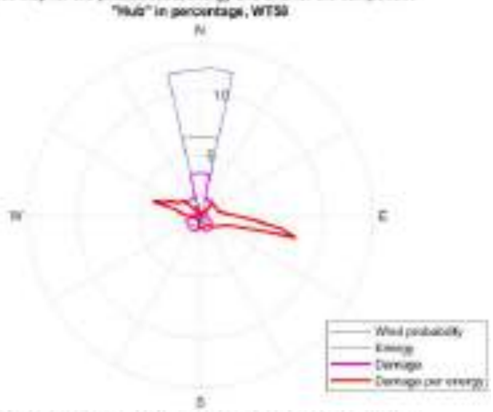
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT58



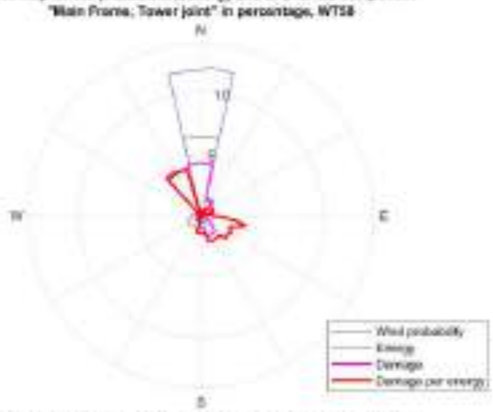
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT58



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT58

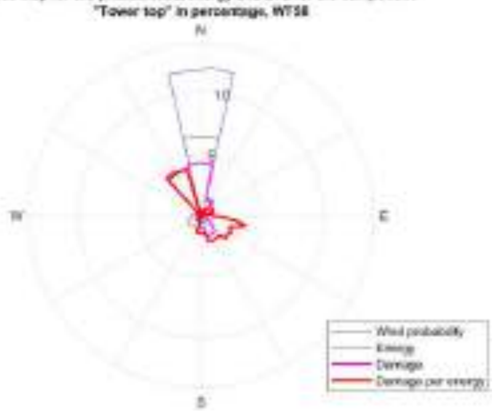


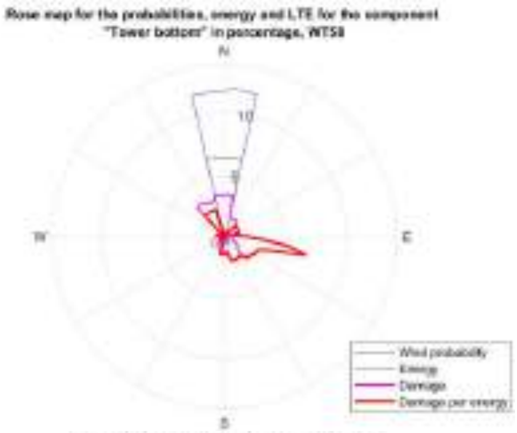
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT58

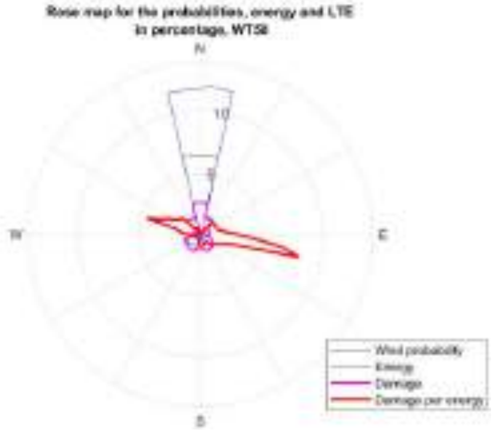


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT58

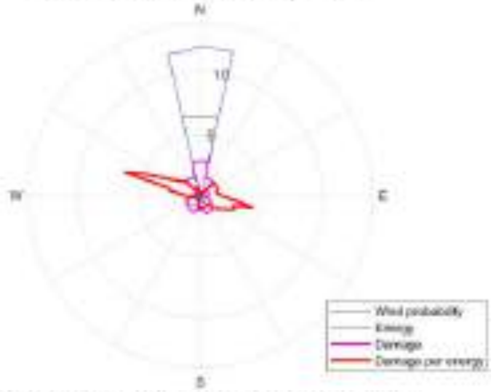
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT58



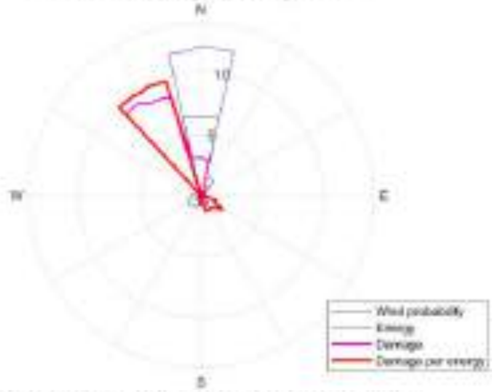

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT58
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT58
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

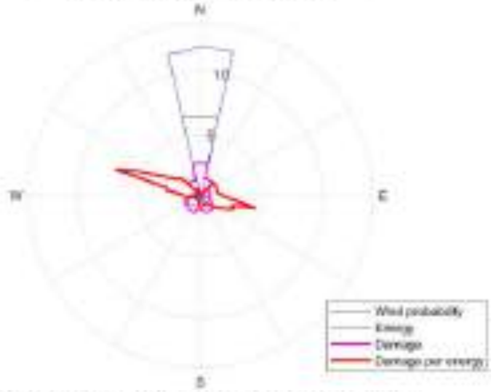
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT59



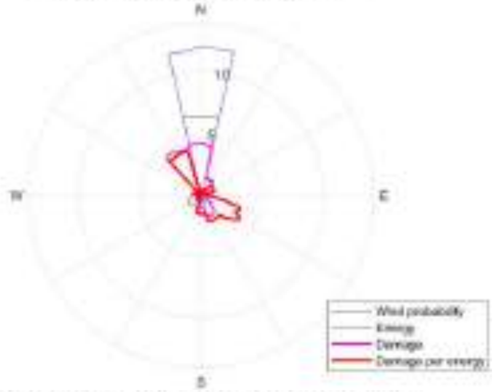
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT59



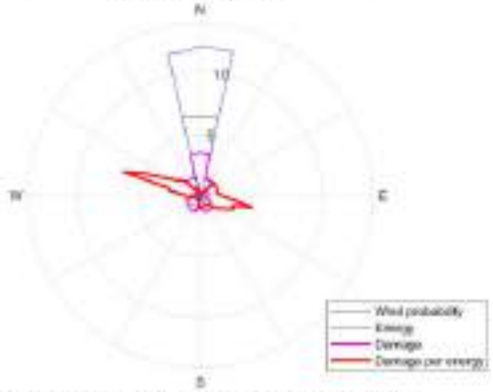
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT59



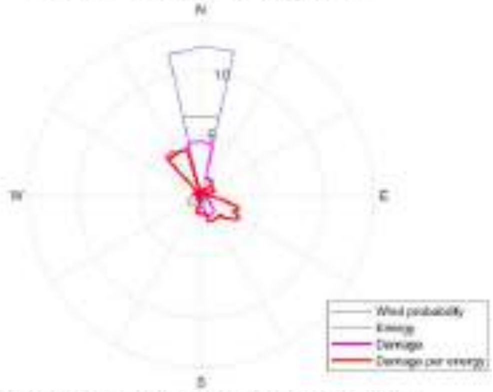
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT59



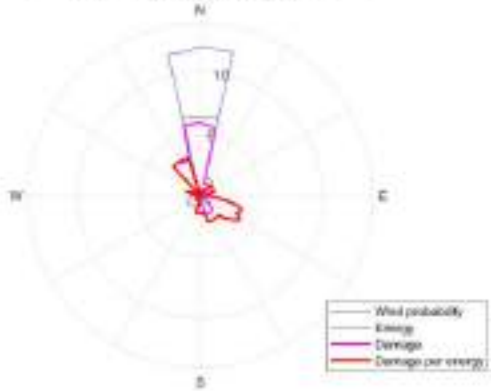
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT59



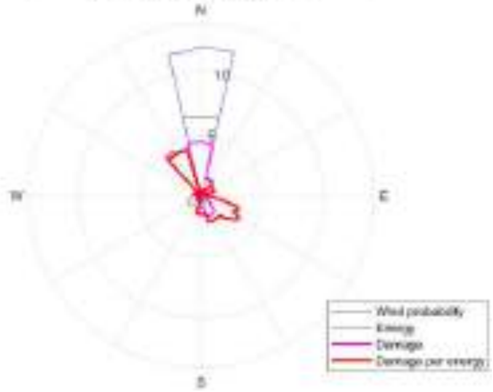
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT59

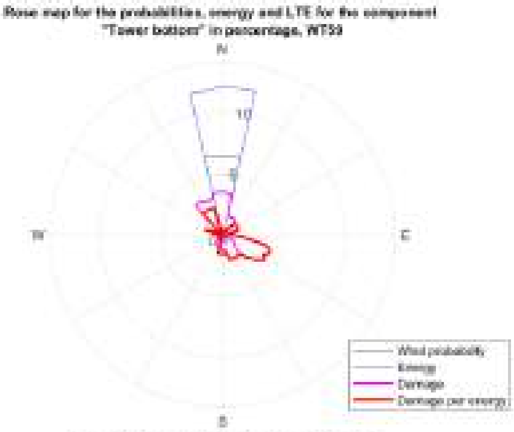


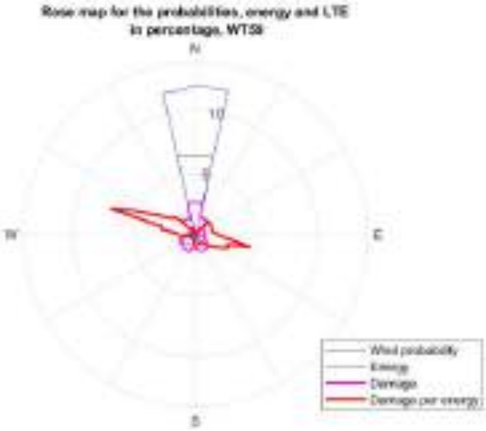
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT59



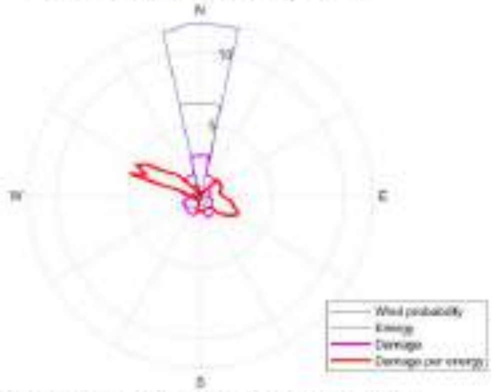
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT59



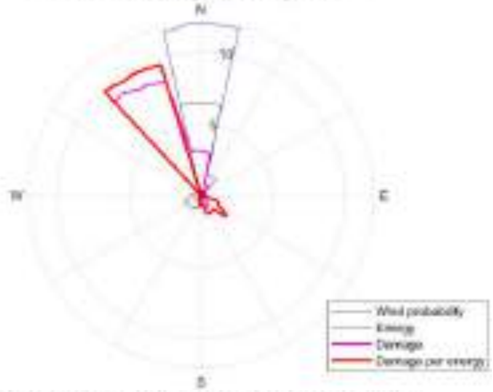

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT59
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT59
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

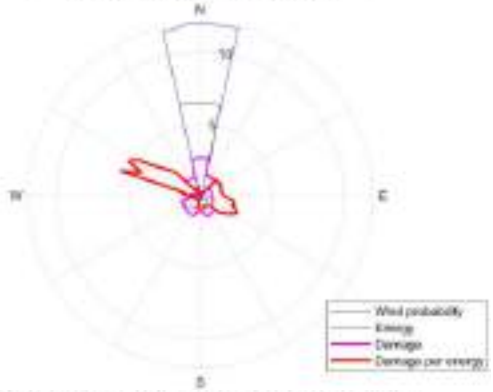
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT60



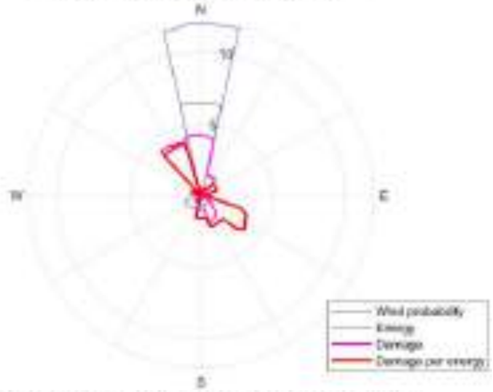
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT60



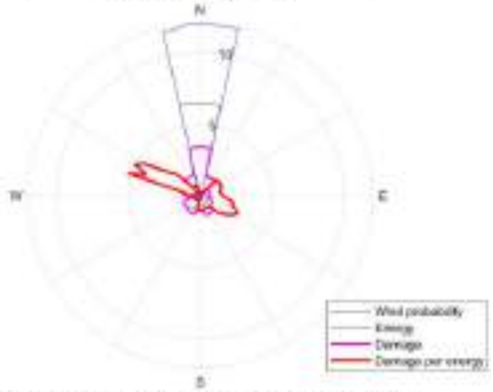
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT60



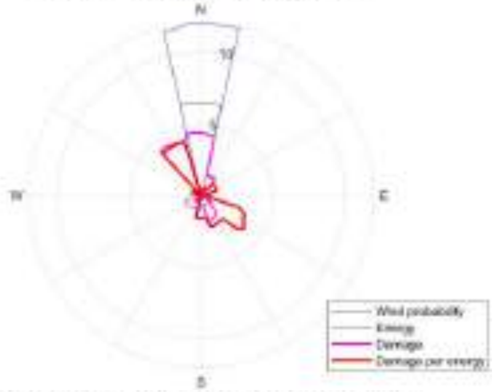
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT60



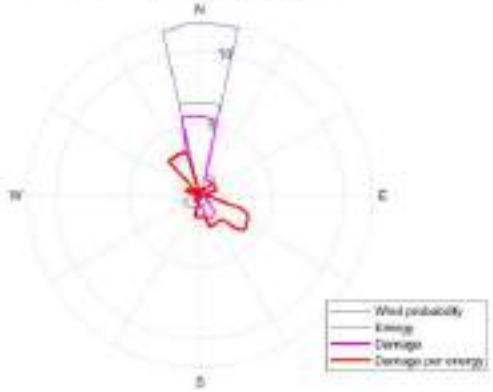
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT60



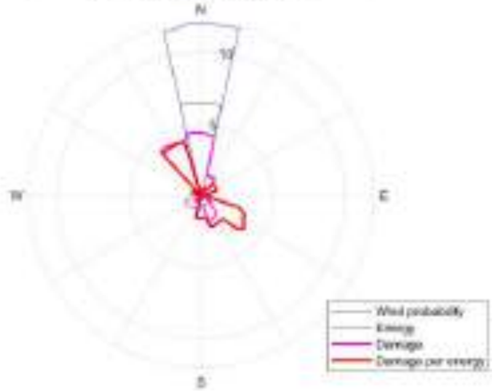
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT60



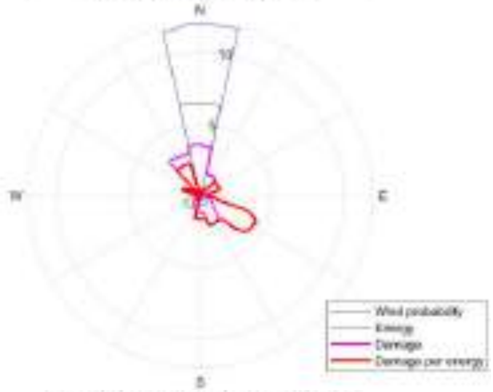
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT60



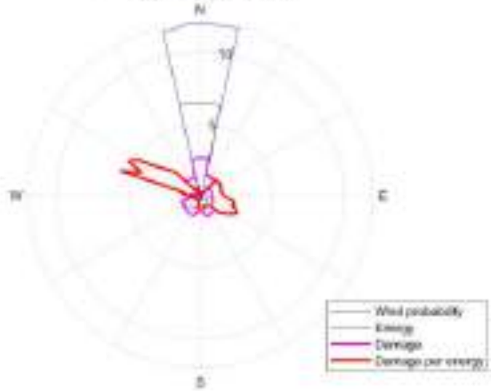
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT60



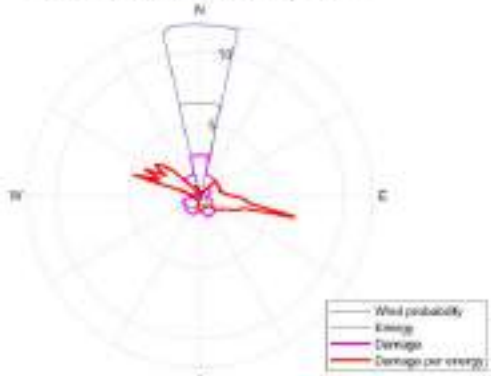
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT68



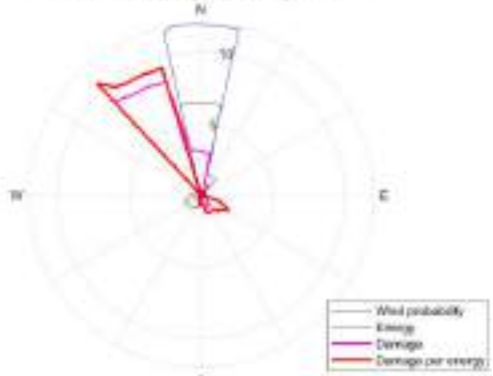
Rose map for the probabilities, energy and LTE in percentage, WT68



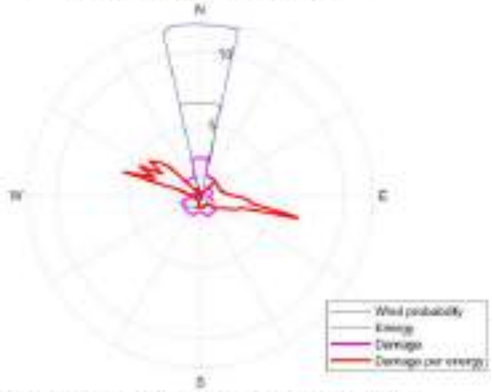
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT01



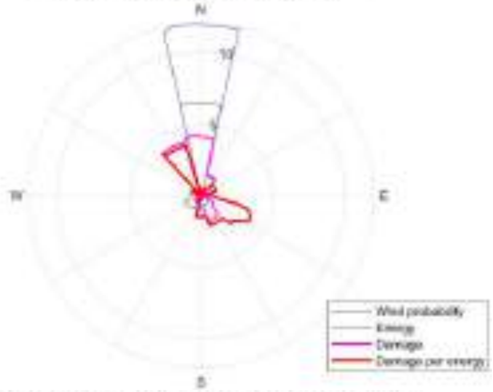
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT01



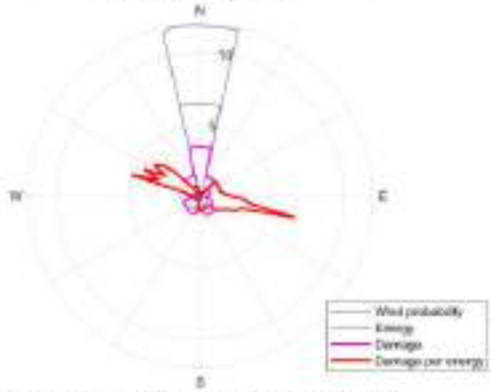
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT01



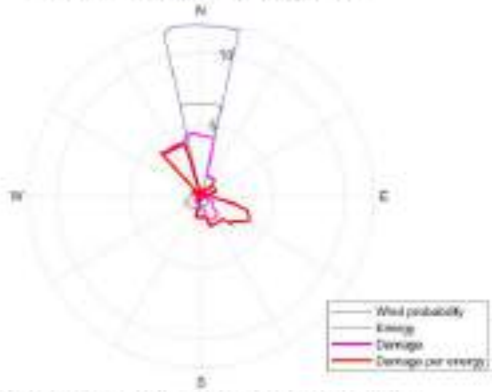
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT01



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT01

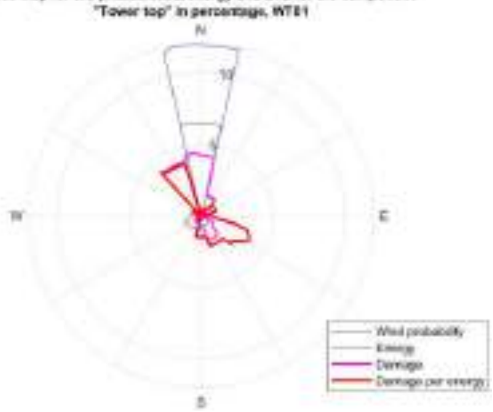


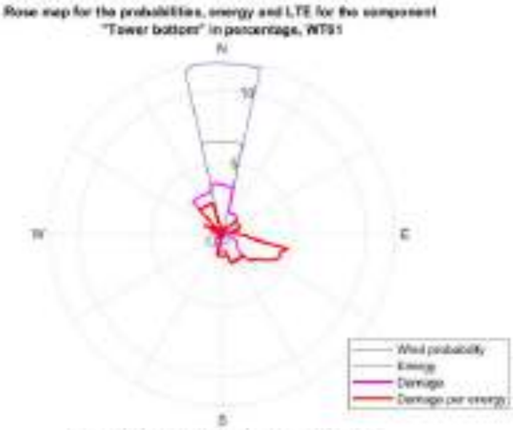
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT01

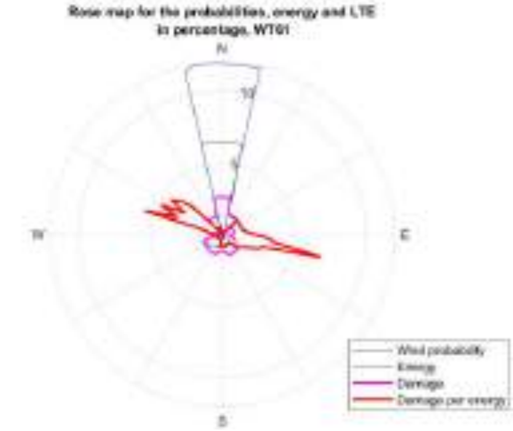


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT01

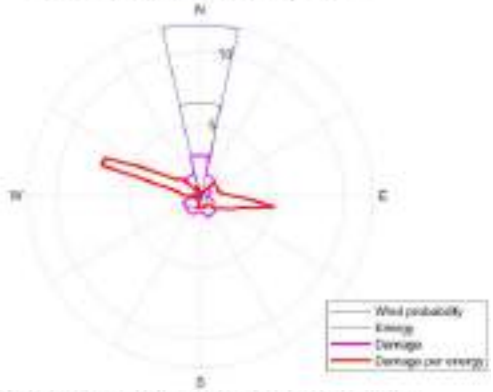
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT01



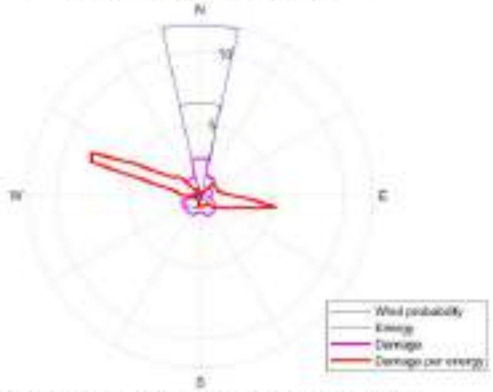

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT01
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT01
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

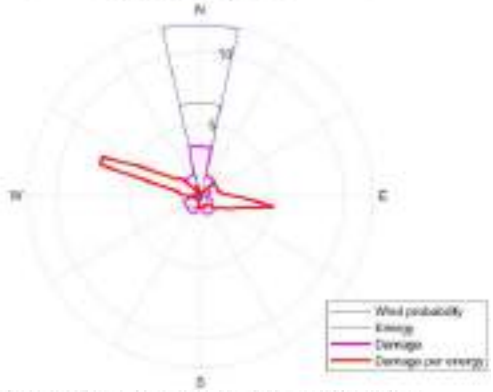
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT62



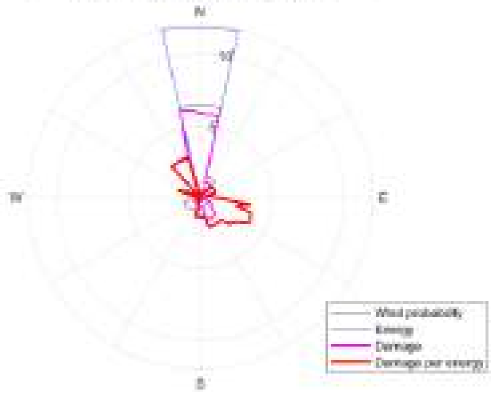
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT62



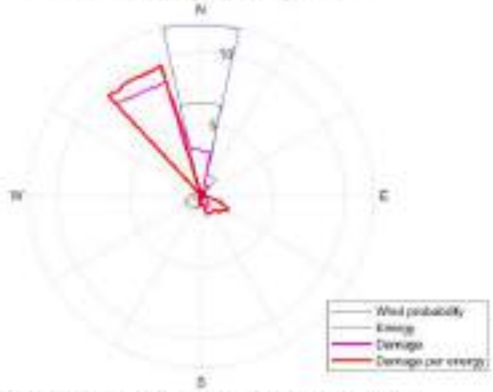
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT62



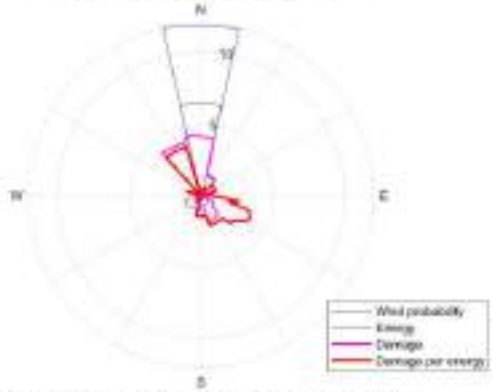
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT62



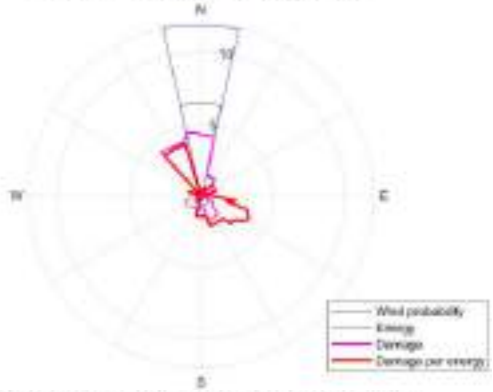
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT62



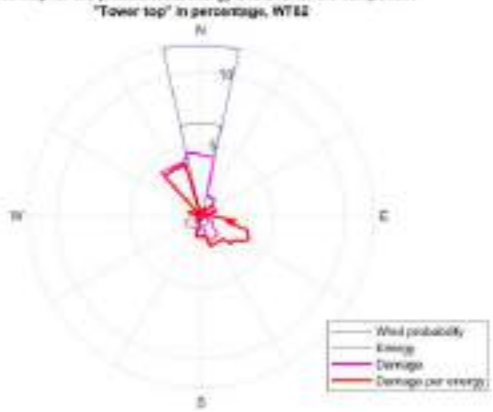
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT62

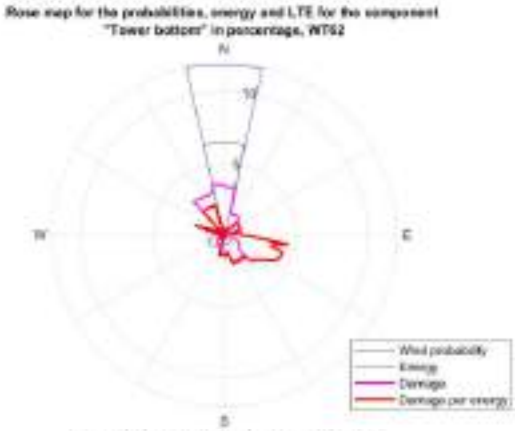


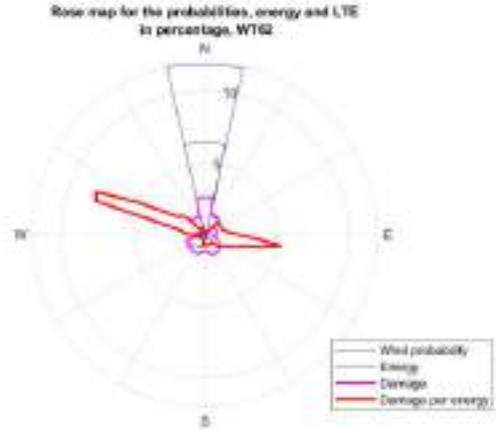
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT62



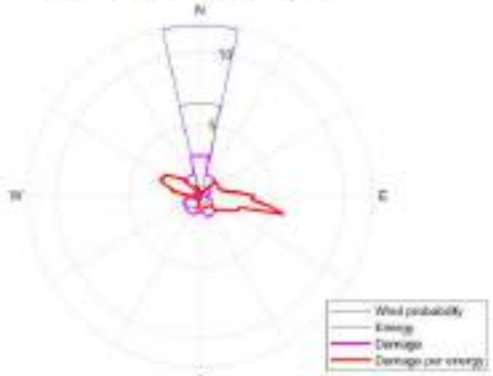
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT62



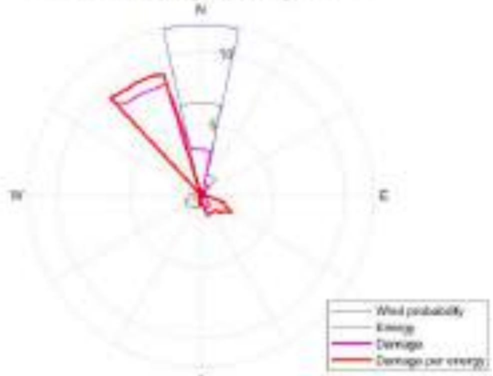

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT62
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT62
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy

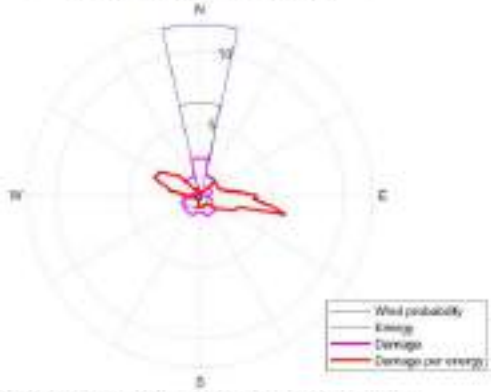
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT63



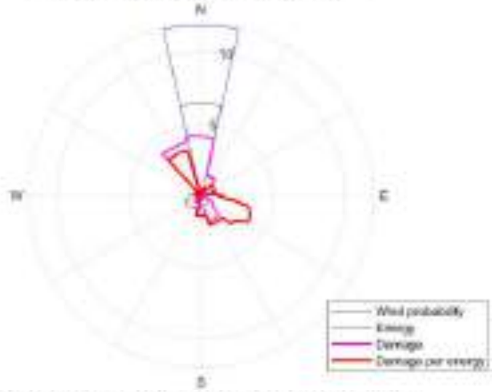
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT63



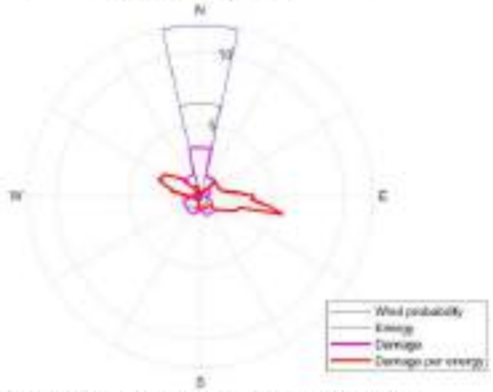
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT63



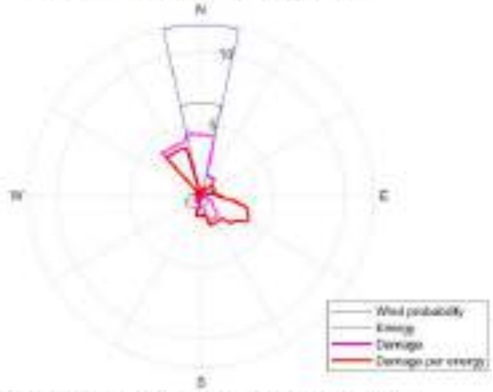
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT63



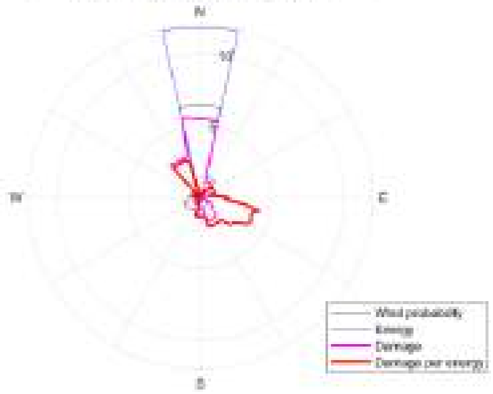
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT63



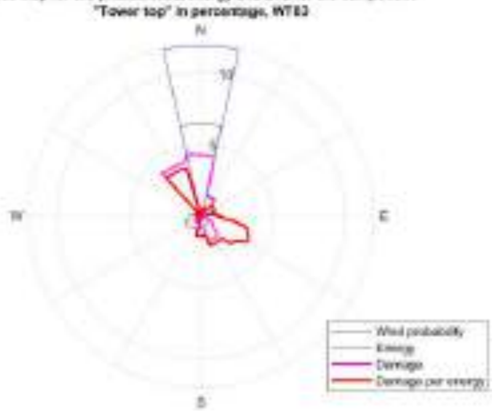
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT63



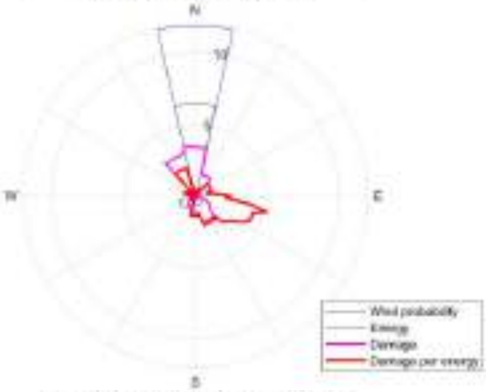
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT63



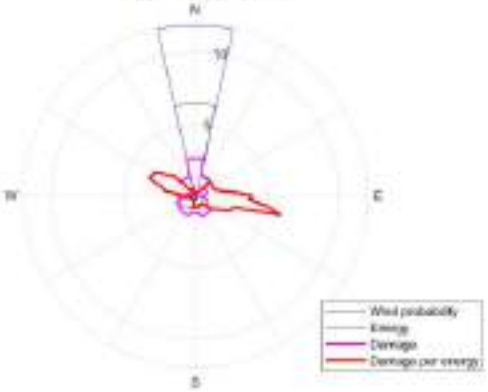
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT63



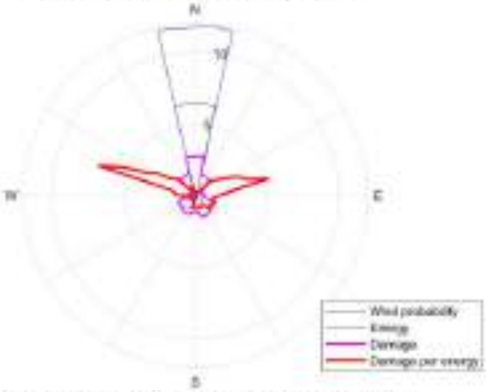
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT63



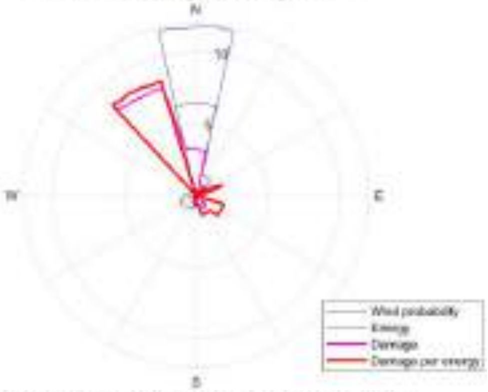
Rose map for the probabilities, energy and LTE in percentage, WT63



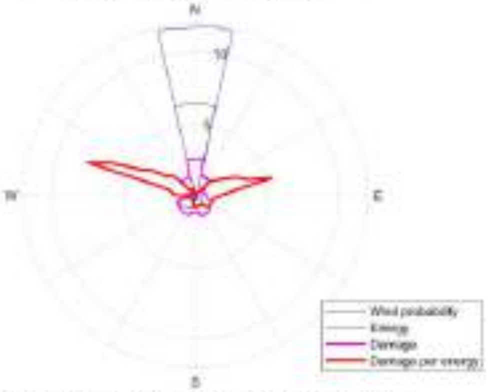
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT64



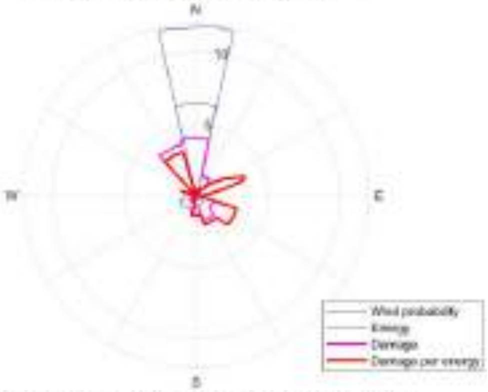
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT64



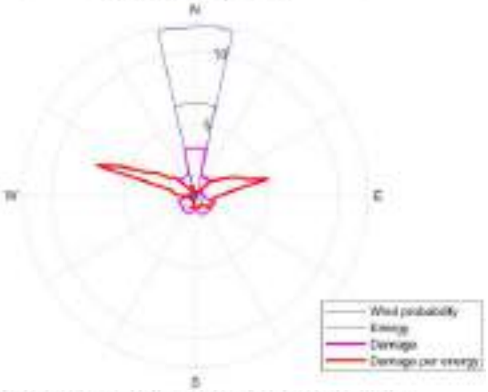
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT64



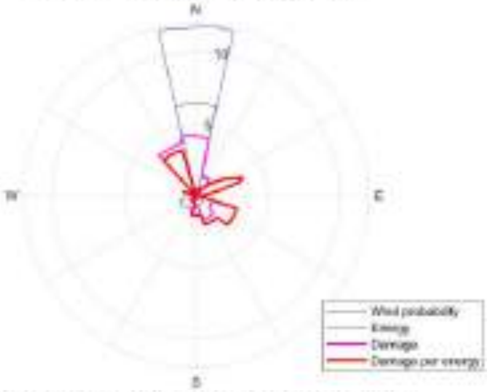
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT64



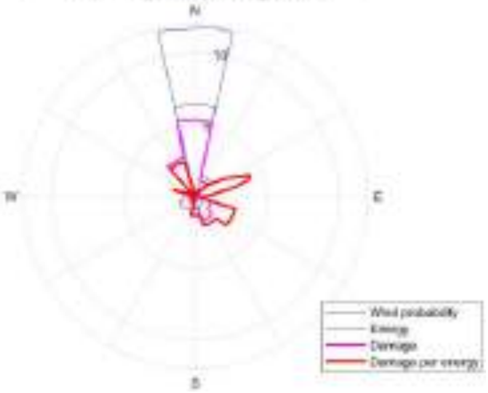
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT64



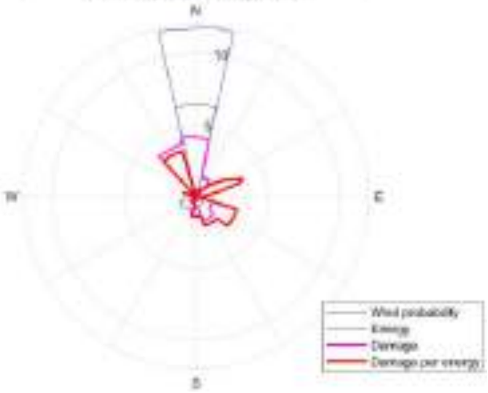
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT64

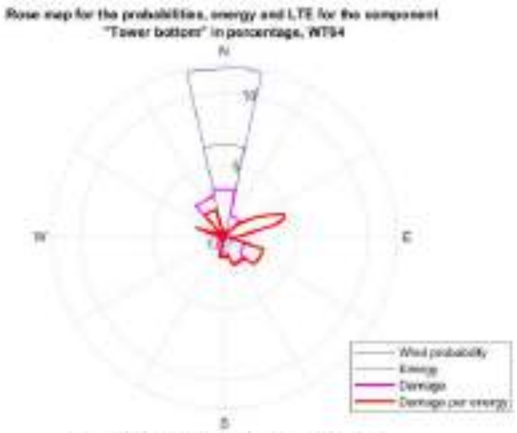


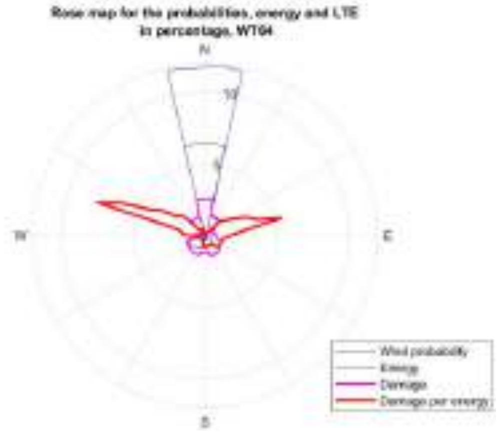
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT64



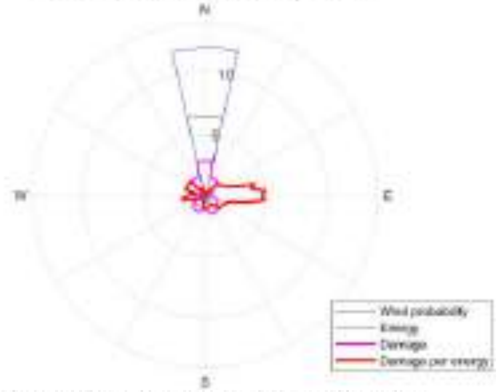
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT64



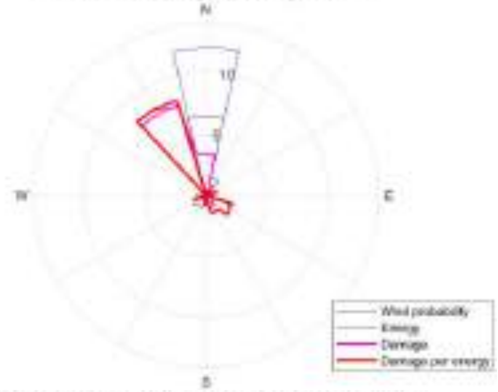

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT64
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT64
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

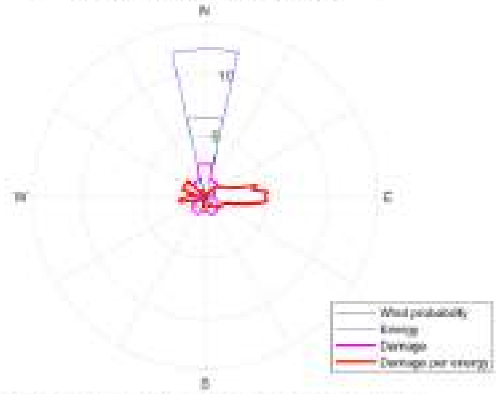
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT65



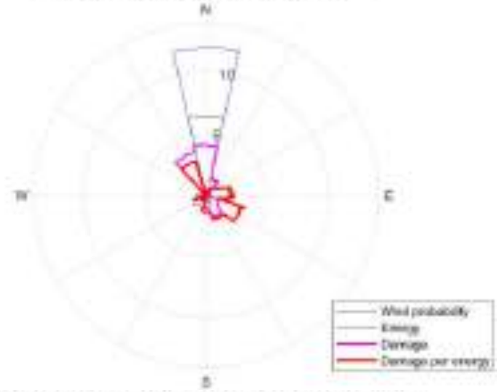
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT65



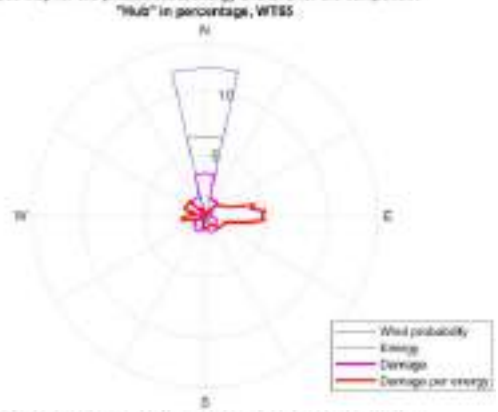
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT65



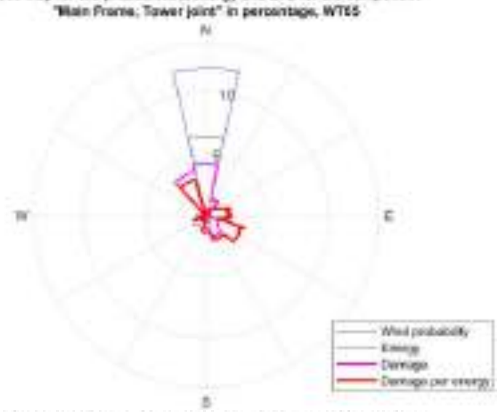
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT65



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT65

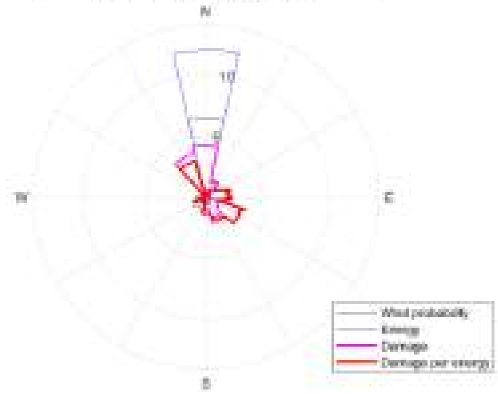


Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT65

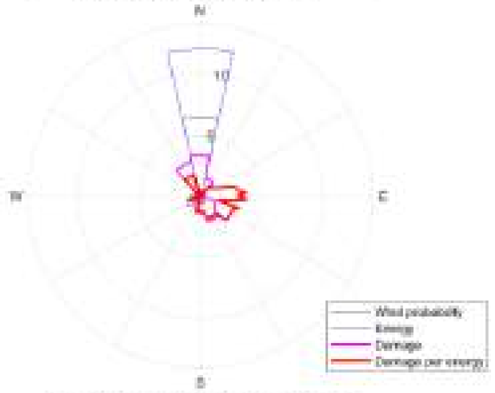


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT65

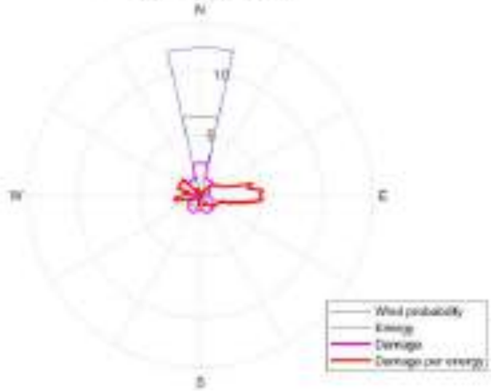
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT65



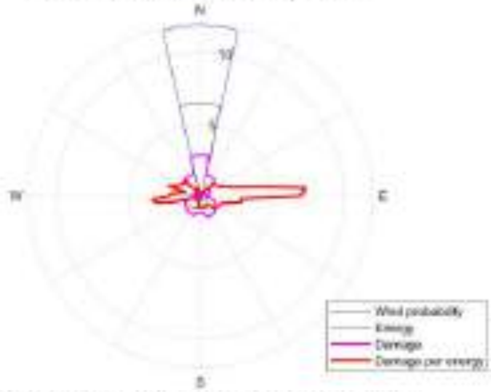
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT65



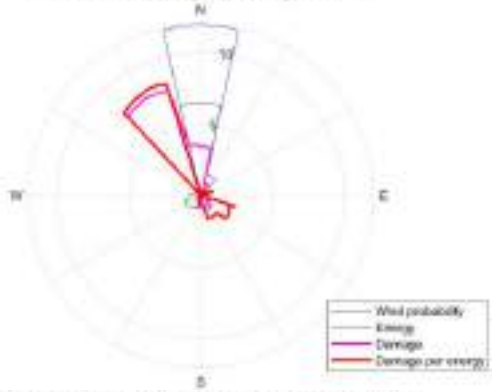
Rose map for the probabilities, energy and LTE in percentage, WT65



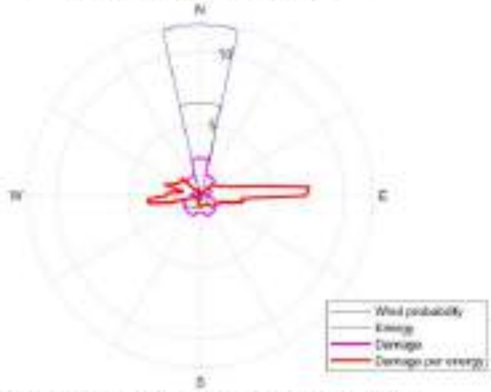
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT66



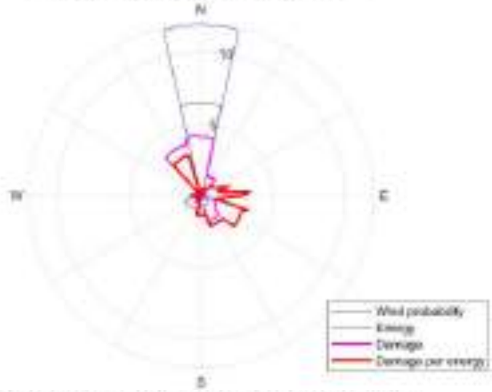
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT66



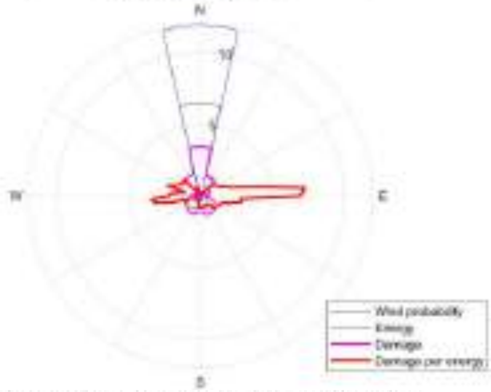
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT66



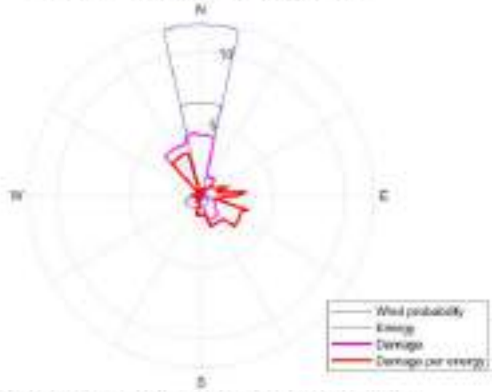
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT66



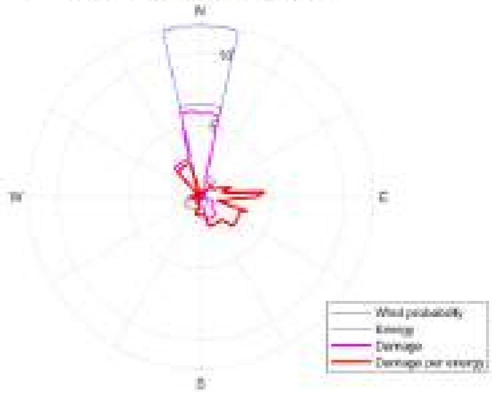
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT66



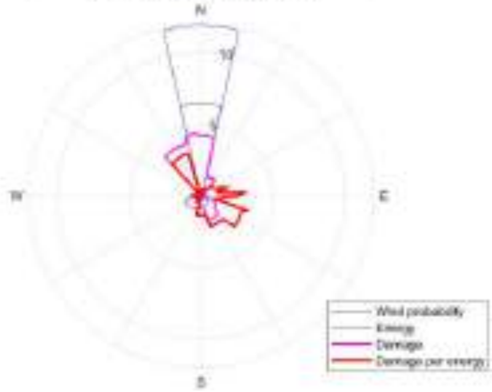
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT66

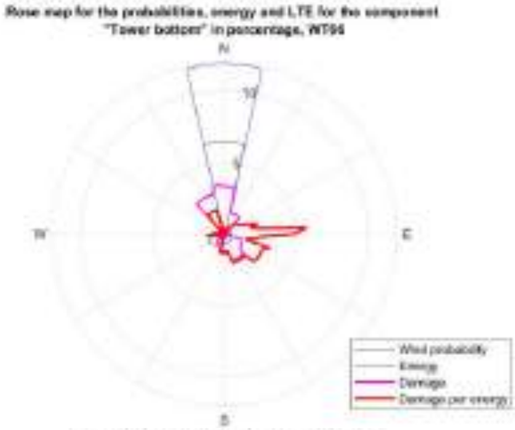


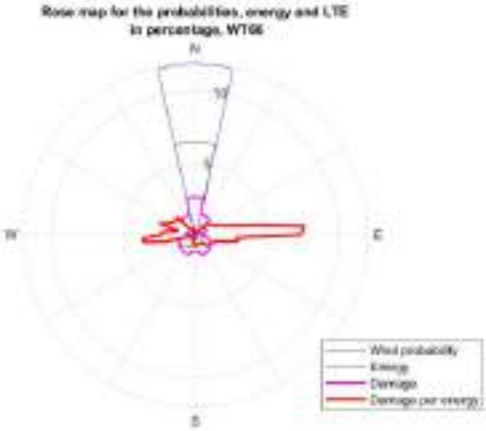
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT66



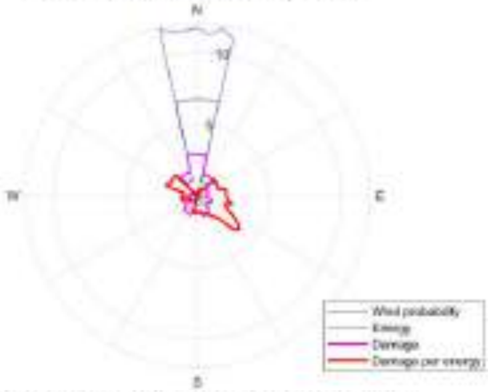
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT66



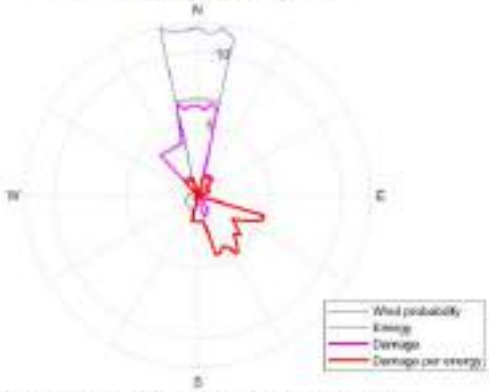

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT66
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT66
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

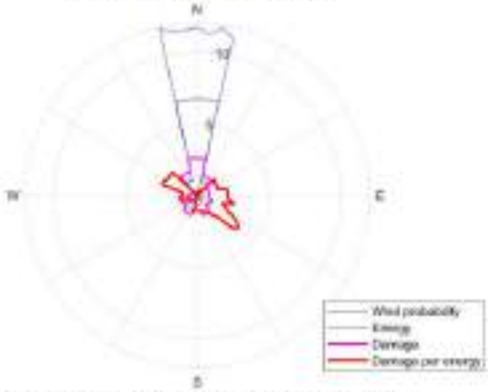
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT67



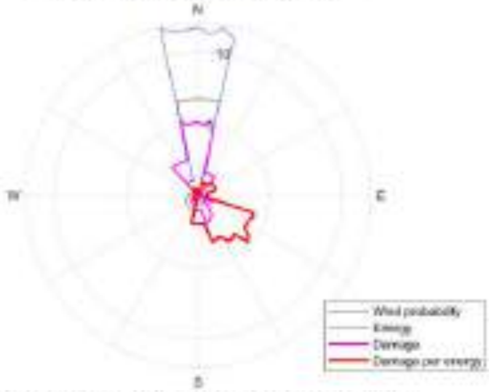
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT67



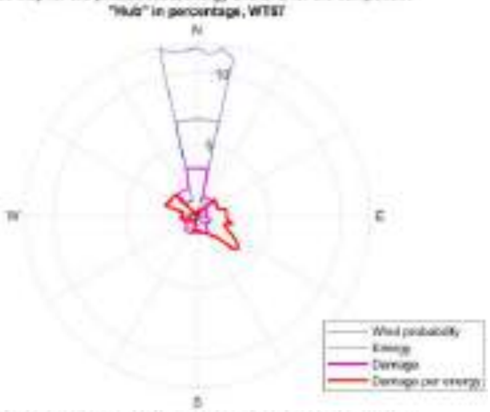
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT67



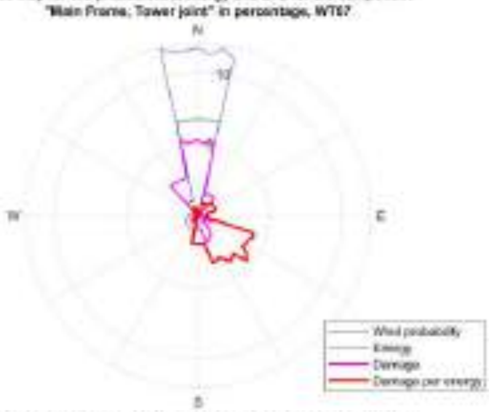
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT67



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT67

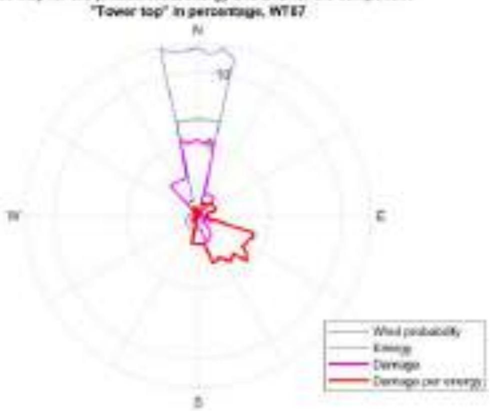


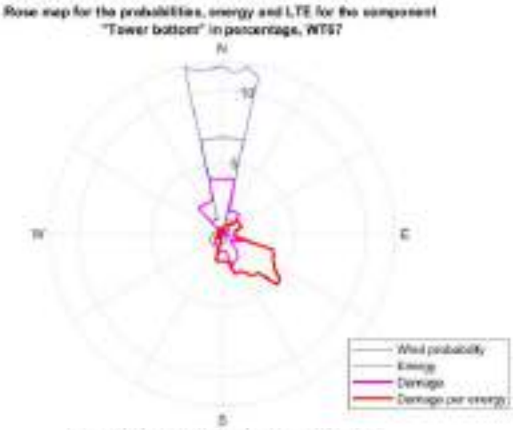
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT67

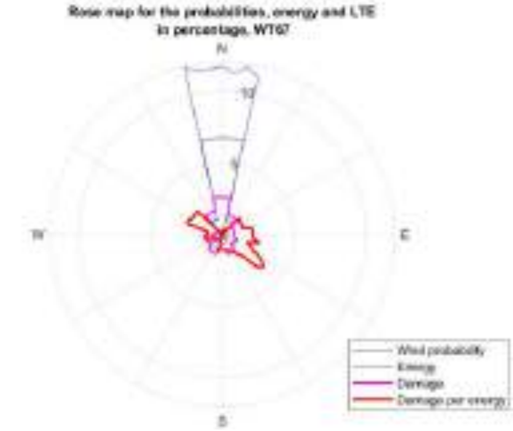


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT67

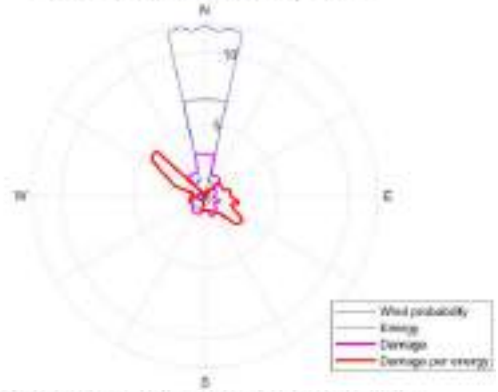
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT67



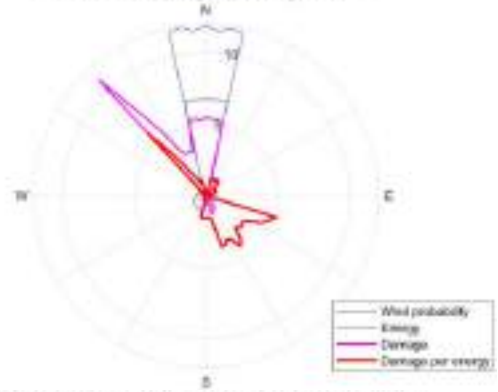

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT67
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT67
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

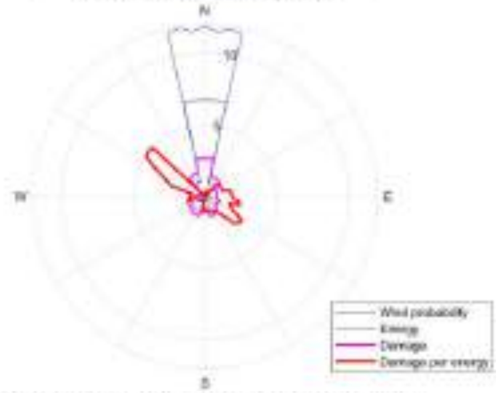
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT68



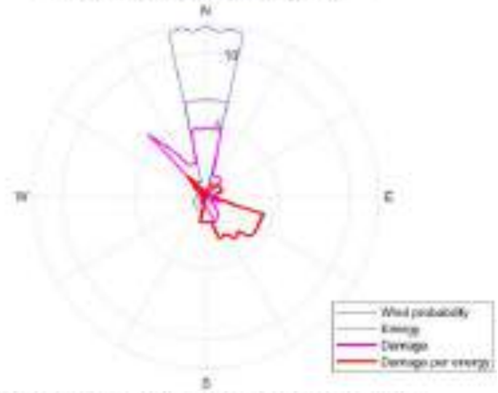
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT68



Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT68

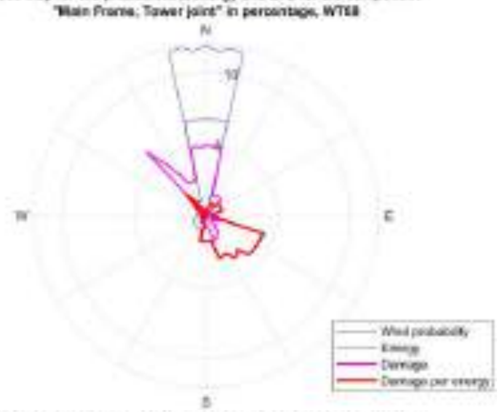


Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT68



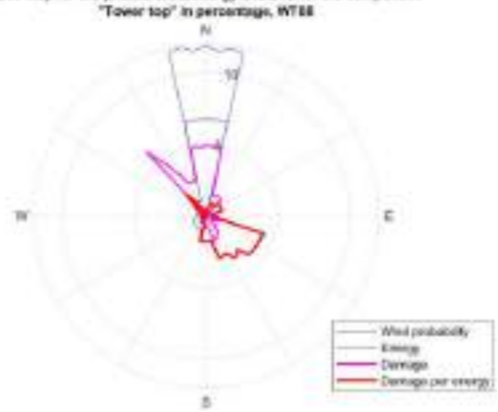
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT68

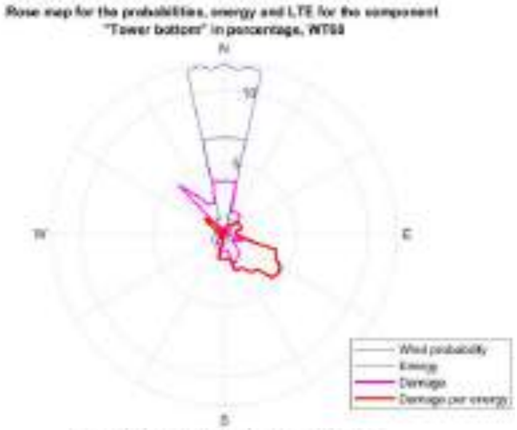
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT68

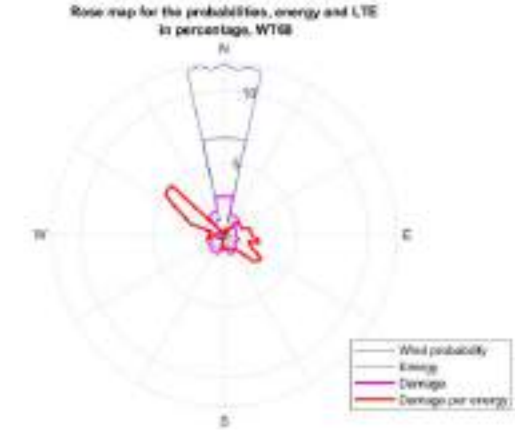


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT68

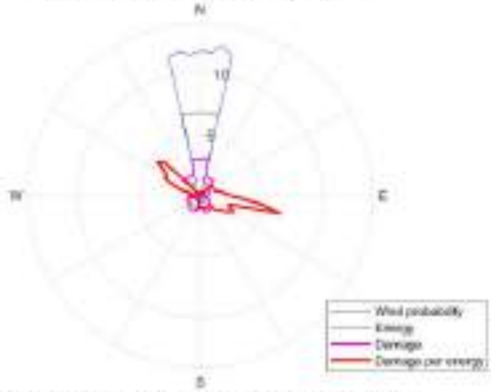
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT68



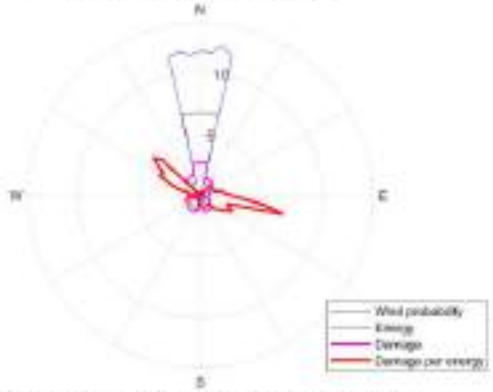

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT68
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT68
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

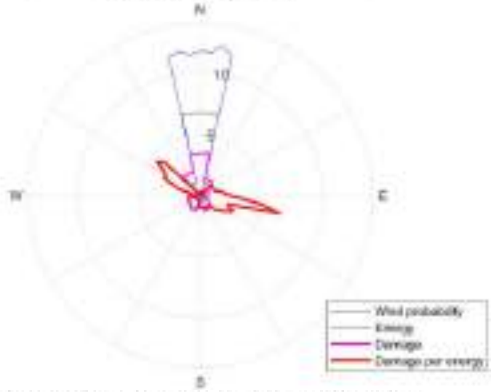
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT69



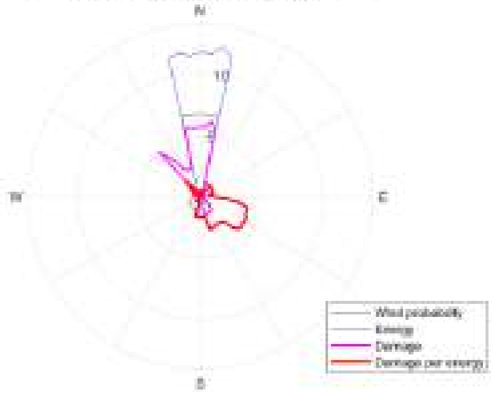
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT69



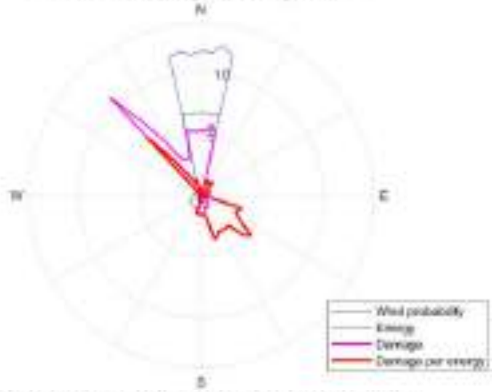
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT69



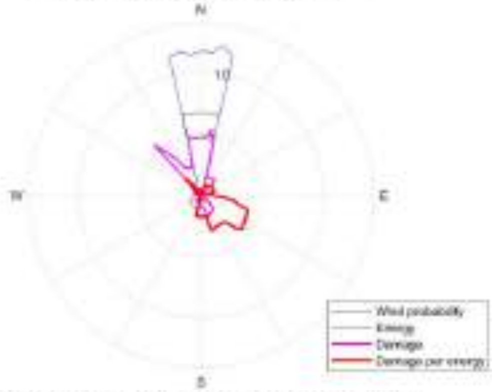
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT69



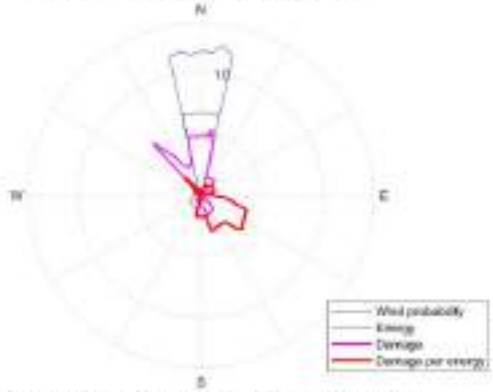
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT69



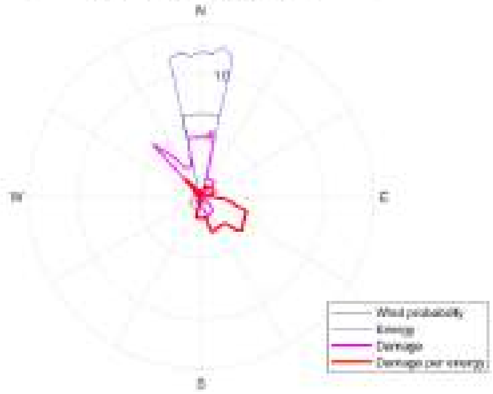
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT69

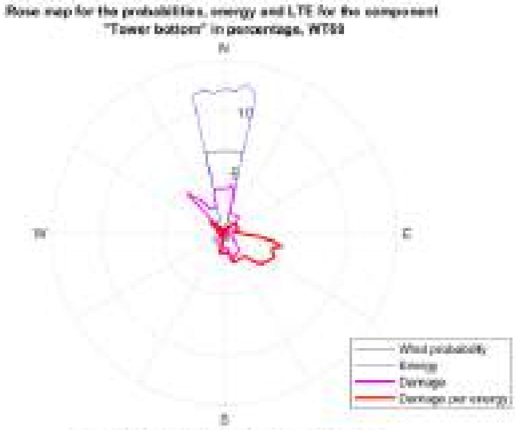


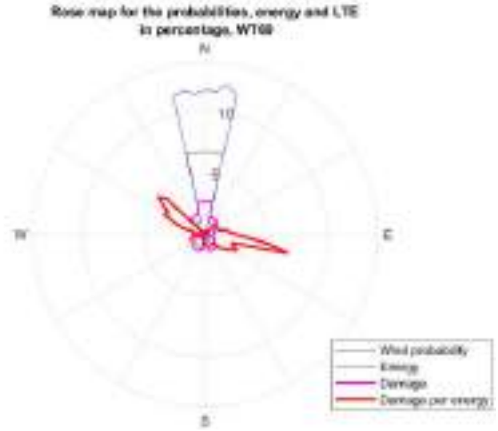
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT69



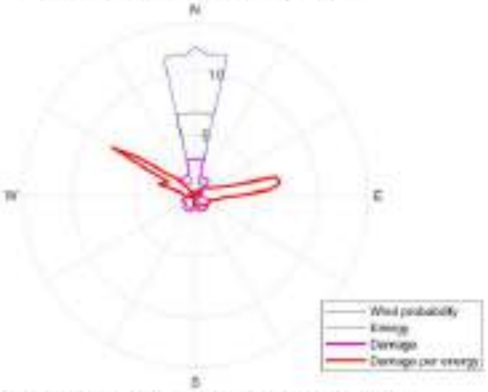
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT69



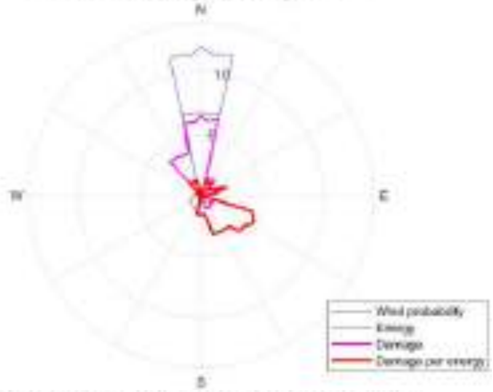

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT59
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT60
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

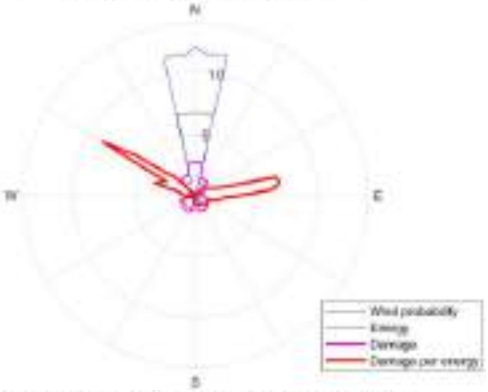
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT70



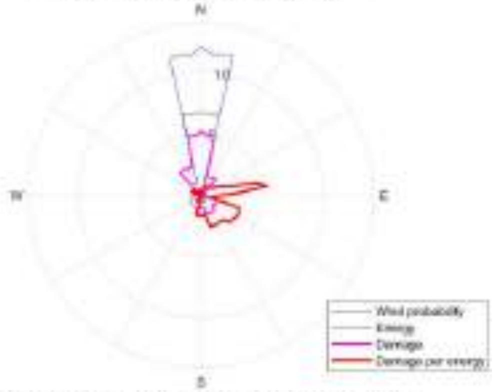
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT70



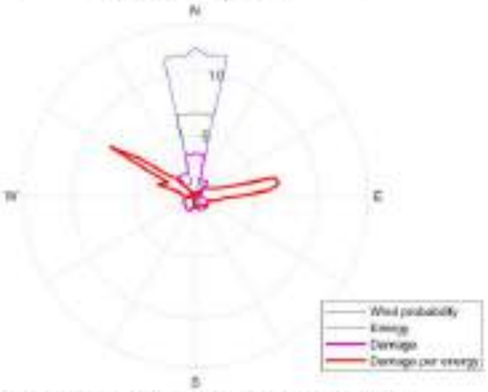
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT70



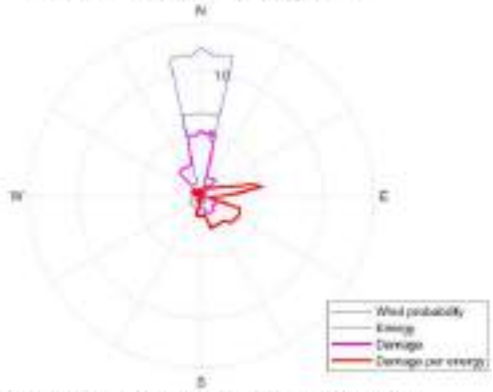
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT70



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT70



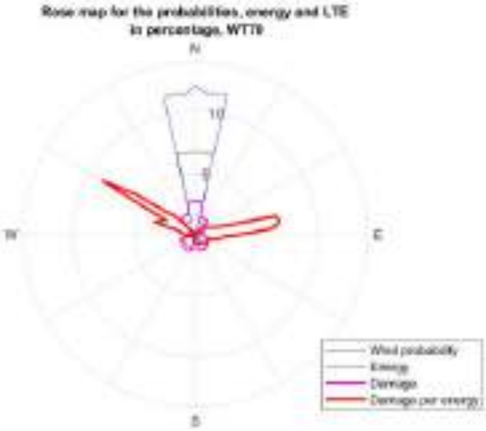
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT70



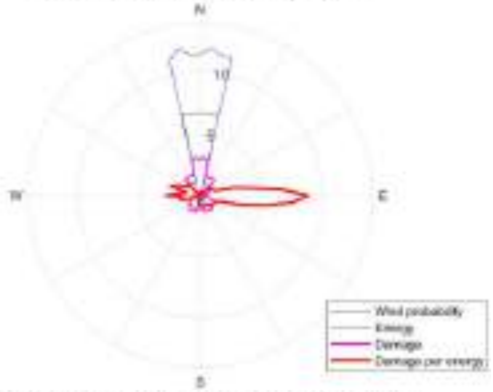
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT70

Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT70

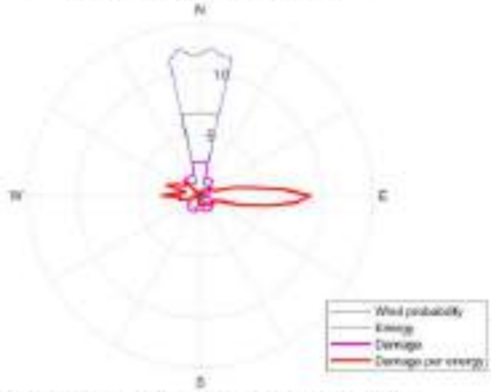

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT79
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT79
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

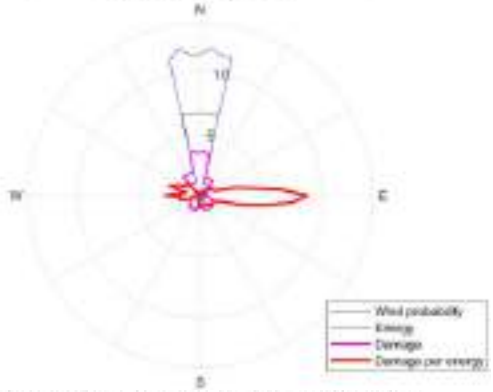
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT71



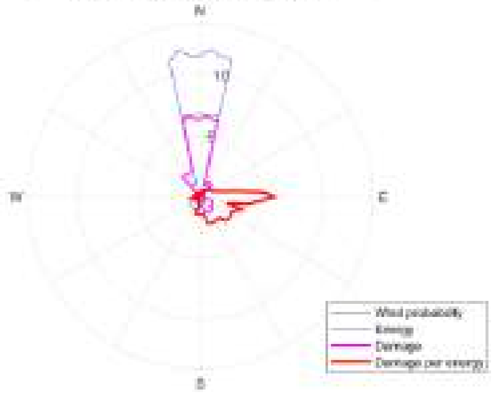
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT71



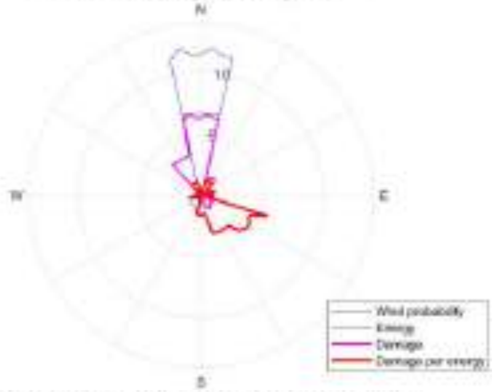
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT71



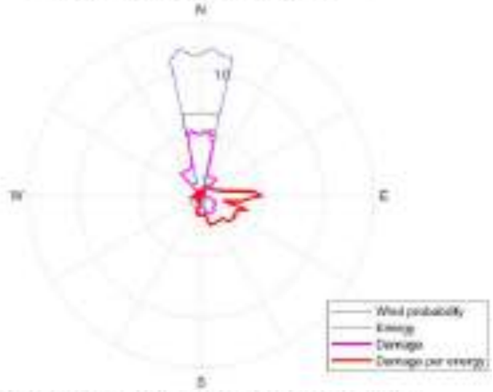
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT71



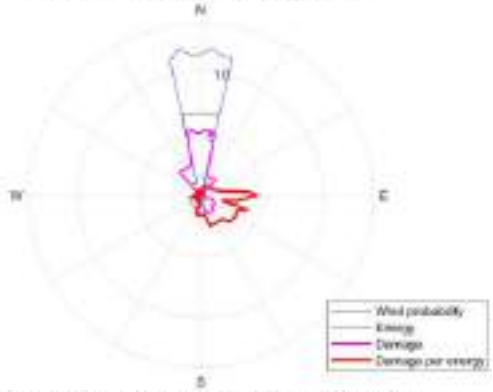
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT71



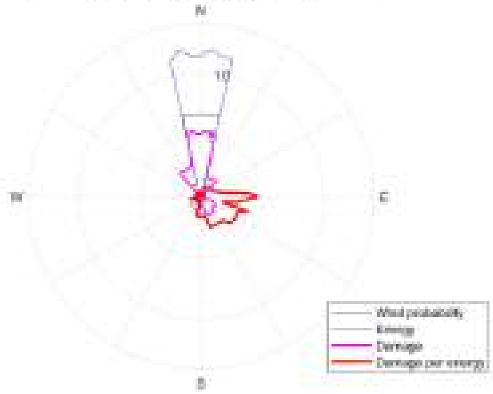
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT71

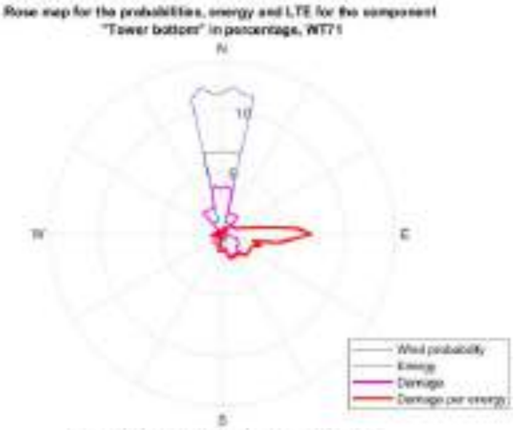


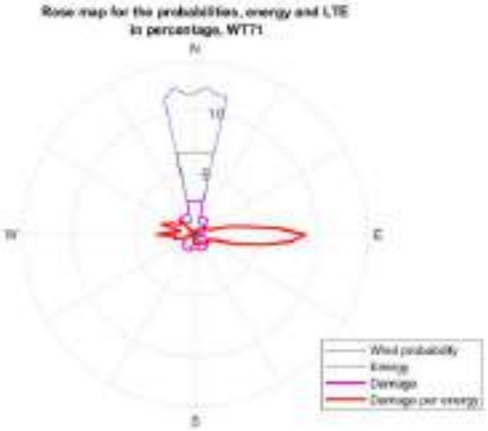
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT71



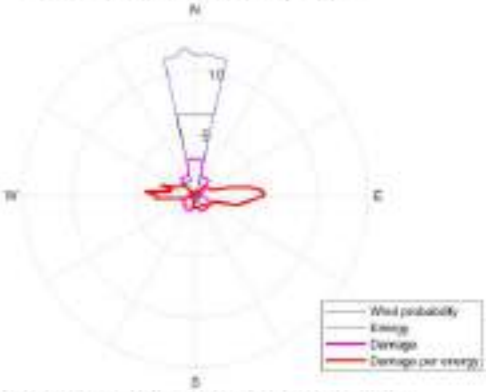
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT71



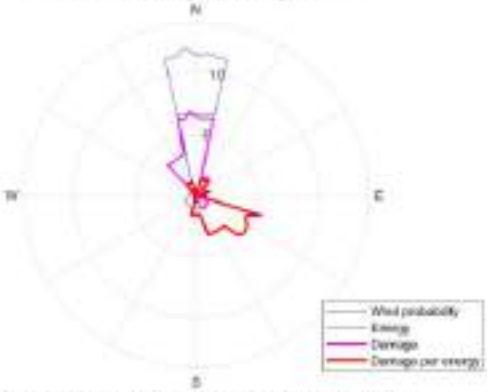

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT71
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT71
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

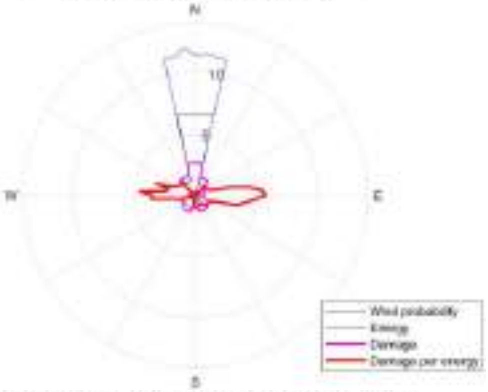
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT72



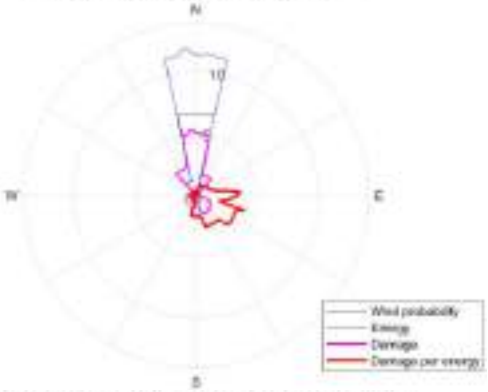
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT72



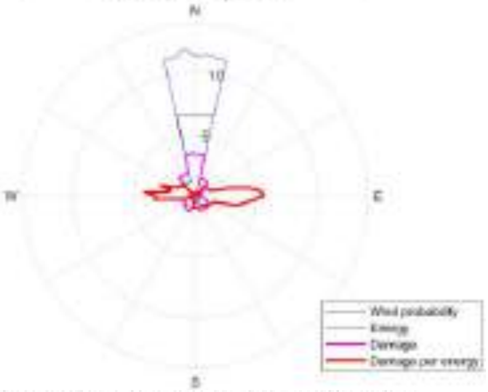
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT72



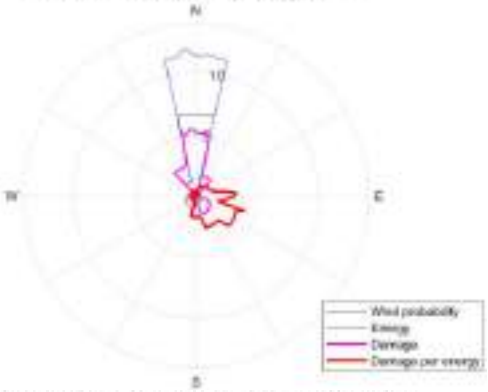
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT72



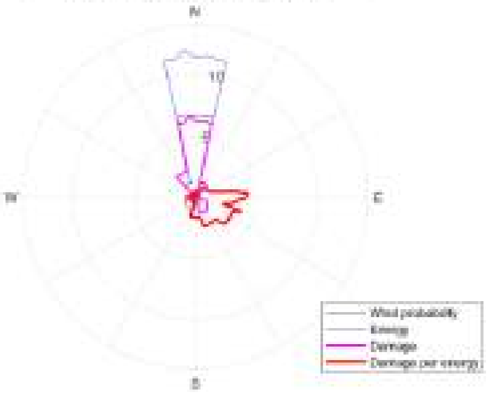
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT72



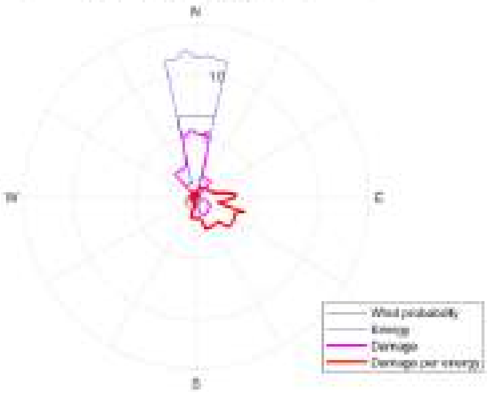
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT72

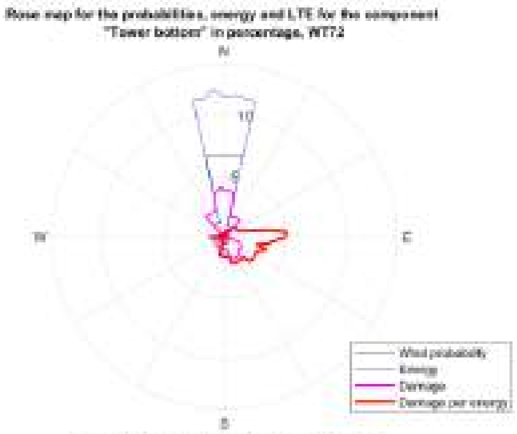


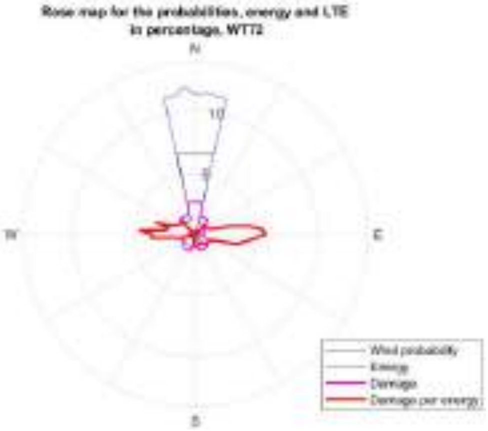
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT72



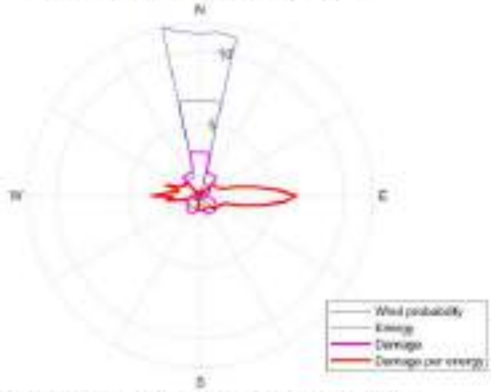
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT72



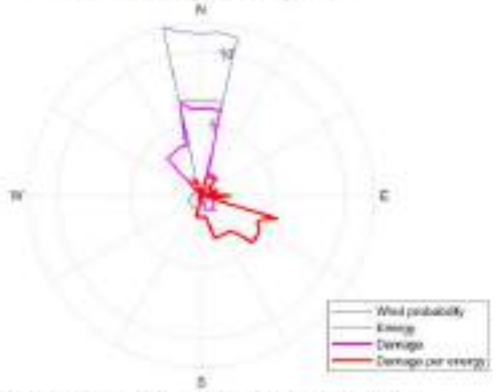

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT72
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT72
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

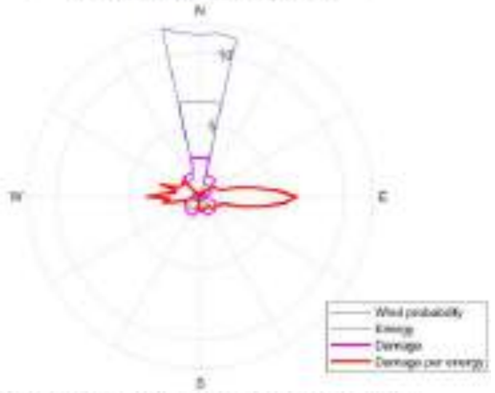
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT73



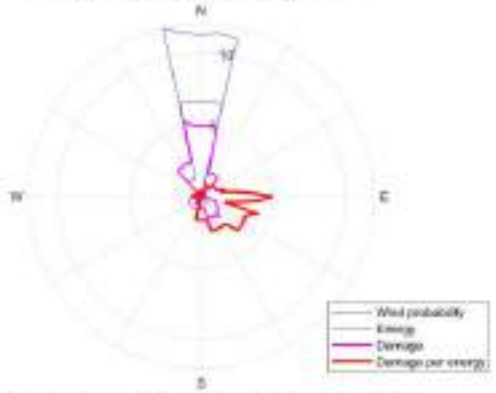
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT73



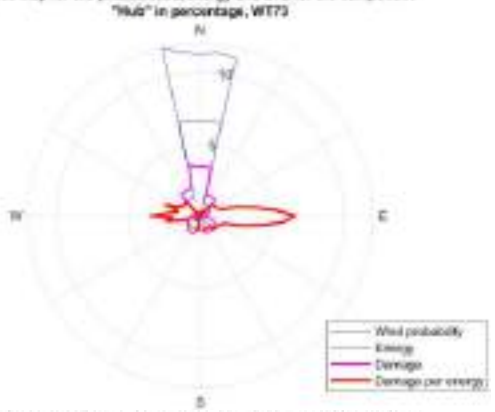
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT73



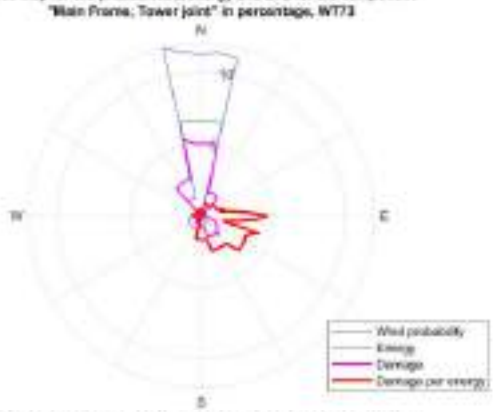
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT73



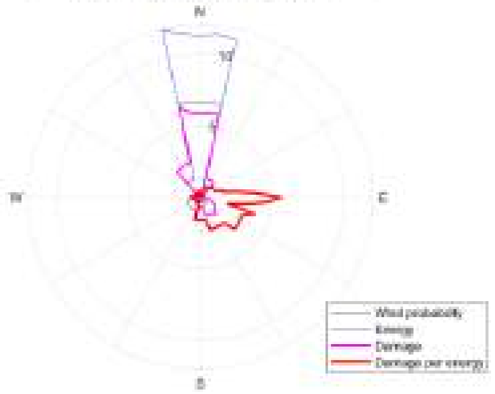
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT73



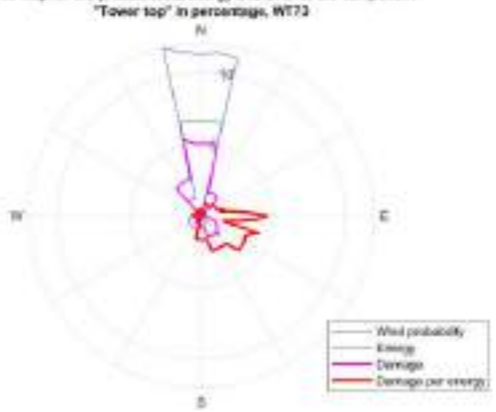
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT73

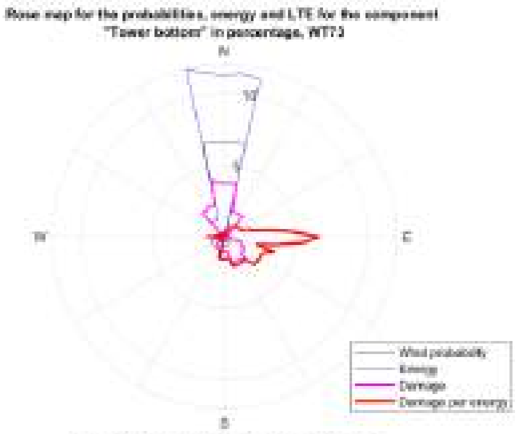


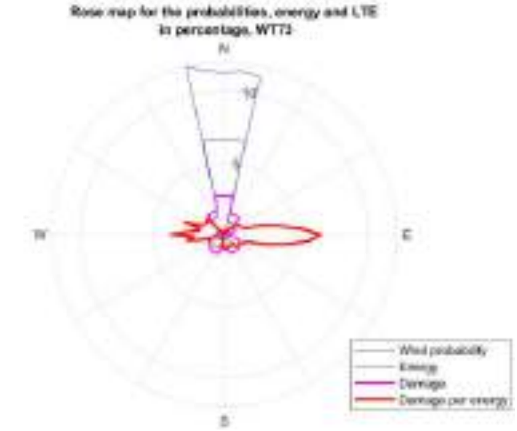
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT73



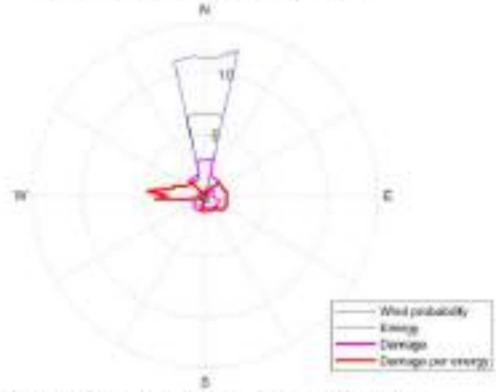
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT73



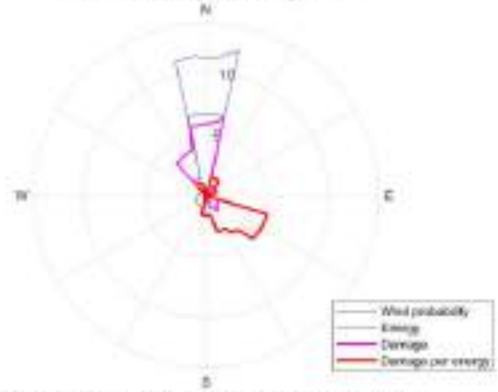

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT73
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT73
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

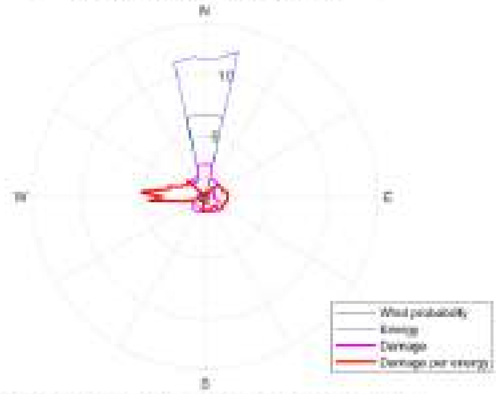
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT74



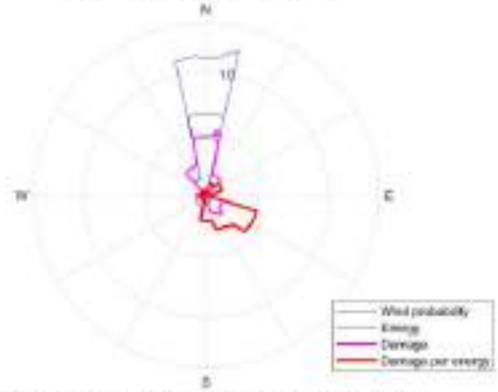
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT74



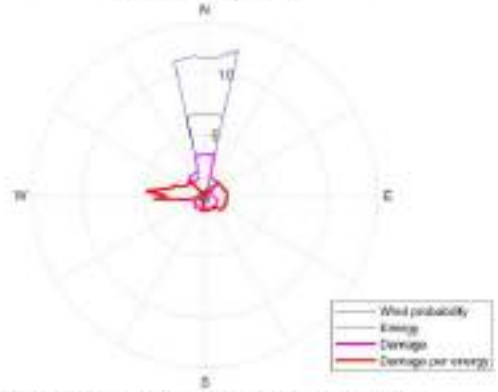
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT74



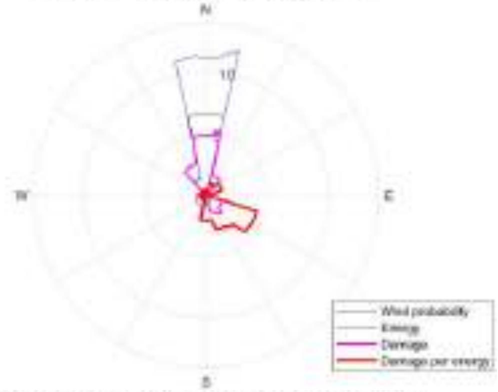
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT74



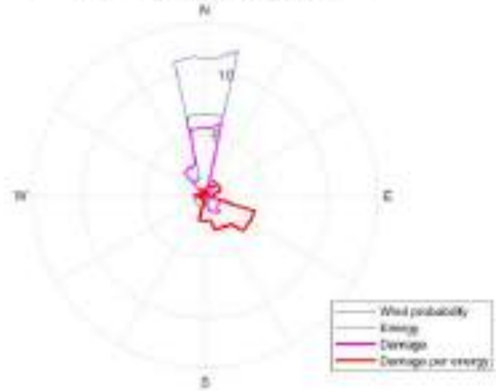
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT74



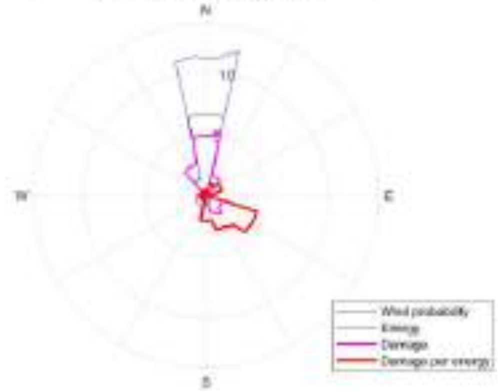
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT74



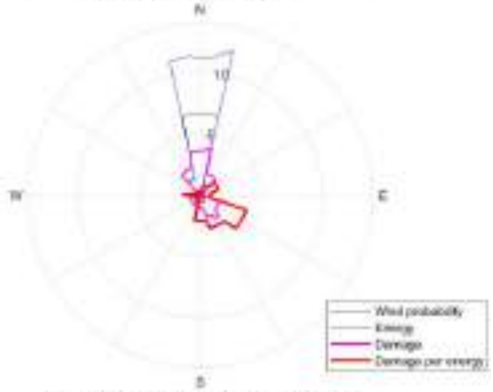
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT74



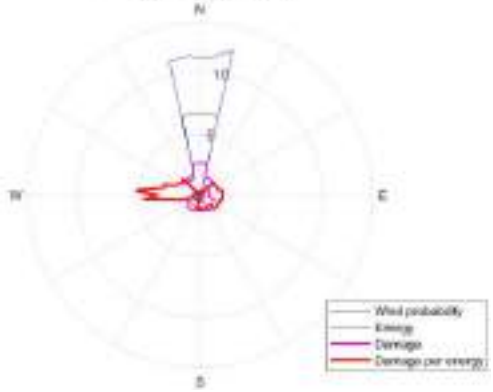
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT74



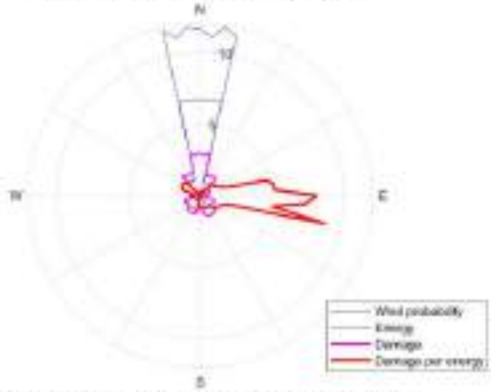
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT74



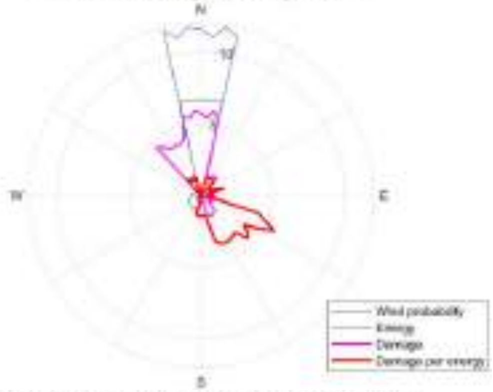
Rose map for the probabilities, energy and LTE in percentage, WT74



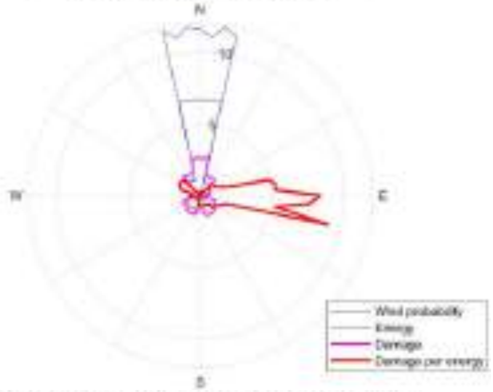
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT75



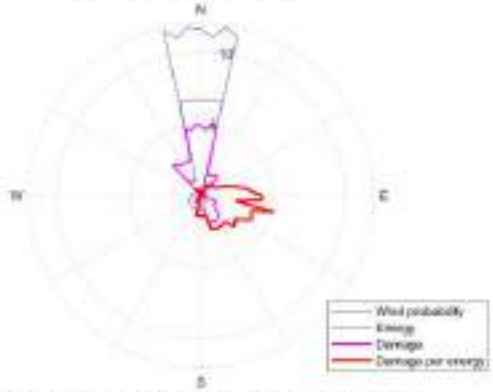
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT75



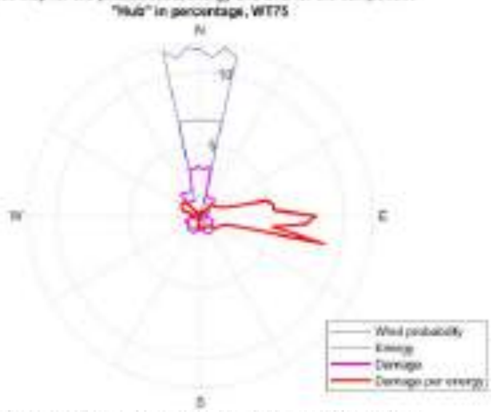
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT75



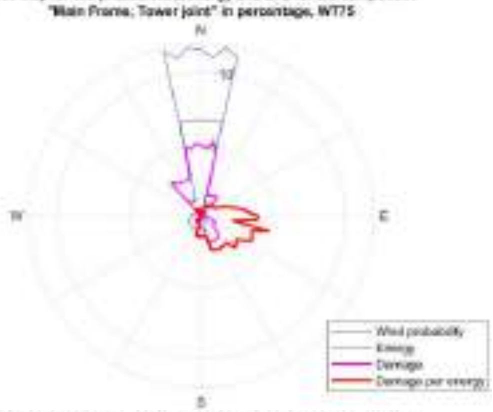
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT75



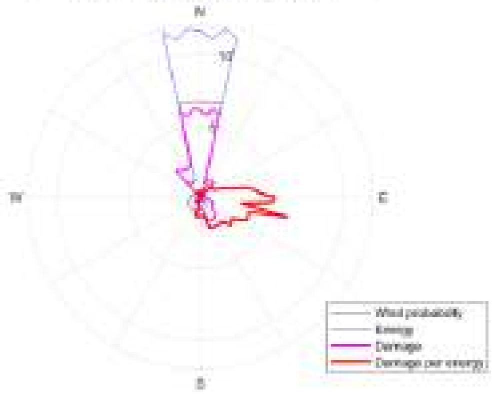
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT75



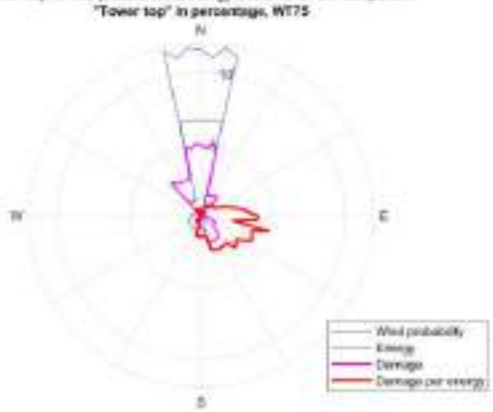
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT75

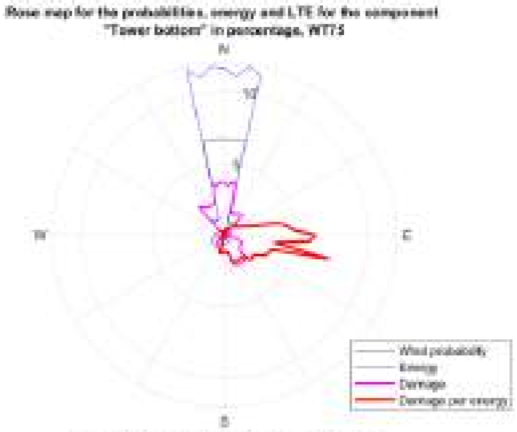


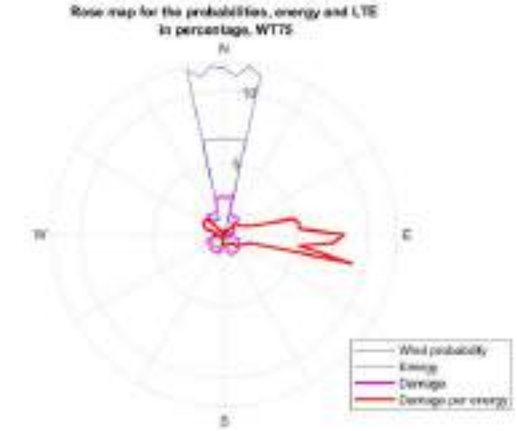
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT75



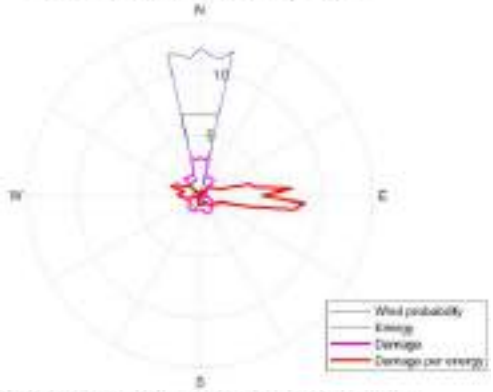
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT75



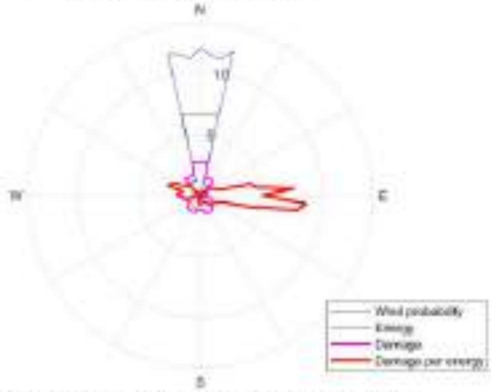

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT75
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT75
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

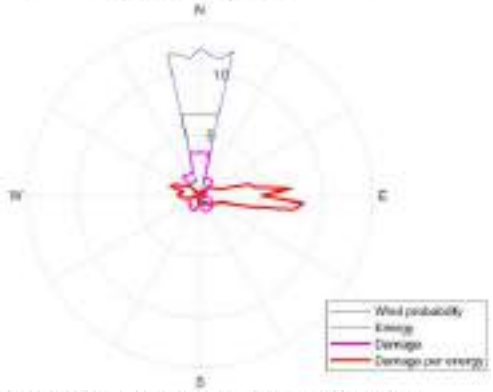
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT76



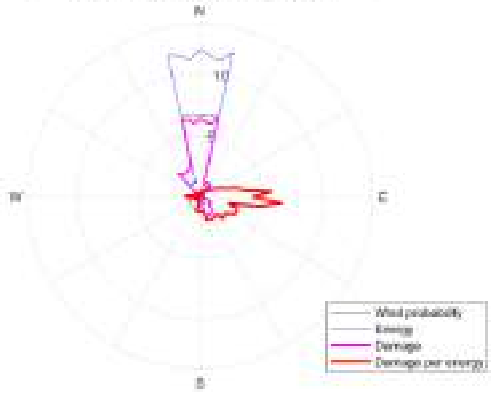
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT76



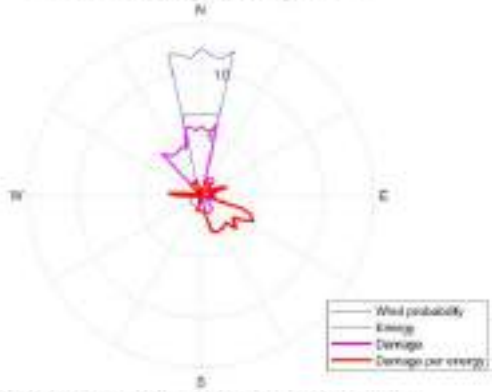
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT76



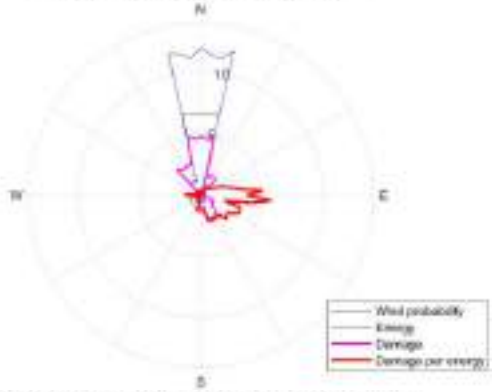
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT76



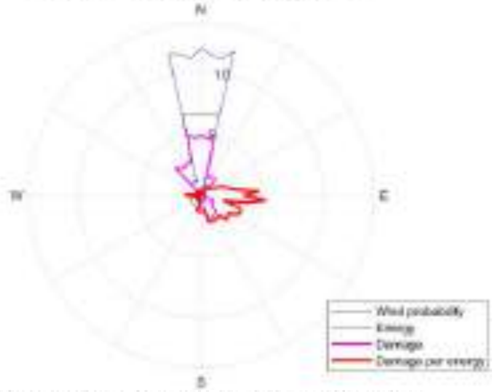
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT76



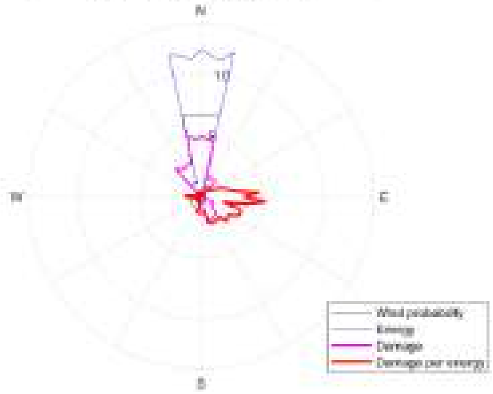
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT76

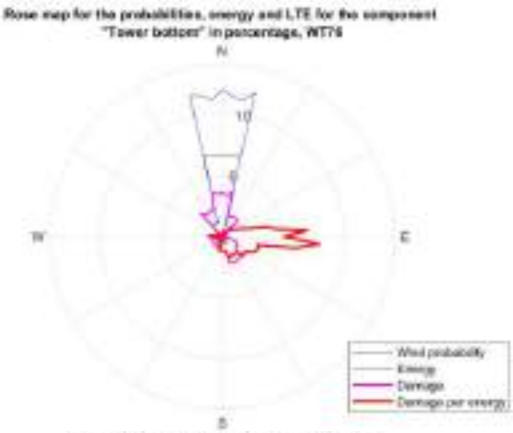


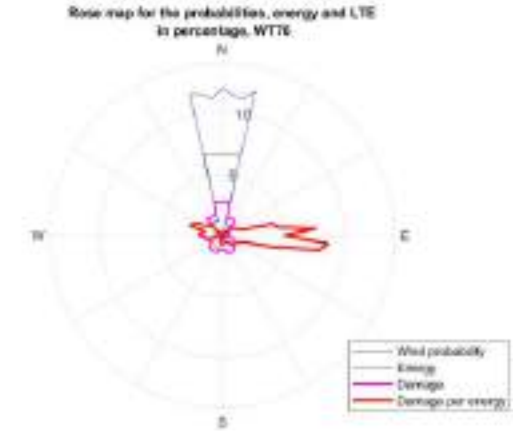
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT76



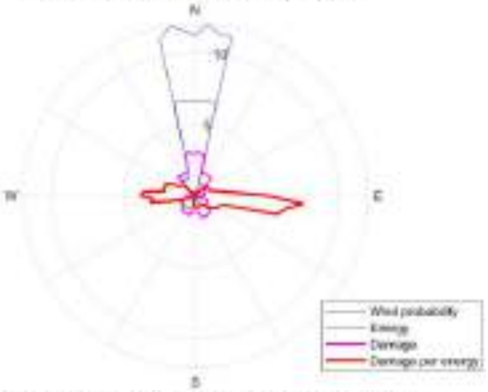
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT76



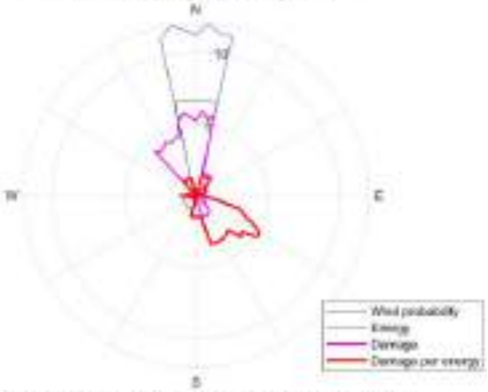

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT76
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT76
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

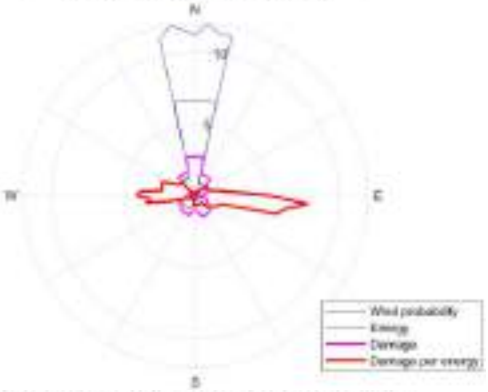
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT77



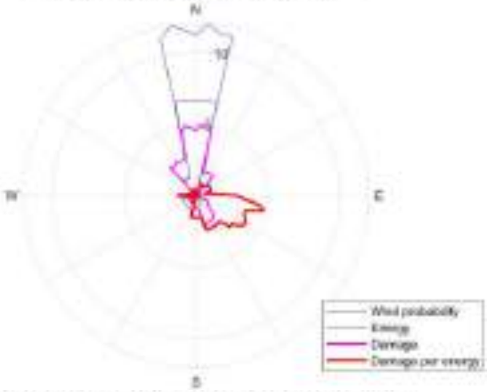
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT77



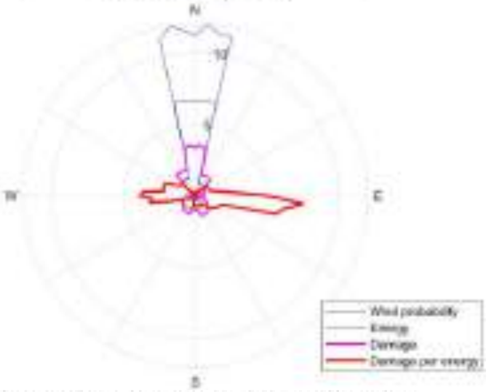
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT77



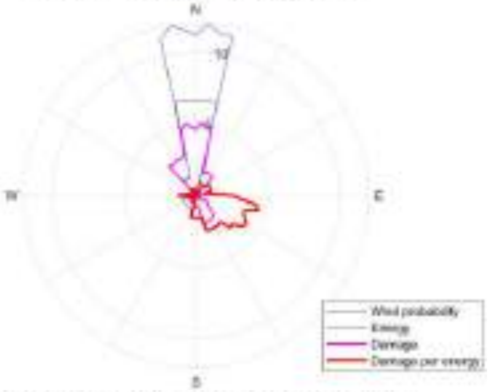
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT77



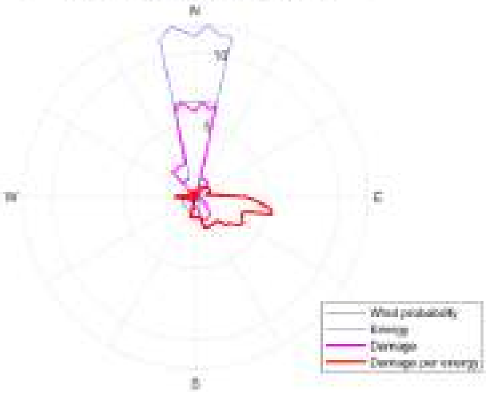
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT77



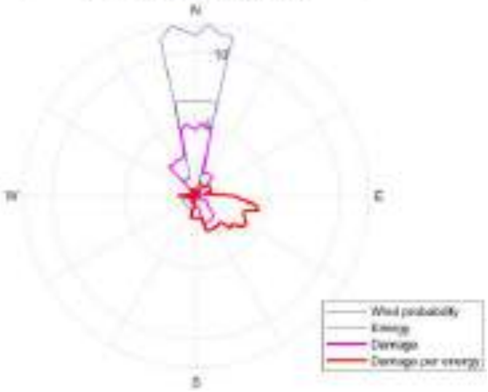
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT77

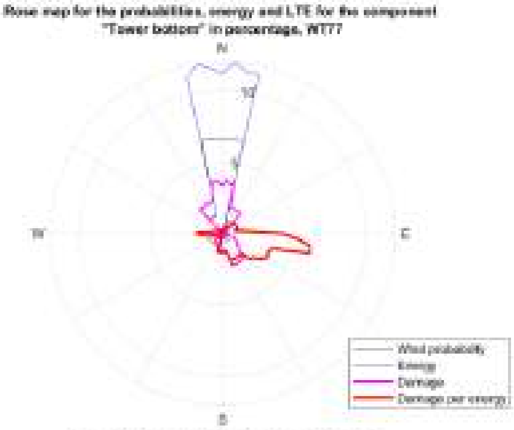


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT77



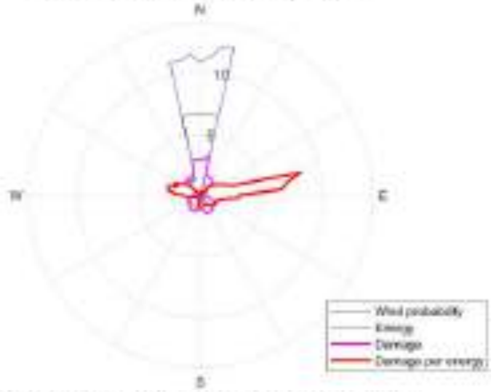
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT77



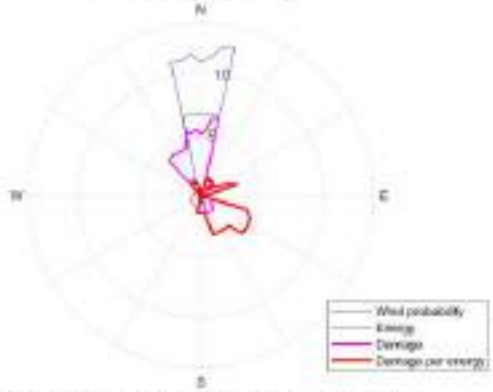

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT77
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT77
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

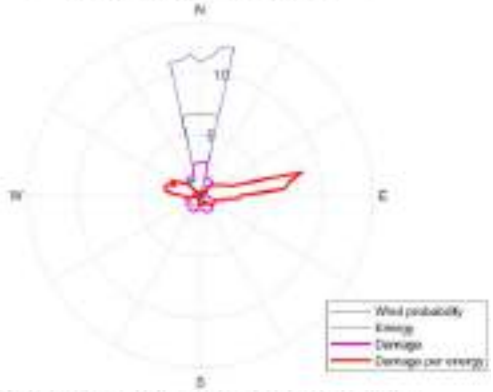
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT78



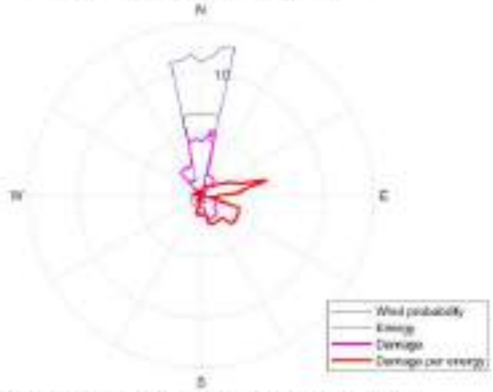
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT78



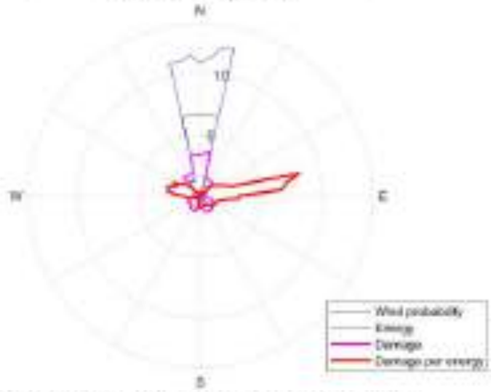
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT78



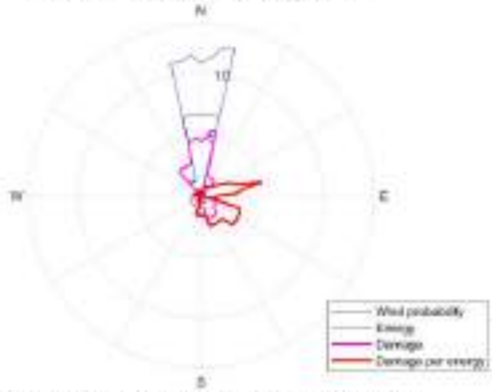
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT78



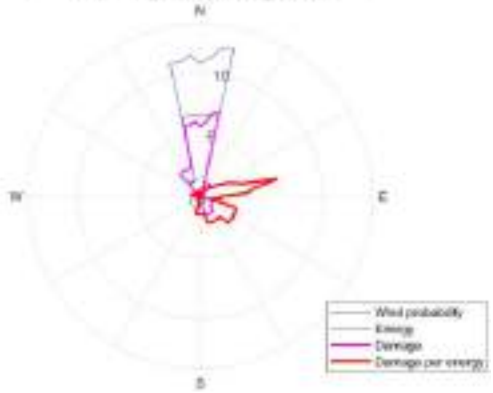
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT78



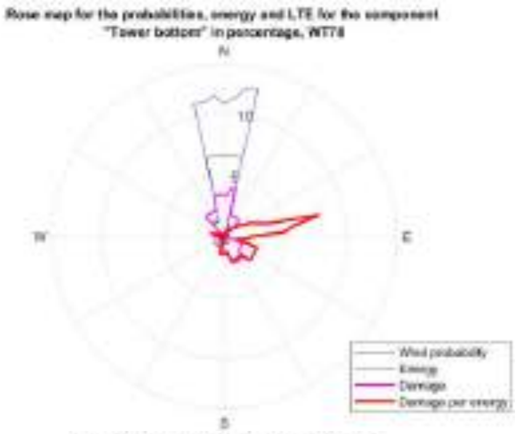
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT78

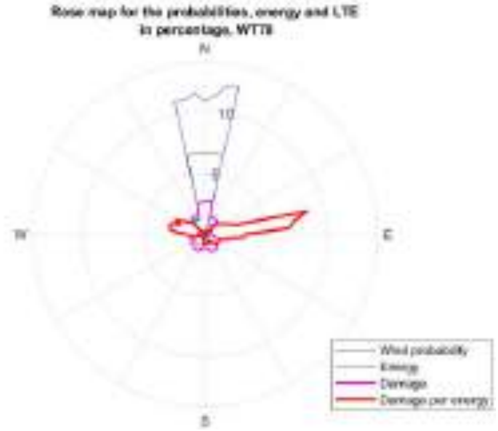


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT78

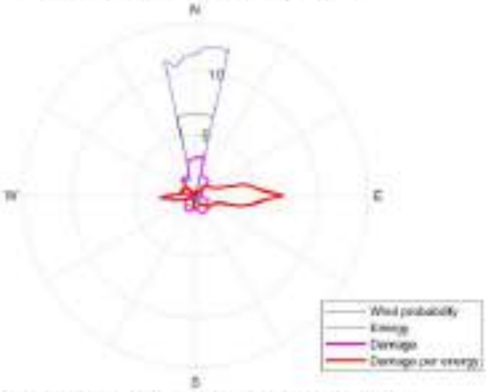


Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT78

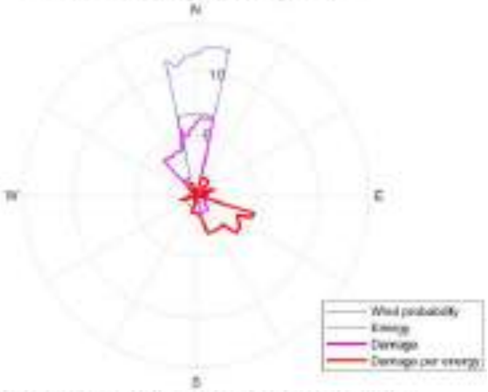

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT78
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT78
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

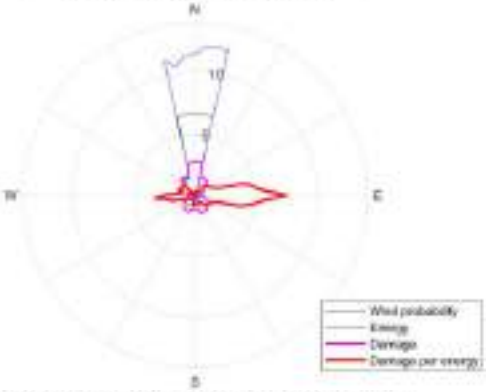
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT79



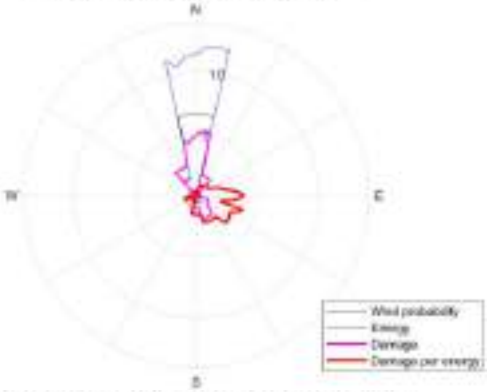
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT79



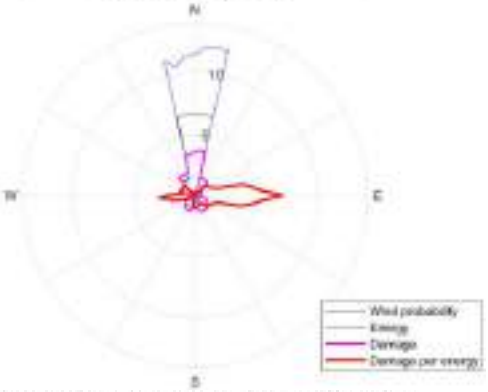
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT79



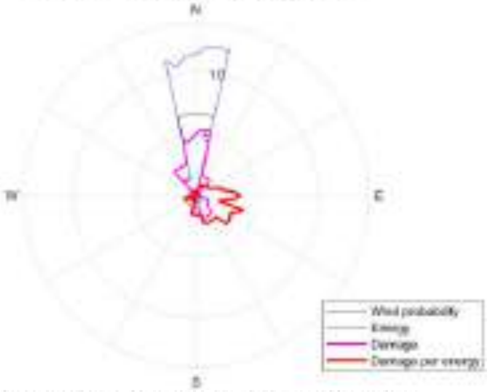
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT79



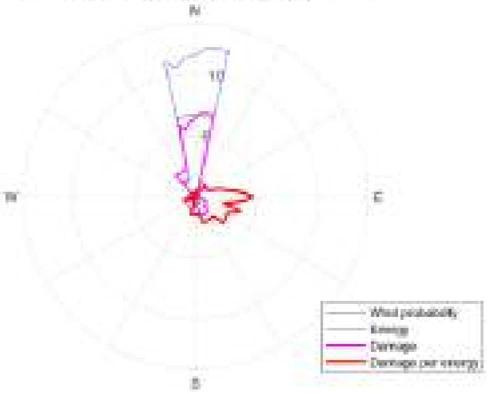
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT79



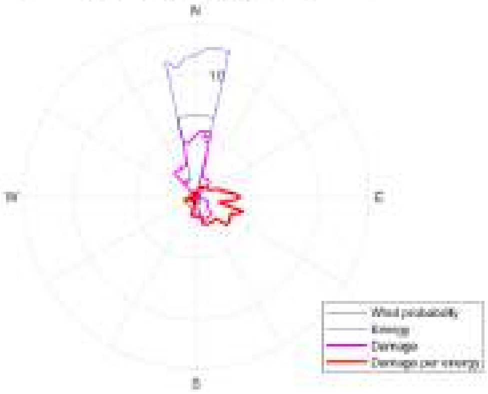
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT79

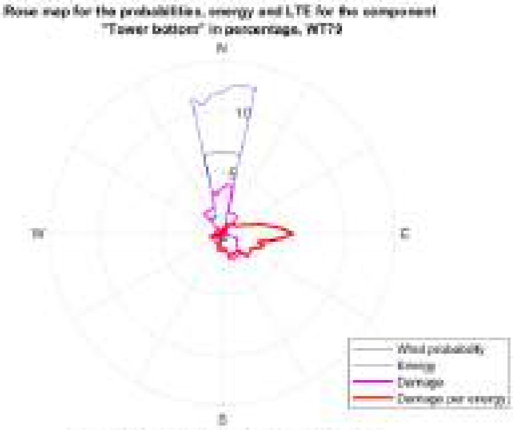


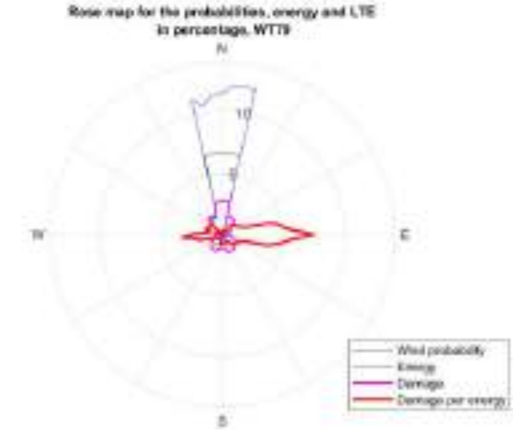
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT79



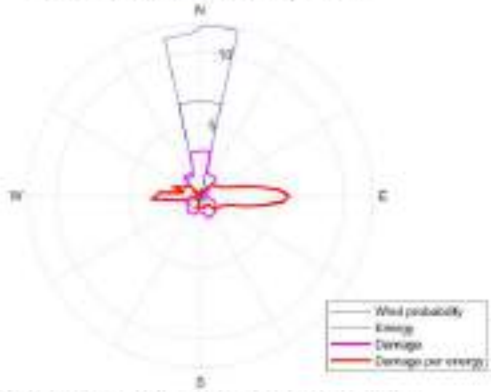
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT79



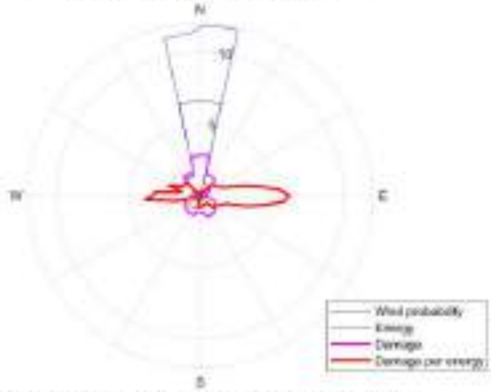

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT79
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT79
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

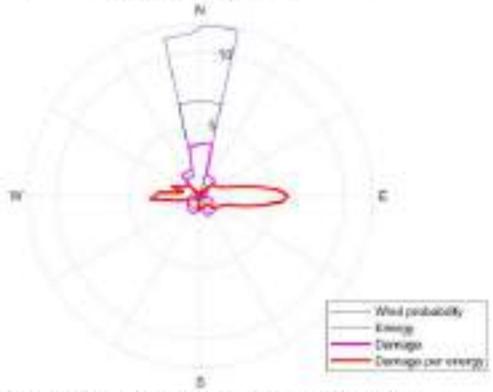
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT88



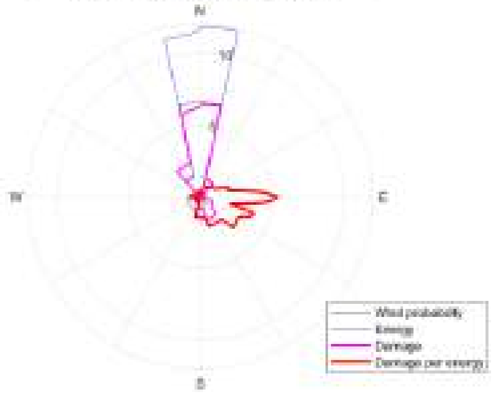
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT88



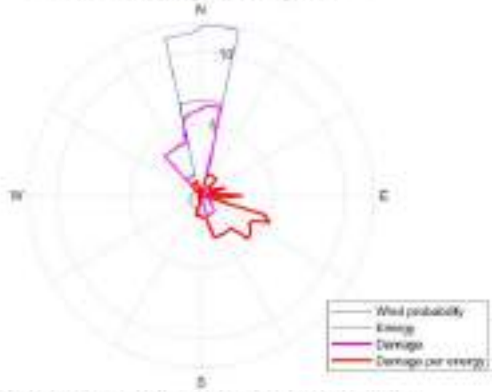
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT88



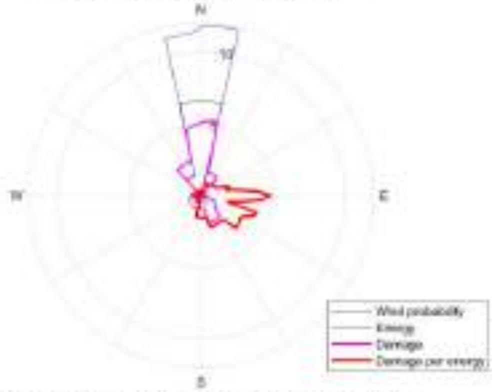
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT88



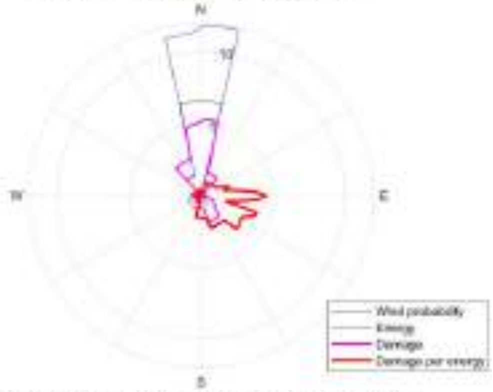
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT88



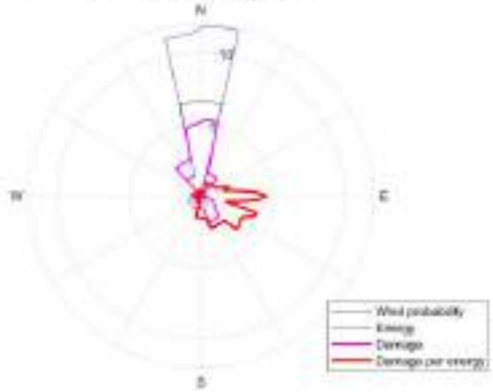
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT88

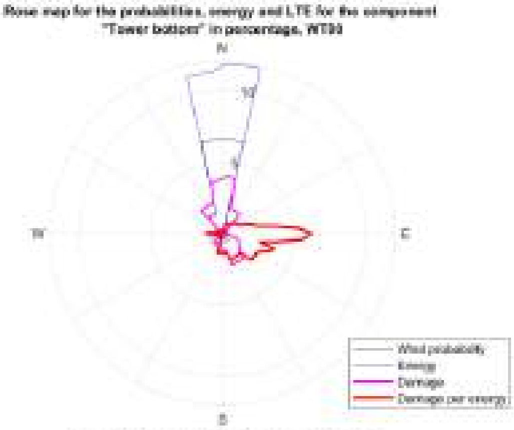


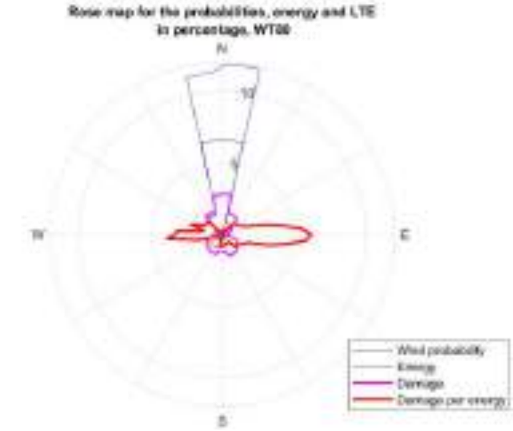
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT88



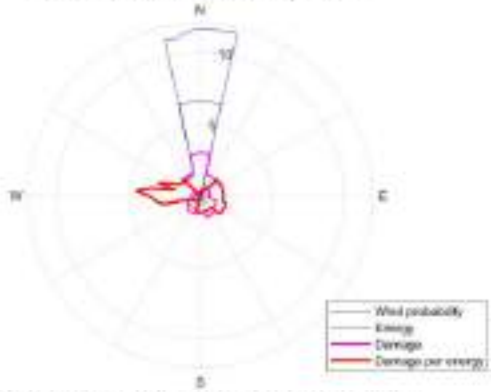
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT88



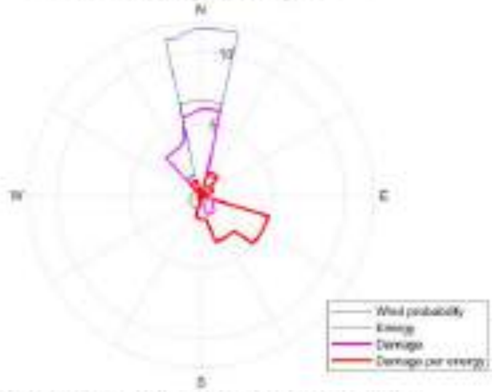

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage,
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage,
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy

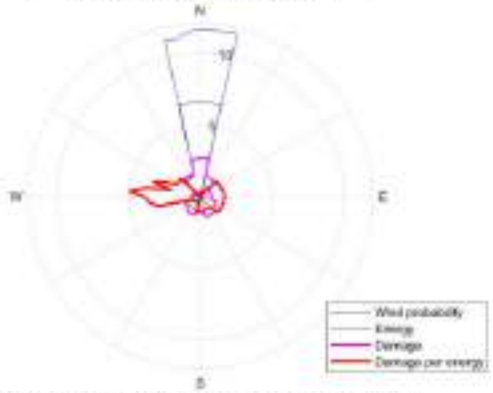
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT01



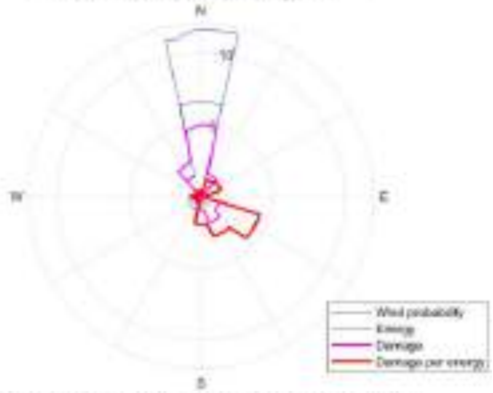
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT01



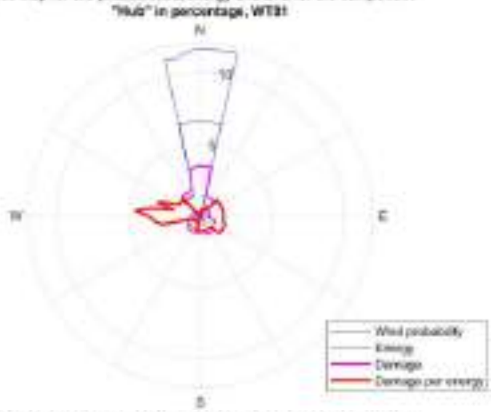
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT01



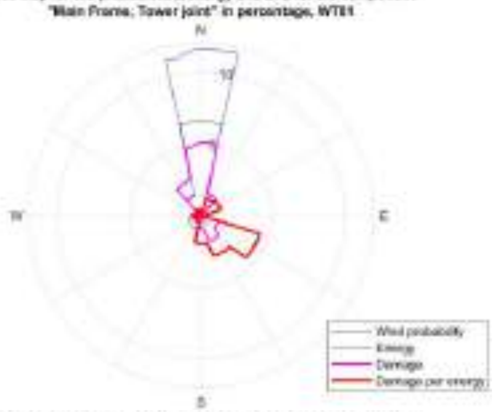
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT01



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT01

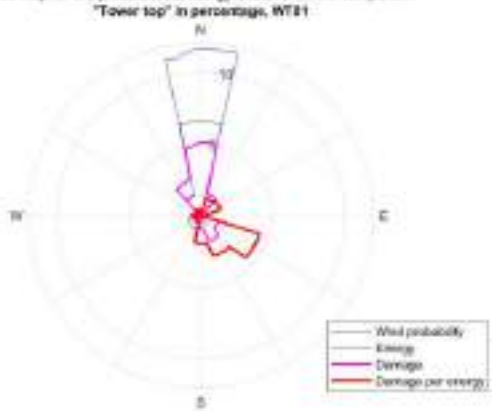


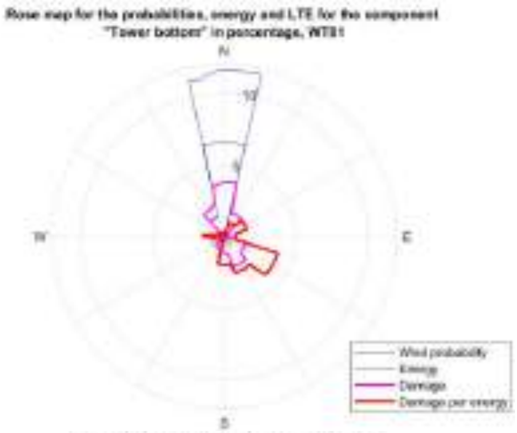
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT01



Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT01

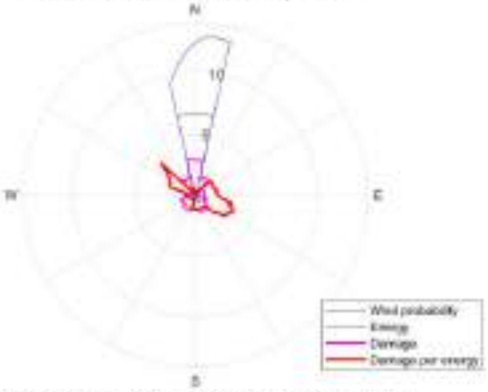
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT01



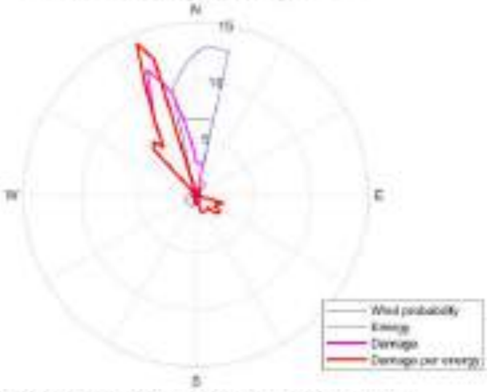

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT01
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT01
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

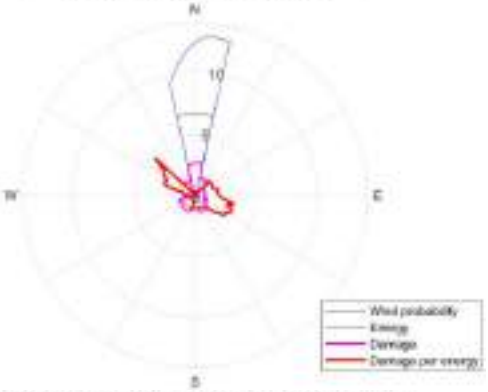
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT82



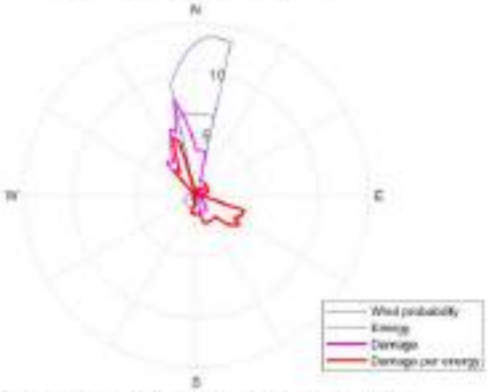
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT82



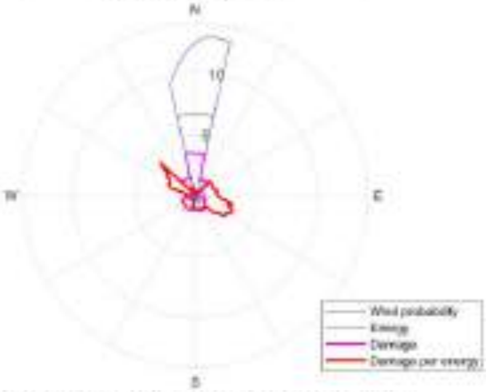
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT82



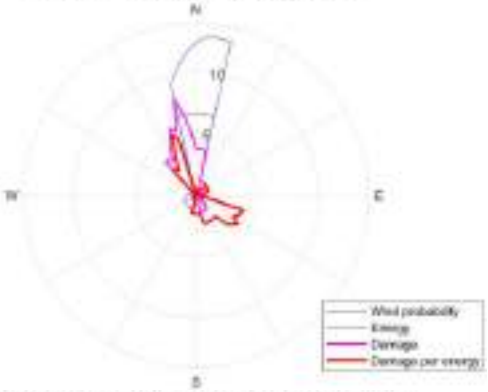
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT82



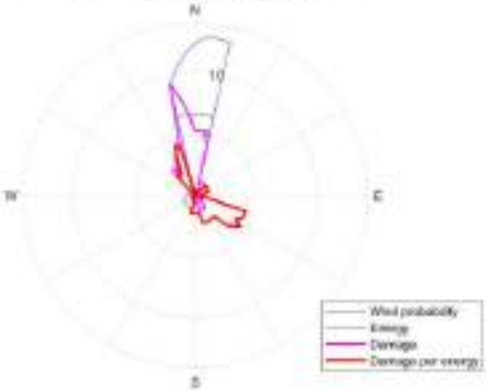
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT82



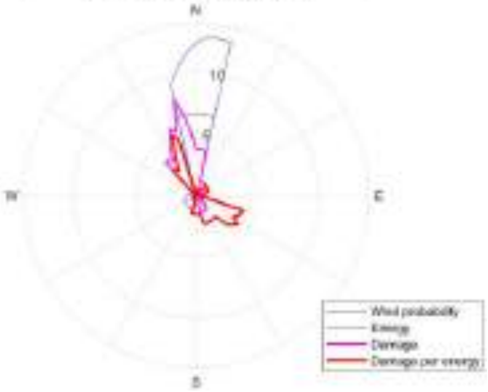
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT82

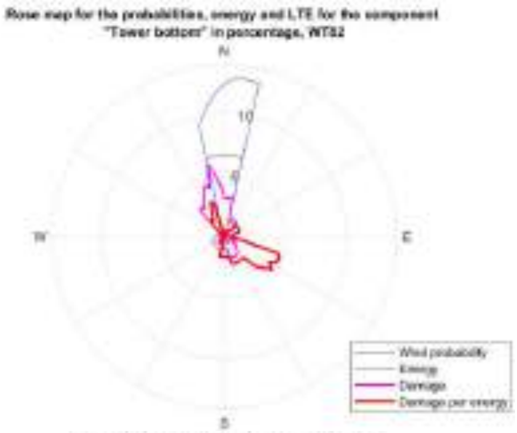


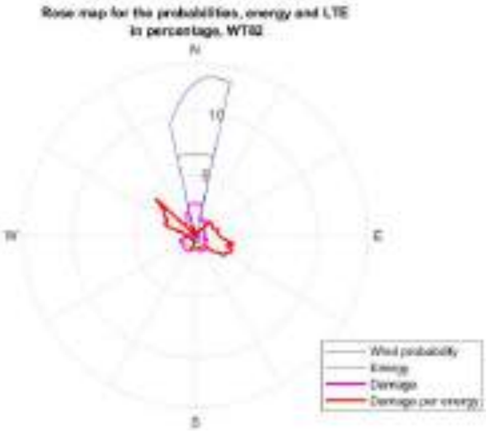
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT82



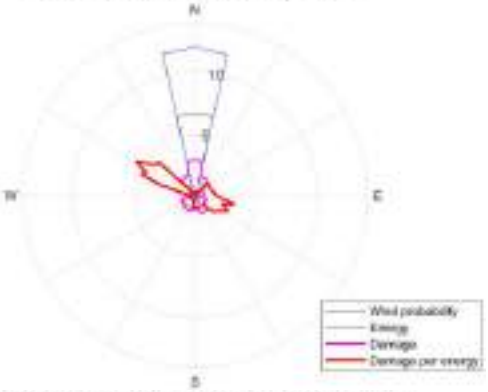
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT82



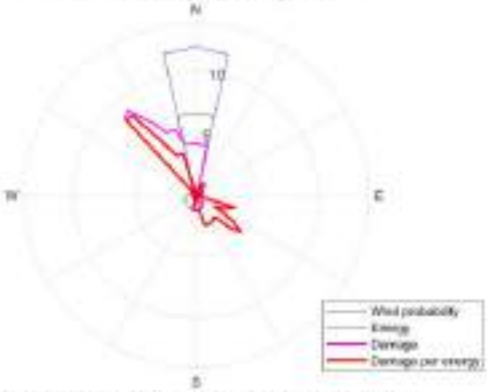

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT82
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT82
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy

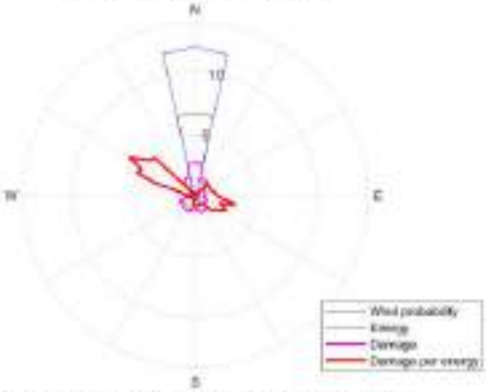
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT83



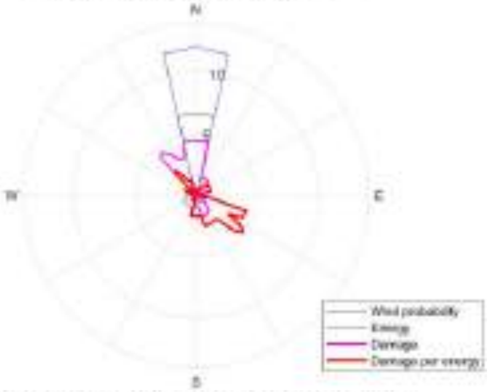
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT83



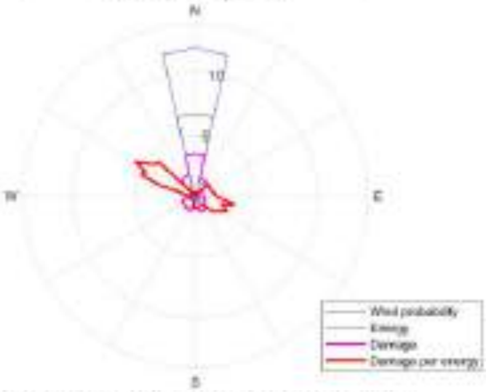
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT83



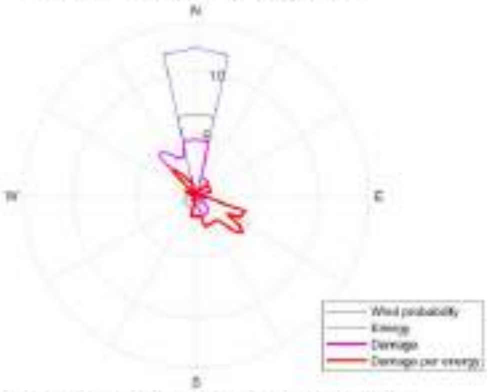
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT83



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT83

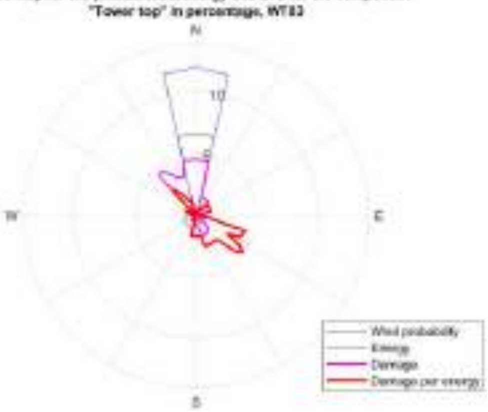


Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT83

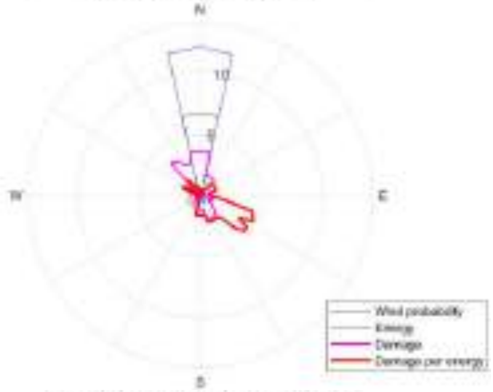


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT83

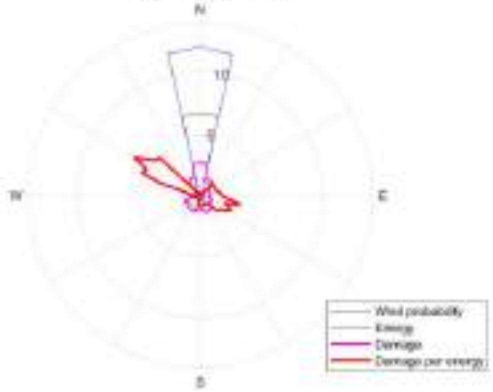
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT83



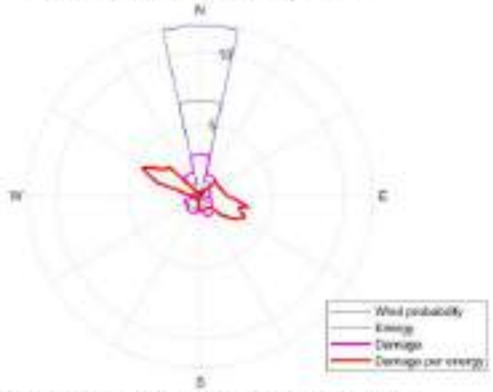
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT03



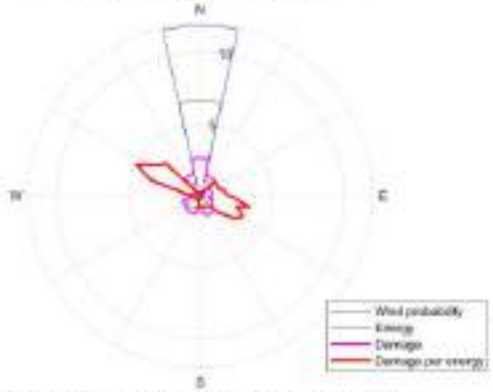
Rose map for the probabilities, energy and LTE in percentage, WT03



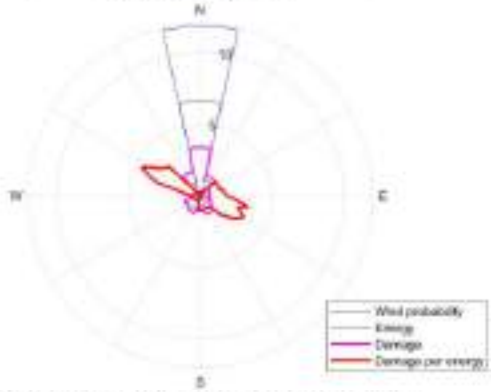
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT84



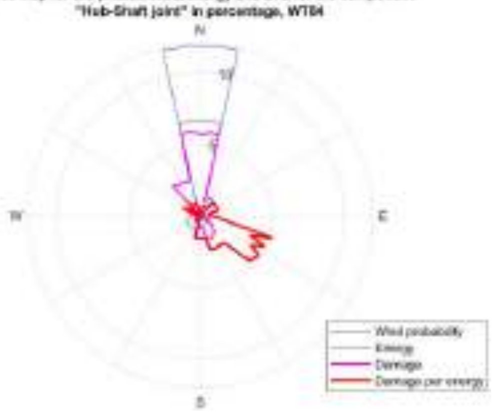
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT84



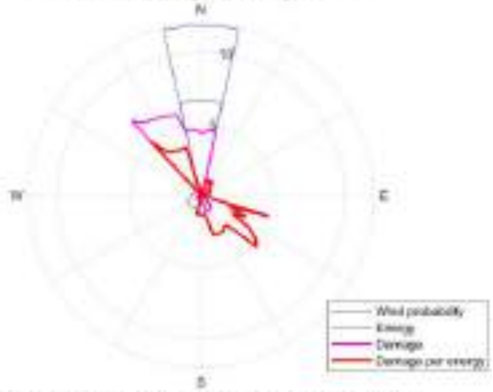
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT84



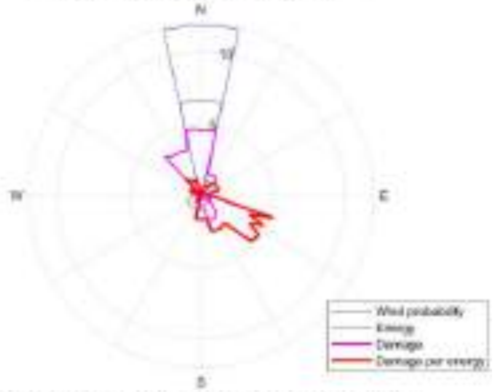
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT84



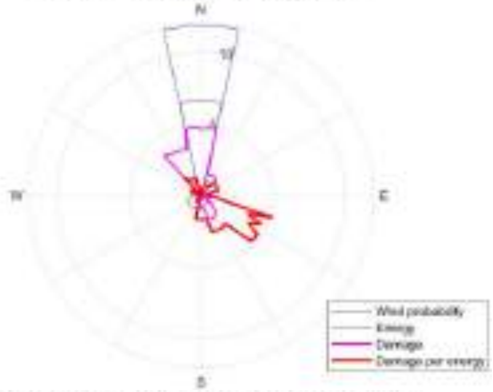
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT84



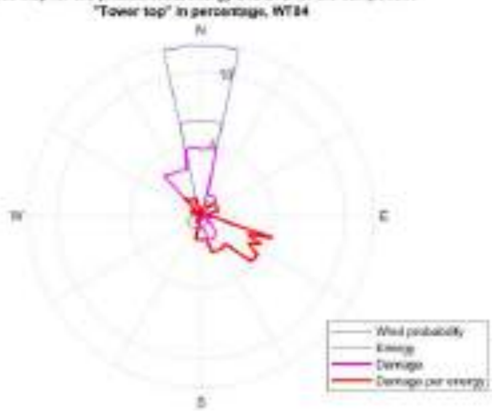
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT84

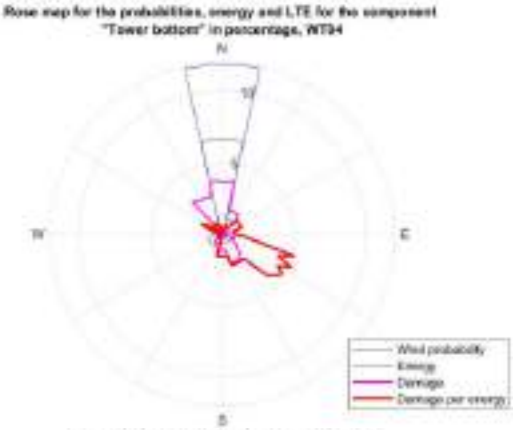


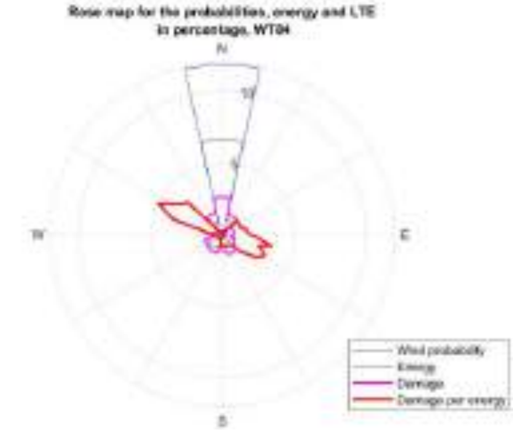
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT84



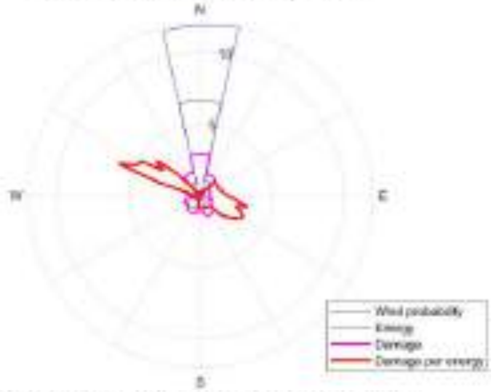
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT84



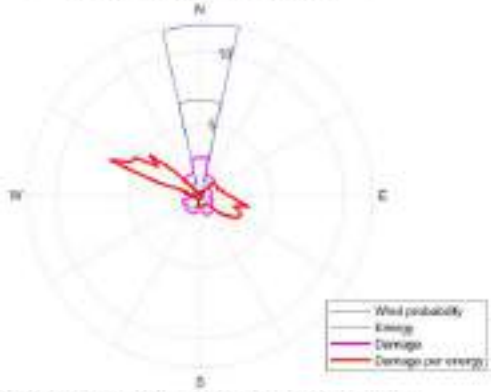

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT04
N
E
S
W
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT04
N
E
S
W
Wind probability
Energy
Damage
Damage per energy

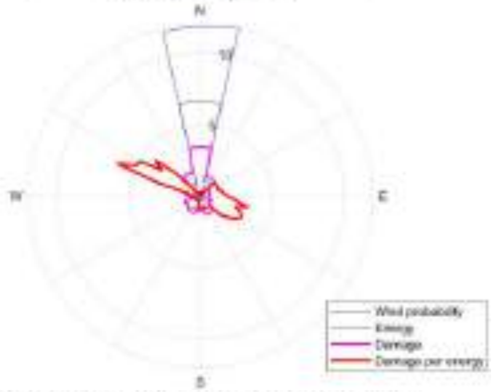
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT85



Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT85

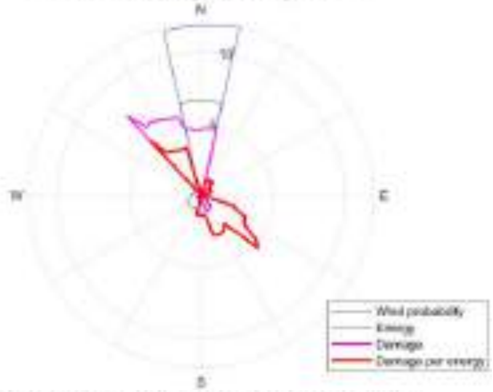


Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT85

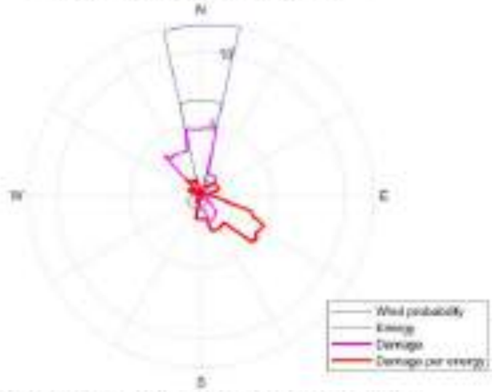


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT85

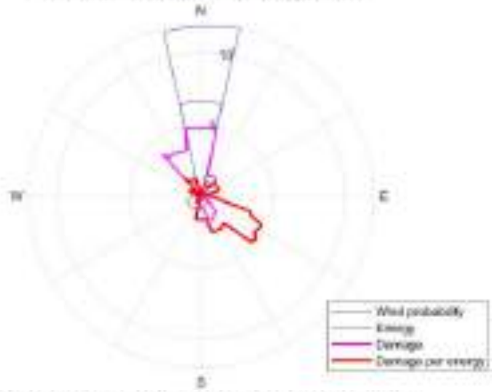
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT85



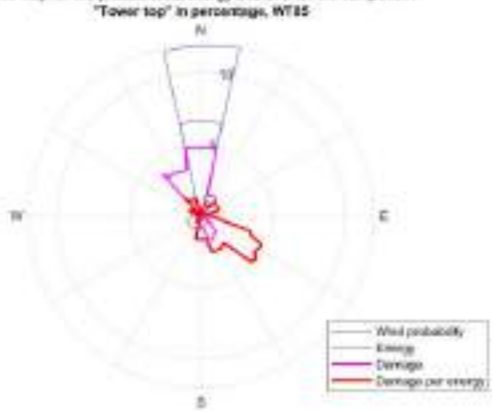
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT85



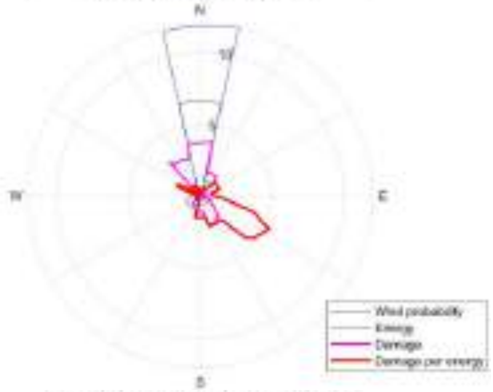
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT85



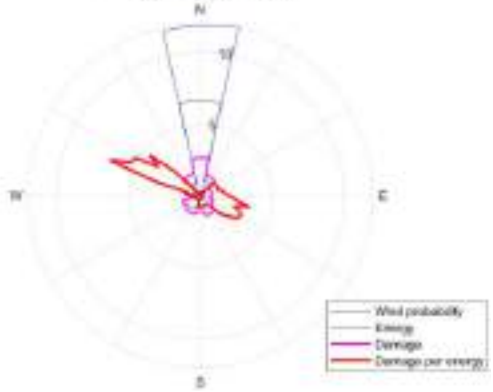
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT85



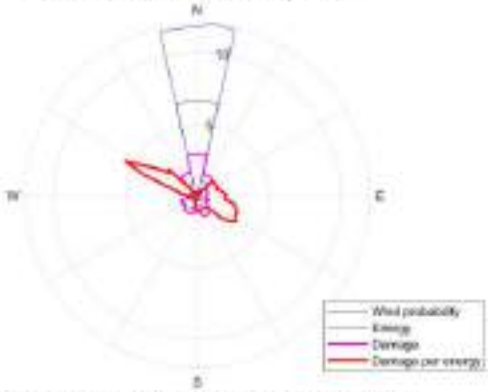
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT85



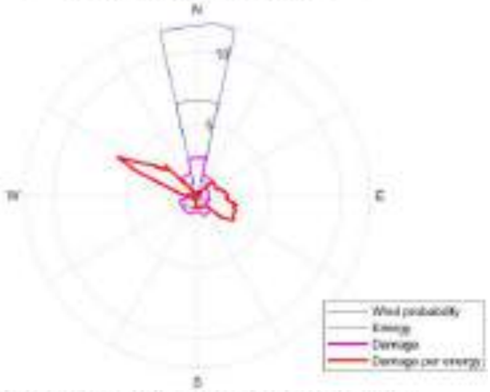
Rose map for the probabilities, energy and LTE in percentage, WT85



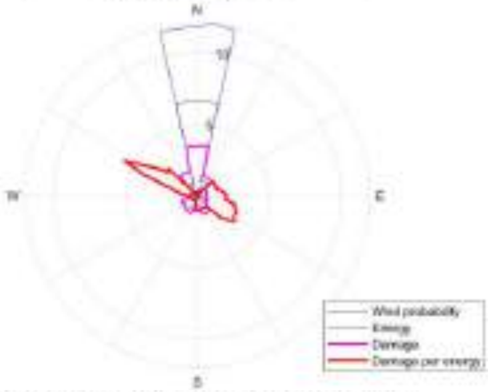
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT86



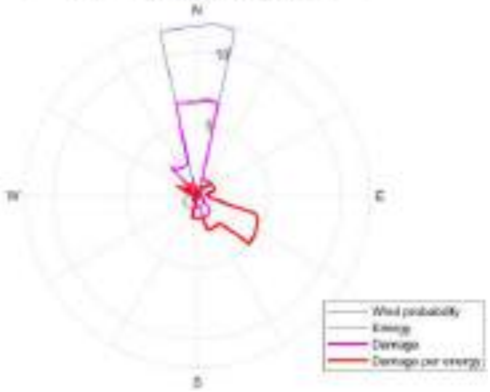
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT86



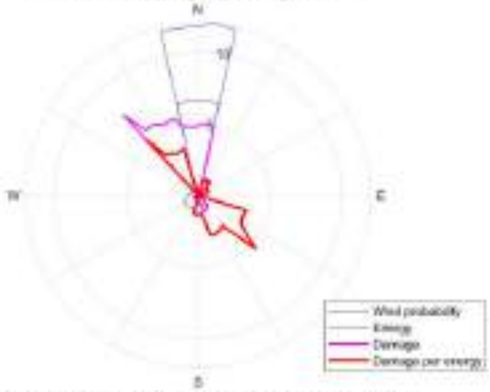
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT86



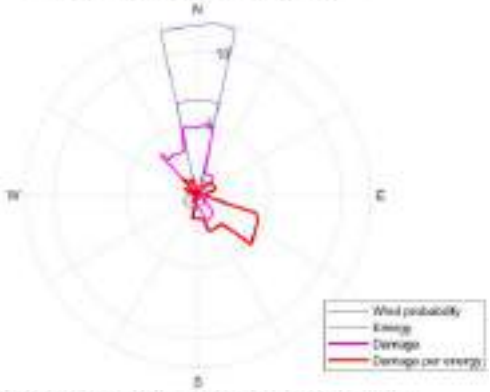
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT86



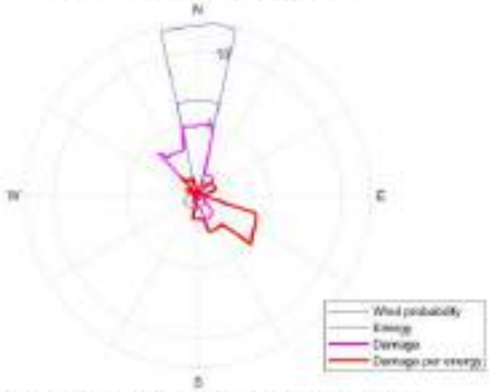
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT86



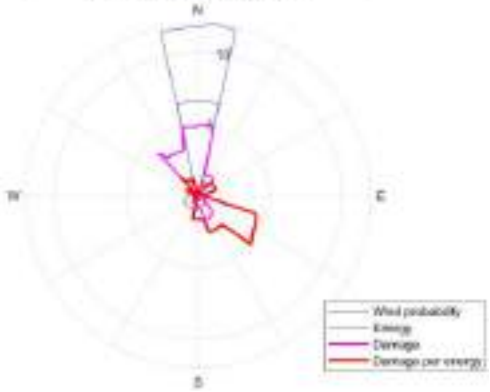
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT86



Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT86



Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT86



Life Time Extension Analysis

PREPARED FOR:
UEP Penonomé II S.A.

Ref. No.: UL-ES-AA20-13321645-03.01

PENONOME II WIND FARM
Panamá

18 June 2020

CLASSIFICATION
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ISSUE	DATE	SUMMARY
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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. EXECUTIVE SUMMARY

Nowadays In PENONOME II WIND FARM, the installed wind turbines are GW106 (107.5m rotor diameter with blade Sinoma52.5, LTE analysis reported in [1]). After several issues with the blades and other components, there is the option to change the blades to LM53.2, which corresponds with one version of the GW 2.5MW model. The resulting wind turbine is a GW109 (109m rotor diameter). In this report, the Lifetime extension analysis is presented for PENONOME II WIND FARM (Penonomé,Panamá), considering this new blades implementation. The analysis has been performed according to the methodology described in the ANSI/UL 4143 Guideline [2]. The analysis has considered the following:

- Certification conditions assuming a 20-year lifetime for all the components
- Site-specific wind conditions according to available information from OpenWind tool including the items below:
  - Wind speed probabilistic distribution
  - Maximum average wind shear
  - 90th percentile turbulence intensity (as stated by IEC 61400-1 Edition 3)
  - Annual average air density
- Independent Aeroelastic Model. IAM. considering available information
  - GoldWind GW109 2500 kW HH 90m (IIA IEC class certified according to [3])
- Appropriate Wöhler slopes related to key component materials (Ref. [4], Ref. [5], Ref. [6].and Ref. [7]).

The foundations and electrical equipment are outside of this review.

Lifetime extension factors have been calculated through a comparison between the certification damage equivalent loads (DELs) and site-specific DELs. Multiplying the certified lifetime (20 years) by this factor results in the estimate of useful life that is available.

When taking into account LTE factors from Table 6.2 and Table 7.3 the following summarized results (Table 1.1) regarding Lifetime Extension (LTE) can be expected for Penonomé II WF.

Table 1.1: Average LTE estimation summary for Penonomé II wind turbines including P50 and P90 load exceedance probabilities and LTE management plan costs per year

	P50	P90
Blade Root, Composite	>30.0	25.8
Blade Root, Joint	29.2	25.9
Hub	>30.0	24.8
Hub-Shaft Joint	>30.0	>30.0
Main Frame, Casting	>30.0	>30.0
Main Frame Welded	>30.0	>30.0
Main Frame Tower Joint	>30.0	>30.0
Tower Top	>30.0	>30.0
Tower Bottom	>30.0	>30.0
Years 1–5 Cost [k€/year]	0.0	0.0
Years 6–10 Cost [k€/year]	0.0	0.0
Years 11–15 Cost [k€/year]	0.0	0.4
Years 16–20 Cost [k€/year]	0.0	24.3
Years 21–25 Cost [k€/year]	0.0	106.8

Table 1.1: Average LTE estimation summary for Penonomé II wind turbines including P50 and P90 load exceedance probabilities and LTE management plan costs per year

Years 26–30 Cost [k€/year]	1.3	221.7

P50 results represent the lifetime estimation analysis according to the point 11 in the IEC 61400-1 Ed.3. as average lifetime for all the wind turbines of the wind farm. P90 includes the uncertainties acting in order to have a coverage factor of the load distribution of 90%.

In this analysis, an average availability of 97% has been considered for the calculations in this report. Nowadays, the availability of some wind turbines is much lower [8]. However, after the rotor change and solve the problems with other components, the average availability for the following years should be close to this value.

As shown in Table 1.1 lifetime expectations can be increased to 30 years in almost all the components doing periodical inspections and with a proper maintenance plan to avoid further problems. It is recommended to implement this maintenance plan from P90 scenario figures in order to minimize the structural risk as far as possible.

Table 1.2: Aging Management Plan Summary [1.1]

Component	Failure Mode	Inspection	Intervals
Blade Root. Composite	Fatigue	Visual Inspection (binoculars, high resolution camera, climbing robot, drones rope access, etc.)	One year
Blade Root. Bolted Joints	Fatigue	Tap testing of all rotor bolts Spot checks of the bolts preload are recommended.	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
	Fatigue and Corrosion	NDT (Ultrasonic analysis, magnetic particles testing or penetrating liquids)	Four years
Rotor Hub	Fatigue and Corrosion	NDT (Ultrasonic analysis, magnetic particles testing or penetrating liquids)	Four years
		Visual inspection	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
Hub to shaft bolted joint	Fatigue	Tap testing of all rotor bolts Spot checks of the bolts preload are recommended.	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
	Fatigue and Corrosion	NDT (Ultrasonic analysis. Magnetic particles testing or penetrating liquids)	Four years
Main frame	Fatigue	Visual inspection	One year
		NDT (Ultrasonic analysis. Magnetic particles testing or penetrating liquids)	Four years

[1.1] The analysis is based on the assumption that actual O&M will prevail as it is with an additional special care given to the corrosion issues.

Table 1.2: Aging Management Plan Summary [1.1]

Component	Failure Mode	Inspection	Intervals
Steel tower	Fatigue and Corrosion	Visual inspection of the tower welds Tap testing of all tower bolts. Spot checks of the bolts preload is recommended.	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
	Fatigue and Corrosion	NDT of the tower welds (magnetic particle testing)	Four years
Nacelle components	Corrosion	Installation of a filter in the nacelle	Once. Replaced or cleaned at maintenance interval
		Visual inspection	One year

The proposed inspection plan is based on the techniques mentioned Table 1.2. Consider that UL recommends an inspection plan based on the P90 scenario in order to reduce the risk due to uncertainties as much as possible.

The proposed inspection plan, based on P90 estimation, aims to detect failure in the incipient state when the retrofit of the component requires a low cost. In the event of doubt regarding the severity of a finding. further inspection techniques to define this severity or its reparation are recommended. The initial global budget for inspections through the lifetime of the assets (assuming P90 results) will be 1.77 M€.

Special remarks must be considered due to corrosion findings and bolted joints maintenance. The lack of action in order to achieve these improvements implies loss of validity of the lifetime analysis here reported.

The IEC 61400-1 standard provides design consideration and analysis procedures in order to maintain the catastrophic failure rate in an acceptable level (1/10000 in the lifetime). All the procedures proposed in the standard are focused on getting this safety levels. From specific site assessment point of view, IEC 61400-1 provides clear statement in its section 11 on how to proceed in order to perform a structural site suitability analysis. In order to perform lifetime analysis reported in this deliverable and in the P50 scenario the lifetime expectancy is analyzed as it is stated in section 11 of IEC 61400-1, maintaining the standard safety levels.

Additionally, it should be considered that the rotor change to a larger blade leads to an increase in the loads and a minor reduction of the expected lifetime in some structural components (compared with [1]). However, in the blade and the bolted joint the consumed lifetime will be zero. Moreover, a larger blade could increase the power production up to 2% with the same wind conditions.

All the wind turbines have been inspected starting at the end of 2019. The inspections consist in general visual inspection of the wind turbine and blade inspection with TSR robot. Additionally, blade root inserts nondestructive testing has been performed for the Sinoma52.5. In this analysis, the blades and the bolted joint are considered as new. The rest of the components will be considered according to the state of the inspections. No mayor defects have been found.

2. DEFINITIONS. SYMBOLS AND ACRONYMS

- A: Weibull's Distribution Scale Coefficient
- Cp: Power Coefficient
- DEL: Damage Equivalent Load
- DLC: Design Load Case
- HAWT: Horizontal Axis Wind Turbine
- HH: Hub Height
- IAM: Independent Aeroelastic Model
- Iu: Longitudinal Turbulence Intensity
- K: Weibull's distribution shape coefficient
- LTE: Lifetime Extension
- N: Number of Cycles
- NTM: Normal Turbulence Model
- ρ: Air Density
- SCADA: Supervisory Control And Data Acquisition
- SMT (Solid metal tip, part of lightning protection)
- WF: Wind Farm
- WSM: Wind Sector Management
- WT(s) or WTG(s): Wind Turbine(s)

3. INTRODUCTION

The Penonomé II Wind Farm is located in Penonomé, Panamá. There are 86 WTs in operation since year 2016. The following wind turbines form it:

- 86 WTs type GoldWind GW106 2500 kW HH 90m (Sinoma Blade). The certified Wind Class is IEC IIA [3]. The LTE analysis has been calculated considering the GW109 due to the current option of a rotor change.

Details of the WTs' technical specifications are shown in the tables below (refer Table 3.1 and Table 3.2) for WTs' specifications and for blades' specifications.

Section 4 describes the scope of LTE estimation in this report.

WF overviews are provided in Section 5.1.

A summary of the environmental conditions relevant for LTE analysis (wind speed, wind rose, turbulence intensity, wind shear, air density, statistical properties, etc.) can be found in Section 5.2.

An Independent Aeroelastic Models (IAM) has been produced to characterize the WT for Penonomé II WF; its definition and properties are shown in Section 5.4.

Simulations (power production) using an aeroelastic model under certification conditions and site-specific conditions have been performed. This section also includes validation of the model when considering reference data from the WF (including power, power coefficient, and thrust coefficient). Campbell diagram has been produced and checked to ensure that resonances are avoided.

Section 5.5 contains the procedure followed in order to calculate the Lifetime Extension Analysis (LTE). Results regarding Lifetime Extension (LTE) factors are also shown in this section (LTE factors for Penonomé II wind turbines are listed in Table 5.7).

Section 7 reflects LTE results per component considering the uncertainties.

Considering these results. recommendations on Lifetime Extension (LTE) are included in Section 8. (summarized in Table 8.1) and associated expenses have been calculated and shown in Table 8.2 for the wind farm.

GoldWind GW109 2500 kW HH 90m (IIA IEC class certified)

Table 3.1: Summary of technical specifications for pitch regulated GoldWind GW109 2500 kW HH 90m wind turbine

Parameter	Value	Units	Description Notes	Ref.
Type	HAWT	-	-	
Onshore/Offshore	Onshore	-	-	
Rotor Location	Upwind	-	-	
Class/Category	IIA	-	-	
Power Regulation	pitch	-	-	
P_Rated	2500	kW	Rated power	
N Blades	3	-	Number of blades	
Vr	10.5	m/s	Rated wind speed	
Vin	3	m/s	Cut-in wind speed	
Vout	25	m/s	Cut-out wind speed	
Tilt Angle	5	deg	-	
Coning Angle	2	deg	-	
Rotor Diameter	109	m	-	
Hub Height	90	m	-	
Hub Diameter	2.5	m	-	
Rotor Speed	13.5	rpm	-	
Generator Speed	13.5	rpm	-	
Gear Ratio	1	-	-	
Mass Rotor + Hub	59700	Kg	-	
Mass Nacelle	101500	Kg	-	
Mass Tower	246000	Kg	-	
Natural Freq. Tower (1st)	0.292	Hz	-	

Note 1: Data estimated by UL when comparing with wind turbines of similar specifications and/or calculations.

Table 3.2: Summary of technical specifications for blade of GoldWind GW109 2500 kW HH 90m

Parameter	Value	Units	Description/Notes	Ref.
Blade length	53.2	m	-	Note 1
Mass Blade	10610.0	Kg	-	Note 1
Natural Freq. Blade (1st Flapwise)	0.63	Hz	-	Note 1
Natural Freq. Blade (1st Edgewise)	1.2	Hz	-	Note 1

Note 1: Data estimated by UL when comparing with wind turbines of similar specifications and/or calculations.

4. SCOPE

LTE analysis is calculated based on a comparison of fatigue life (allowable number of cycles) that is performed at critical locations (load stations) of the wind turbine IAM under two scenarios of power production and external conditions:

- Those corresponding to certification (design basis of the turbine)
- Those estimated for the site-specific conditions

The LTE factors can be determined with a certain accuracy level, which is heavily influenced by the quantity and quality of available data (from design/certification phase and data gathered from on-site conditions), WT models, and simulations. The following remarks have to be considered regarding the data used in this report:

1. External Conditions
   - On-site meteorological data (wind speed, wind frequency distribution parameters, wind shear coefficient, air density, etc.) are considered.
2. IAM
   - In order to simulate turbulence in a representative way, every wind speed has been simulated using different turbulence seeds (several simulations per wind speed bin as stated in [9]).
   - Extreme load values are not considered because LTE calculation is based on fatigue life.
   - Available information on airfoils' data (polar curves) has been considered. Available technical specifications (e.g. mass, Stiffness, etc.) are considered.
   - Flex5 software has been used to carry out the load simulations and for post-processing (Ref. [10]).
   - Design Load Cases (DLCs) of power production conditions are according to the data in [9].
3. Determination of LTE
   - DEL (certification) is not available, but a reference set of design fatigue loads has been generated using the same IAM as was used to calculate the site-specific loads.

The following points can be considered as a limitation to the current LTE estimation:

1. Airfoil data (polar curves), which are based on in-house experience and well-known airfoil databases.
2. Internal structure of wind turbine's blades (mass distribution, stiffness distribution, position of center of gravity, etc.), which are based on UL knowledge.

In any case, the refined treatment of all available data and simulations has reduced the uncertainty and increased the accuracy of LTE estimation.

5. LIFETIME EXTENSION ANALYSIS

5.1 WF Data

The Penonomé II wind farm is located in the Coclé province in Panamá. Figure 5.1 shows Penonomé II wind farm.

Figure 5.1: Overview of Penonomé II WF. N Source: Google Earth

There are 86 wind turbines operating in this wind farm. The following list has been extracted from Ref. [11]:

- Penonomé II WF: 86 Wind turbines GoldWind GW106 2500 kW HH 90m IEC class IIA

Details of wind turbine technical specifications are shown in Table 3.1 while Table 3.2 contains the blade specifications.

5.2 Analysis of Environmental Conditions

For the calculation of the wind conditions at each wind turbine position and direction, firstly, an analysis of the wind resource data (Ref. [12] and Ref. [13]) has been carried out. With the wind data extracted from the wind resource analysis and other detailed data as the terrain elevation, the inflow, roughness and a mesoscale wind model of the area, a horizontal extrapolation of the mast to each wind turbine position has been accomplished. Thus, wake affected wind speed distributions, effective turbulence intensity, wind shear, air density and inflow angle are calculated for each wind turbine and wind direction.

5.2.1 Wind Speed Distributions

The following averaged wake affected wind speed has been used to calculate de LTE for Penonomé II WF. Table 5.1 shows the average mean wake affected wind speed per WT of the wind farm. Specific wind rose factors (84 sectors have been considered in the analysis) and wind speed per wind turbine and direction can be found on Appendix A - Wind site conditions

Table 5.1: Mean wake affected wind speed per WT for Penonomé II WF.

WT	Wake wind speed (m/s)	WT	Wake wind speed (m/s)	WT	Wake wind speed (m/s)
WTG001	6.4	WTG030	6.0	WTG064	6.0
WTG002	6.3	WTG031	6.0	WTG065	6.0
WTG003	6.3	WTG032	6.2	WTG066	6.0
WTG004	6.3	WTG033	6.2	WTG067	6.0
WTG005	6.3	WTG034	6.2	WTG068	6.0
WTG006	6.2	WTG035	6.2	WTG069	6.0
WTG007	6.2	WTG036	6.3	WTG070	5.9
WTG008	6.2	WTG037	6.2	WTG071	5.9
WTG009	6.0	WTG038	6.2	WTG109	6.0
WTG010	6.0	WTG039	6.2	WTG110	5.9
WTG011	6.1	WTG040	6.2	WTG111	5.9
WTG012	6.1	WTG041	6.2	WTG112	5.9
WTG013	6.1	WTG042	6.1	WTG093	5.9
WTG014	6.1	WTG043	6.2	WTG094	5.9
WTG015	6.1	WTG044	6.1	WTG095	5.9
WTG016	6.1	WTG045	6.1	WTG096	6.0
WTG017	6.1	WTG046	6.1	WTG097	5.8
WTG018	6.4	WTG047	6.0	WTG098	5.7
WTG019	6.4	WTG048	6.0	WTG099	5.7
WTG020	6.4	WTG054	6.0	WTG100	5.8
WTG021	6.4	WTG055	5.8	WTG101	5.8
WTG022	6.4	WTG056	5.9	WTG102	5.9
WTG023	6.4	WTG057	6.0	WTG103	5.9
WTG024	6.3	WTG058	6.0	WTG104	5.7
WTG025	6.1	WTG059	6.0	WTG105	6.0
WTG026	6.1	WTG060	5.9	WTG106	6.0
WTG027	6.0	WTG061	6.0	WTG107	6.0
WTG028	6.0	WTG062	6.0	WTG108	5.9
WTG029	5.9	WTG063	6.0		

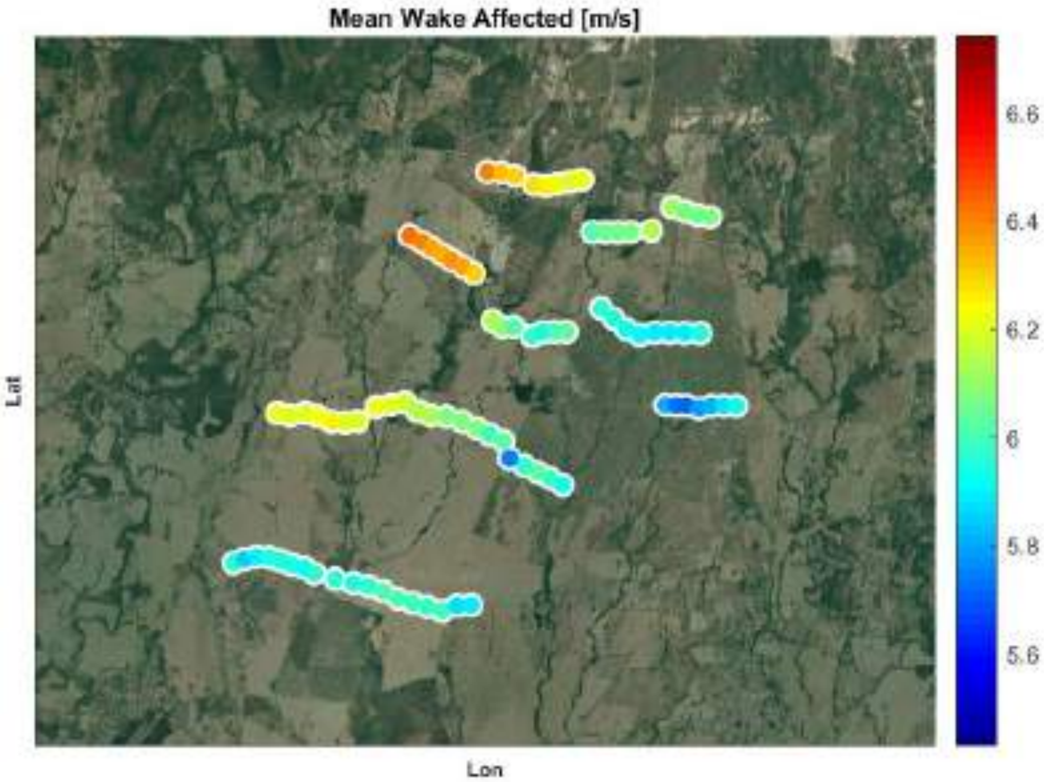

Figure 5.2: Average wake affected wind speed for Penonomé II WF.

5.2.2 Effective turbulence Intensity

Meteorological mast wind turbulence intensity data has been used in this analysis and OpenWind tool has been used for the calculation of the effective turbulence intensity, and the effect of the layout at Penonomé II wind farm has been taken into account (wake effects have been estimated using Frandsen method as described in [14]). The average calculated turbulence intensities at 15 m/s are shown in Table 6. The simulations have been performed in 84 sectors. The turbulence intensity that has been used in each sector includes the wake effect according to the layout of Penonomé II WF and nearby wind farms. In Appendix A - Wind site conditions can be found the turbulence intensity per wind turbine, bin speed and direction.

Table 5.2: Effective Turbulence Intensity from OpenWind tool for Penonomé II WF

WT	$IT_{ef,15m/s}$ [%]	WT	$IT_{ef,15m/s}$ [%]	WT	$IT_{ef,15m/s}$ [%]
WTG001	14.3	**WTG030**	14.7	**WTG064**	14.9
WTG002	14.4	**WTG031**	14.6	**WTG065**	14.8
WTG003	14.5	**WTG032**	14.3	**WTG066**	14.8
WTG004	14.5	**WTG033**	14.3	**WTG067**	14.8
WTG005	14.5	**WTG034**	14.3	**WTG068**	14.8
WTG006	14.6	**WTG035**	14.4	**WTG069**	14.8
WTG007	14.6	**WTG036**	14.4	**WTG070**	14.8
WTG008	14.7	**WTG037**	14.5	**WTG071**	14.9
WTG009	15.2	**WTG038**	14.5	**WTG109**	14.5
WTG010	14.9	**WTG039**	14.3	**WTG110**	14.7

Table 5.2: Effective Turbulence Intensity from OpenWind tool for Penonomé II WF

WT	$IT_{ef,15m/s}$ [%]	WT	$IT_{ef,15m/s}$ [%]	WT	$IT_{ef,15m/s}$ [%]
WTG011	15.0	**WTG040**	14.3	**WTG111**	14.9
WTG012	15.0	**WTG041**	14.3	**WTG112**	15.0
WTG013	15.0	**WTG042**	14.5	**WTG093**	15.0
WTG014	14.9	**WTG043**	14.4	**WTG094**	15.0
WTG015	15.0	**WTG044**	14.5	**WTG095**	15.0
WTG016	15.0	**WTG045**	14.5	**WTG096**	14.9
WTG017	15.0	**WTG046**	14.4	**WTG097**	15.1
WTG018	14.3	**WTG047**	14.6	**WTG098**	15.1
WTG019	14.3	**WTG048**	14.5	**WTG099**	15.1
WTG020	14.4	**WTG054**	14.7	**WTG100**	15.2
WTG021	14.4	**WTG055**	14.7	**WTG101**	15.2
WTG022	14.3	**WTG056**	14.6	**WTG102**	15.2
WTG023	14.2	**WTG057**	14.5	**WTG103**	15.2
WTG024	14.3	**WTG058**	14.5	**WTG104**	16.4
WTG025	14.5	**WTG059**	14.6	**WTG105**	14.8
WTG026	14.7	**WTG060**	14.7	**WTG106**	14.5
WTG027	14.6	**WTG061**	14.9	**WTG107**	14.6
WTG028	14.8	**WTG062**	14.8	**WTG108**	14.8
WTG029	14.8	**WTG063**	14.9		

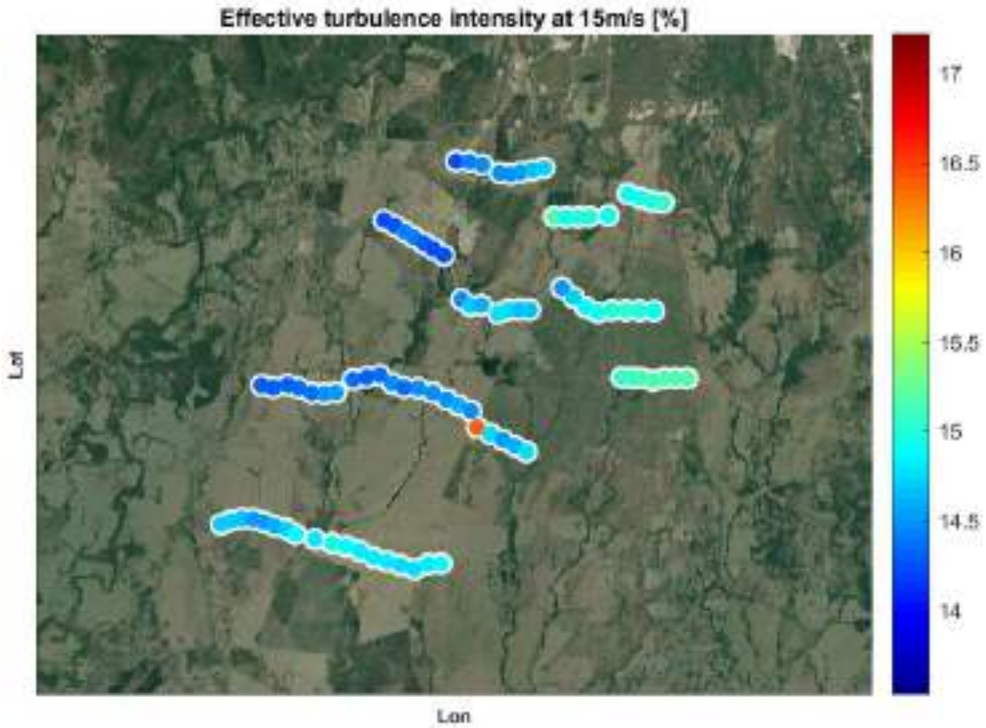

Figure 5.3: Effective TI at 15 m/s for Penonomé II WF.

As it can be seen in Figure 5.4 the effective turbulence intensity per wind speed bin is above wind Class A between 3 m/s and 8 m/s and bellow the wind Class for the rest of wind speed bins for most of the WTs.

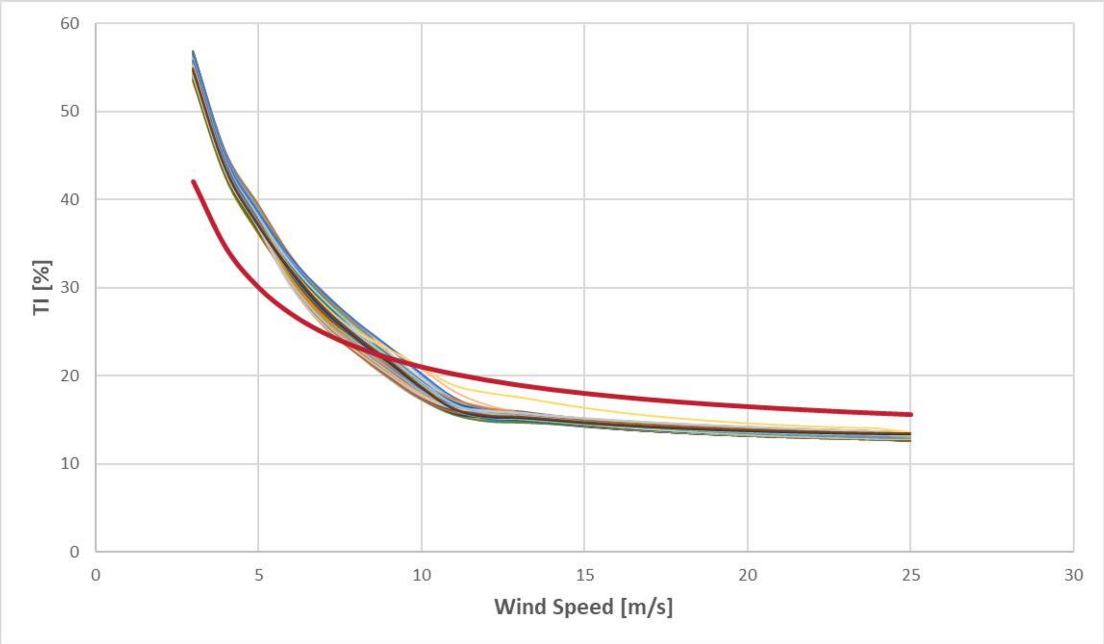

Figure 5.4: Effective TI per wind speed bin and wind turbine at Penonomé II WF.

5.2.3 Wind Shear

The site conditions (roughness) and data from OpenWind tool have been processed for the calculation of the wind shear exponent. Refer to Appendix A - Wind site conditions for detailed wind shear exponents per wind turbine and direction. Table 5.3 shows the average wind shear of the wind turbines that represent the average wind shear of the wind farm.

Table 5.3: Wind shear from OpenWind tool for Penonomé II WF [-]

Wind Direction	Shear [-]
0º (-15º - 15º)	0.23
30º (15º - 45º)	0.1
60º (45º - 75º)	0.08
90º (75º - 105º)	0.06
120º (105º - 135º)	0.1
150º (135º - 165º)	0.11
180º (165º - 195º)	0.1
210º (195º - 225º)	0.2
240º (225º - 255º)	0.29
270º (255º - 285º)	0.21
300º (285º - 315º)	0.1
330º (315º - 345º)	0.16

Table 5.3: Wind shear from OpenWind tool for Penonomé II WF [-]

Wind Direction	Shear [-]
Average	0.21

5.2.4 Air Density

The corresponding air density value has been extracted from meteorological mast data. In Appendix A - Wind site conditions can be found the air density used per wind turbine in the analysis.

Table 5.4: Air density from OpenWind tool for Penonomé II Wind Farm

Wind Farm	Density [kg/m^3]
Penonome2	1.165

5.2.5 Summary External Conditions

In Table 5.5. a comparison is presented between on-site and design conditions used for certification. A graphical indication of the implications of the difference in these conditions on lifetime has been included by each considered parameter. Green arrows suggest an opportunity for increased fatigue lifetime while red arrows indicate a negative impact on lifetime. The loads analysis determines to what degree the opportunities for enhanced fatigue life outweigh the negative factors.

Table 5.5: Environmental conditions. expected impact on LTE analysis for Penonomé II WF (GoldWind GW109 2500 kW HH 90m).

		Penonomé II WF (GoldWind GW109 2500 kW HH 90m Class IIA)		LTE impact
Parameter	Units	Cert.	Site	
Air Density	kg/m^3	1.225	1.165	↑
Wind Shear Coeff	-	0.2	0.21	↓
Yaw Misalignment	deg	0.0	0.0	=
Inflow Angle	deg	8.0	0.02	↑
Wind speed	m/s	8.5	6.06	↑
Turbulence Intensity at 15 m/s	%	18.0	14.71	↑
Availability	%	100.0	100.0	=

5.3 Analysis of Operational Conditions

All the wind turbines have been inspected starting at the end of 2019. The inspections consist in general visual inspection of the wind turbine and blade inspection with TSR robot. Additionally, blade root inserts nondestructive testing has been performed for the Sinoma52.5 (GW106).

The related documents are the following:

- UL-ES-AM20-1101772929-01.05 [15]
- UL-ES-AA20-13321645-01.03_NDT_results [16]

As a summary of the most relevant findings:

Figure 5.5: Lose torque mark in rotor hub

Figure 5.6: Displaced nut

Figure 5.7: Pitch bearing grease leakage

Figure 5.8: Oil leakage and low oil level in pitch drive motor

Figure 5.9: Lose torque mark in blade bolts

5.4 Aerodynamics / Independent Aeroelastic Model / Loads

An Independent Aeroelastic Model has been produced for Penonomé II wind farm. The Independent Aeroelastic Model has been produced by UL. Refer to Table 3.1 for a given wind turbine's specifications and Table 3.2 for blade's specifications. Flex5 software has been used to carry out the simulations and post processing [10].

The validation of the aeroelastic models of wind turbines consists of a comparison of power curve, power coefficient (CP) curve and thrust coefficient (CT) curve. In addition, the Campbell diagrams for the models to be validated have been produced. In these diagrams, the natural frequencies of tower/blade have been checked to be above operating frequencies that may produce high vibration/loads.

The Normal Turbulence Model (NTM) is used to determine the wind's statistical properties (as defined in IEC 61400-1 in section 7 (Ref. [14]). Kaimal Turbulent model has been used according to the state of the art (IEC 61400-1 Ed.3 [9]).

Refer to Section 5.2 for a detailed description of the environmental conditions considered for validation purposes.

The validation of the aeroelastic model is shown from Figure 5.10 to Figure 5.12 including the characteristic power curve, power coefficient, thrust coefficient and Campbell diagram.

GoldWind GW109 2500 kW HH 90m Wind Turbine Aeroelastic Model Validation

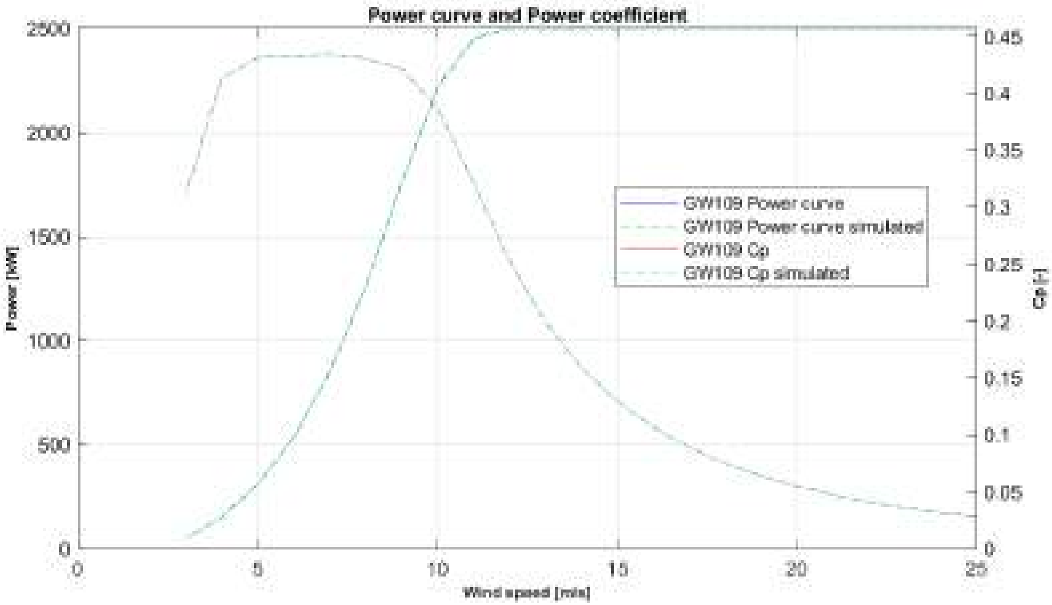

Figure 5.10: Power curve and power coefficient (Cp) of pitch-regulated wind turbine (GoldWind GW109 2500 kW HH 90m WT model validation)

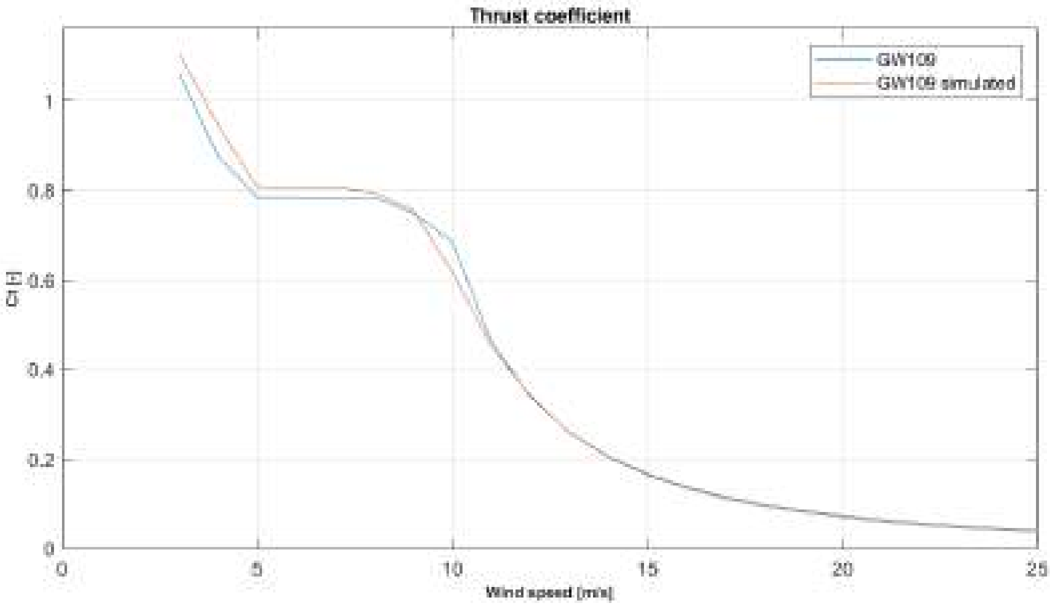

Figure 5.11: Thrust coefficient (CT) curve of pitch-regulated wind turbine (GoldWind GW109 2500 kW HH 90m WT model validation)

From Table 3.1. the following specifications of the GoldWind GW109 2500 kW HH 90m wind turbine are obtained:

- Rotor speed. Rg = 13.5 rpm
- Gear ratio GR = 1
- Natural freq. Tower (1st) = 0.292 Hz

From Table 3.2. the following blade's specifications for the GoldWind GW109 2500 kW HH 90m wind turbine are obtained:

- Natural freq. Blade (1st flapwise) = 0.63 Hz
- Natural freq. Blade (1st edgewise) = 1.2 Hz

Rated rotor speed (13.5 rpm) is shown as a vertical, dashed line in Figure 5.12.

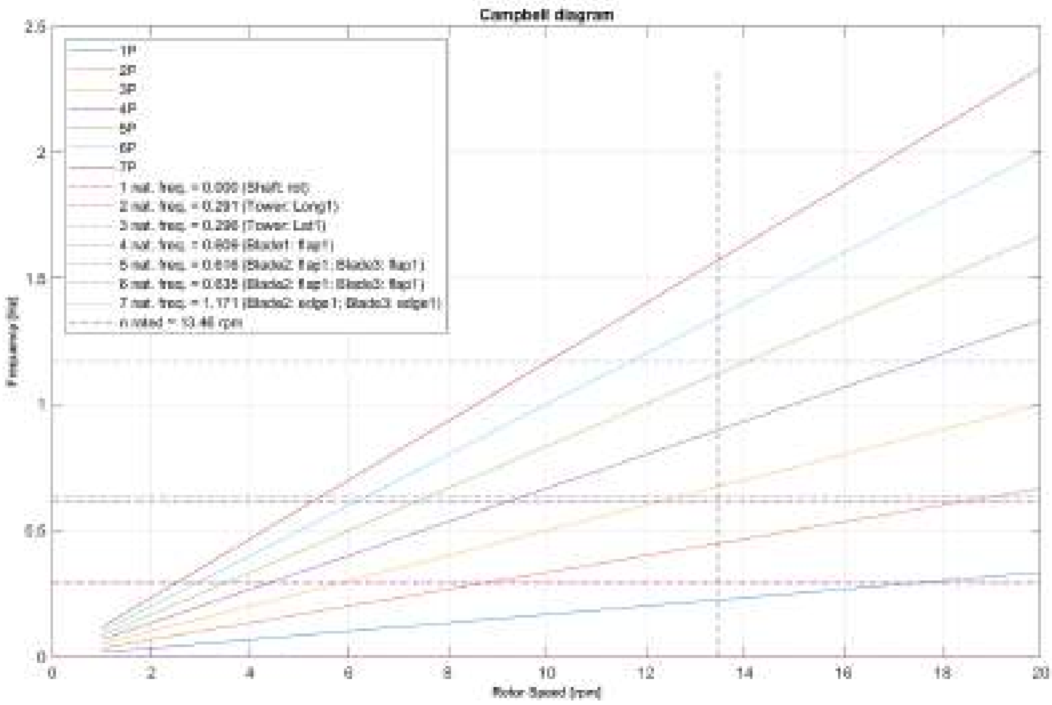

Figure 5.12: Campbell diagram of pitch-regulated wind turbine GoldWind GW109 2500 kW HH 90m

From inspection of the Campbell diagram in Figure 5.12. the following remarks can be made:

- The first natural frequency of the tower is above 1P at 13.5 rpm. Thus, the tower is not expected to be operating close to natural frequencies that may produce high vibrations/loads.
- The first natural frequency of the blade (flapwise) is below 3P at 13.5 rpm. The first natural frequency of the blade (edgewise) is above 5P at 13.5 rpm. The controller takes this frequencies into account to avoid the resonance of the wind turbine.

5.5 LTE Analysis

LTE Analysis is based on the calculation of "Lifetime Extension Factor" (LTE factor), which is calculated by comparing fatigue life (allowable number of cycles) at critical wind turbine's components (those considered critical for its structural integrity) during one year in two scenarios (see 5.2 for a description of environmental conditions and 5.3 for a description of operational conditions):

1. Certification conditions
2. On-site conditions

A brief summary of the LTE factor calculation process is provided below.

Step 1) Damage Equivalent Load (DEL) and allowable number of cycles (under certification conditions):

- Run simulations of the aeroelastic model (time series).
- Perform rain flow counting of selected loads for critical components of the wind turbine and obtain Markov matrices.
- Calculate DEL considering the following:
  - the Markov matrices previously calculated
  - the annual distribution of 10-minutes long power production simulations
  - the Wöhler parameter (inverse of S-N fatigue's curve slope) for the particular wind turbine component under consideration
  - and the number of allowable cycles in one year
    - from Ref [9], the minimum required lifetime for certification is 20 years
    - from Ref [9], 1e7 cycles are usually considered as a reference in certification documents for 20-year lifetime
    - thus, the number of allowable cycles in a year is 1.e7 / 20 years = 500000 cycles (designated as "N_cert". N_cert=500000 cycles)

Step 2) Allowable number of cycles (under site-specific conditions):

- Run simulations of the aeroelastic model (time series). 84 sectors considered per wind turbine.
- Perform rain flow counting of selected loads for critical components of the wind turbine and obtain Markov matrices.
- Calculate the number of cycles the wind turbine component under consideration is able to withstand (designated as "N_site") when considering the following:
  - the Damage Equivalent Loads (DEL's) previously calculated for certification conditions
  - the Markov matrices calculated for site specific conditions
  - the annual distribution of 10-minute long power production simulations
  - the Wöhler parameter (inverse of S-N fatigue's curve slope) for the particular wind turbine component under consideration

The LTE factor is calculated as the ratio between the number of allowable cycles obtained in Step 1 (N_cert) divided by the number of allowable cycles obtained in Step 2 (N_site):

LTE factor = (N_cert) / (N_site)

If the LTE factor is greater than one, the estimated fatigue life of wind turbine component is greater under site conditions than under certification conditions.

Expected life is obtained by multiplying the LTE factor by the certified lifetime:

Expected Life = 20 x (LTE factor)

The critical components, loads and Wöhler parameters considered for calculation of LTE factors are:

- Blade root composite: flapwise / edgewise moments m=10
- Blade root joint: flapwise / edgewise moments m=5
- Hub: flapwise / edgewise moments at blade root m=8
- Hub-shaft joint: rotating low-speed shaft bending moment (Mx. My) m=5
- Main frame casting: Hub fixed moment (Mx. My) m=8
- Main frame welded: Hub fixed moment (Mx. My) m=5
- Main frame-tower joint: tower-top bearing roll / pitch moment (My. Mz) m=5
- Tower top: tower-top bearing roll / pitch moment (My. Mz) m=5
- Tower bottom: tower base roll / pitch moment (My. Mz) m=5

LTE factors for pitch-regulated wind turbine in Penonomé II WF, as calculated following the procedure outlined above, are listed in Table 5.7 (critical components/loads have been highlighted).

The nomenclature of loads obtained in order to perform the LTE analysis and the coordinate systems that have been considered (from Ref [9]) are described in Table 5.6. The coordinate systems that these loads are referred to are shown in Figure 5.13 (tower top/yaw). Figure 5.15 (Hub fixed /nacelle). Figure 5.14 (low-speed shaft and high-speed shaft) and Figure 5.16 (blade).

Table 5.6: Nomenclature of loads used for LTE analysis

Component	Station	Description
Blade Root. Composite	BRMz10	Edgewise moment at the blade root with m=10
Blade Root. Joint	BRMz5	Edgewise moment at the blade root with m=5
Hub	BRMz8	Edgewise moment at the blade root with m=8
Hub-Shaft Joint	HRMxy5	Rotating low-speed shaft bending moment at the shaft tip with m=5
Main Frame. Casting	HFMxy8	Rotating (with nacelle) tower-top / yaw bearing pitch moment with m=8
Main Frame. Welded	HFMxy5	Rotating (with nacelle) tower-top / yaw bearing pitch moment with m=5
Main Frame-Tower Joint	TTMyz5	Rotating (with nacelle) tower-top / yaw bearing pitch moment with m=5
Tower Top	TTMyz5	Rotating (with nacelle) tower-top / yaw bearing pitch moment with m=5
Tower Bottom	TBMyz5	Tower base pitching (or fore-aft) moment with m=5

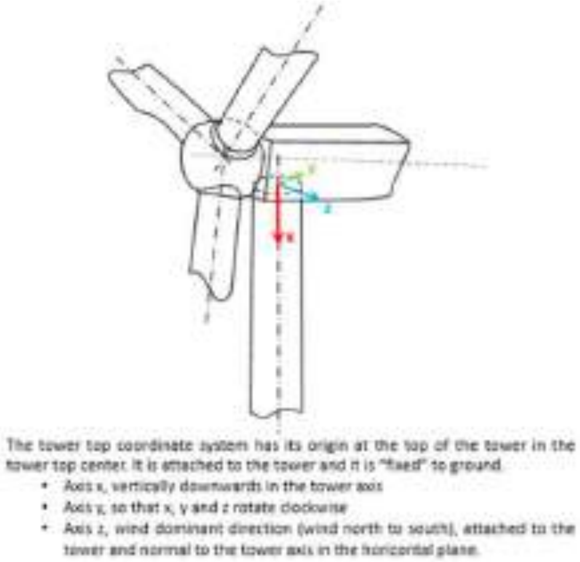

Figure 5.13: Tower-top/yaw coordinate system

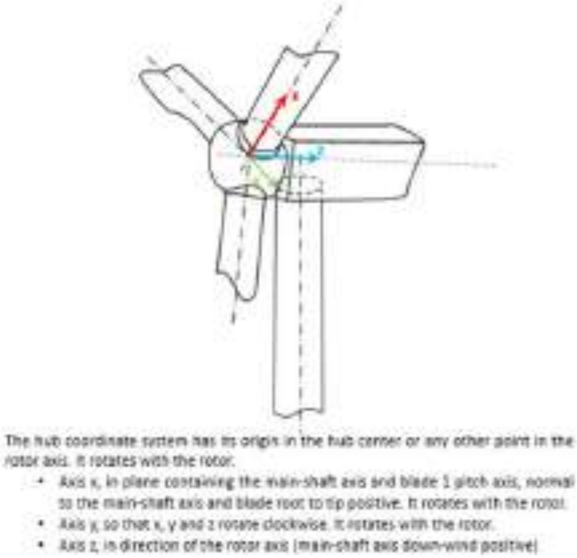

Figure 5.14: Rotating hub/shaft coordinate system

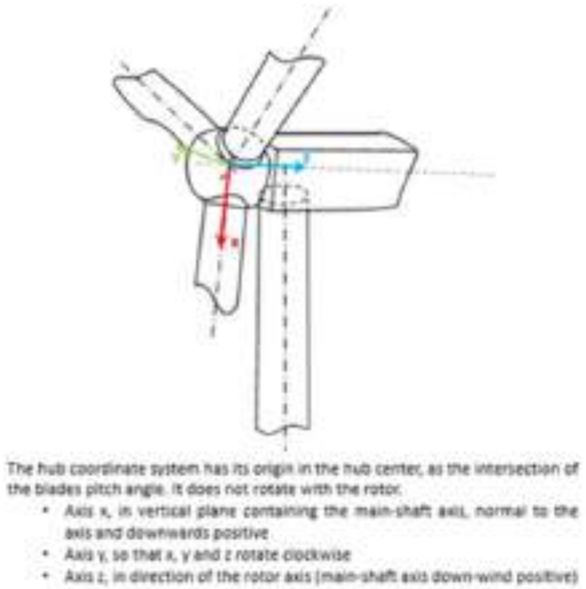

Figure 5.15: Hub Fixed/Nacelle coordinate system

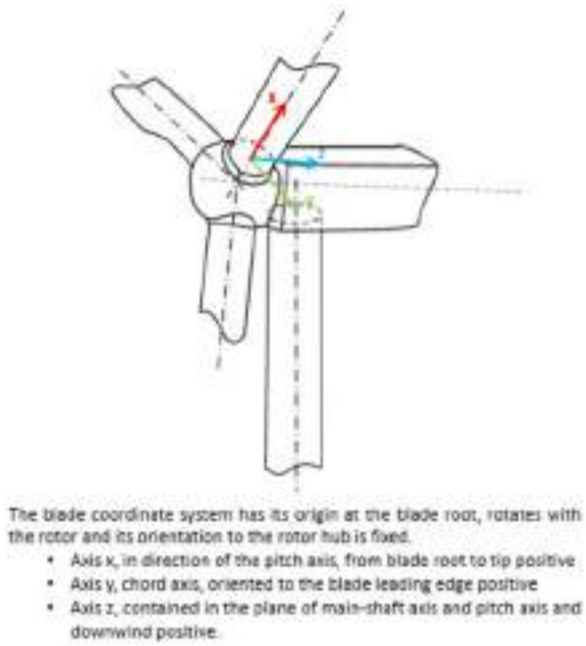

Figure 5.16: Blade coordinate system

LTE factors for GoldWind GW109 2500 kW HH 90m wind turbines at the Penonomé II WF are listed from Table 5.7:

Table 5.7: Critical components loads for GoldWind GW109 2500 kW HH 90m at Penonomé II WF.

	LTE factor per Component								
Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG001	1.6	1.4	1.5	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG002	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG003	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG004	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG005	1.7	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG006	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG007	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG008	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG009	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG010	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG011	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG012	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG013	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG014	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG015	1.6	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG016	1.6	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0

Table 5.7: Critical components loads for GoldWind GW109 2500 kW HH 90m at Penonomé II WF.

	LTE factor per Component								
Wind Turbine	**Blade Root. Composite**	**Blade Root. Joint**	**Hub**	**Hub-Shaft Joint**	**Main Frame. Casting**	**Main Frame. Welded**	**Main Frame. Tower Joint**	**Tower Top**	**Tower Bottom**
WTG017	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG018	1.6	1.4	1.5	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG019	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG020	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG021	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG022	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG023	1.7	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG024	1.6	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG025	1.7	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG026	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG027	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG028	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG029	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG030	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG031	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG032	1.7	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG033	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0

Table 5.7: Critical components loads for GoldWind GW109 2500 kW HH 90m at Penonomé II WF.

	LTE factor per Component								
Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG034	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG035	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG036	1.7	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG037	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG038	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG039	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG040	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG041	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG042	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG043	1.7	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG044	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG045	1.7	1.4	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG046	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG047	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG048	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG054	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG055	1.8	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0

Table 5.7: Critical components loads for GoldWind GW109 2500 kW HH 90m at Penonomé II WF.

	LTE factor per Component								
Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG056	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG057	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG058	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG059	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG060	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG061	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG062	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG063	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG064	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG065	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG066	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG067	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG068	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG069	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG070	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG071	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG109	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0

Table 5.7: Critical components loads for GoldWind GW109 2500 kW HH 90m at Penonomé II WF.

	LTE factor per Component								
Wind Turbine	**Blade Root. Composite**	**Blade Root. Joint**	**Hub**	**Hub-Shaft Joint**	**Main Frame. Casting**	**Main Frame. Welded**	**Main Frame. Tower Joint**	**Tower Top**	**Tower Bottom**
WTG110	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG111	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG112	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG093	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG094	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG095	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG096	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG097	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG098	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG099	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG100	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG101	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG102	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG103	1.6	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG104	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG105	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG106	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0

Table 5.7: Critical components loads for GoldWind GW109 2500 kW HH 90m at Penonomé II WF.

	LTE factor per Component								
Wind Turbine	Blade Root. Composit e	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG107	1.7	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WTG108	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
WF	1.7	1.5	1.6	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0
Min WF	1.8	1.5	1.7	>2.0	>2.0	>2.0	>2.0	>2.0	>2.0

5.6 Damage per wind sector and energy production and damage contribution per load case

5.6.1 Damage per wind sector and energy production.

According to the estimated energy production obtained with the OpenWind tool after the wind resource analysis and the LTE factors per wind sector calculated on the LTE analysis, different rose maps of wind, energy and damage per energy for each WT and component have been created (see Appendix B – Lifetime And Production Roses Per Wind Turbine and Component)

As an example, in Figure 5.17 is shown the rose map with the wind probability energy and damage per sector in percentage for the WTG01 at the Blade root composite. Furthermore, a ratio between the damage and the estimated energy production per sector has been calculated.

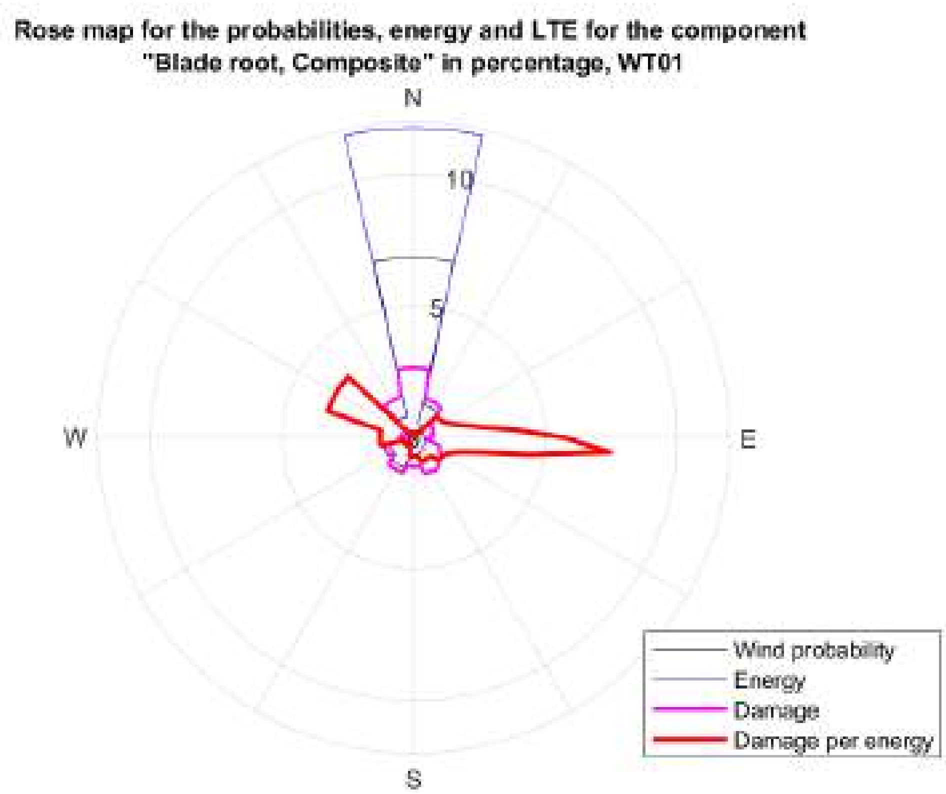

Figure 5.17: Example Rose map for the probabilities, energy and LTE.

6. LTE RESULTS PER MAIN COMPONENT

When taking into account LTE factors in Table 5.7 the following time frames regarding Lifetime Extension (LTE) are shown for Penonomé II wind turbines (refer to Table 6.2 for a summary) by considering an average availability of each wind turbine (see Table 6.1) and a certification lifetime of 20 years. Nowadays, the availability of some wind turbines are much lower [8]. However, after the rotor change and solve the problems with other components, the average availability for the following years should be close to the presented in Table 6.1.

Table 6.1: Availability of each wind turbines at Penonomé II Wind Farm

Wind turbine	Availability [%]	Wind turbine	Availability [%]	Wind turbine	Availability [%]
WTG001	97.0	WTG030	97.0	WTG064	97.0
WTG002	97.0	WTG031	97.0	WTG065	97.0
WTG003	97.0	WTG032	97.0	WTG066	97.0
WTG004	97.0	WTG033	97.0	WTG067	97.0
WTG005	97.0	WTG034	97.0	WTG068	97.0
WTG006	97.0	WTG035	97.0	WTG069	97.0
WTG007	97.0	WTG036	97.0	WTG070	97.0
WTG008	97.0	WTG037	97.0	WTG071	97.0
WTG009	97.0	WTG038	97.0	WTG109	97.0
WTG010	97.0	WTG039	97.0	WTG110	97.0
WTG011	97.0	WTG040	97.0	WTG111	97.0
WTG012	97.0	WTG041	97.0	WTG112	97.0
WTG013	97.0	WTG042	97.0	WTG093	97.0
WTG014	97.0	WTG043	97.0	WTG094	97.0
WTG015	97.0	WTG044	97.0	WTG095	97.0
WTG016	97.0	WTG045	97.0	WTG096	97.0
WTG017	97.0	WTG046	97.0	WTG097	97.0
WTG018	97.0	WTG047	97.0	WTG098	97.0
WTG019	97.0	WTG048	97.0	WTG099	97.0
WTG020	97.0	WTG054	97.0	WTG100	97.0
WTG021	97.0	WTG055	97.0	WTG101	97.0
WTG022	97.0	WTG056	97.0	WTG102	97.0
WTG023	97.0	WTG057	97.0	WTG103	97.0
WTG024	97.0	WTG058	97.0	WTG104	97.0
WTG025	97.0	WTG059	97.0	WTG105	97.0
WTG026	97.0	WTG060	97.0	WTG106	97.0
WTG027	97.0	WTG061	97.0	WTG107	97.0
WTG028	97.0	WTG062	97.0	WTG108	97.0
WTG029	97.0	WTG063	97.0	Average	97.0

Table 6.2: Lifetime P50-values in years per component for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG001	>30.0	29.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG002	>30.0	29.4	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG003	>30.0	29.4	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG004	>30.0	29.5	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG005	>30.0	29.8	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG006	>30.0	29.8	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG007	>30.0	29.8	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG008	>30.0	29.6	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG009	>30.0	29.7	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG010	>30.0	29.8	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG011	>30.0	29.7	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG012	>30.0	29.7	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG013	>30.0	29.6	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG014	>30.0	29.8	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG015	>30.0	30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG016	>30.0	30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG017	>30.0	29.8	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG018	>30.0	29.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0

Table 6.2: Lifetime P50-values in years per component for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG019	>30.0	29.2	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG020	>30.0	29.2	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG021	>30.0	29.3	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG022	>30.0	29.3	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG023	>30.0	29.5	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG024	>30.0	29.5	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG025	>30.0	29.9	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG026	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG027	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG028	>30.0	30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG029	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG030	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG031	>30.0	30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG032	>30.0	29.9	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG033	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG034	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG035	>30.0	30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG036	>30.0	29.8	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0

Table 6.2: Lifetime P50-values in years per component for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG037	>30.0	30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG038	>30.0	30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG039	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG040	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG041	>30.0	30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG042	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG043	>30.0	29.9	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG044	>30.0	30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG045	>30.0	29.9	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG046	>30.0	30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG047	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG048	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG054	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG055	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG056	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG057	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG058	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG059	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0

Table 6.2: Lifetime P50-values in years per component for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG060	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG061	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG062	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG063	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG064	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG065	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG066	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG067	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG068	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG069	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG070	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG071	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG109	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG110	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG111	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG112	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG093	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG094	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0

Table 6.2: Lifetime P50-values in years per component for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG095	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG096	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG097	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG098	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG099	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG100	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG101	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG102	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG103	>30.0	30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG104	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG105	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG106	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG107	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WTG108	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
WF	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0
Min WF	>30.0	29.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0	>30.0

Figure 6.1:P50 Lifetime at Blade root composite

Figure 6.2: P50 Lifetime at Blade root Joint

Figure 6.3: P50 Lifetime at Hub

Figure 6.4: P50 Lifetime at Hub-Shaft joint

Figure 6.5: P50 Lifetime at main frame casting

Figure 6.6: P50 Lifetime at main frame welded

Figure 6.7: P50 Lifetime at main frame tower joint

Figure 6.8: P50 Lifetime at Tower top

Figure 6.9: P50 Lifetime at tower bottom

Figure 6.10: P50 Minimum Lifetime per WT

7. UNCERTAINTIES CALCULATIONS

According to ANSI/UL 4143 [2], the RUL (Remaining Useful Life) can be derived by measurements and several assumptions either in load analysis or statistical analysis (e.g. analysis of the SCADA data), and therefore, a certain uncertainty exists in the RUL determination. The uncertainty of the determined LTE factors considers contributions from the characterization of the uncertainties from external conditions (wind speed, turbulence intensity, wind shear, inflow angle and air density) and the wind turbine modelling uncertainties. The operational conditions are reviewed to determine if the design levels are exceeded or not and corrections are applied on DELs only in case of exceedance.

With the site-specific uncertainties and the wind turbine modelling uncertainties, which are assumed to be stochastic and independent, an overall uncertainty for each LTE factor is calculated by means of the sensitivity of the LTE factors in regard to each of the parameters. The sensitivity factors are obtained using the slope (change in LTE factor for a given change in the parameter under revision) and are specific for each loads station or component. The sensitivity is critical for many of the LTE uncertainties as it is connected with the inverse of the Wöhler exponents on the S-N curves. This connection means that moderate variations on the load levels (DELs) may derive into significant variations on the theoretical cycles. This effect is particularly significant for cast (m=8) and even more for composites (m=10).

The use of operational wind plant data together with proper crosschecks with the meteorological mast data and the calculated wind data obtained with OpenWind tool allows for partly reducing some of the uncertainty elements. The existence and quality of a well-documented source of data is critical for the robustness of the results.

The use of clusters, grouping wind turbines under single calculations, also reduces uncertainties when considering the results valid for the average values, see Ref. [17]. This approximation is considered adequate for lifetime extension analysis when the values are conservatively taken (WF value in P90).

The sensitivities for each loads station and Wöhler exponent come from the changes in LTE factors for different changes on the wind speed distributions per wind sector. UL obtains the different sensitivity factors by running different simulations with the same turbine model changing the parameter whose sensitivity is analyzed. At least five different simulations to obtain the slope for each Loads Station are systematically carried out per each wind turbine and wind sector. The sensitivity factors are calculated for the wind speed, wind shear, wind turbulence intensity, upflow and density. The IAM sensibility is analyzed too, by the analysis of the impact of several inputs in the IAM generation and how these inputs impact on the lifetime of each wind turbine component.

Each sensitivity factor is multiplied for the respective uncertainty to obtain the uncertainty for the LTE factors on each Load Station/Component. It should be considering that not all the wind parameters have the same sensitivity on the LTE calculation. For example, the LTE factor determination is very sensitive to wind speed and wind turbulence intensity on some Loads Stations as it is linked with the inverse of the S-N curve slope. This link evidences the need to reduce uncertainties in order to achieve sufficiently robust results.

Analysis of an individual wind turbine, without proper information, will get an uncertainty level in wind distribution that is not acceptable from LTE analysis point of view (uncertainties over 100%). In order to get this individual analysis with acceptable uncertainty met-mast data and operational data are required. Anyway, the compilation of the results in the statistical value of the wind farm, for example the average value per component, allows to reduce uncertainty in the values by individual uncertainties stacking-up process.

Sensitivities has been calculated for each wind turbine and per wind direction.

Considering that the different uncertainty contributions (wind speed, turbulence intensity, wind shear, air density and WT model, see Table 7.1) are independent, and after multiplying each one for the respective sensitivity factor, a quadratic sum is applied to obtain the overall uncertainty for the LTE factors. When applying those LTE factors per component and considering normal distributions, the respective P-values are obtained (considering the S-N curves are set to 97.5% for the material properties and the P-values reflect the year when this 97.5% level is reached). The uncertainties values are shown in Table 7.2 whereas the P90 values of lifetime extension for the wind turbines are shown in Table 7.3.

Table 7.1:Uncertainty contribution of Wind conditions, inspections and aero elastic model at Penonomé II Wind Farm

External conditions	Uncertainty [%]
Wind speed	6.10%
TI	15.13%
Shear	15.52%
Air density	4.06%
Upflow	3.32%
Inspections	0.99%
Aero model	5.44%

The WF results have been calculated according to the standard of the European Accreditation for uncertainty calculation [18]. Basically the P50 of the wind farm is obtained as an average value of the values of the wind turbine per component, and the P90 value for the wind farm has been calculated considering the WF P50 value per component, and the WF uncertainty per component as an stack-up process of individual wind turbines uncertainties as is described in [18], considering proper correlation between them.

Table 7.2: Uncertainties values per component and WT for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG001	25.4%	12.6%	26.6%	61.1%	72.1%	62.5%	62.5%	62.5%	62.2%
WTG002	25.4%	12.6%	26.7%	61.1%	72.1%	62.5%	62.6%	62.6%	62.2%
WTG003	25.4%	12.6%	26.5%	61.3%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG004	25.3%	12.5%	26.4%	61.2%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG005	25.4%	12.5%	26.4%	61.2%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG006	25.4%	12.5%	26.7%	60.9%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG007	25.4%	12.5%	26.7%	60.9%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG008	25.3%	12.5%	26.8%	60.8%	72.1%	62.5%	62.6%	62.6%	62.2%
WTG009	25.9%	12.9%	27.2%	60.9%	72.1%	62.5%	62.6%	62.6%	62.2%
WTG010	25.6%	12.7%	27.1%	60.9%	72.1%	62.6%	62.7%	62.7%	62.3%
WTG011	25.5%	12.7%	27.0%	60.9%	72.1%	62.6%	62.7%	62.7%	62.3%
WTG012	25.5%	12.6%	26.9%	61.0%	72.1%	62.6%	62.7%	62.7%	62.3%
WTG013	25.4%	12.6%	26.6%	61.1%	72.1%	62.6%	62.7%	62.7%	62.2%
WTG014	25.4%	12.6%	26.6%	61.1%	72.1%	62.6%	62.7%	62.7%	62.3%
WTG015	25.4%	12.6%	26.8%	61.0%	72.1%	62.6%	62.7%	62.7%	62.3%
WTG016	25.4%	12.5%	26.8%	61.0%	72.1%	62.6%	62.7%	62.7%	62.3%
WTG017	25.4%	12.5%	26.7%	61.0%	72.1%	62.6%	62.7%	62.7%	62.3%
WTG018	25.5%	12.7%	26.7%	61.0%	72.1%	62.5%	62.5%	62.5%	62.2%

Table 7.2: Uncertainties values per component and WT for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG019	25.6%	12.7%	26.5%	61.4%	72.1%	62.5%	62.6%	62.6%	62.2%
WTG020	25.6%	12.7%	26.6%	61.3%	72.1%	62.5%	62.6%	62.6%	62.2%
WTG021	25.6%	12.7%	26.6%	61.4%	72.1%	62.5%	62.6%	62.6%	62.2%
WTG022	25.5%	12.7%	26.4%	61.6%	72.1%	62.5%	62.6%	62.6%	62.2%
WTG023	25.5%	12.7%	26.3%	61.6%	72.1%	62.5%	62.5%	62.5%	62.2%
WTG024	25.4%	12.7%	26.2%	61.7%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG025	25.3%	12.7%	26.6%	60.9%	72.1%	62.5%	62.5%	62.5%	62.2%
WTG026	25.5%	12.7%	26.5%	61.2%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG027	25.4%	12.7%	26.5%	61.2%	72.1%	62.6%	62.6%	62.6%	62.3%
WTG028	25.4%	12.7%	26.6%	61.1%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG029	25.5%	12.7%	26.7%	61.2%	72.1%	62.6%	62.7%	62.7%	62.2%
WTG030	25.4%	12.7%	26.6%	61.1%	72.1%	62.6%	62.6%	62.6%	62.3%
WTG031	25.4%	12.7%	26.5%	61.1%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG032	25.4%	12.7%	26.6%	60.9%	72.1%	62.5%	62.5%	62.5%	62.1%
WTG033	25.5%	12.8%	26.7%	60.8%	72.1%	62.5%	62.5%	62.5%	62.1%
WTG034	25.6%	12.8%	26.7%	60.8%	72.1%	62.5%	62.5%	62.5%	62.1%
WTG035	25.5%	12.7%	26.6%	61.0%	72.1%	62.5%	62.5%	62.5%	62.2%
WTG036	25.6%	12.8%	26.6%	61.1%	72.1%	62.5%	62.5%	62.5%	62.2%

Table 7.2: Uncertainties values per component and WT for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG037	25.7%	12.8%	26.8%	61.0%	72.1%	62.5%	62.6%	62.6%	62.2%
WTG038	25.8%	12.8%	26.8%	61.2%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG039	25.8%	12.8%	26.6%	61.3%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG040	25.7%	12.8%	26.6%	61.3%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG041	25.4%	12.7%	26.5%	61.1%	72.1%	62.5%	62.6%	62.6%	62.2%
WTG042	25.5%	12.7%	26.5%	61.1%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG043	25.4%	12.7%	26.4%	61.2%	72.1%	62.5%	62.6%	62.6%	62.2%
WTG044	25.3%	12.7%	26.4%	61.2%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG045	25.2%	12.7%	26.1%	61.4%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG046	25.2%	12.7%	26.1%	61.3%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG047	25.1%	12.6%	26.2%	61.1%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG048	25.1%	12.6%	25.9%	61.6%	72.1%	62.6%	62.6%	62.6%	62.2%
WTG054	25.5%	12.8%	26.4%	61.3%	72.2%	62.6%	62.6%	62.6%	62.1%
WTG055	25.8%	12.9%	26.5%	61.4%	72.2%	62.6%	62.7%	62.7%	62.1%
WTG056	25.5%	12.8%	26.4%	61.2%	72.2%	62.6%	62.6%	62.6%	62.1%
WTG057	25.4%	12.8%	26.3%	61.1%	72.1%	62.6%	62.6%	62.6%	62.1%
WTG058	25.2%	12.7%	26.4%	60.9%	72.1%	62.6%	62.6%	62.6%	62.1%
WTG059	25.2%	12.7%	26.4%	60.9%	72.1%	62.6%	62.6%	62.6%	62.1%

Table 7.2: Uncertainties values per component and WT for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG060	25.1%	12.6%	26.3%	61.0%	72.2%	62.6%	62.6%	62.6%	62.2%
WTG061	25.3%	12.7%	26.0%	61.5%	72.2%	62.6%	62.7%	62.7%	62.1%
WTG062	25.3%	12.7%	26.3%	61.1%	72.2%	62.6%	62.7%	62.7%	62.1%
WTG063	25.3%	12.7%	26.4%	61.1%	72.2%	62.6%	62.7%	62.7%	62.1%
WTG064	25.3%	12.7%	26.2%	61.3%	72.2%	62.6%	62.7%	62.7%	62.2%
WTG065	25.3%	12.7%	26.0%	61.6%	72.2%	62.6%	62.7%	62.7%	62.2%
WTG066	25.2%	12.7%	26.1%	61.3%	72.2%	62.6%	62.7%	62.7%	62.2%
WTG067	25.3%	12.7%	26.2%	61.2%	72.2%	62.6%	62.6%	62.6%	62.2%
WTG068	25.2%	12.7%	25.9%	61.5%	72.2%	62.6%	62.7%	62.7%	62.2%
WTG069	25.2%	12.7%	25.9%	61.6%	72.2%	62.6%	62.7%	62.7%	62.1%
WTG070	25.3%	12.7%	26.2%	61.4%	72.2%	62.7%	62.7%	62.7%	62.2%
WTG071	25.2%	12.7%	26.2%	61.3%	72.2%	62.7%	62.7%	62.7%	62.2%
WTG109	25.0%	12.6%	25.9%	61.5%	72.1%	62.6%	62.6%	62.6%	62.3%
WTG110	25.3%	12.7%	26.1%	61.5%	72.1%	62.6%	62.7%	62.7%	62.3%
WTG111	25.4%	12.7%	26.3%	61.5%	72.1%	62.6%	62.7%	62.7%	62.3%
WTG112	25.3%	12.7%	26.4%	61.3%	72.2%	62.7%	62.7%	62.7%	62.3%
WTG093	25.4%	12.7%	26.4%	61.3%	72.2%	62.7%	62.7%	62.7%	62.3%
WTG094	25.3%	12.7%	26.3%	61.4%	72.2%	62.7%	62.7%	62.7%	62.3%

Table 7.2: Uncertainties values per component and WT for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG095	25.3%	12.7%	26.3%	61.5%	72.2%	62.7%	62.7%	62.7%	62.3%
WTG096	25.3%	12.6%	26.2%	61.7%	72.2%	62.7%	62.7%	62.7%	62.3%
WTG097	25.1%	12.7%	26.1%	61.4%	72.2%	62.7%	62.8%	62.8%	62.3%
WTG098	25.2%	12.7%	26.4%	61.2%	72.2%	62.7%	62.8%	62.8%	62.3%
WTG099	25.1%	12.7%	26.3%	61.2%	72.2%	62.7%	62.8%	62.8%	62.3%
WTG100	25.2%	12.7%	26.5%	61.2%	72.2%	62.7%	62.8%	62.8%	62.3%
WTG101	25.5%	12.7%	26.6%	61.2%	72.2%	62.7%	62.7%	62.7%	62.3%
WTG102	25.6%	12.7%	26.6%	61.3%	72.2%	62.7%	62.7%	62.7%	62.3%
WTG103	25.6%	12.7%	26.6%	61.3%	72.2%	62.7%	62.8%	62.8%	62.3%
WTG104	26.9%	13.4%	27.8%	61.2%	72.1%	62.6%	62.7%	62.7%	62.3%
WTG105	25.3%	12.7%	26.2%	61.4%	72.1%	62.6%	62.7%	62.7%	62.2%
WTG106	25.1%	12.6%	25.9%	61.7%	72.1%	62.6%	62.7%	62.7%	62.2%
WTG107	25.2%	12.6%	26.1%	61.5%	72.1%	62.6%	62.7%	62.7%	62.2%
WTG108	25.2%	12.6%	26.3%	61.2%	72.1%	62.6%	62.7%	62.7%	62.3%
WF	17.1%	8.5%	17.8%	41.1%	48.4%	42.0%	42.1%	42.1%	41.8%

Table 7.3: Lifetime P90-values in years per component and WT for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG001	22.4	24.2	20.9	22.5	16.7	21.2	20.5	20.5	22.8
WTG002	22.7	24.6	21.1	22.6	16.4	21.1	20.5	20.5	22.9
WTG003	22.7	24.6	21.4	23.4	16.3	21.2	20.5	20.5	23.0
WTG004	22.9	24.8	21.6	23.4	16.3	21.3	20.7	20.7	23.2
WTG005	23.0	25.1	21.8	23.3	16.4	21.3	20.7	20.7	23.3
WTG006	23.0	25.1	21.4	21.3	16.2	21.2	20.6	20.6	23.1
WTG007	22.9	24.9	21.3	21.0	16.0	21.1	20.5	20.5	23.1
WTG008	22.8	24.8	21.1	20.1	16.0	21.0	20.4	20.4	23.0
WTG009	22.3	24.7	21.0	20.0	14.3	19.5	19.0	19.0	21.3
WTG010	22.6	24.9	21.1	20.1	15.2	20.4	19.9	19.9	22.4
WTG011	22.6	24.9	21.1	19.7	15.2	20.5	19.9	19.9	22.5
WTG012	22.7	24.9	21.3	20.2	15.2	20.5	20.0	20.0	22.6
WTG013	22.6	24.7	21.5	21.5	15.3	20.6	20.1	20.1	22.6
WTG014	22.8	24.9	21.6	21.5	15.5	20.8	20.3	20.3	22.8
WTG015	22.9	25.2	21.6	20.7	15.5	20.9	20.3	20.3	22.9
WTG016	22.9	25.2	21.6	20.5	15.3	20.8	20.2	20.2	22.9
WTG017	22.8	25.1	21.5	20.5	15.2	20.7	20.1	20.1	22.8
WTG018	22.4	24.2	20.7	21.6	16.4	21.0	20.4	20.4	22.7

Table 7.3: Lifetime P90-values in years per component and WT for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG019	22.6	24.4	21.2	24.2	16.5	21.2	20.5	20.5	22.7
WTG020	22.5	24.4	21.1	23.7	16.1	21.0	20.3	20.3	22.5
WTG021	22.6	24.5	21.3	24.3	16.2	21.2	20.5	20.5	22.7
WTG022	22.7	24.5	21.5	25.5	16.6	21.4	20.7	20.7	22.8
WTG023	22.9	24.7	21.9	26.4	17.2	22.0	21.2	21.2	23.3
WTG024	22.9	24.6	22.0	26.6	17.4	22.1	21.3	21.3	23.4
WTG025	23.2	25.1	21.8	22.2	17.2	22.2	21.4	21.4	24.0
WTG026	23.2	25.2	22.1	23.5	16.4	21.8	21.1	21.1	23.6
WTG027	23.5	25.5	22.4	24.0	17.0	22.2	21.5	21.5	24.0
WTG028	23.1	25.1	22.0	22.5	16.3	21.8	21.1	21.1	23.7
WTG029	23.5	25.7	22.4	23.2	16.3	21.8	21.1	21.1	23.7
WTG030	23.4	25.4	22.2	23.3	16.5	21.9	21.2	21.2	23.8
WTG031	23.3	25.2	22.2	23.4	16.6	22.0	21.2	21.2	23.8
WTG032	23.2	25.1	21.6	22.5	17.6	22.5	21.8	21.8	23.9
WTG033	23.3	25.3	21.6	22.1	17.6	22.4	21.8	21.8	23.9
WTG034	23.4	25.3	21.6	21.9	17.4	22.4	21.6	21.6	23.8
WTG035	23.2	25.1	21.6	22.8	17.1	22.2	21.5	21.5	23.7
WTG036	23.0	24.9	21.5	23.0	16.7	21.9	21.2	21.2	23.4

Table 7.3: Lifetime P90-values in years per component and WT for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG037	23.1	25.2	21.4	22.1	16.2	21.5	20.9	20.9	23.2
WTG038	23.1	25.1	21.5	22.7	16.0	21.3	20.7	20.7	23.0
WTG039	23.2	25.2	21.9	24.1	16.5	21.6	21.0	21.0	23.1
WTG040	23.3	25.3	22.0	24.2	16.8	22.0	21.2	21.2	23.4
WTG041	23.3	25.2	21.9	23.1	17.1	22.3	21.5	21.5	23.8
WTG042	23.3	25.2	22.0	23.4	16.9	22.3	21.6	21.6	23.9
WTG043	23.2	25.1	22.1	23.8	17.4	22.5	21.8	21.8	24.0
WTG044	23.3	25.1	22.1	23.7	17.3	22.5	21.9	21.9	24.1
WTG045	23.3	25.1	22.4	25.3	17.5	22.7	22.1	22.1	24.3
WTG046	23.4	25.2	22.5	25.2	17.9	23.0	22.4	22.4	24.7
WTG047	23.6	25.3	22.5	24.1	17.6	23.0	22.4	22.4	24.8
WTG048	23.8	25.4	23.0	27.3	18.0	23.4	22.7	22.7	25.2
WTG054	23.6	25.6	22.6	24.3	16.9	22.7	22.1	22.1	24.3
WTG055	24.2	26.4	23.2	24.9	16.9	22.8	22.2	22.2	24.3
WTG056	24.0	26.0	22.9	24.3	17.5	23.2	22.6	22.6	24.7
WTG057	24.2	26.0	22.9	24.6	18.1	23.8	23.1	23.1	25.4
WTG058	24.1	25.9	22.7	23.7	18.4	24.0	23.3	23.3	25.6
WTG059	24.0	25.8	22.6	23.5	18.2	24.0	23.4	23.4	25.7

Table 7.3: Lifetime P90-values in years per component and WT for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG060	24.2	26.0	22.9	24.4	18.0	24.2	23.5	23.5	25.8
WTG061	23.9	25.7	23.2	26.8	17.3	23.7	23.1	23.1	25.3
WTG062	23.6	25.5	22.6	23.9	16.9	23.1	22.5	22.5	24.9
WTG063	23.5	25.4	22.4	22.9	16.3	22.7	22.1	22.1	24.6
WTG064	23.6	25.5	22.7	24.3	16.5	22.9	22.3	22.3	24.7
WTG065	23.6	25.4	22.9	26.5	16.8	23.1	22.4	22.4	24.7
WTG066	23.5	25.4	22.6	24.7	16.8	23.0	22.4	22.4	24.8
WTG067	23.5	25.3	22.5	23.8	16.8	22.9	22.3	22.3	24.6
WTG068	23.6	25.4	22.9	26.4	17.2	23.2	22.6	22.6	24.9
WTG069	23.5	25.3	22.9	26.8	17.3	23.1	22.5	22.5	24.8
WTG070	23.7	25.7	22.9	25.1	17.1	22.9	22.3	22.3	24.7
WTG071	23.5	25.5	22.7	24.2	17.1	22.9	22.3	22.3	24.8
WTG109	23.8	25.4	23.1	27.3	18.1	23.4	22.7	22.7	25.1
WTG110	23.6	25.5	22.9	26.6	17.1	22.7	22.1	22.1	24.4
WTG111	23.4	25.4	22.8	26.0	16.5	22.2	21.5	21.5	23.9
WTG112	23.3	25.3	22.6	24.0	16.4	22.0	21.3	21.3	23.9
WTG093	23.5	25.5	22.7	24.2	16.4	22.0	21.3	21.3	23.8
WTG094	23.3	25.3	22.6	24.6	16.3	22.0	21.3	21.3	23.8

Table 7.3: Lifetime P90-values in years per component and WT for GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Wind Turbine	Blade Root. Composite	Blade Root. Joint	Hub	Hub-Shaft Joint	Main Frame. Casting	Main Frame. Welded	Main Frame. Tower Joint	Tower Top	Tower Bottom
WTG095	23.4	25.5	22.8	25.3	16.2	21.9	21.2	21.2	23.8
WTG096	23.3	25.3	22.8	26.3	16.2	22.0	21.2	21.2	23.7
WTG097	23.6	25.5	23.1	25.8	17.2	22.9	22.3	22.3	24.8
WTG098	23.9	26.0	23.1	24.0	17.2	22.9	22.3	22.3	24.9
WTG099	23.9	25.9	23.1	24.0	17.1	22.9	22.3	22.3	24.9
WTG100	23.6	25.7	22.7	22.8	16.2	22.1	21.4	21.4	24.2
WTG101	23.5	25.7	22.6	22.5	15.6	21.4	20.9	20.9	23.6
WTG102	23.2	25.5	22.4	23.1	15.1	20.9	20.3	20.3	23.0
WTG103	22.8	25.2	22.1	22.8	14.6	20.5	19.9	19.9	22.6
WTG104	22.5	25.3	21.6	20.0	11.0	17.6	17.1	17.1	19.5
WTG105	23.5	25.4	22.7	25.5	16.8	22.6	22.0	22.0	24.4
WTG106	23.6	25.4	22.9	27.3	17.5	23.1	22.4	22.4	24.8
WTG107	23.6	25.4	22.8	26.1	17.2	22.9	22.2	22.2	24.7
WTG108	23.5	25.4	22.5	23.9	16.9	22.6	22.0	22.0	24.5
WF	26.9	26.8	25.9	30.9	30.9	30.9	30.9	30.9	30.9
Min WF	22.3	24.2	20.7	19.7	11.0	17.6	17.1	17.1	19.5

Figure 7.1:P90 Lifetime at Blade root. composite

Figure 7.2: P90 Lifetime at Blade root. Joint

Figure 7.3: P90 Lifetime at Hub

Figure 7.4: P90 Lifetime at Hub-Shaft joint

Figure 7.5: P90 Lifetime at main frame. casting

Figure 7.6: P90 Lifetime at main frame. Welded

Figure 7.7: P90 Lifetime at main frame. tower joint

Figure 7.8: P90 Lifetime at Tower top

Figure 7.9: P90 Lifetime at Tower bottom

Figure 7.10: P90 Minimum Lifetime per WT

8. ESTIMATION AND ANALYSIS OF THE PRODUCTION EXTENDING THE WF LIFE

The purpose of this section is to evaluate the possibilities to ensure safe operation of the most critical mechanical components identified in the wind turbines by recurrent inspection (as far as possible) in order to reduce costs, thus optimizing the O&M of the assets, under a specific target time frame. Based on the assessments to support a 30-year useful economic life on the assets, the results show that lifetime expectations can be increased to 30 years in some of the components, but it is not possible to guarantee that lifetime in blade bolted joint.

UL strongly recommends including corrosion-related inspections and components' treatment and protection in the O&M strategy. Including in the current maintenance plan the following LTE management plan (based on LTE calculations and the specific corrosion issues and environment effects on Penonomé II wind farm) ensures that he probability of failure is significantly reduced for the addressed components.

The components that are addressed belong to a selection of mechanical components which are estimated to be the most safety critical.

According to the results shown from Table 6.2 for a P50 scenario and from Table 7.3 for a P90 scenario it can be summarize:

- P50 scenario
  - The estimated lifetime expectation for the different components are the following: Blade root-joint (29.0->30 years)-
- P90 scenario
  - The estimated lifetime expectation for the different components are the following: Blade root-composite (22.3-24.2 years), blade root-joint (24.2-26.4 years), hub (20.7-23.2 years), Hub-Shaft joint (19.7-27.3 years), Main Frame-Casing (11.0-18.4 years), Main Frame-Welded (17.6-24.2 years), Main Frame-Tower joint (17.1-23.5 years), Tower top (17.1-23.5 years) and Tower bottom (29.5-25.8 years).

8.1 Recommended Inspections Program

The Recommended Inspection Program is focused on the critical structural components for life extension, and it is based on recurrent inspection and non-destructive testing, by which the probability of serious and costly failures can be significantly reduced. However, the preferable interval and technique may vary between the components since the possibility to detect the damage and the time scale for the damage evolution varies between the components. In this particular case and due to the dynamic nature of the operation of a wind turbine. Fatigue is the most dominant damage mechanism. Optimal inspection intervals are obviously such that the time between two inspections are maximized and at the same time safe operation of the component is ensured. The recommended interval inspection is four years for the hub and one year for the blade root (composite & bolted joints).

Table 8.1: Aging Management Plan Summary [8.1]

Component	Failure Mode	Inspection	Intervals
Blade Root. Composite	Fatigue	Visual Inspection (binoculars, high resolution camera, climbing robot, drones rope access etc.)	One year
Blade Root. Bolted Joints	Fatigue	Tap testing of all rotor bolts Spot checks of the bolts preload are recommended.	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
	Fatigue and Corrosion	NDT (Ultrasonic analysis, magnetic particles testing or penetrating liquids)	Four years
Rotor Hub	Fatigue and Corrosion	NDT (Ultrasonic analysis, magnetic particles testing or penetrating liquids)	Four years
		Visual inspection	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
Hub to shaft bolted joint	Fatigue	Tap testing of all rotor bolts Spot checks of the bolts preload are recommended.	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
	Fatigue and Corrosion	NDT (Ultrasonic analysis. Magnetic particles testing or penetrating liquids)	Four years
Main frame	Fatigue	Visual inspection	One year
		NDT (Ultrasonic analysis. Magnetic particles testing or penetrating liquids)	Four years
Steel tower	Fatigue and Corrosion	Visual inspection of the tower welds Tap testing of all tower bolts. Spot checks of the bolts preload is recommended.	One year
	Corrosion	Proper surface treatment and protection for the corrosion issues	Once before year 20. When necessary afterwards
	Fatigue and Corrosion	NDT of the tower welds (magnetic particle testing)	Four years
Nacelle components	Corrosion	Installation of a filter in the nacelle	Once. Replaced or cleaned at maintenance interval
		Visual inspection	One year

The effect of corrosion issues is of secondary importance on the lifetime of the wind farm when compared to the fatigue damage mechanism. This means that the corrosion, as secondary damage mechanism, can create initiation sites for fatigue processes that would otherwise not take place. As mentioned above, the fatigue is the most dominant damage mechanism; therefore, the corrosion was not considered in the LTE calculations. UL strongly recommends considering the corrosion as a damage mechanism of secondary importance as well as a worsening factor for the fatigue damage mechanism. Therefore, regular visual inspections and proper surface treatments are to be considered for all components showing corrosion issues.

[8.1] The analysis is based on the assumption that actual O&M will prevail as it is with an additional special care given to the corrosion issues.

UL strongly recommends taking the corrosion and environment effects into account when establishing a maintenance plan.

8.2 Structural Components Inspection Cost Analysis

It is initially considered that the O&M contract will be reaming as actual status for the target frame of 30 years.

The total cost for one day of inspection by a trained inspection engineer is 800 EUR. This cost could potentially be minimized by coordination with other inspection activities. such the standard periodical inspection performed according to an O&M contract. When taking this coordination into account and assuming each inspection is done independently, the following cost can be assumed to reach the target frame of 30 years. Costs only consider the inspections previously explained. No repair cost is considered. Prices consider that visual inspections for different components are done simultaneously.

Table 8.2: Aging management plan scheduled cost GoldWind GW109 2500 kW HH 90m at Penonomé II WF

Component	Program Inspections	P	Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	Year 26-30
Blade root, Composite	Yearly visual inspection NDT (not included in the cost calculations)	P50	0 €	0 €	0 €	0 €	0 €	0 €
		P90	0 €	0 €	0 €	0 €	4,576 €	13,760 €
Blade root, Joint (metallic parts)	Yearly bolts tap testing. Preload test Yearly visual inspection NDT (every 4 years)	P50	0 €	0 €	0 €	0 €	0 €	1,320 €
		P90	0 €	0 €	0 €	0 €	480 €	49,920 €
Rotor Hub	NDT Yearly visual inspection	P50	0 €	0 €	0 €	0 €	0 €	0 €
		P90	0 €	0 €	0 €	0 €	9,600 €	17,200 €
Hub-Shaft joint	Yearly visual inspection. Yearly tap testing & Preload test of bolts NDT (every 4 years)	P50	0 €	0 €	0 €	0 €	0 €	0 €
		P90	0 €	0 €	0 €	0 €	16,680 €	49,080 €
Main Frame (casting) Main Frame (welded)	NDT (performed together)	P50	0 €	0 €	0 €	0 €	0 €	0 €
		P90	0 €	0 €	400 €	23,760 €	34,400 €	34,400 €
Main Frame - Tower joint	NDT (every 4 years)	P50	0 €	0 €	0 €	0 €	0 €	0 €
		P90	0 €	0 €	0 €	160 €	12,320 €	17,200 €
Tower	NDT(every 4 years) Bolts yearly tap testing. Preload test Yearly visual inspection	P50	0 €	0 €	0 €	0 €	0 €	0 €
		P90	0 €	0 €	0 €	373 €	28,747 €	40,133 €
		Sum P50	0 €	0 €	0 €	0 €	0 €	1,320 €
		Sum P90	0 €	0 €	400 €	24,293 €	106,803 €	221,693 €

NOTE: The above figures are rough estimates, and variations may occur. The costs refer to total cost unless otherwise stated.

In the case of visual inspection of the blade root composite, if damage is found, then NDT is recommended. The total cost for thermographic examination(Ref. [19]) is about 15.000 EUR for a three-blade wind turbine. This cost could certainly be reduced if this approach is introduced on a larger scale (meaning performing the inspection at all turbines); thus, 10.000 EUR should not be unrealistic.

For metallic parts, the recommended NDT test are Ultrasonic analysis (Ref. [20]), magnetic particles testing (Ref. [21]) or penetrating liquids (Ref. [22]) in all cases the aim of these test is detect defects in an incipient state of damage on the components. Ultrasonic test is capable to detect internal defects whereas the magnetic particles and penetrating liquids detect superficial defects.

For the surface treatments for the corrosion issues, the working time was estimated to be 1 day per turbine with 2 experienced technicians and 2000 EUR of materials. This work was estimated to be done once before year 20 in order to bring the components to a better condition related to the corrosion issues that the turbines experience.

Inspection costs can be reduced if the activities are well-planned. This estimation has considered the following:

- Blade root composite:
  - Visual Inspection (binoculars, high resolution camera, TSR robot, rope access, etc.) in order to detect cracks or lightning strikes on the blades with 2 inspections per day with 1 specialized technician.
  - NDT (infrared test) every 4 years at 2 turbines per day with 2 specialized technicians to detect internal defects in the composite.
- Blade root joint:
  - Yearly bolt tap test and preload test: 2 inspections per day with 1 specialized technician in order to detect regular level of preload in all the bolts of the joint. Additionally, if a re-tightening process is performed, then a reference could be stated by Ultrasonic (US) test in each bolt, and this preload level could be quantified in further US inspections.
  - NDT every 4 years at 2 turbines per day with 2 specialized technicians to detect possible cracks. Is possible to apply ultrasonic, magnetic particles and or penetrating liquids test.
  - Surface treatment only once before year 20 with 2000 EUR materials per turbine for the surface treatment at 1 day per turbine with 2 technicians
- Hub: one visual inspection every year and an NDT every 4 years to detect cracks or internal damage in the component.

In the event of damaged bolts, a small CAPEX is expected. This CAPEX can be estimated based on the following assumptions.

- Cost per Bolt, Nut, and Wash: around 50€
- Total Cost of Materials per Repair: around 350 €
- Cost of Replacement (Manpower) per Repair: 700 €
- Total Cost per Repairs: 350€ + 700 € = 1050€/Turbine

NOTE: Cost of energy lost due to 4 hours of turbine stop is not considered.

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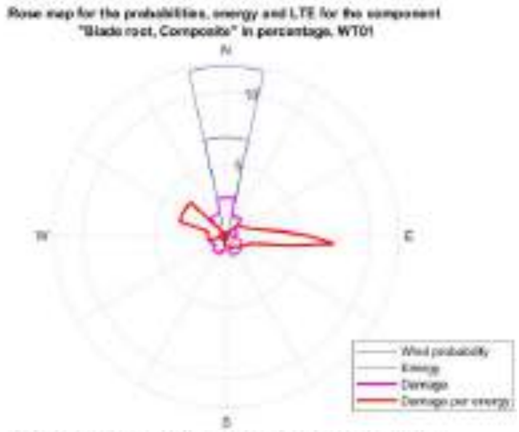
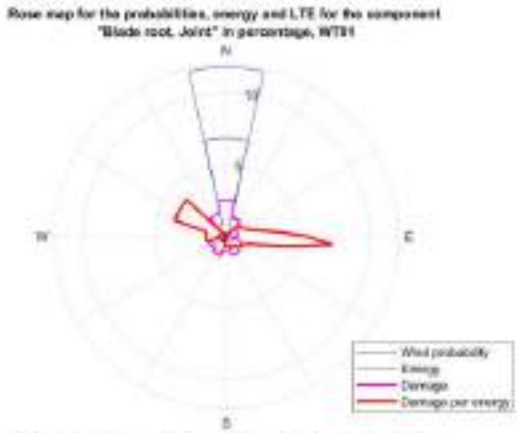
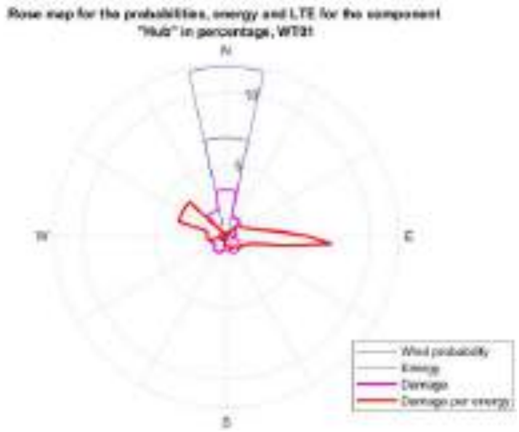
APPENDIX A - WIND SITE CONDITIONS

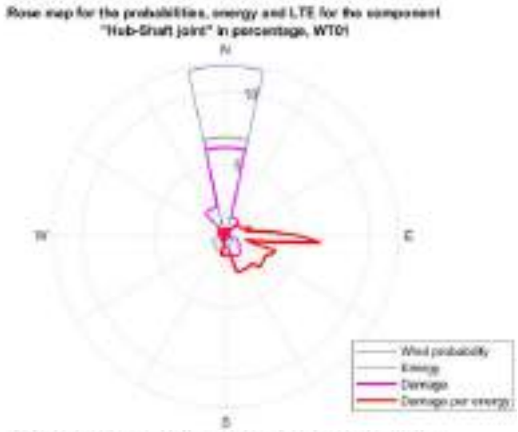
Electronic source of UL Openwind model.

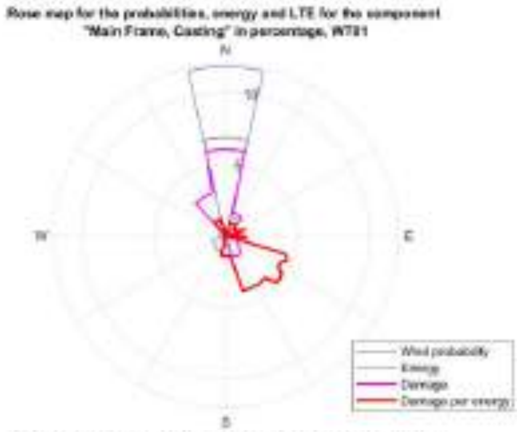
APPENDIX B – LIFETIME AND PRODUCTION ROSES PER WIND TURBINE AND COMPONENT

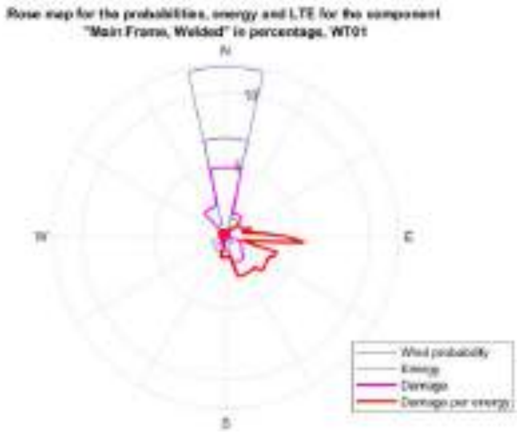




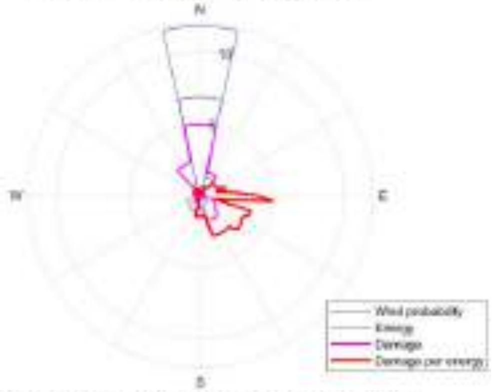




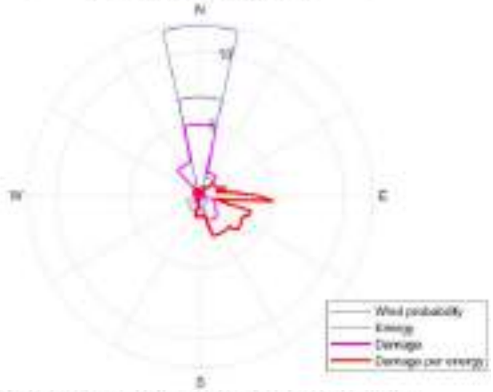




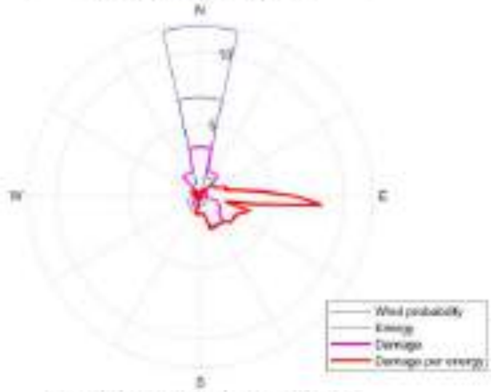
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT01



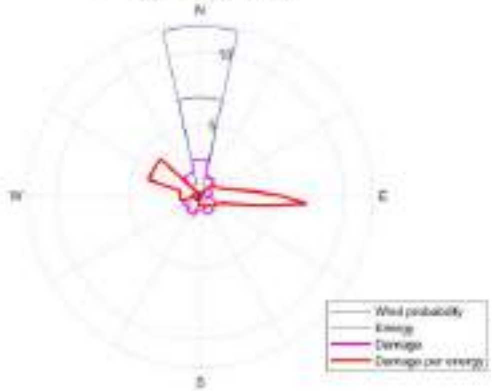
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT01



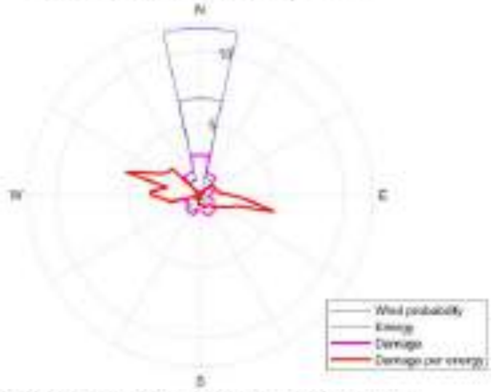
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT01



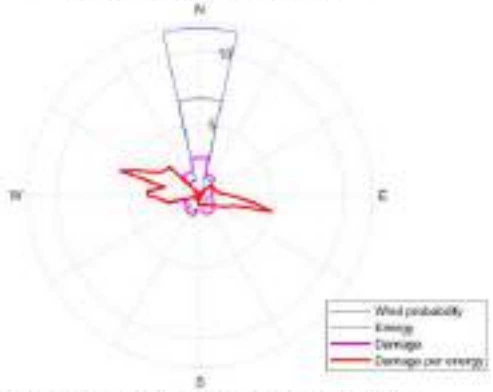
Rose map for the probabilities, energy and LTE in percentage, WT01



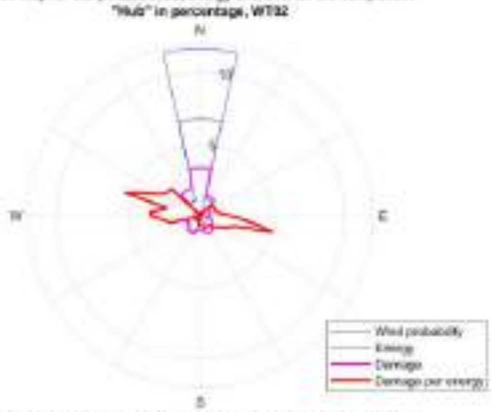
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT02



Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT02

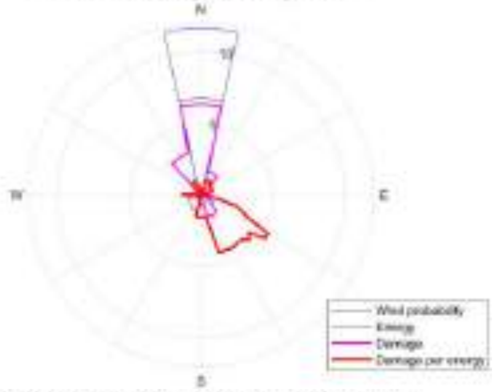


Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT02

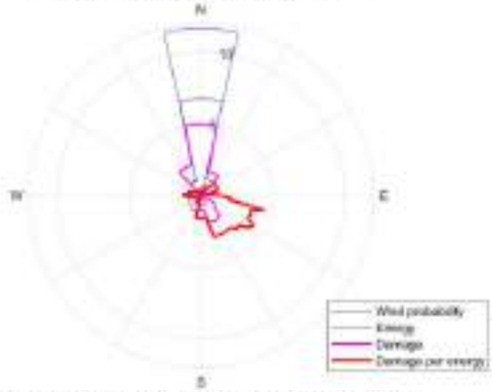


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT02

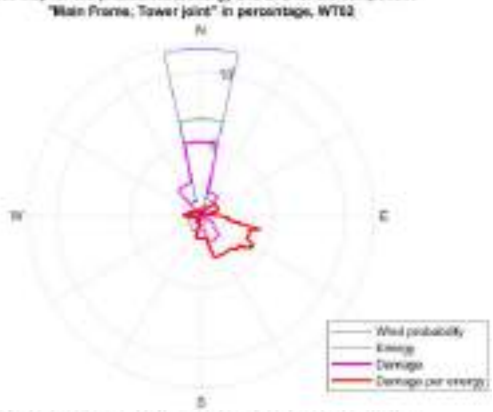
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT02



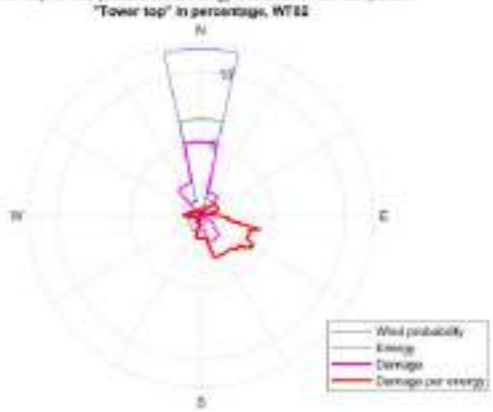
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT02



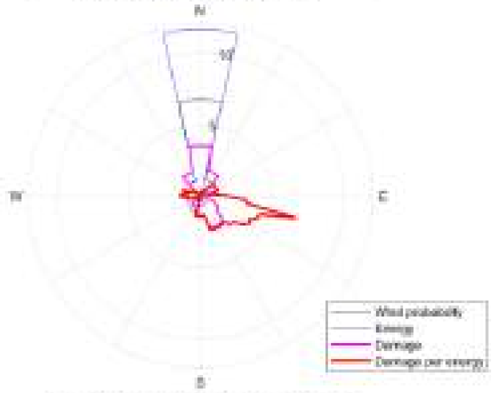
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT02



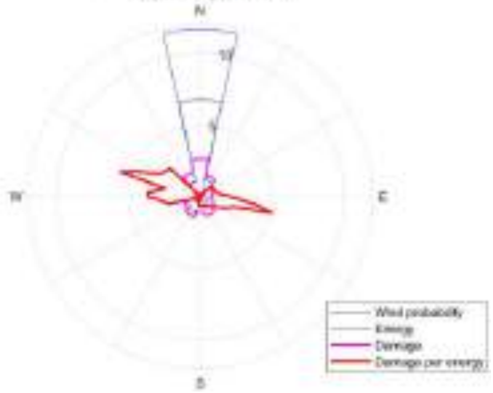
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT02



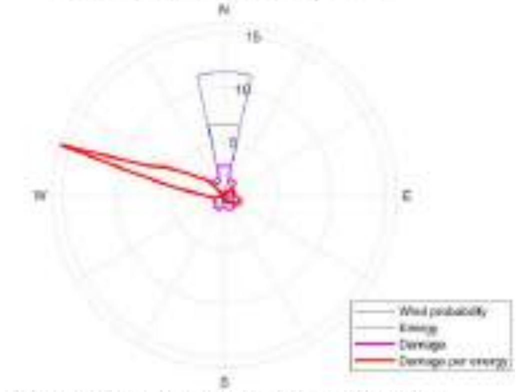
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT02



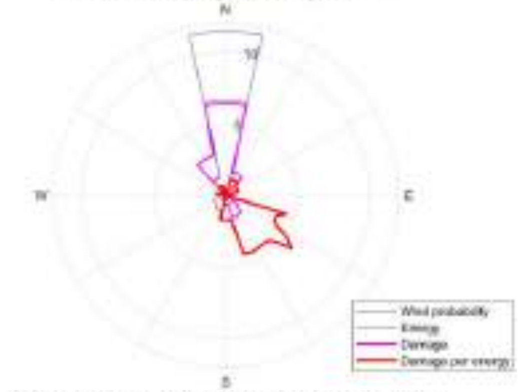
Rose map for the probabilities, energy and LTE in percentage, WT02



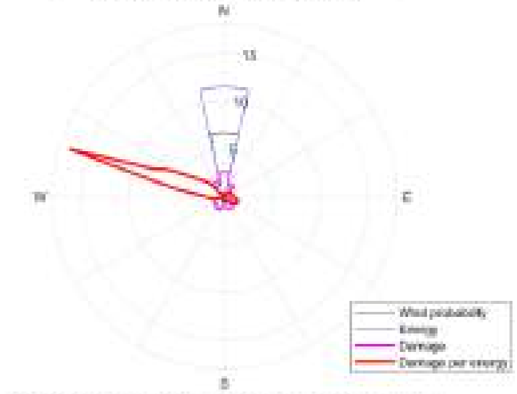
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT03



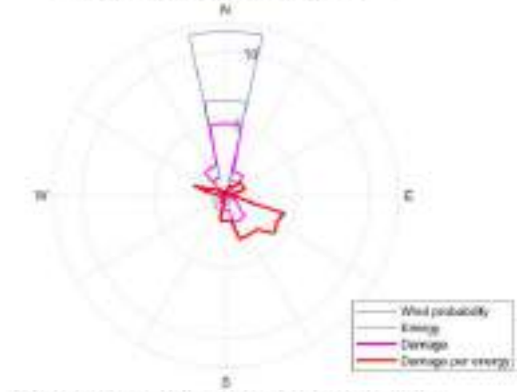
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT03



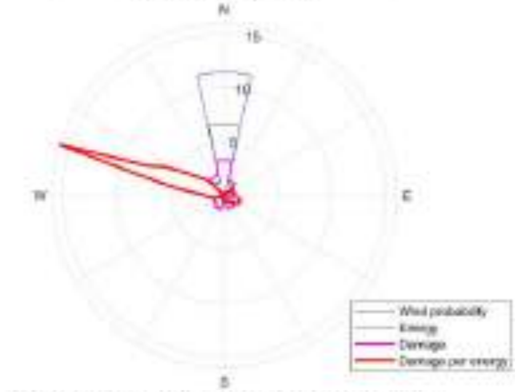
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT03



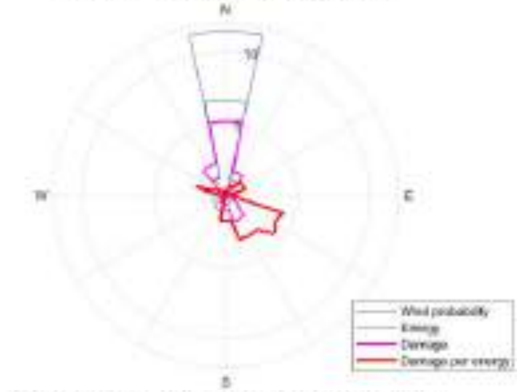
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT03



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT03

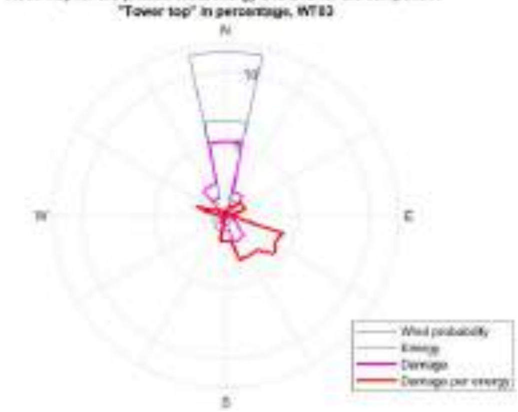


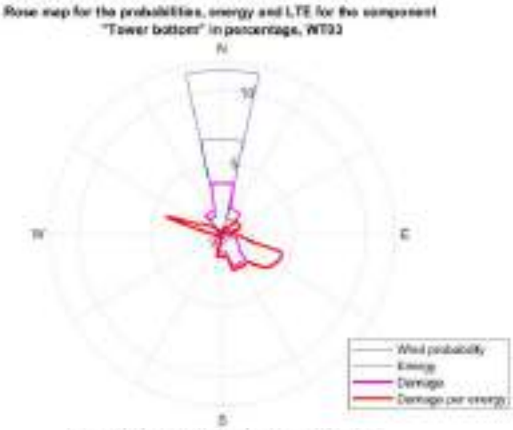
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT03

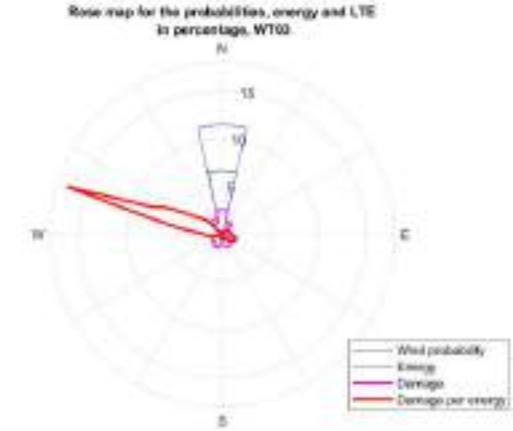


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT03

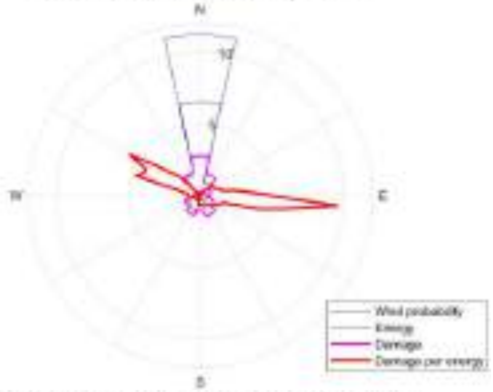
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT03



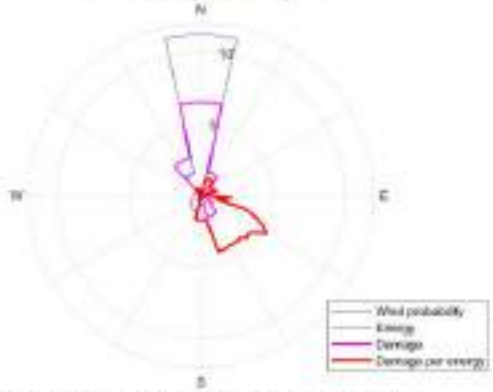

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT03
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT03
N
15
10
W
E
S
Wind probability
Energy
Damage
Damage per energy

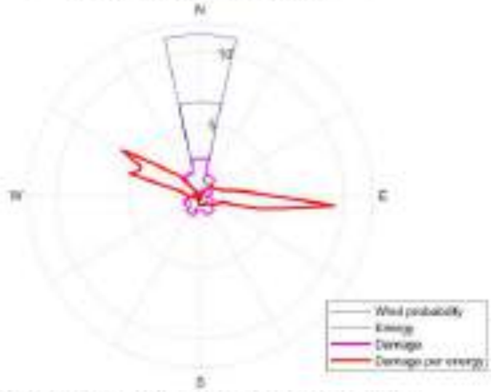
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT04



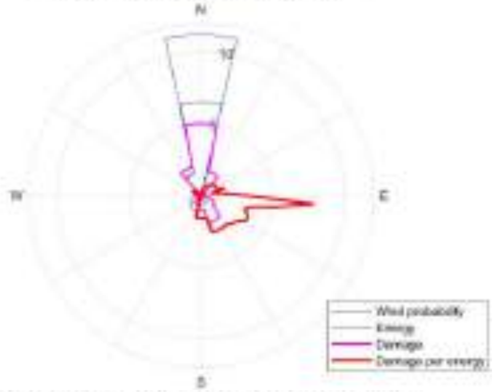
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT04



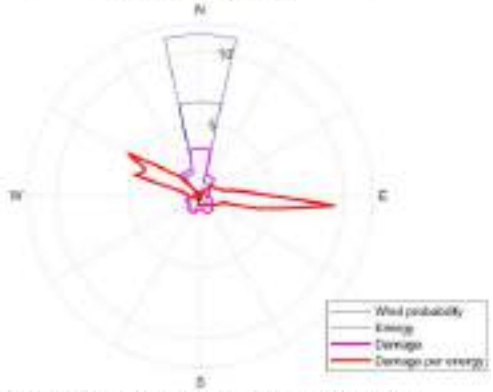
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT04



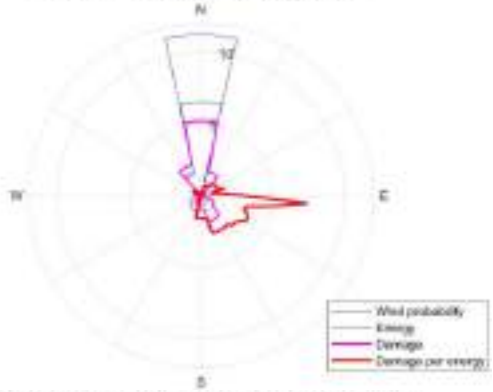
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT04



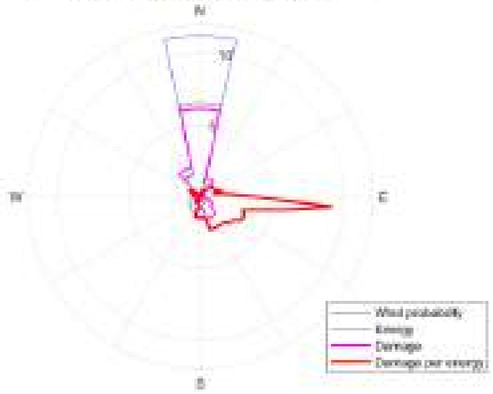
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT04



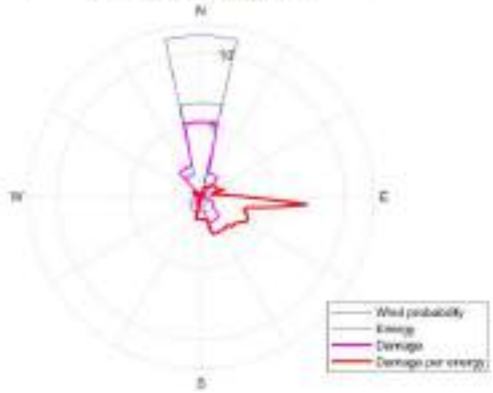
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT04

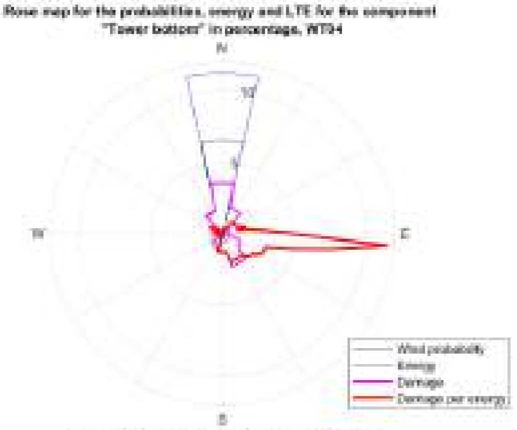


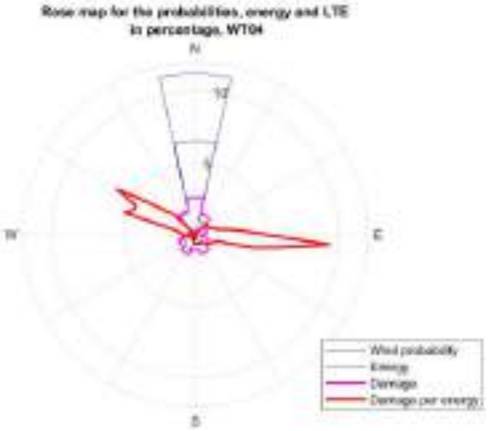
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT04



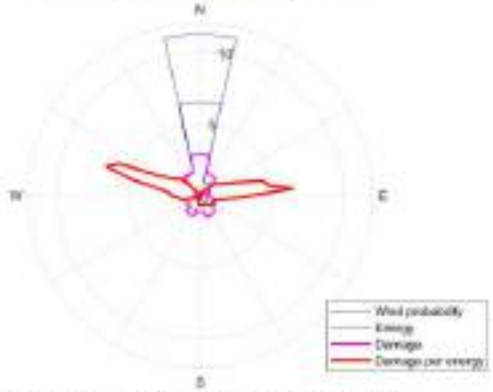
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT04



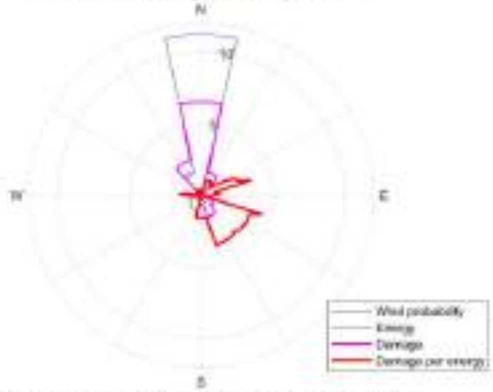

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT04
N
E
W
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT04
N
E
W
S
Wind probability
Energy
Damage
Damage per energy

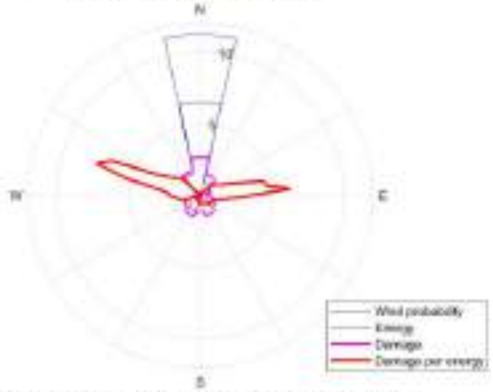
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT05



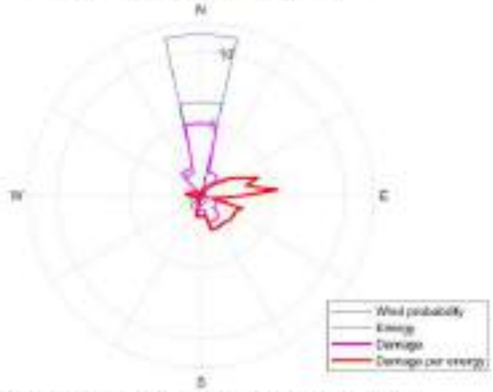
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT05



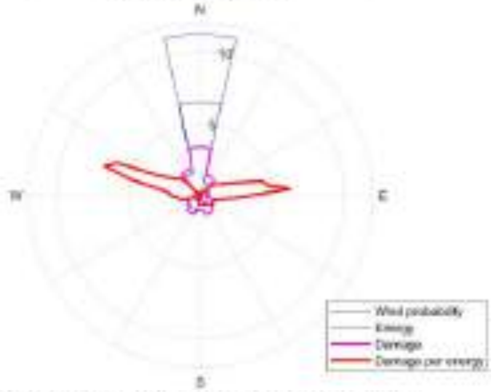
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT05



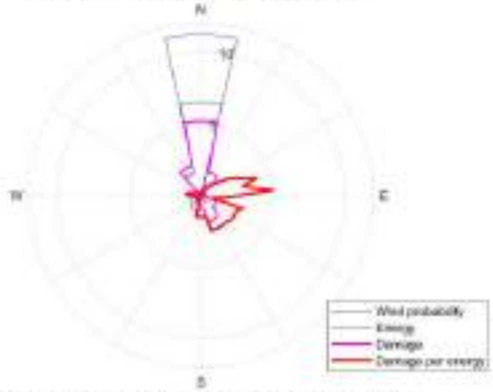
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT05



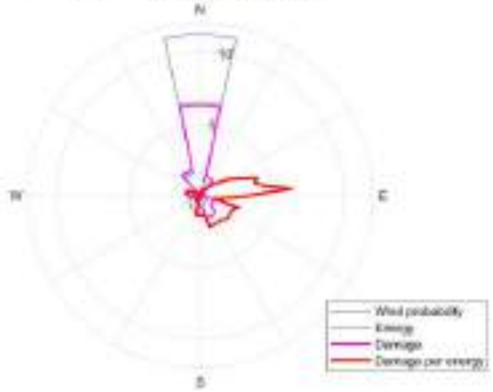
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT05



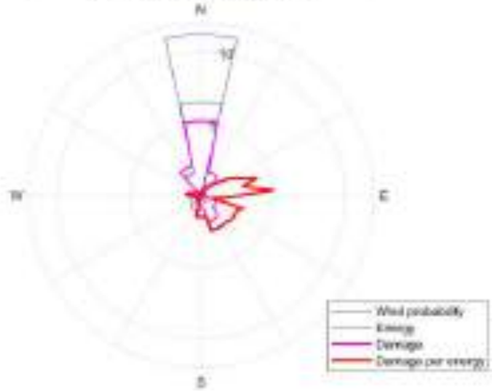
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT05



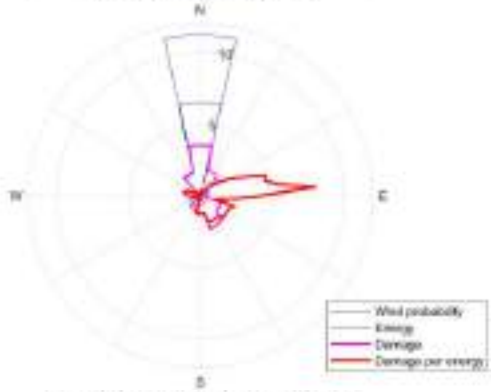
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT05



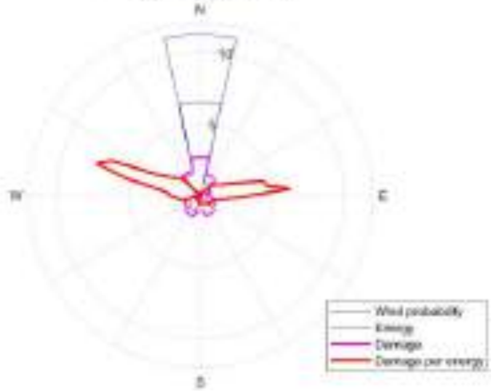
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT05

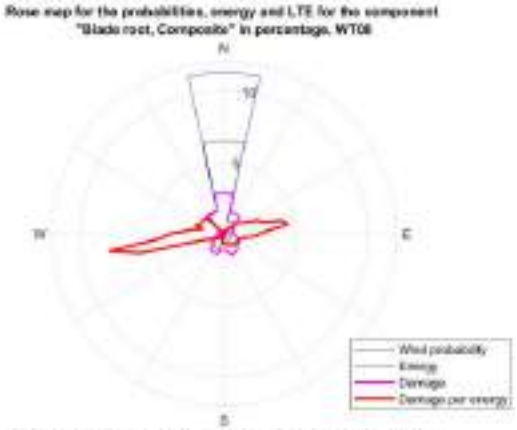


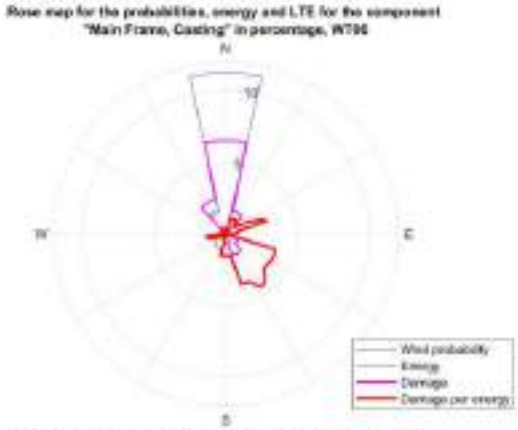
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT05

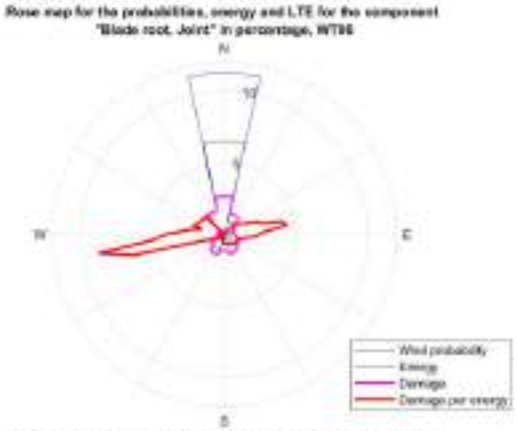


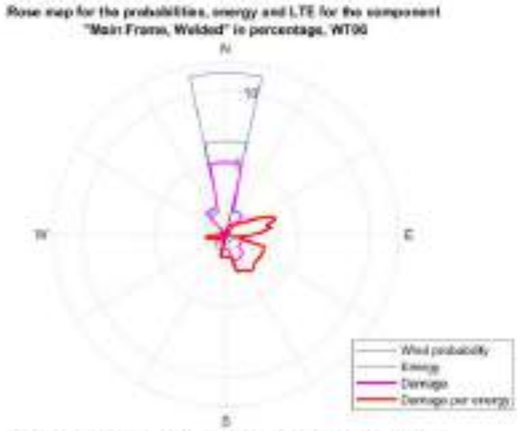
Rose map for the probabilities, energy and LTE in percentage, WT05

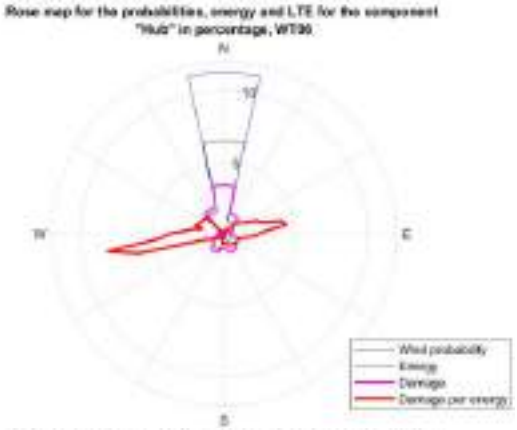


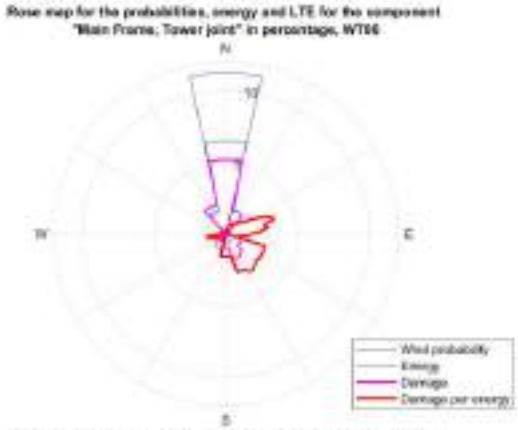

Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT06
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

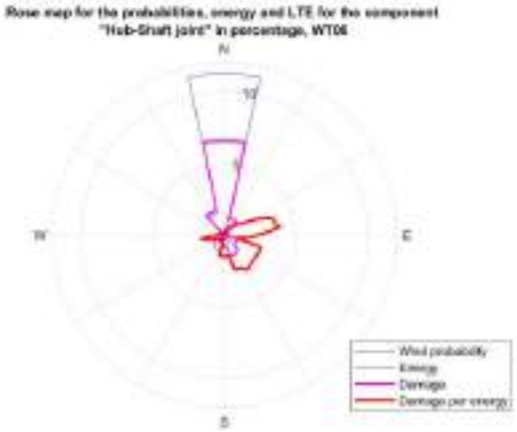

Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT06
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

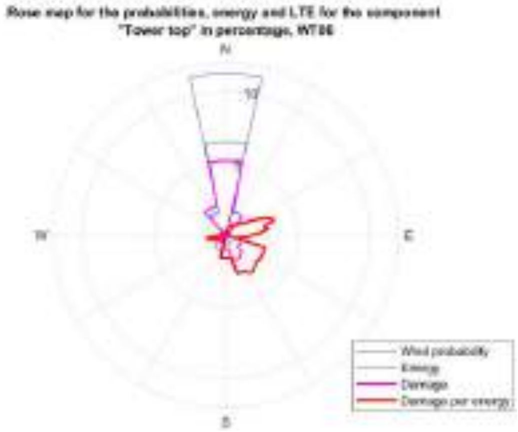

Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT06
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT06
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

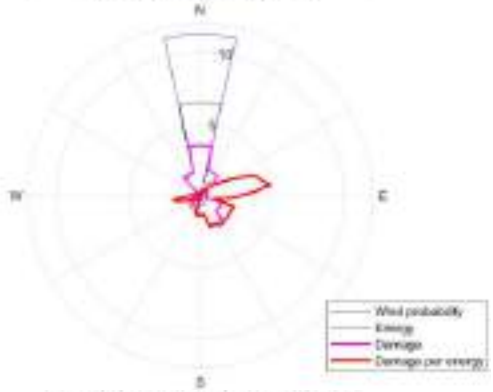

Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT06
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT06
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

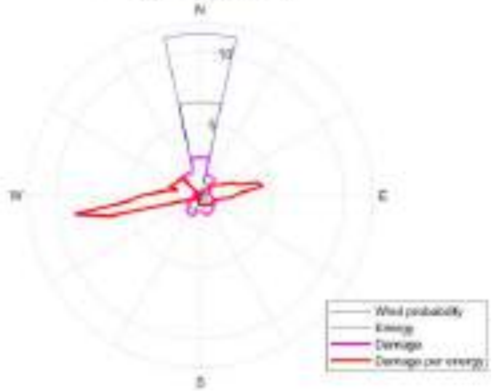

Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT06
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT06
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

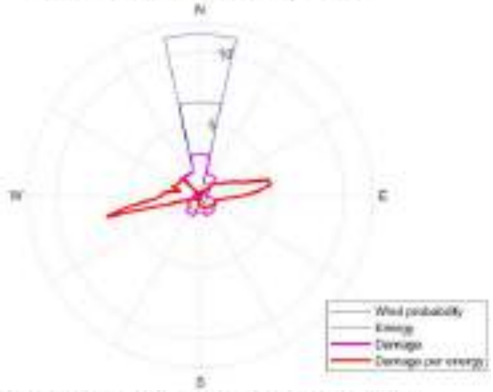
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT06



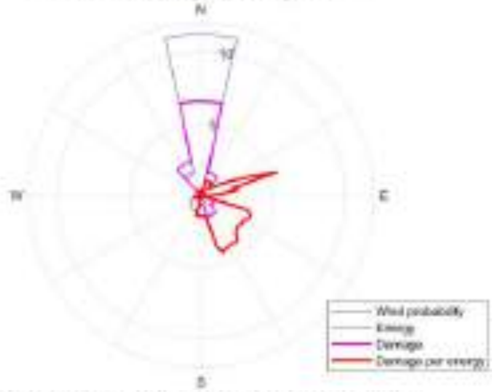
Rose map for the probabilities, energy and LTE in percentage, WT06



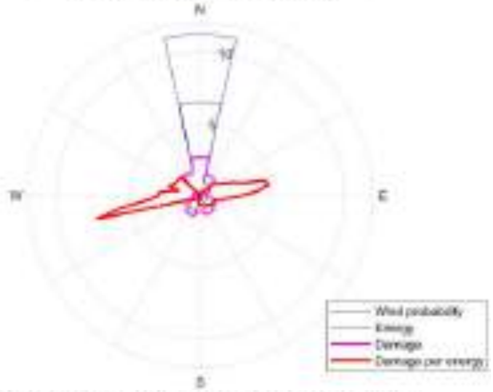
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT07



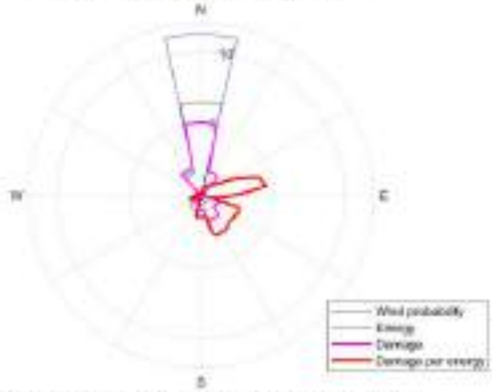
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT07



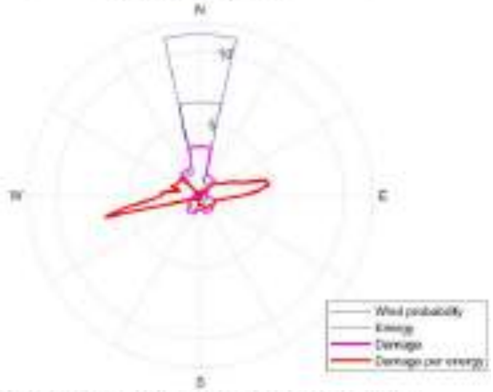
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT07



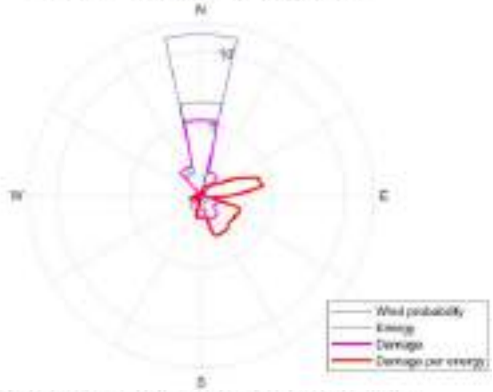
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT07



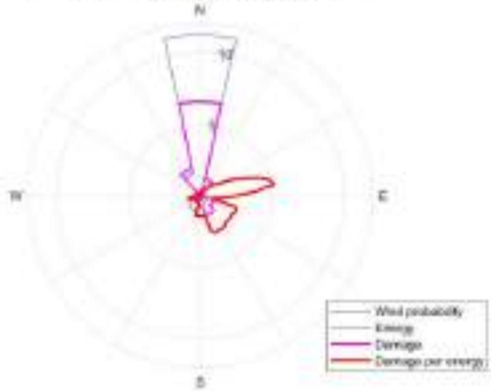
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT07



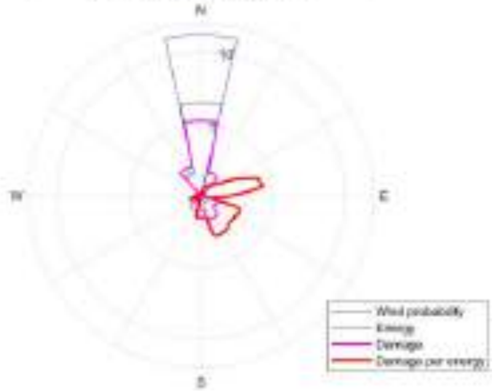
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT07



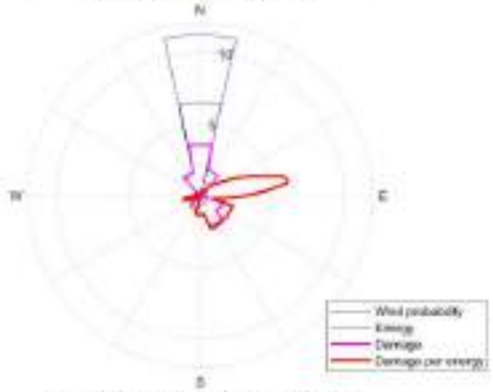
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT07



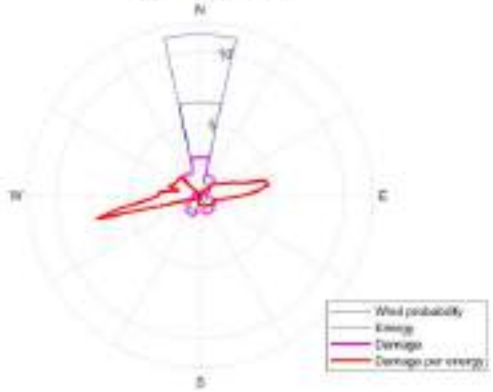
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT07



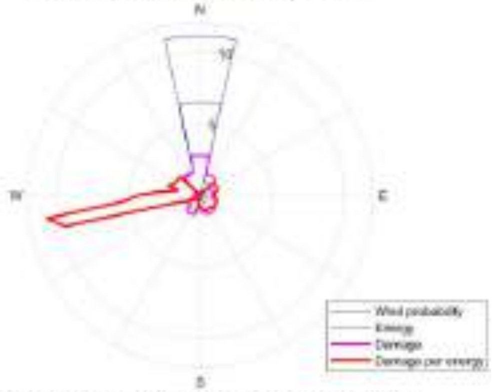
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT07



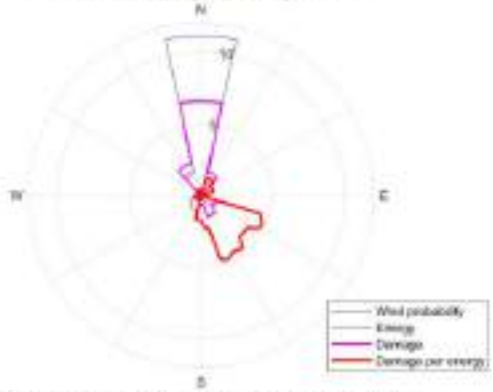
Rose map for the probabilities, energy and LTE in percentage, WT07



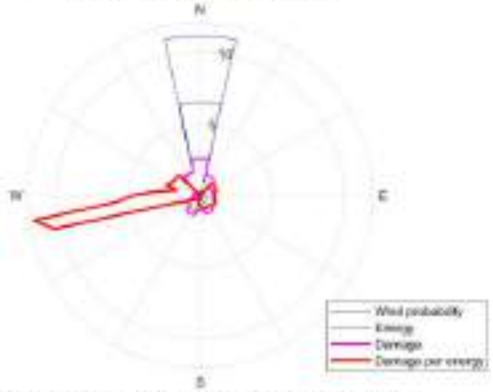
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT08



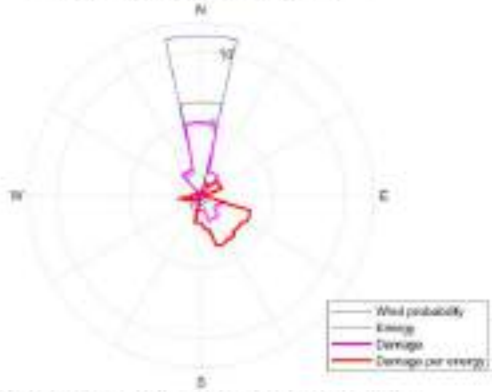
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT08



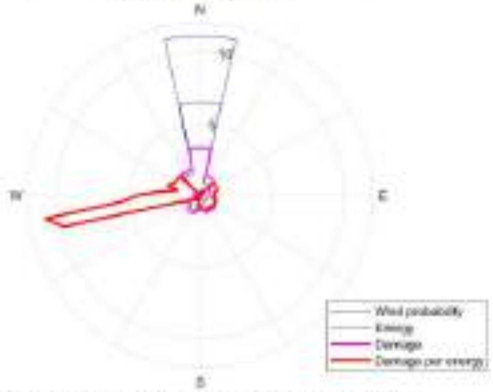
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT08



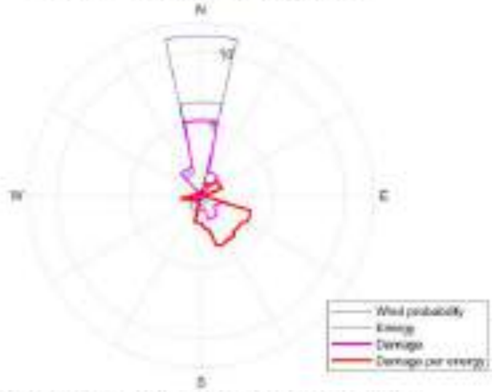
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT08



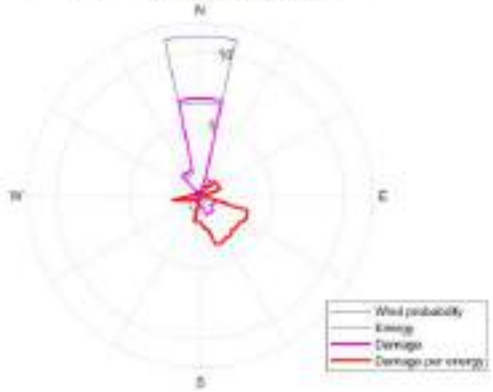
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT08



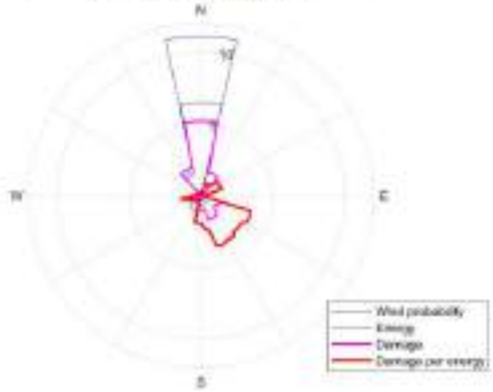
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT08

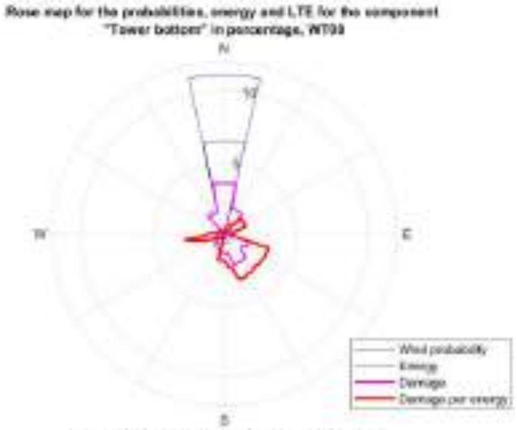


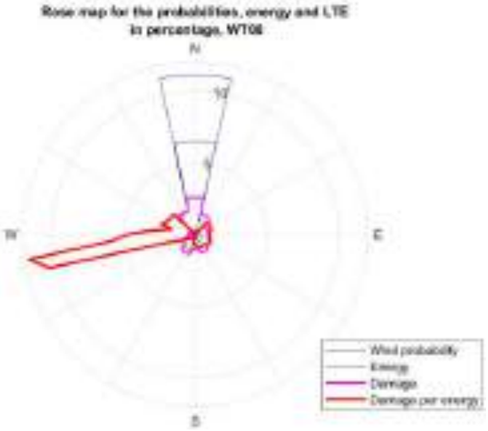
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT08



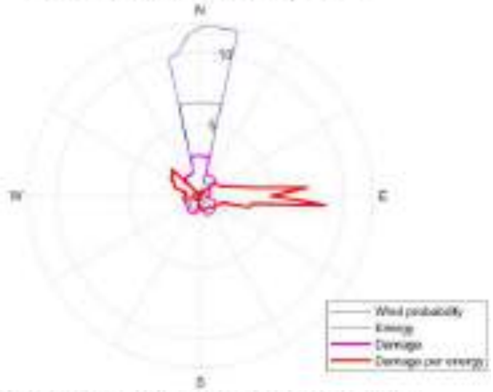
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT08



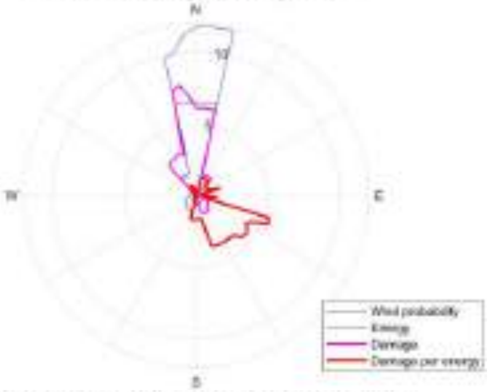

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

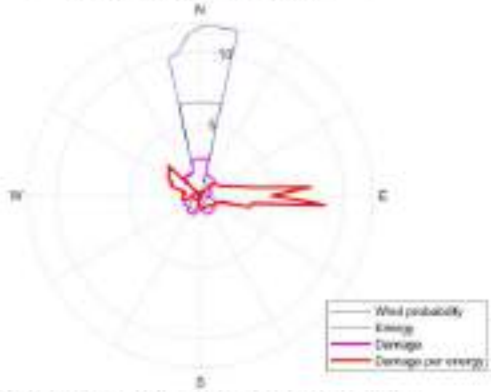
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT08



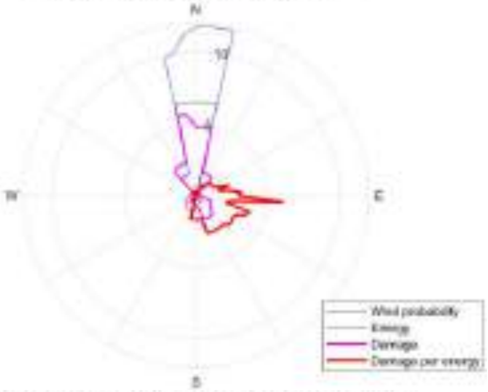
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT09



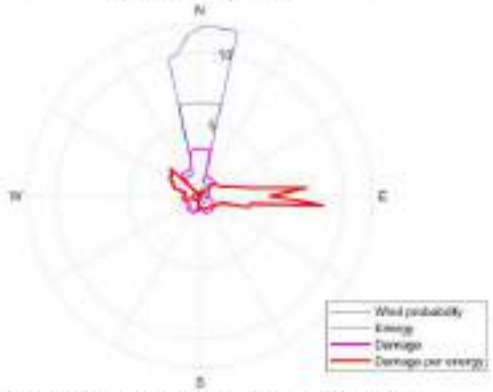
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT09



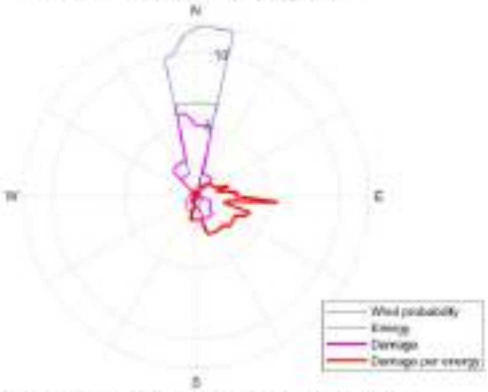
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT09



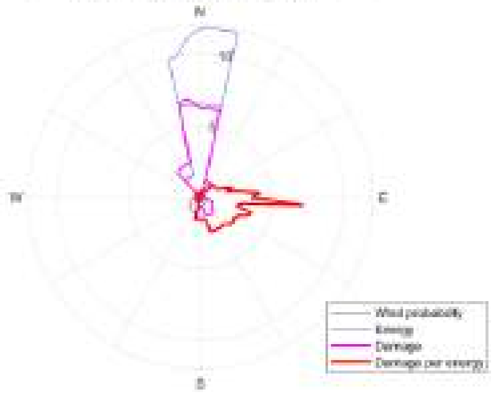
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT09



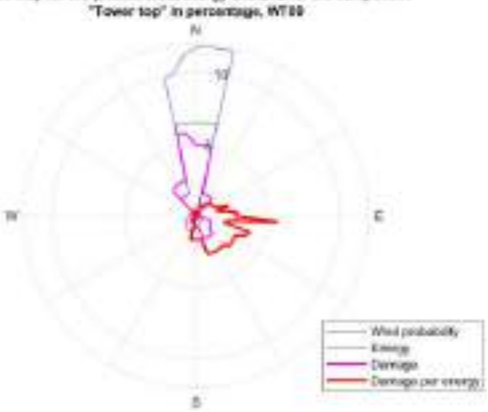
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT09



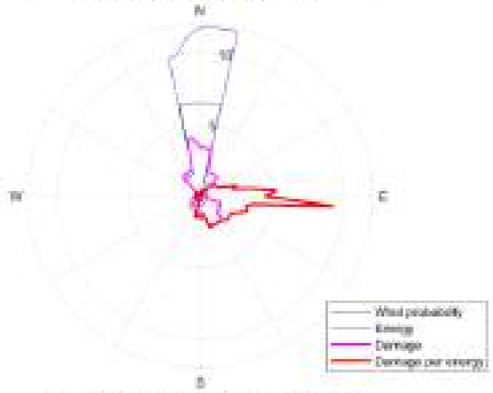
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT09



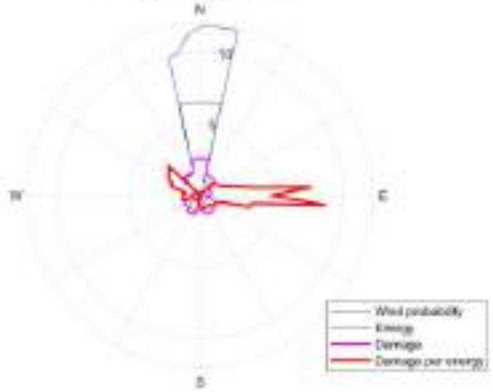
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT09



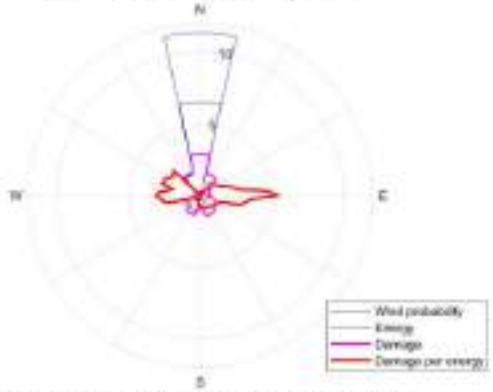
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT08



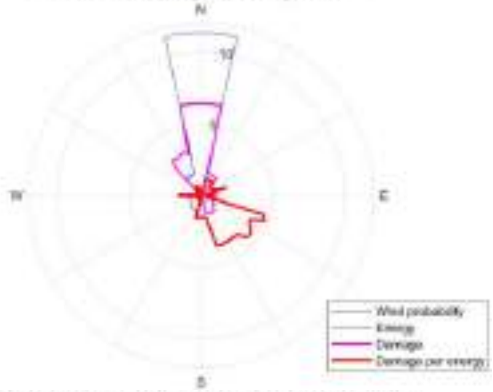
Rose map for the probabilities, energy and LTE in percentage, WT08



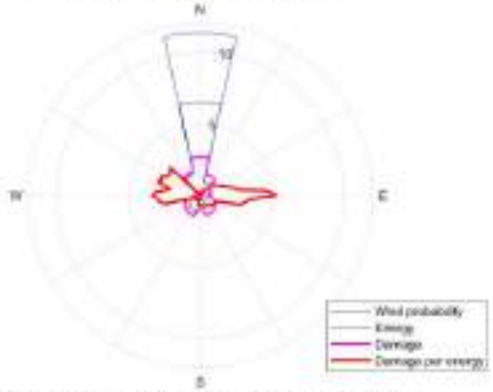
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT10



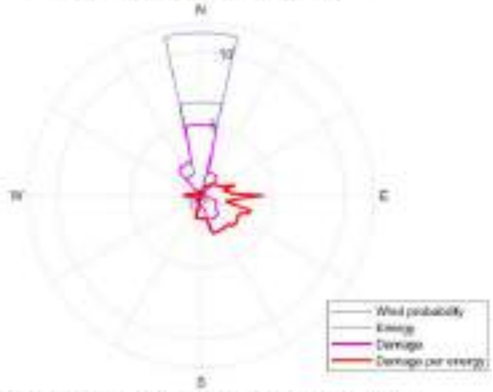
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT10



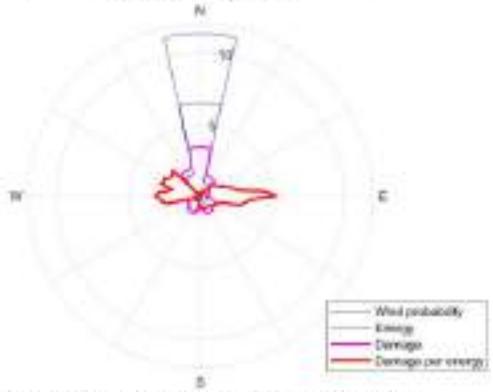
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT10



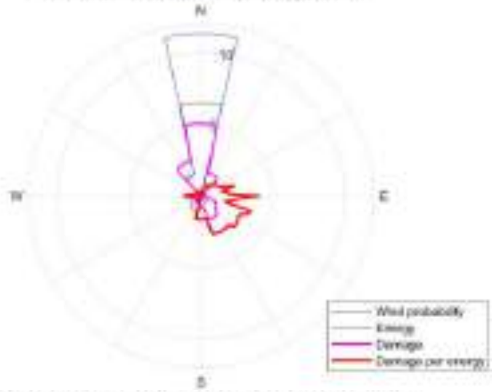
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT10



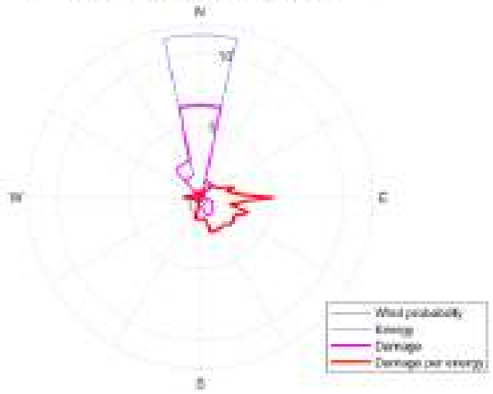
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT10



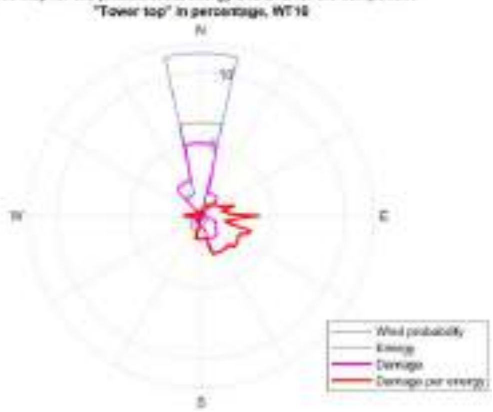
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT10

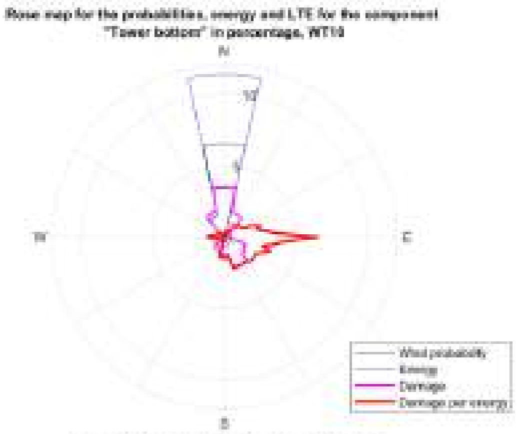


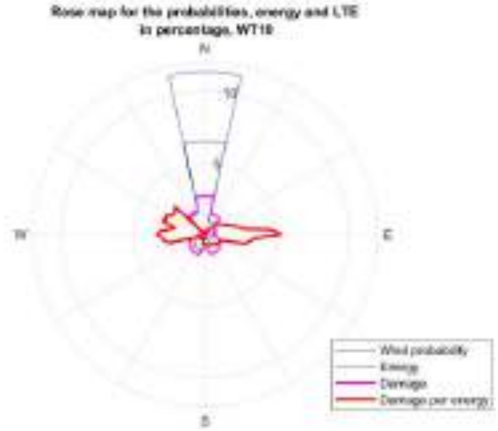
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT10



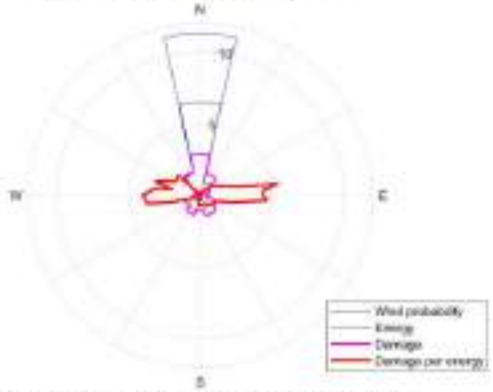
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT10



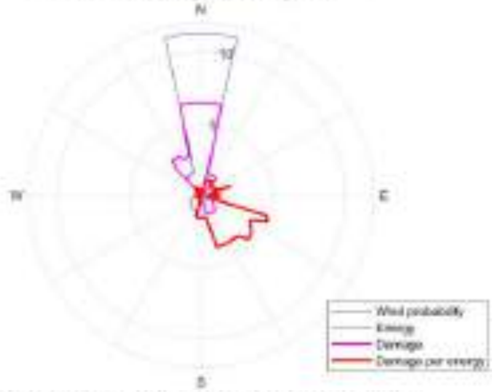

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT10
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT10
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

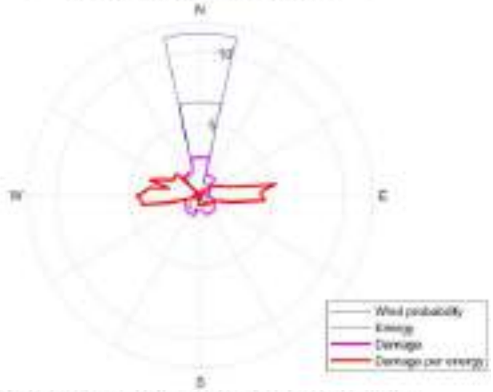
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT11



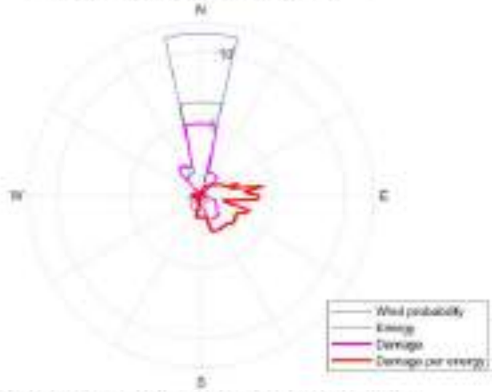
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT11



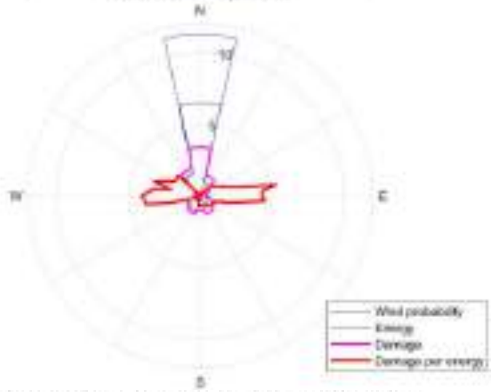
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT11



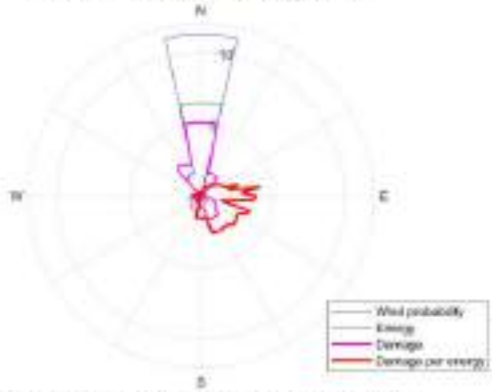
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT11



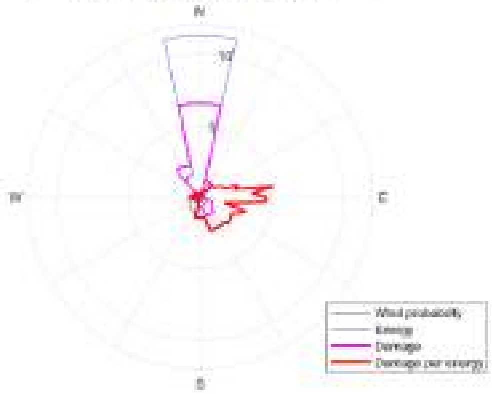
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT11



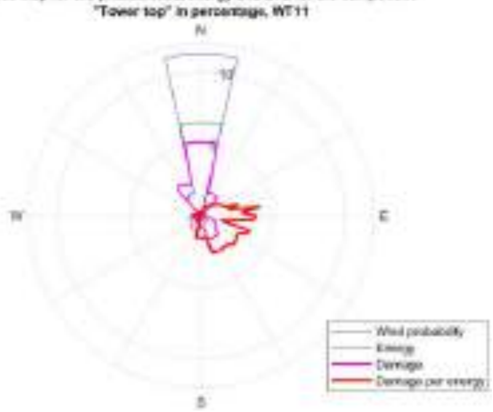
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT11

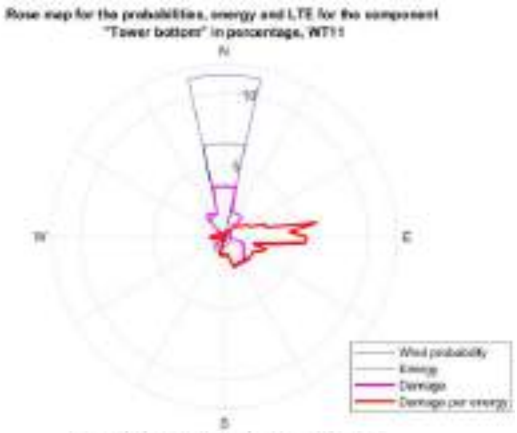


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT11



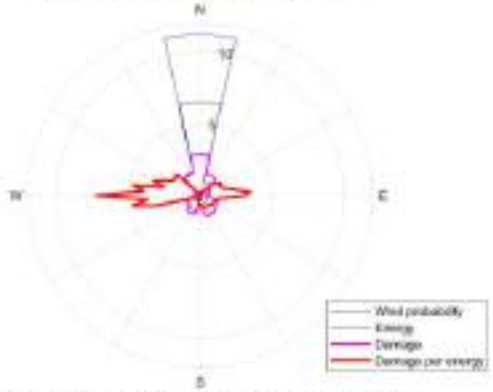
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT11



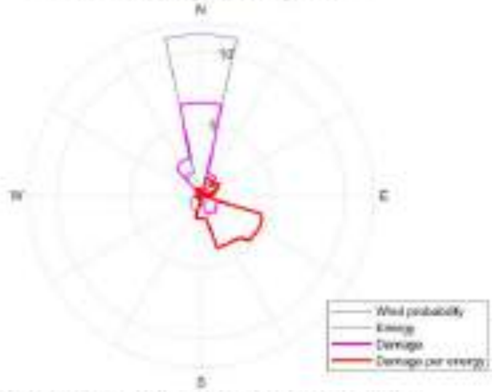

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT11
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT11
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

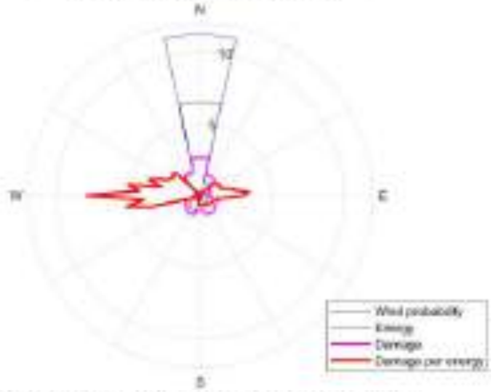
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT12



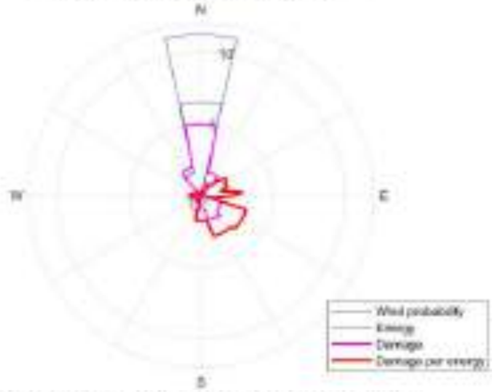
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT12



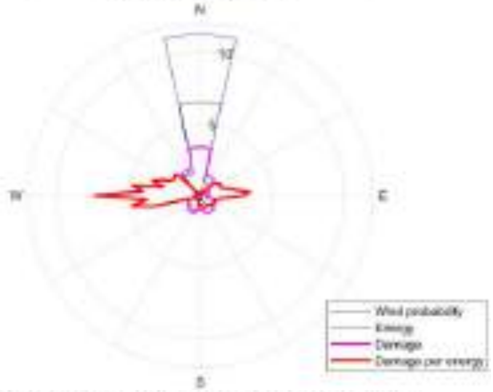
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT12



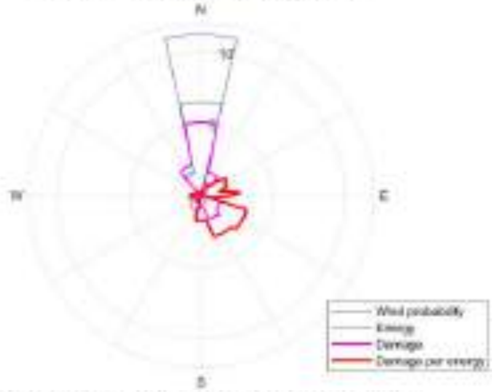
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT12



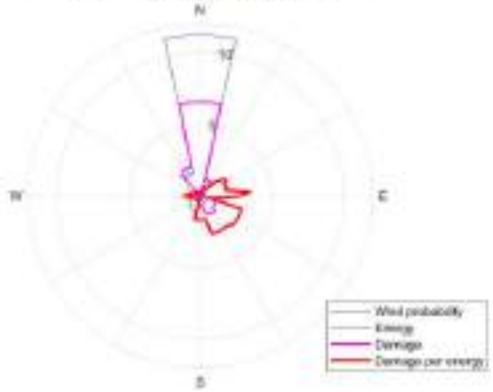
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT12



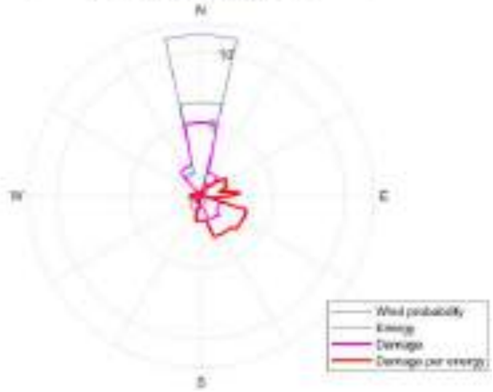
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT12

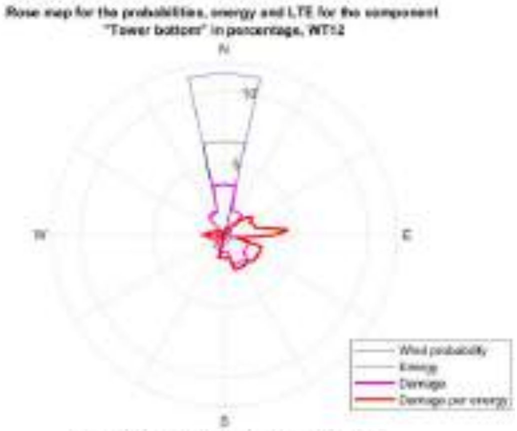


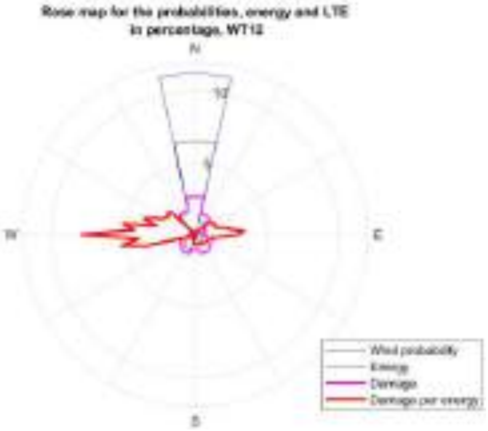
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT12



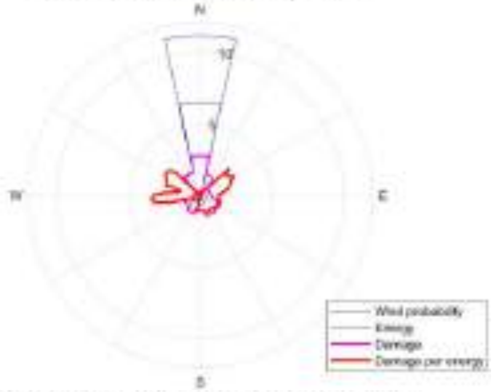
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT12



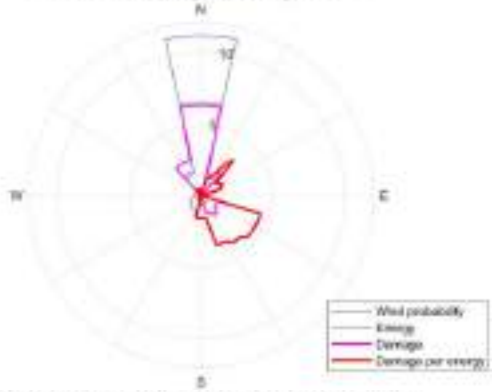

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT12
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT12
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

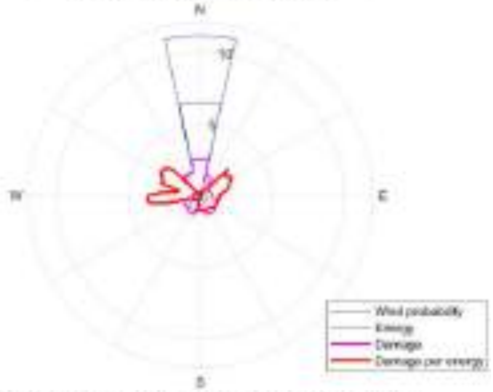
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT13



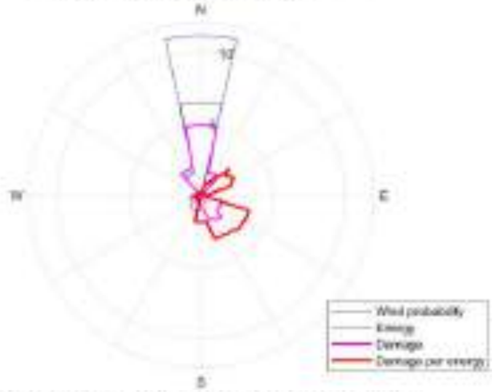
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT13



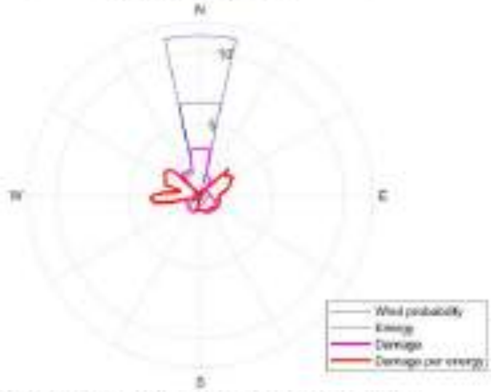
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT13



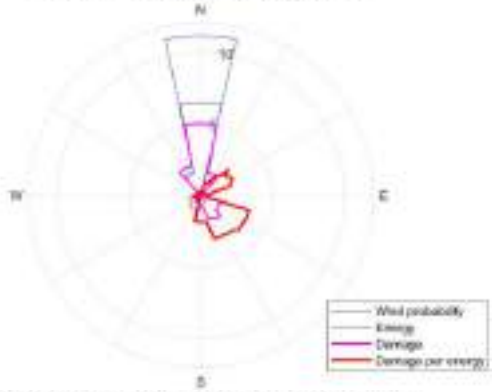
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT13



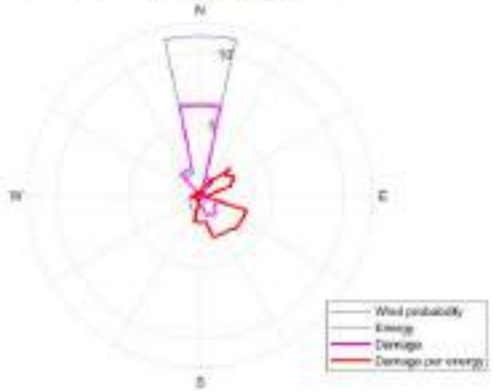
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT13



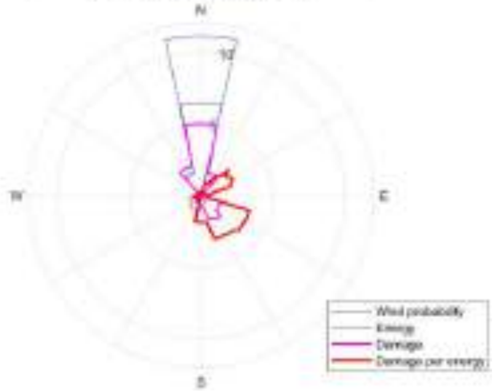
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT13

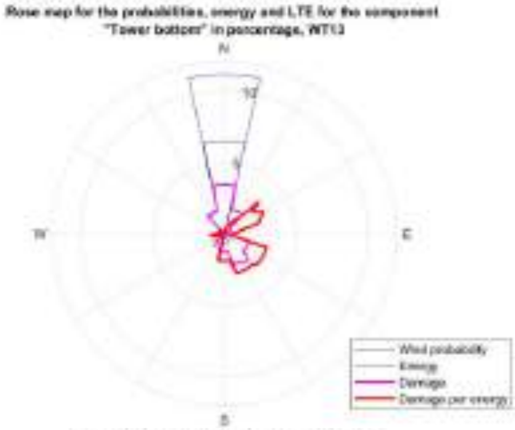


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT13

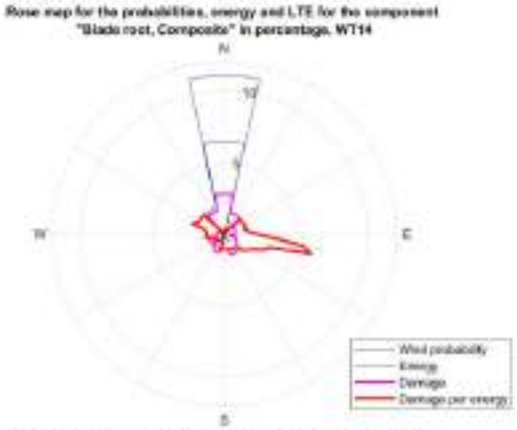


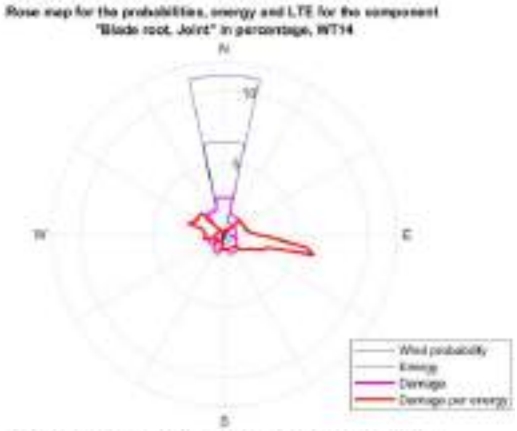
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT13

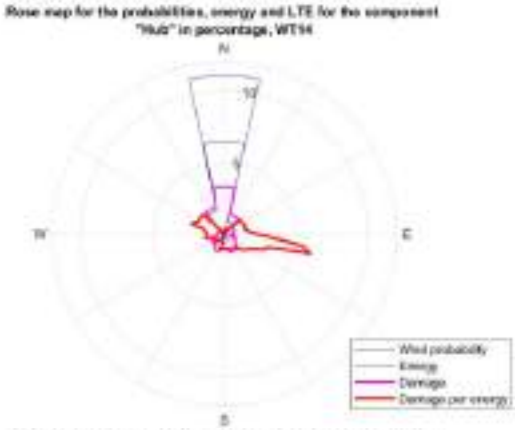


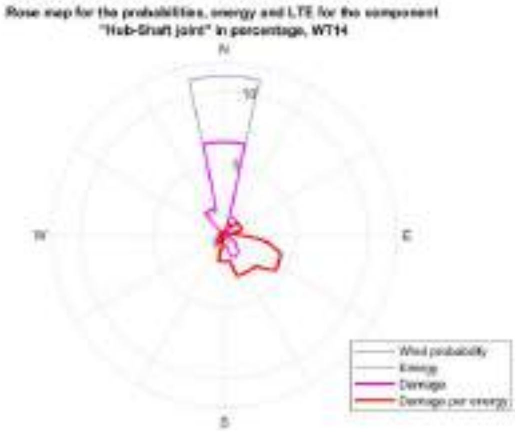

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT13
N
E
S
W
Wind probability
Energy
Damage
Damage per energy

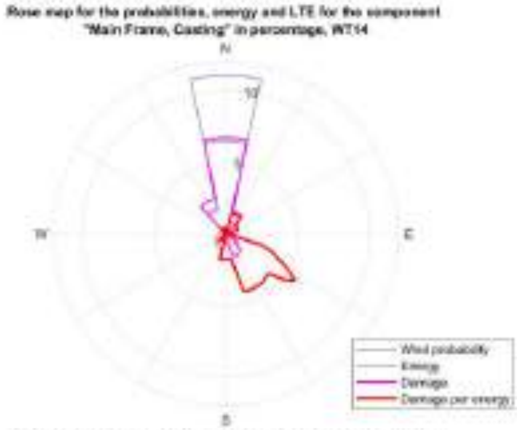

Rose map for the probabilities, energy and LTE
in percentage, WT13
N
E
S
W
Wind probability
Energy
Damage
Damage per energy

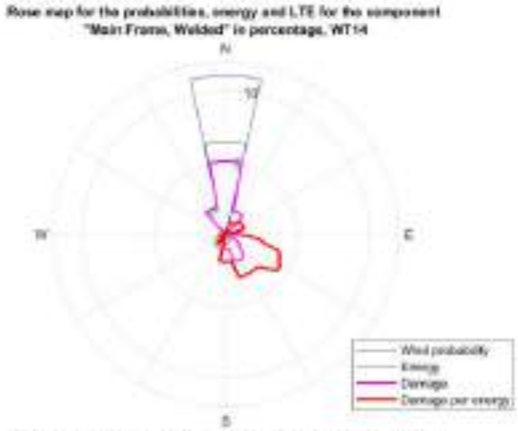

Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT14
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

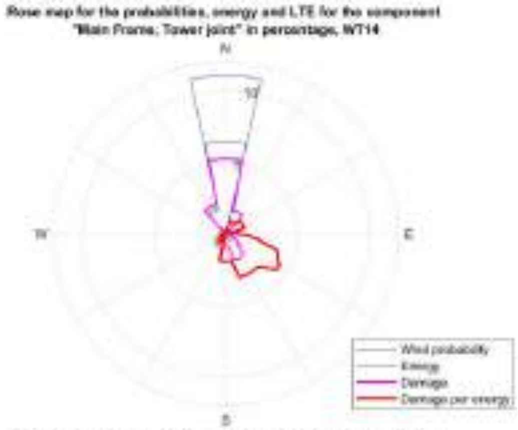

Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT14
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

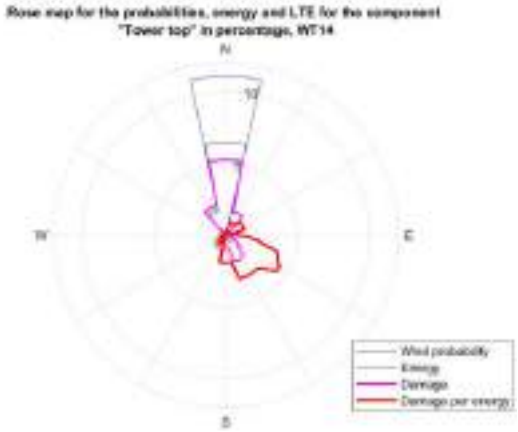

Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT14
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

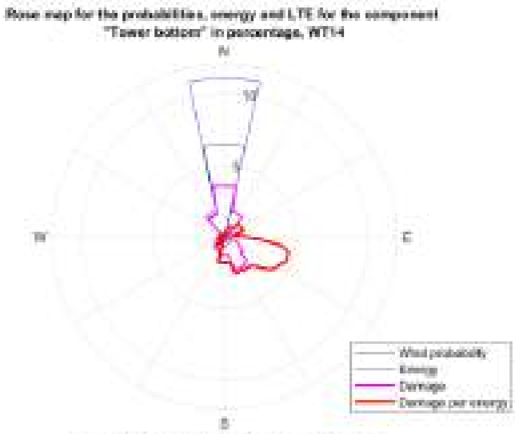

Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT14
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

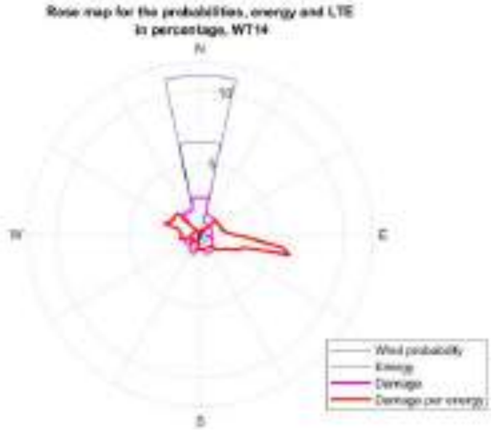

Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT14
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

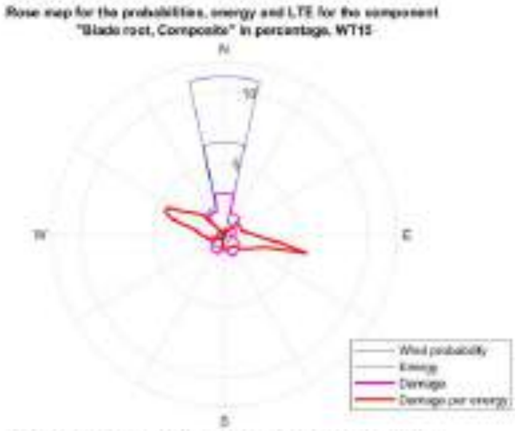

Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT14
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

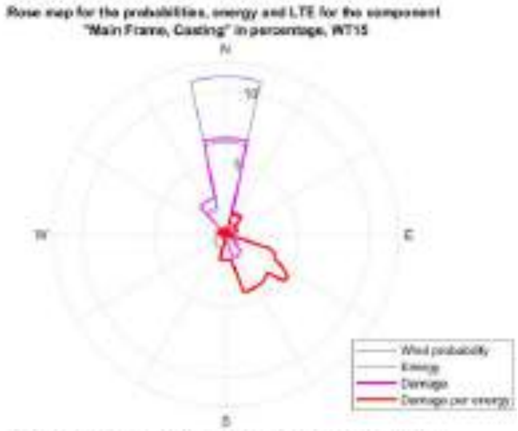

Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT14
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

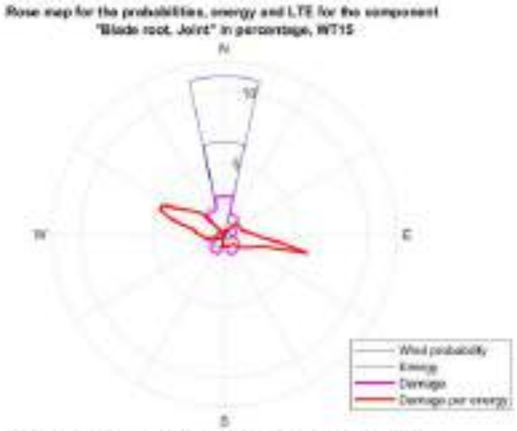

Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT14
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

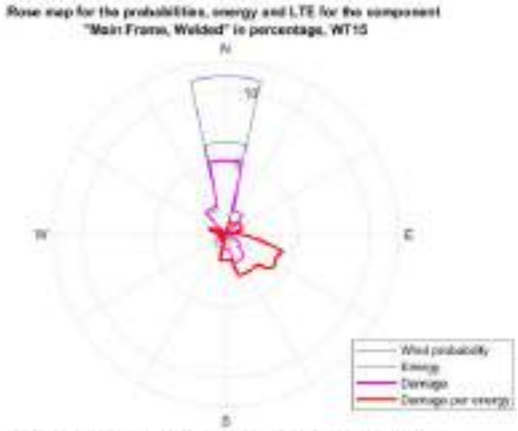

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT14
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

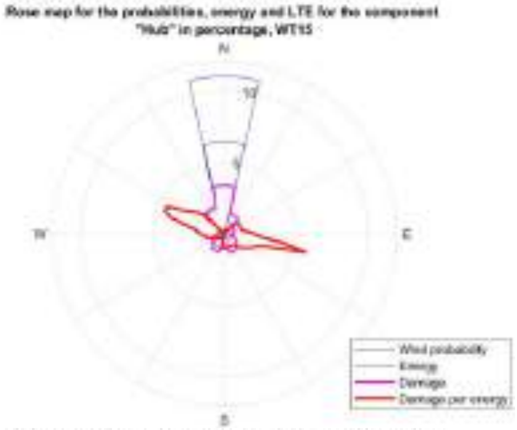

Rose map for the probabilities, energy and LTE
in percentage, WT14
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

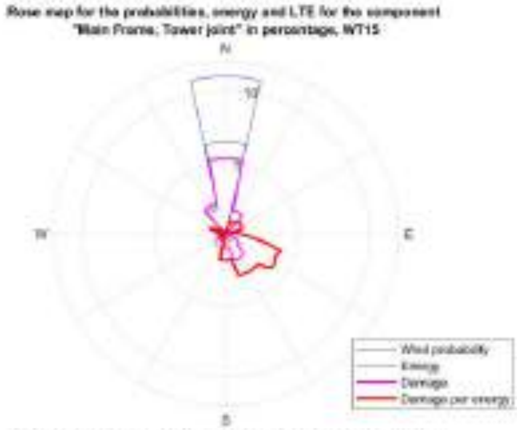

Rose map for the probabilities, energy and LTE for the component
"Blade root, Composite" in percentage, WT15
N
E
S
W
10
Wind probability
Energy
Damage
Damage per energy

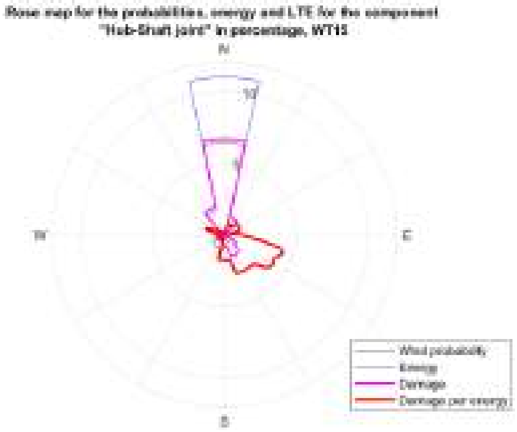

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Casting" in percentage, WT15
N
E
S
W
10
Wind probability
Energy
Damage
Damage per energy

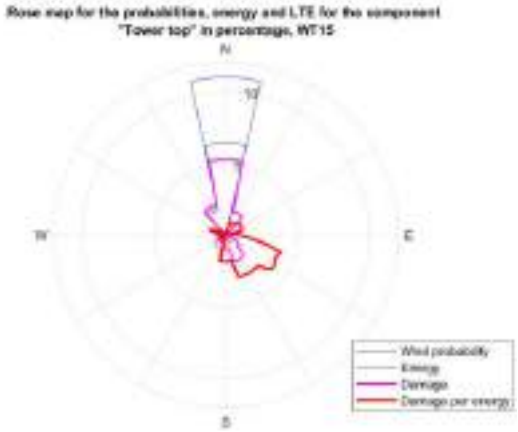

Rose map for the probabilities, energy and LTE for the component
"Blade root, Joint" in percentage, WT15
N
E
S
W
10
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Main Frame, Welded" in percentage, WT15
N
E
S
W
10
Wind probability
Energy
Damage
Damage per energy

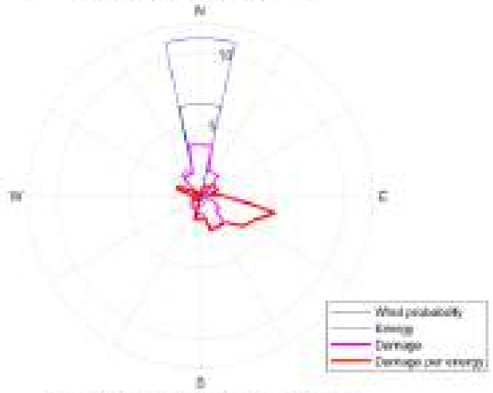

Rose map for the probabilities, energy and LTE for the component
"Hub" in percentage, WT15
N
E
S
W
10
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Main Frame, Tower joint" in percentage, WT15
N
E
S
W
10
Wind probability
Energy
Damage
Damage per energy

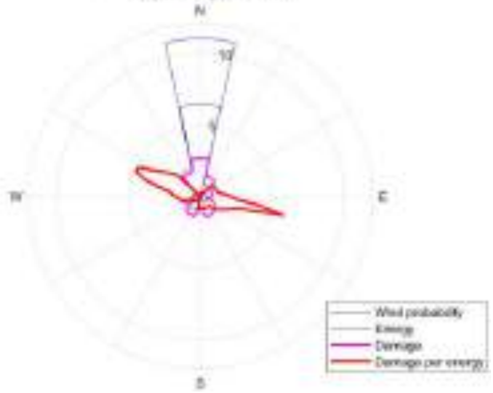

Rose map for the probabilities, energy and LTE for the component
"Hub-Shaft joint" in percentage, WT15
N
E
S
W
10
Wind probability
Energy
Damage
Damage per energy

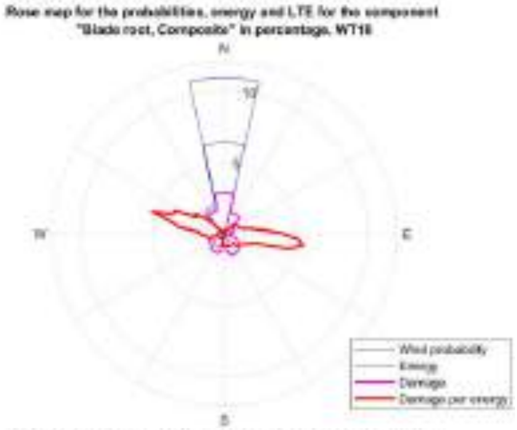

Rose map for the probabilities, energy and LTE for the component
"Tower top" in percentage, WT15
N
E
S
W
10
Wind probability
Energy
Damage
Damage per energy

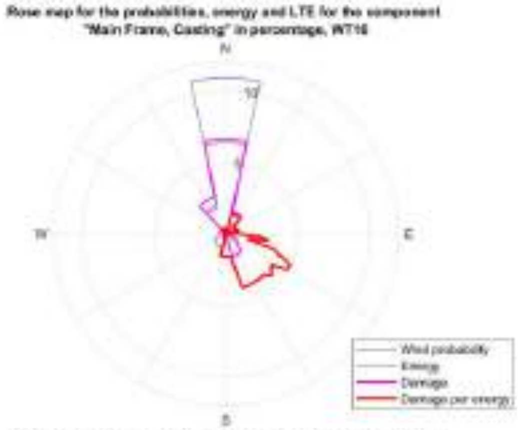
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT15

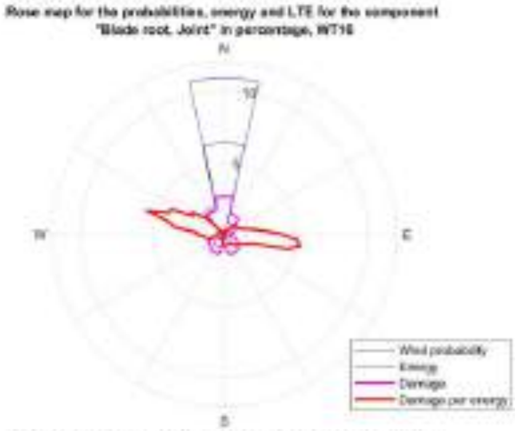


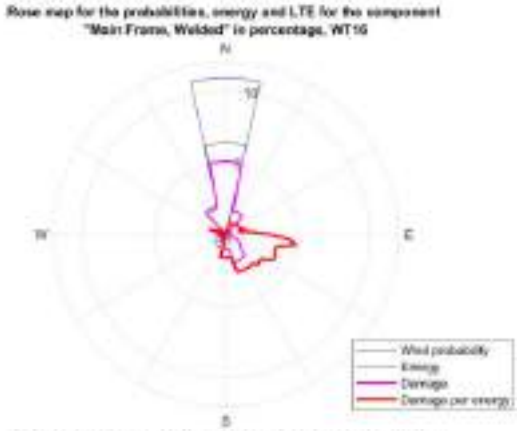
Rose map for the probabilities, energy and LTE in percentage, WT15

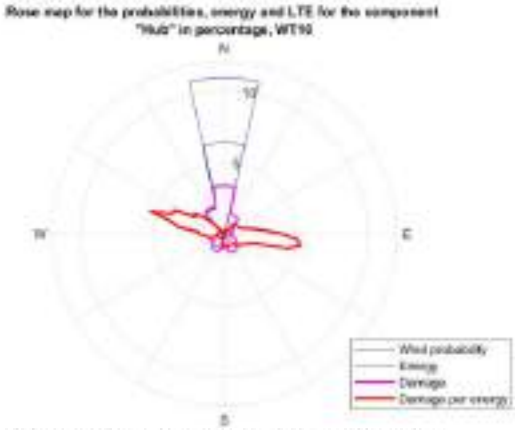


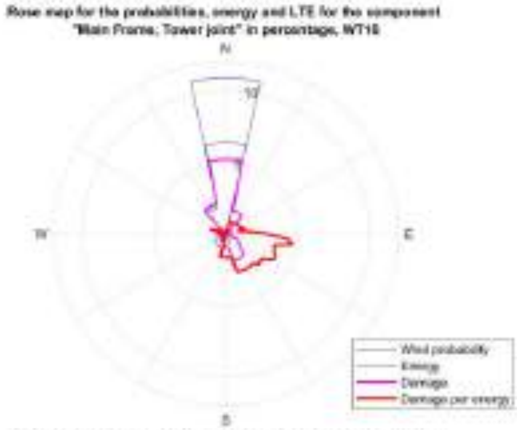

Rose map for the probabilities, energy and LTE for the component
"Blade root, Composite" in percentage, WT16
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

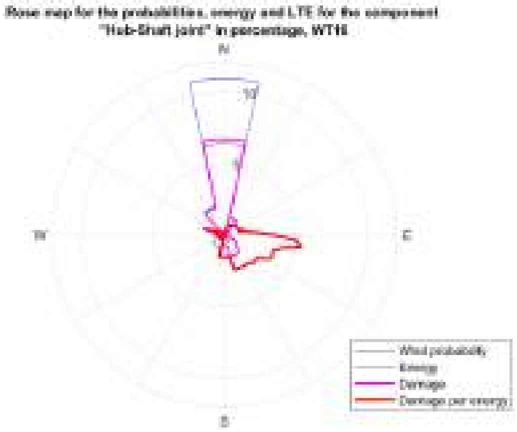

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Casting" in percentage, WT16
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

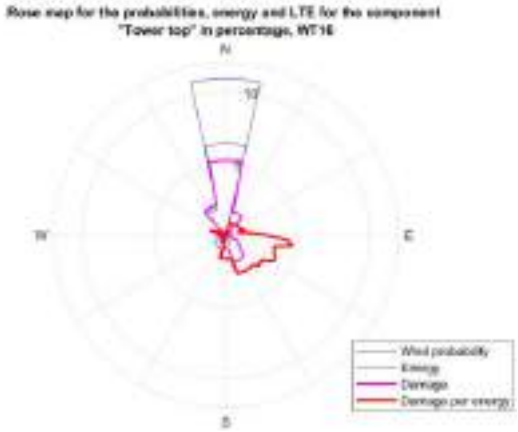

Rose map for the probabilities, energy and LTE for the component
"Blade root, Joint" in percentage, WT16
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

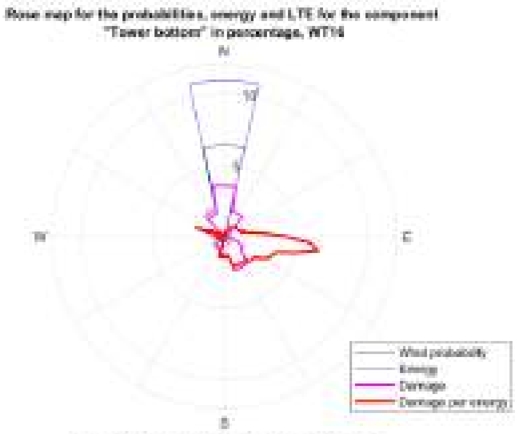

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Welded" in percentage, WT16
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy

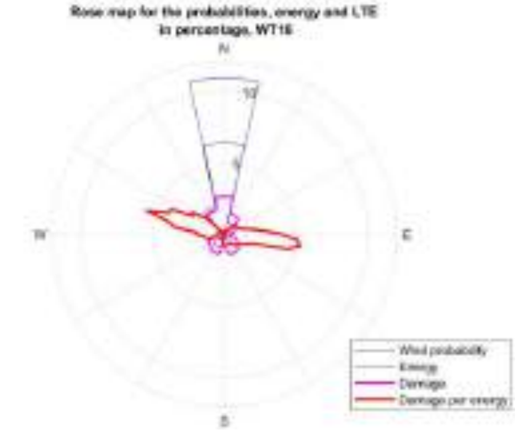

Rose map for the probabilities, energy and LTE for the component
"Hub" in percentage, WT16
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

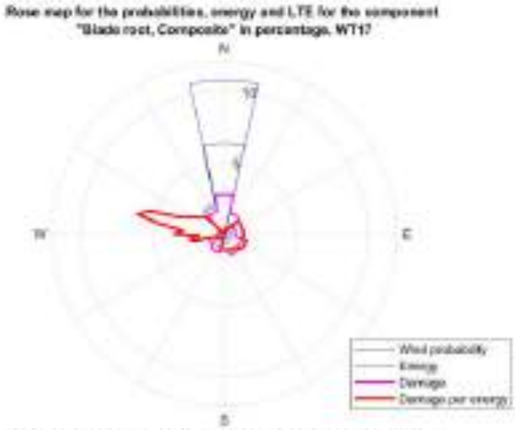

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Tower joint" in percentage, WT16
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy

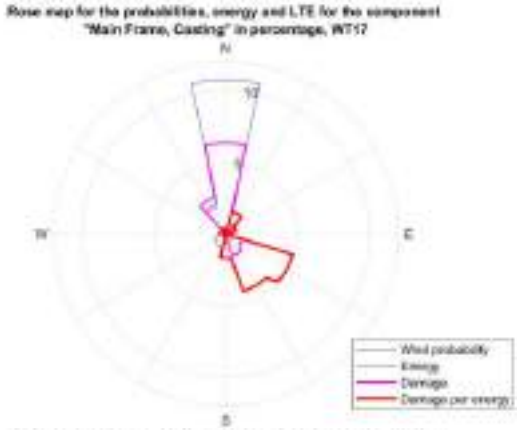

Rose map for the probabilities, energy and LTE for the component
"Hub-Shaft joint" in percentage, WT16
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Tower top" in percentage, WT16
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy

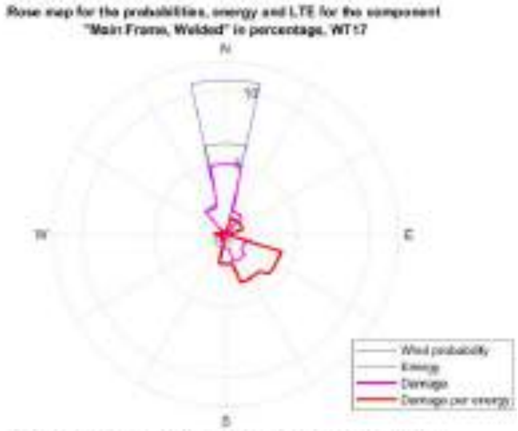

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT16
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

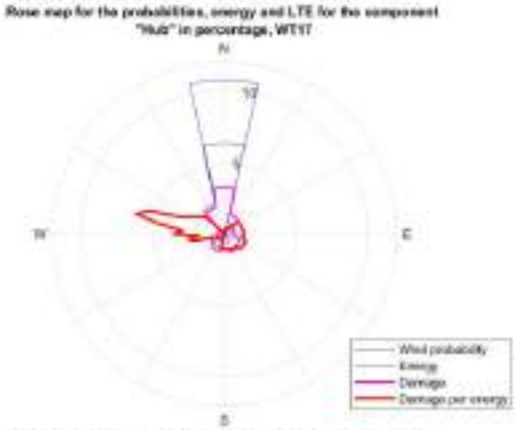

Rose map for the probabilities, energy and LTE in percentage, WT16
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

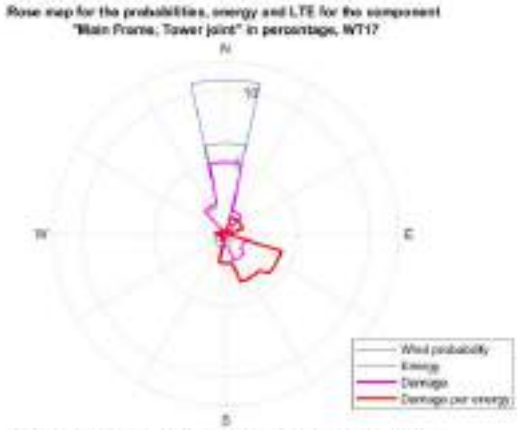

Rose map for the probabilities, energy and LTE for the component
"Blade root, Composite" in percentage, WT17
N
12
W
E
S
Wind probability
Energy
Damage
Damage per energy

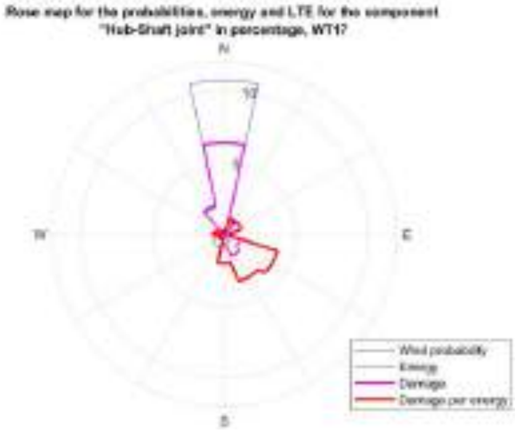

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Casting" in percentage, WT17
N
12
W
E
S
Wind probability
Energy
Damage
Damage per energy

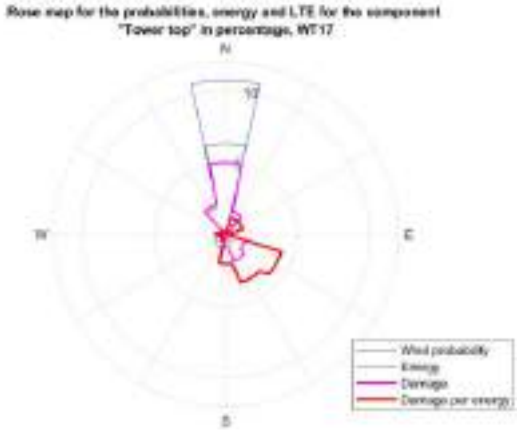

Rose map for the probabilities, energy and LTE for the component
"Blade root, Joint" in percentage, WT17
N
12
W
E
S
Wind probability
Energy
Damage
Damage per energy

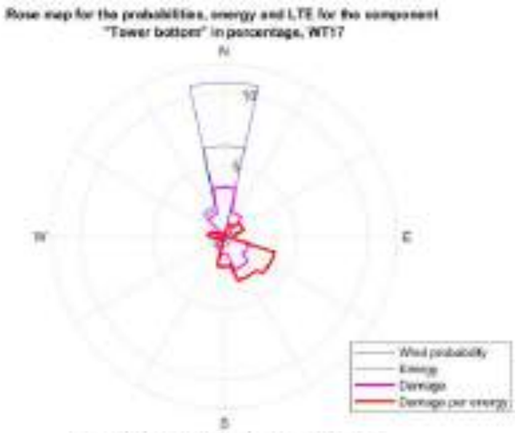

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Welded" in percentage, WT17
N
12
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Hub" in percentage, WT17
N
12
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Main Frame; Tower joint" in percentage, WT17
N
12
W
E
S
Wind probability
Energy
Damage
Damage per energy

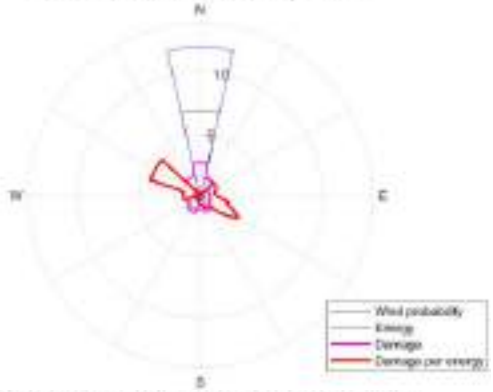

Rose map for the probabilities, energy and LTE for the component
"Hub-Shaft joint" in percentage, WT17
N
12
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Tower top" in percentage, WT17
N
12
W
E
S
Wind probability
Energy
Damage
Damage per energy

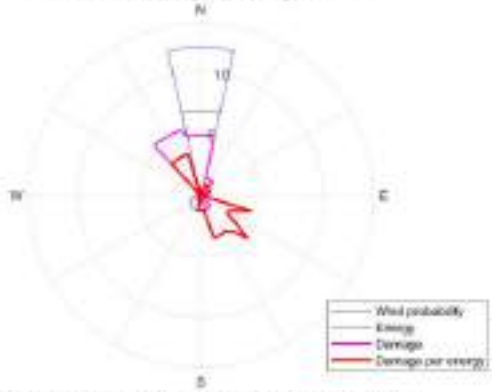

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT17
N
12
6
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT17
N
12
6
W
E
S
Wind probability
Energy
Damage
Damage per energy

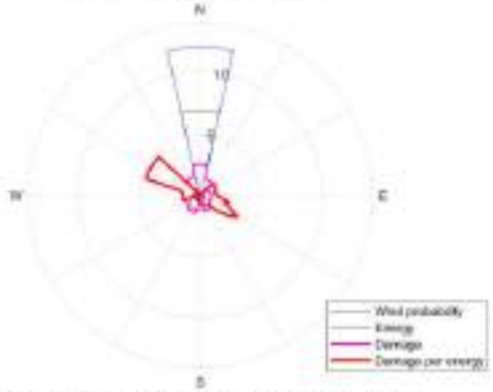
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT18



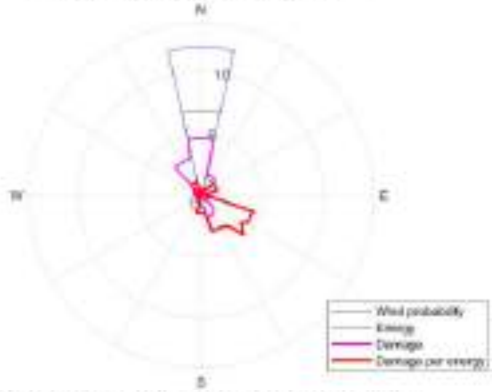
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT18



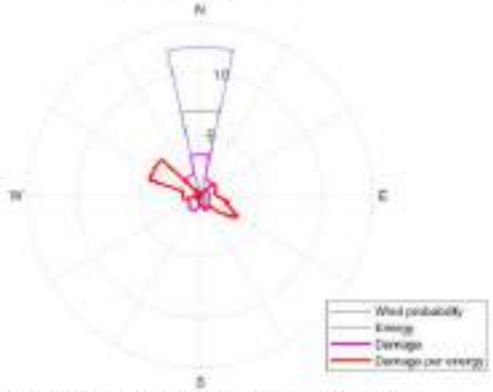
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT18



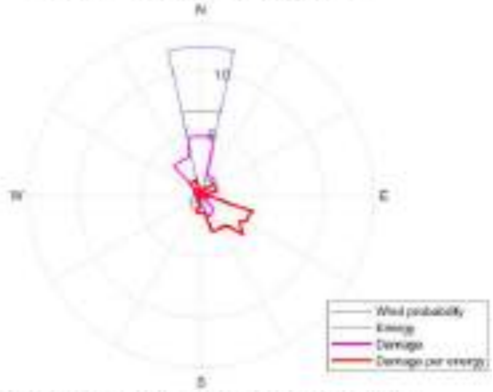
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT18



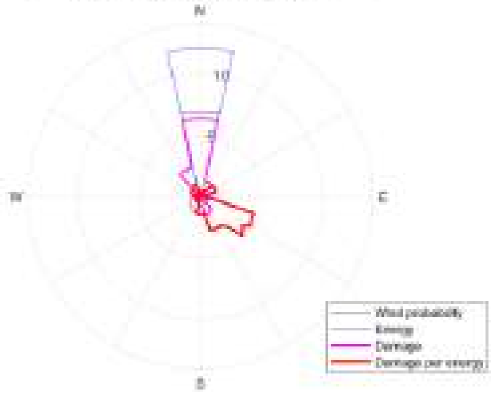
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT18



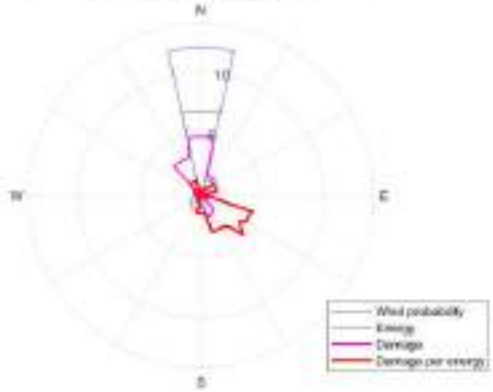
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT18



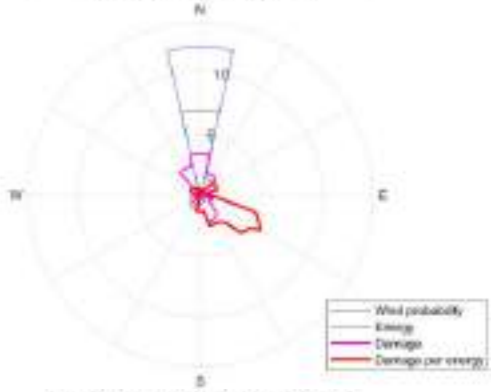
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT18



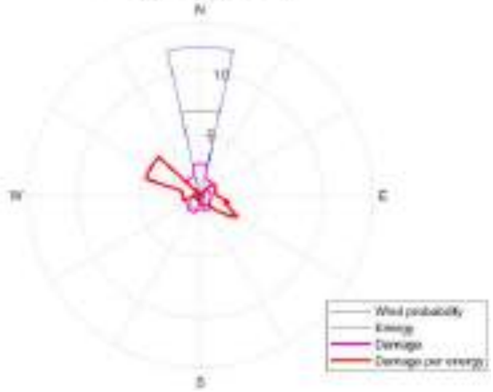
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT18



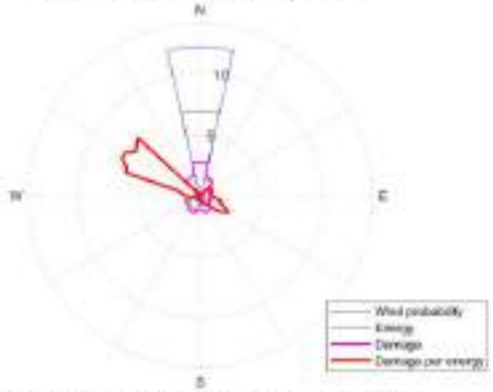
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT18



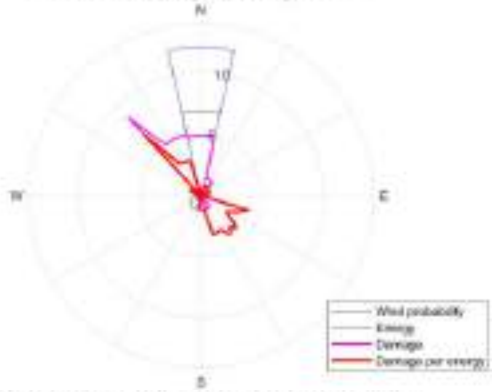
Rose map for the probabilities, energy and LTE in percentage, WT18



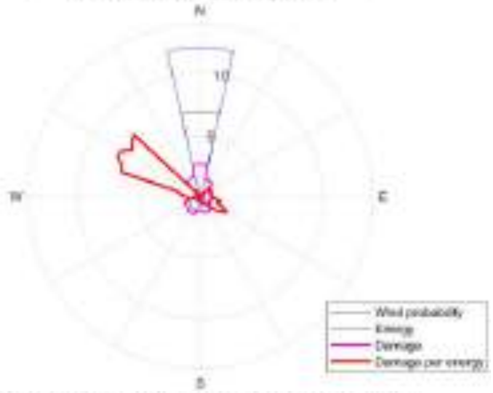
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT19



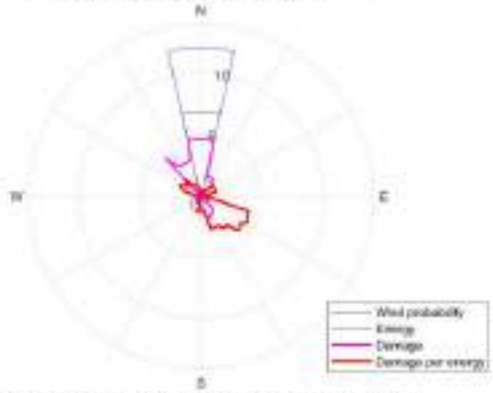
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT19



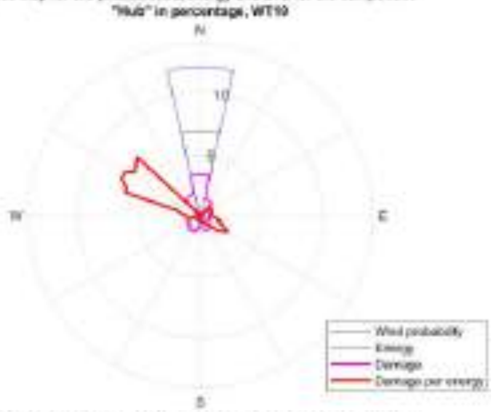
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT19



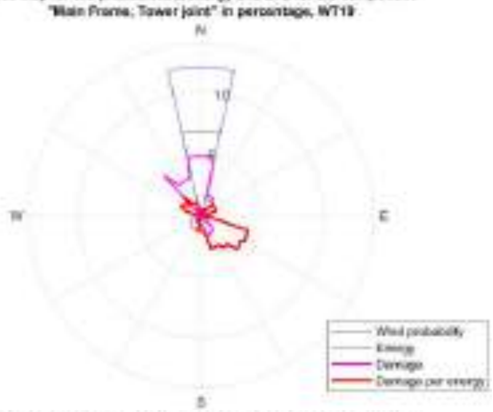
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT19



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT19

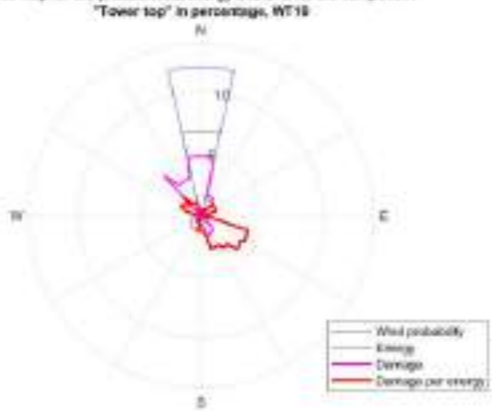


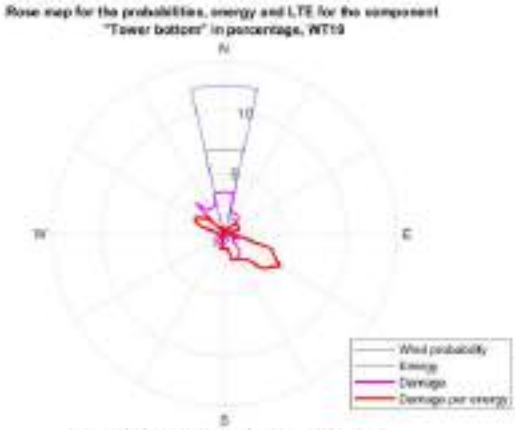
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT19

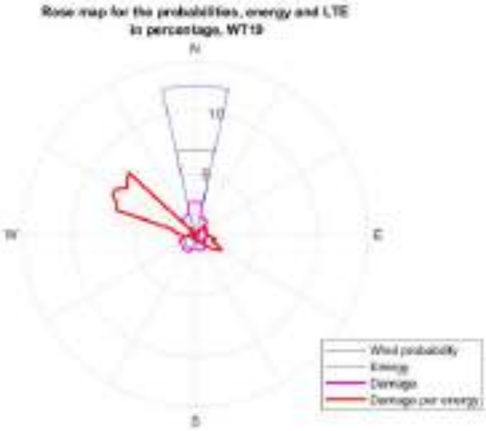


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT19

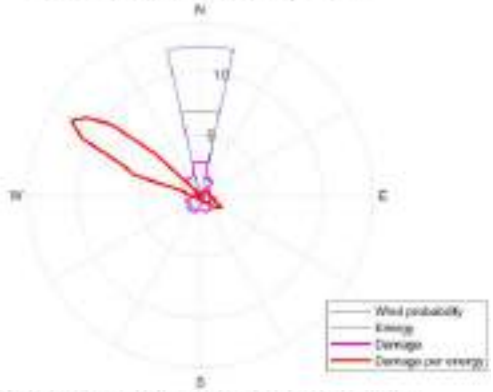
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT19



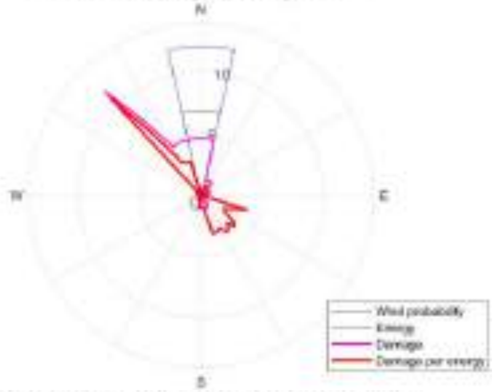

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT19
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT19
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

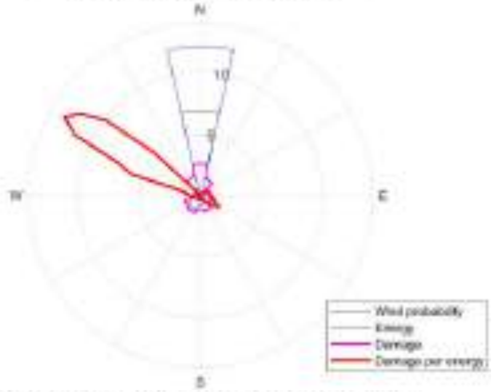
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT20



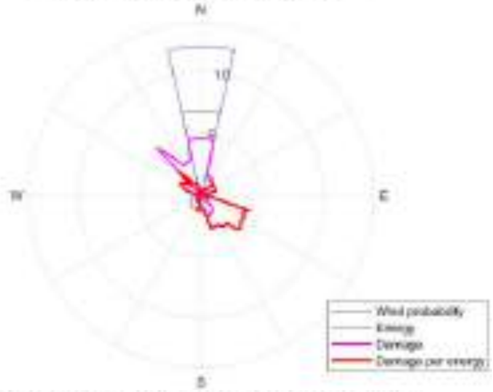
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT20



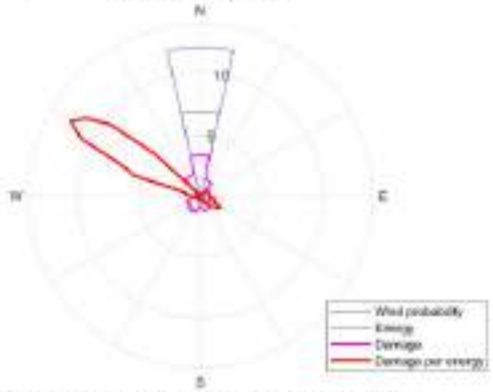
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT20



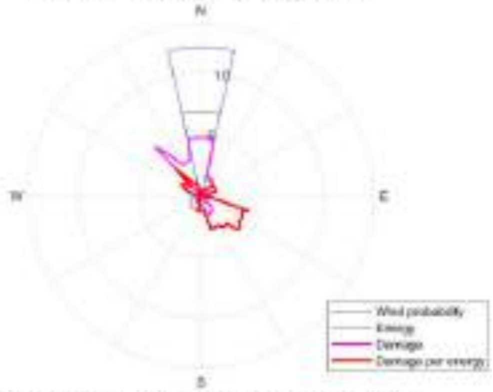
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT20



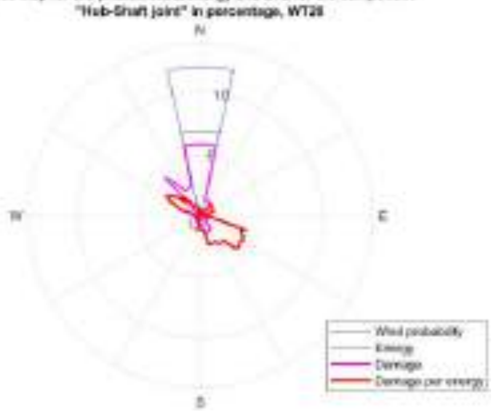
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT20



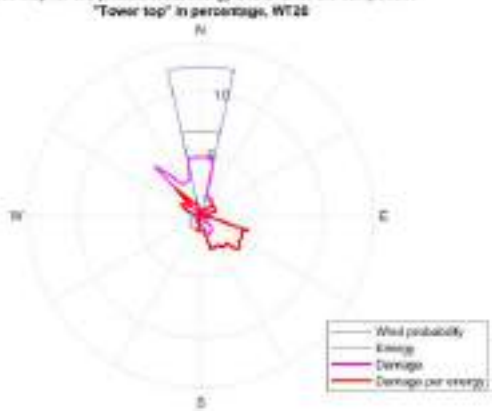
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT20



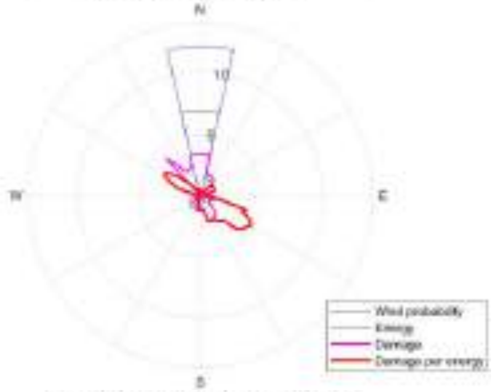
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT20



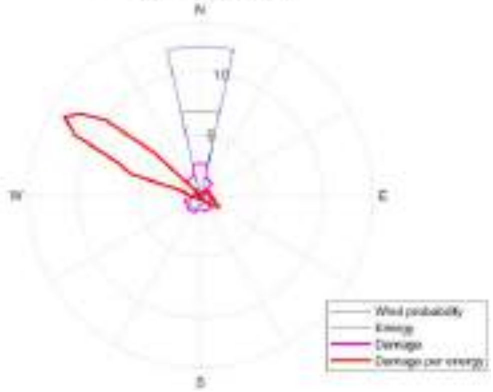
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT20

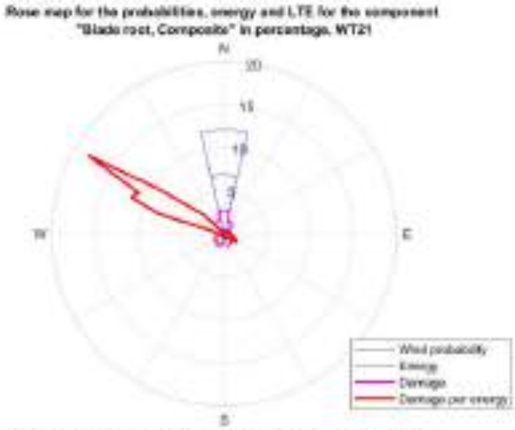


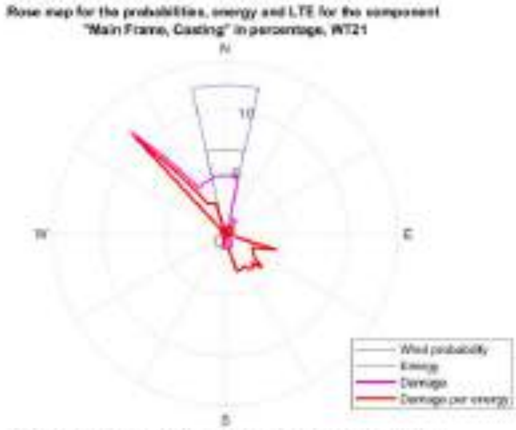
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT20

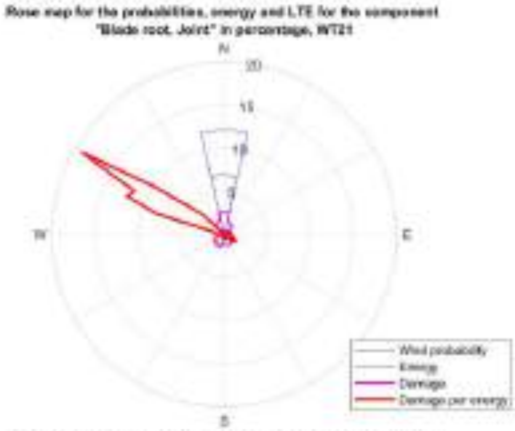


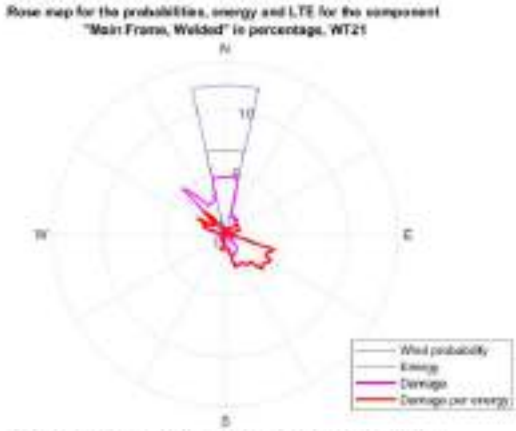
Rose map for the probabilities, energy and LTE in percentage, WT20

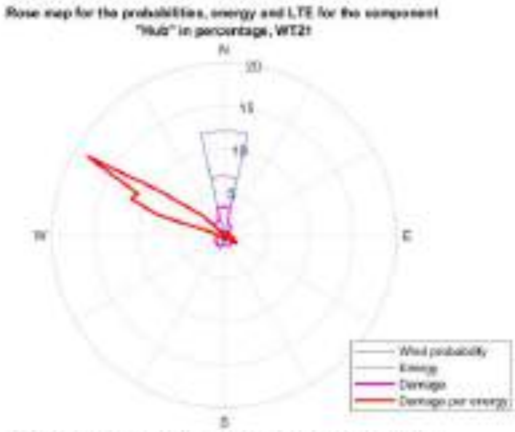


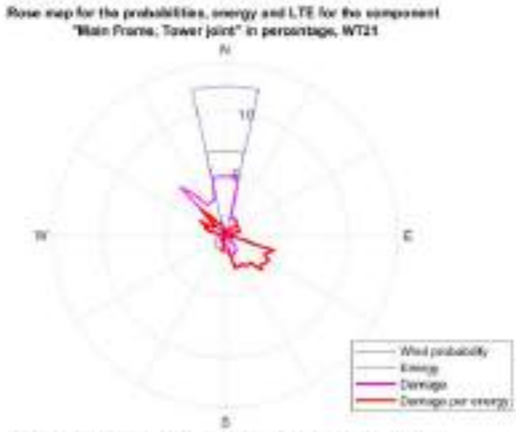

Rose map for the probabilities, energy and LTE for the component
"Blade root, Composite" in percentage, WT21
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

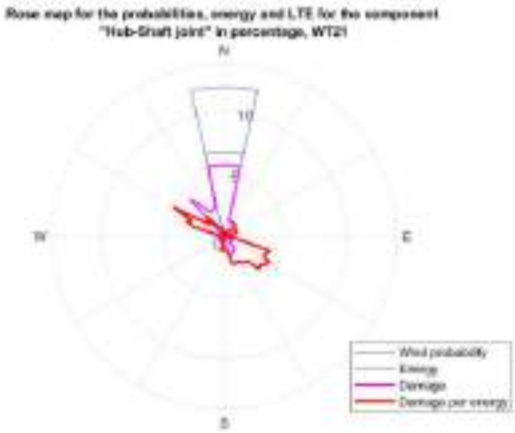

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Casting" in percentage, WT21
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

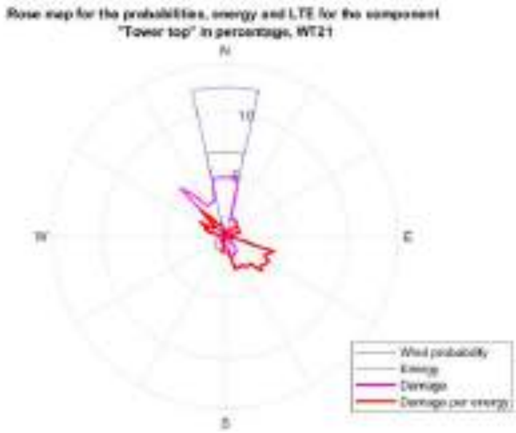

Rose map for the probabilities, energy and LTE for the component
"Blade root, Joint" in percentage, WT21
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

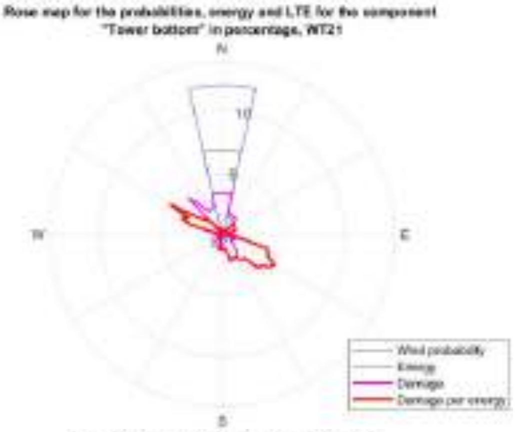

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Welded" in percentage, WT21
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

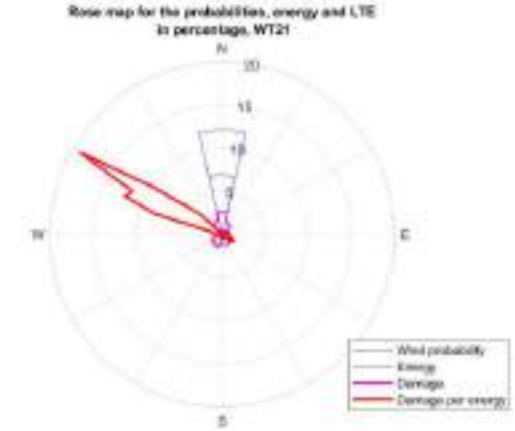

Rose map for the probabilities, energy and LTE for the component
"Hub" in percentage, WT21
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Main Frame, Tower joint" in percentage, WT21
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

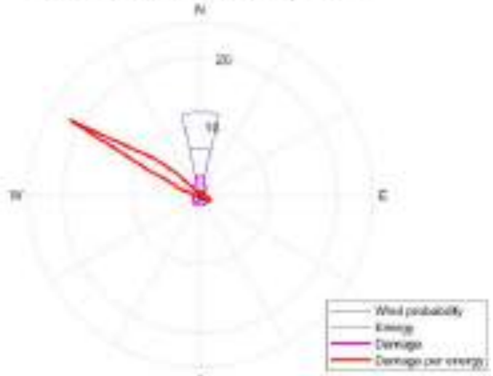

Rose map for the probabilities, energy and LTE for the component
"Hub-Shaft joint" in percentage, WT21
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Tower top" in percentage, WT21
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

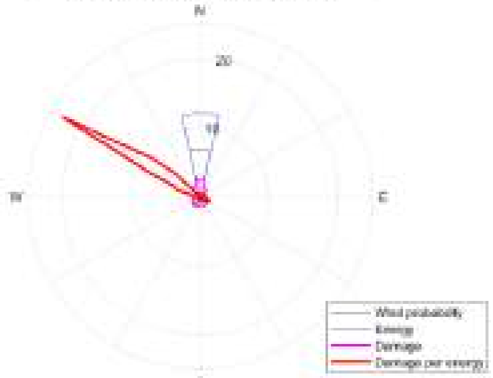

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT21
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT21
N
20
15
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

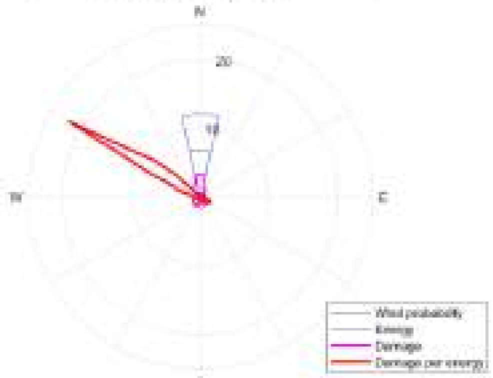
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT22



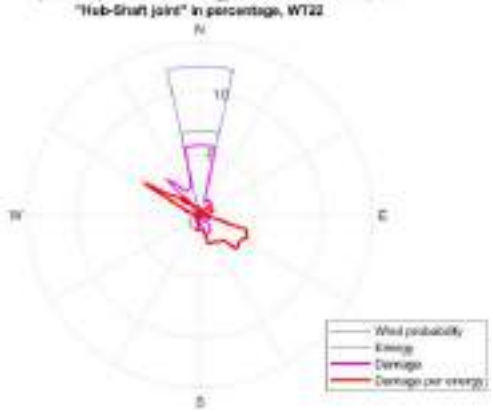
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT22



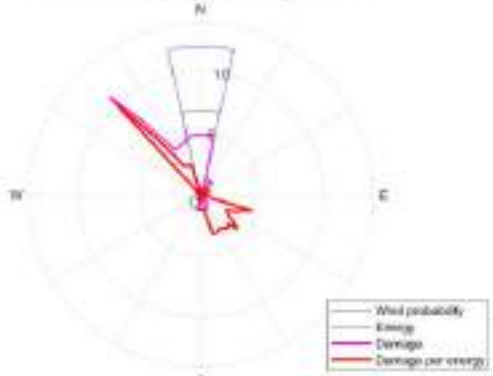
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT22



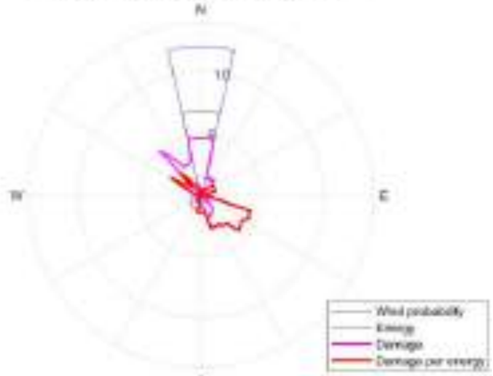
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT22



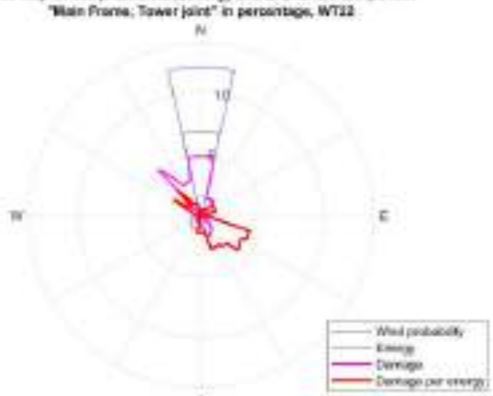
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT22



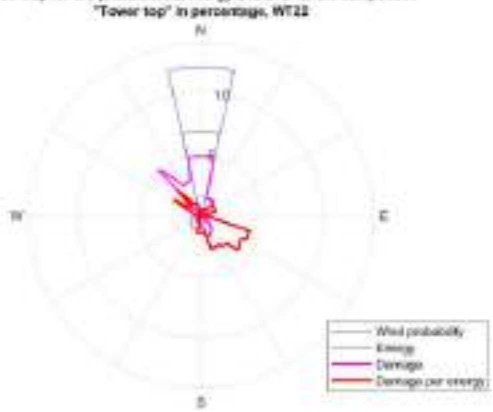
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT22



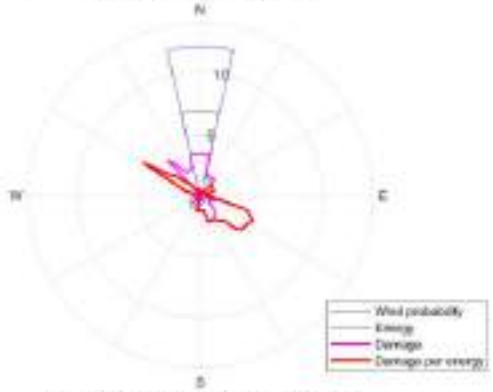
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT22



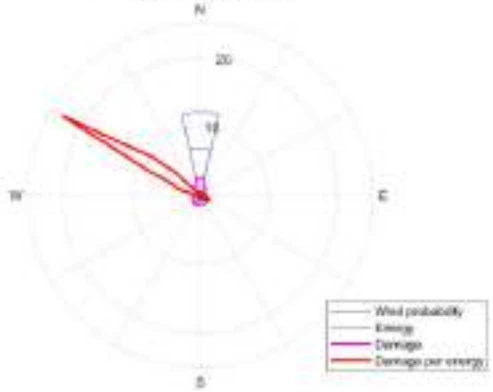
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT22



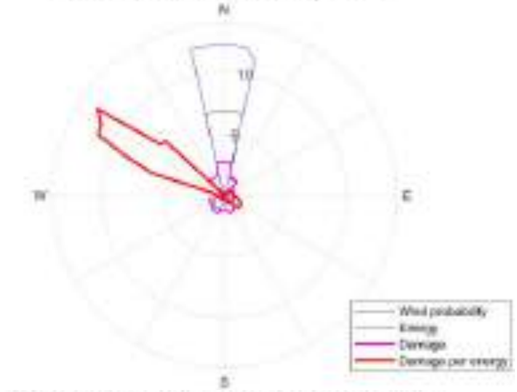
Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT22



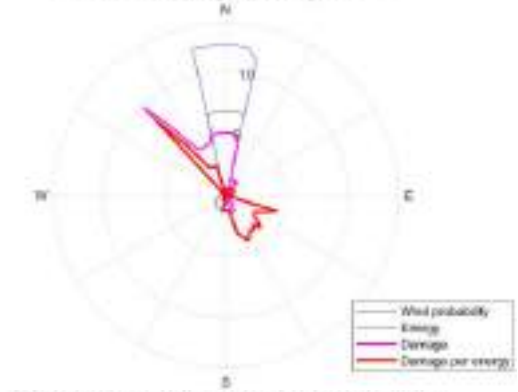
Rose map for the probabilities, energy and LTE
in percentage, WT22



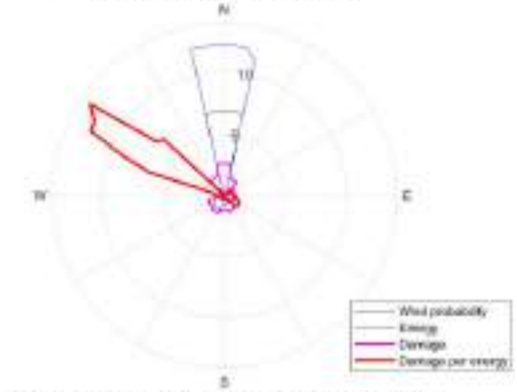
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT23



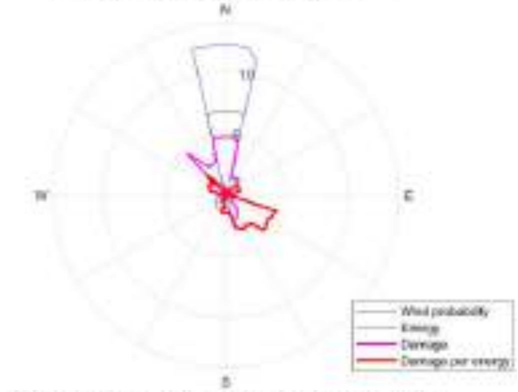
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT23



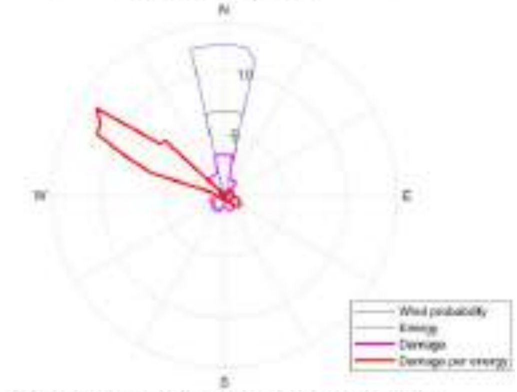
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT23



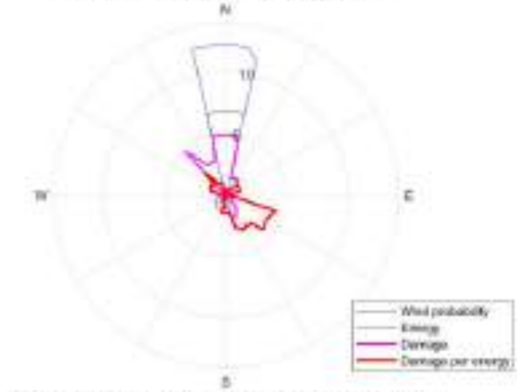
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT23



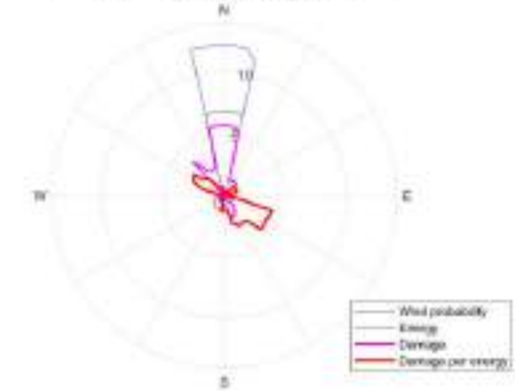
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT23



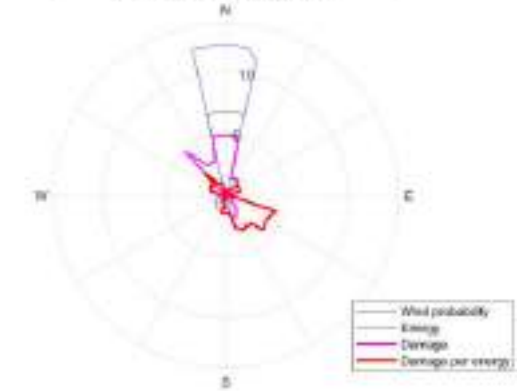
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT23

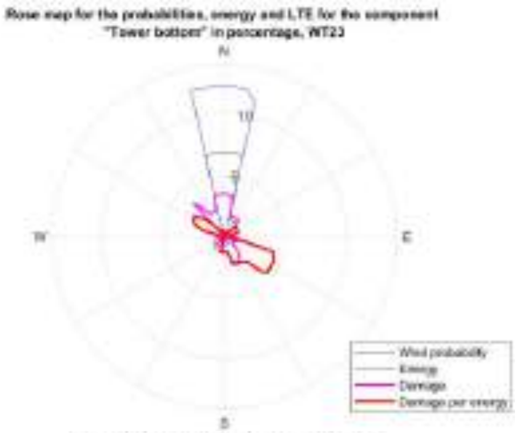


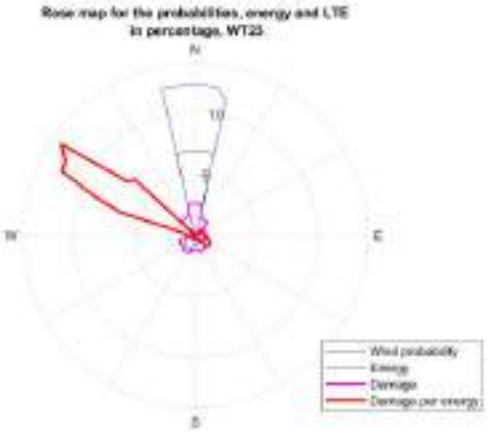
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT23



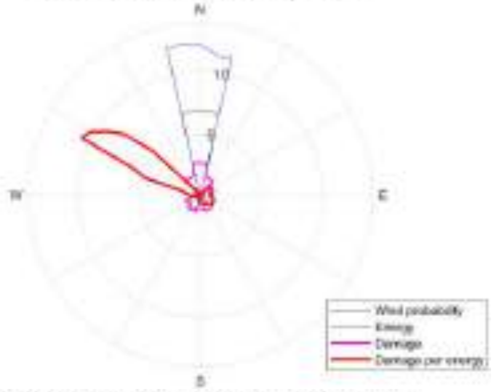
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT23



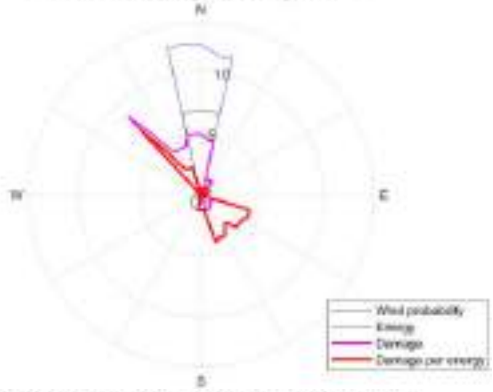

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT23
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT23
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

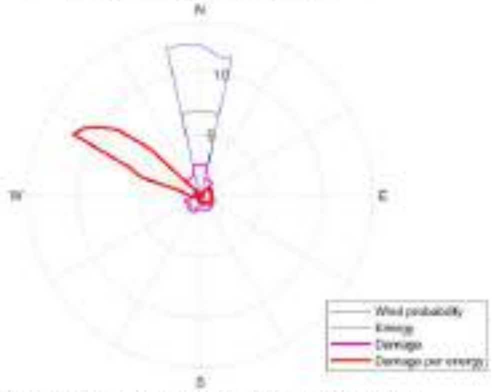
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT24



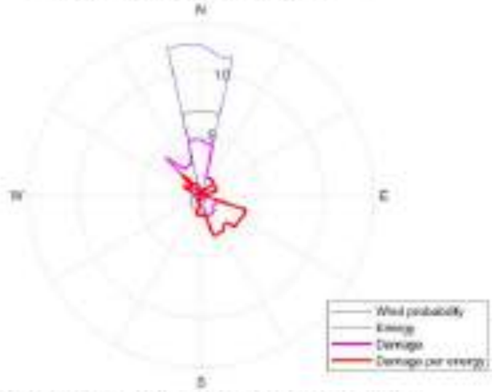
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT24



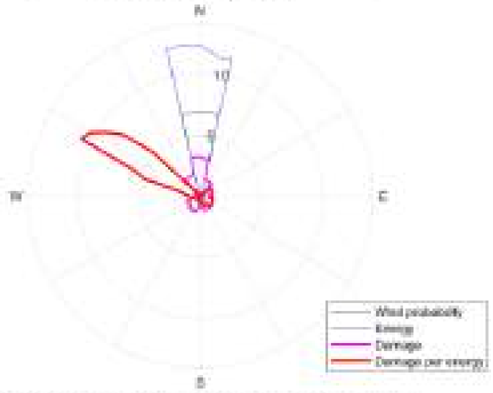
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT24



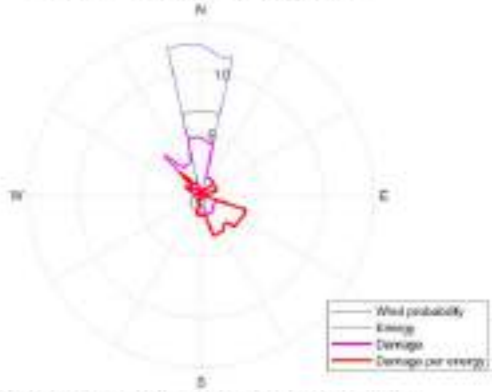
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT24



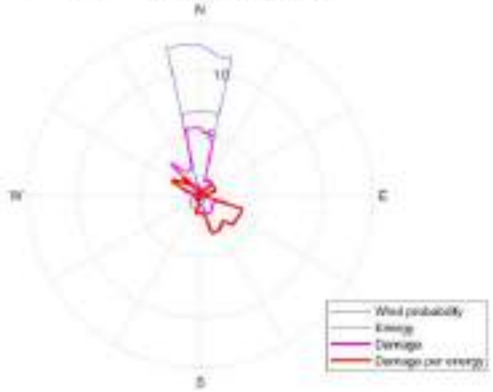
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT24



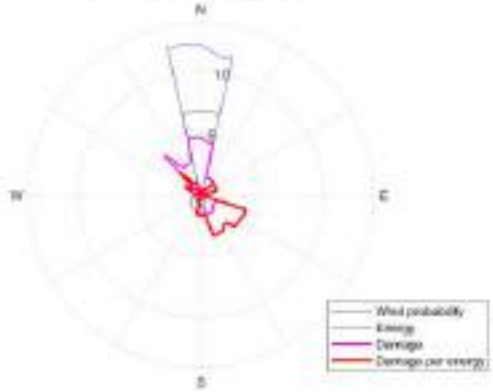
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT24

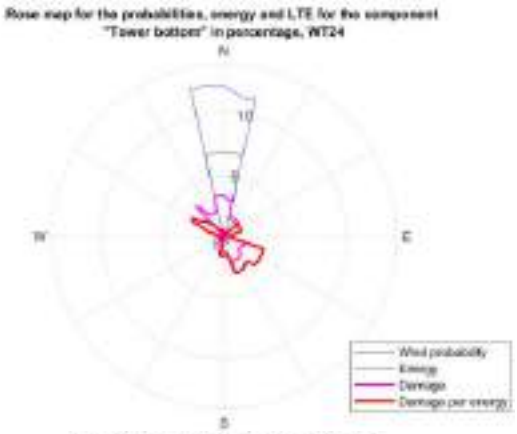


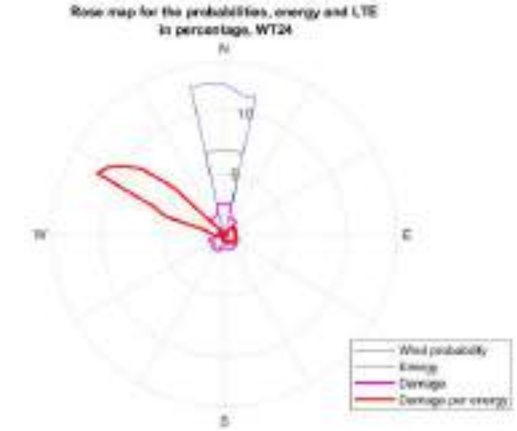
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT24



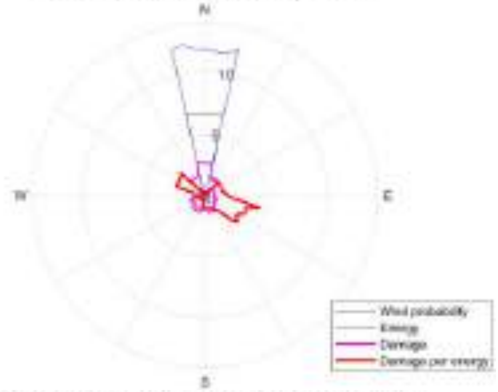
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT24



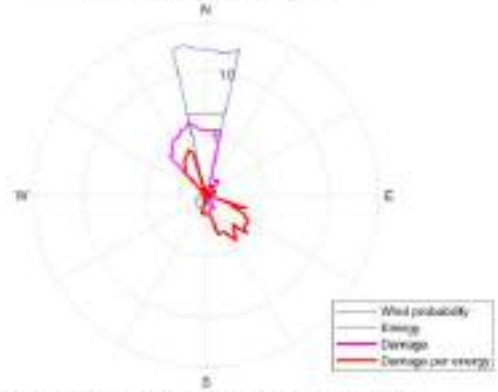

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT24
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT24
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

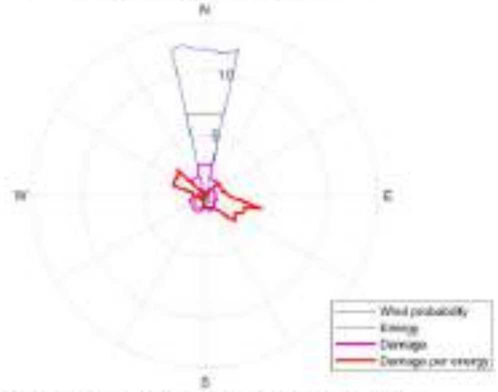
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT25



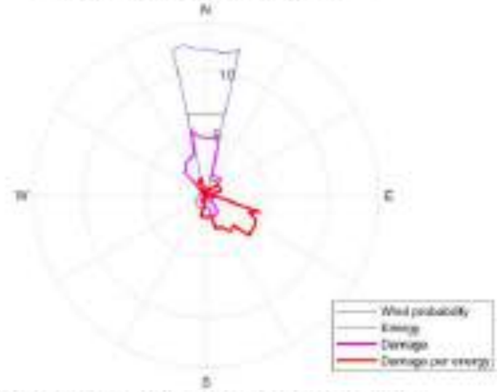
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT25



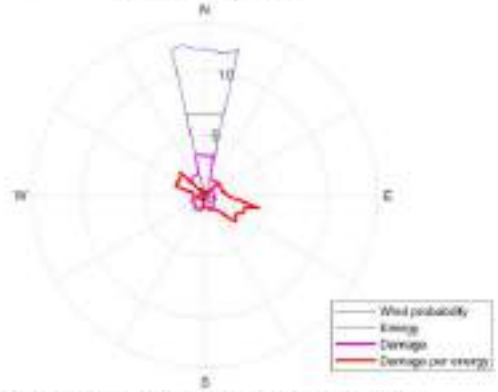
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT25



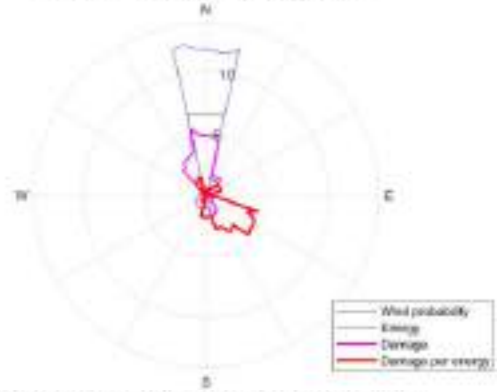
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT25



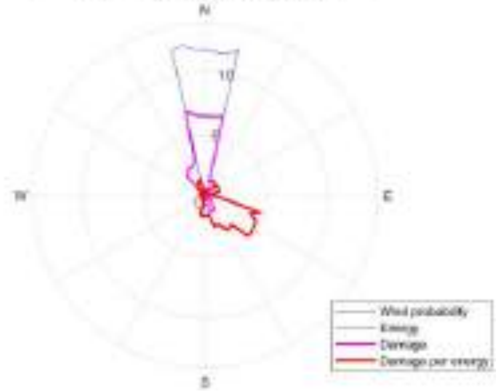
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT25



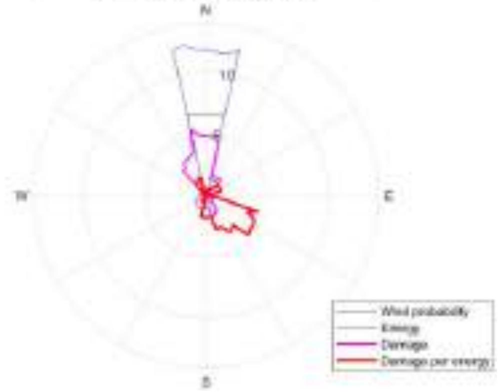
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT25

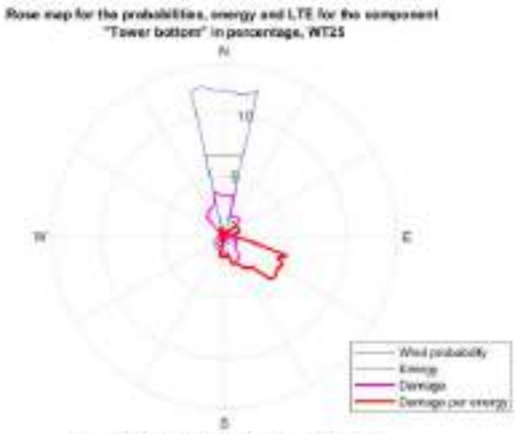


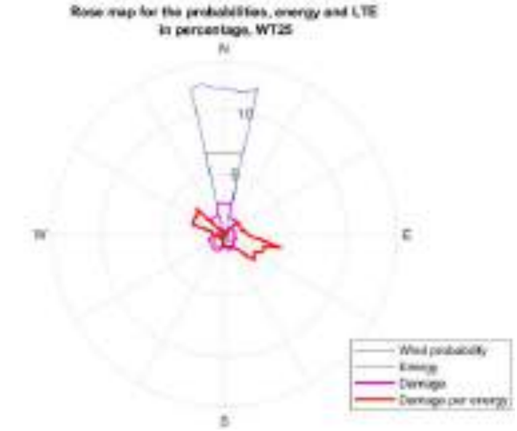
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT25



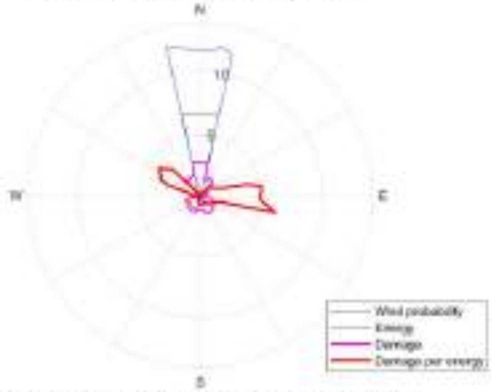
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT25



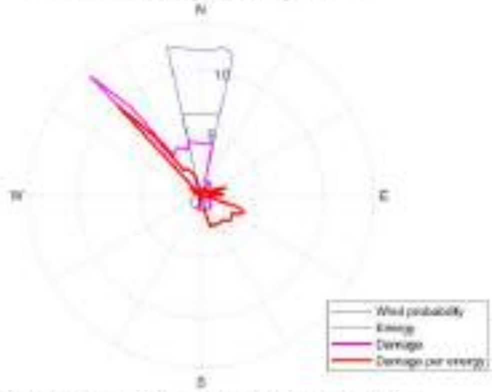

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT25
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT25
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

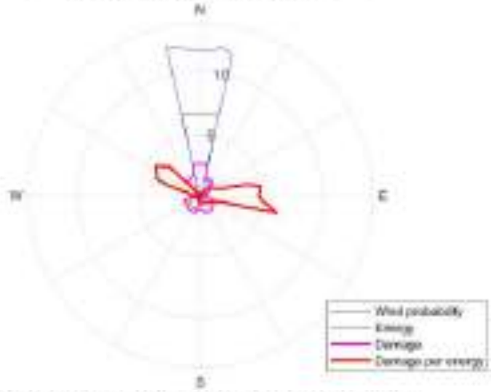
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT26



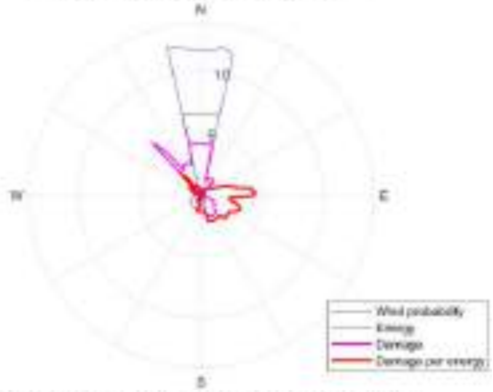
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT26



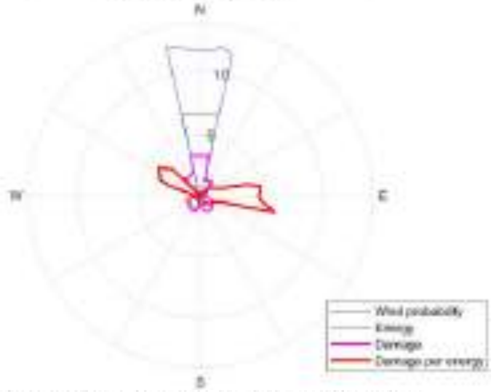
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT26



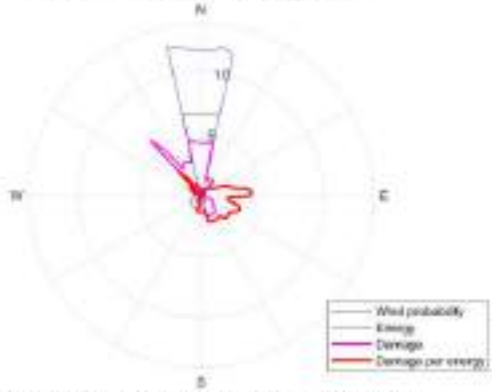
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT26



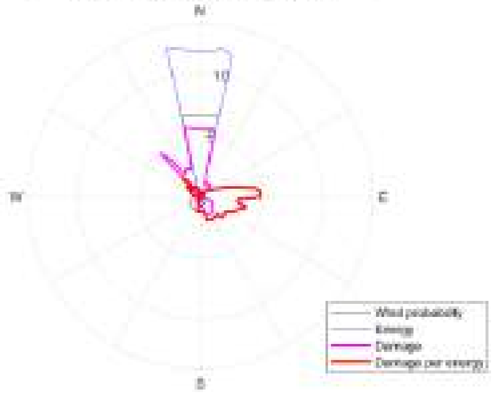
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT26



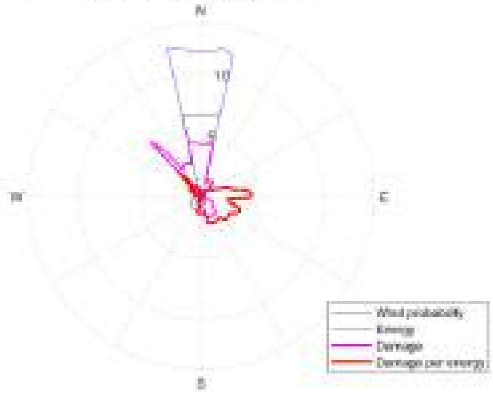
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT26



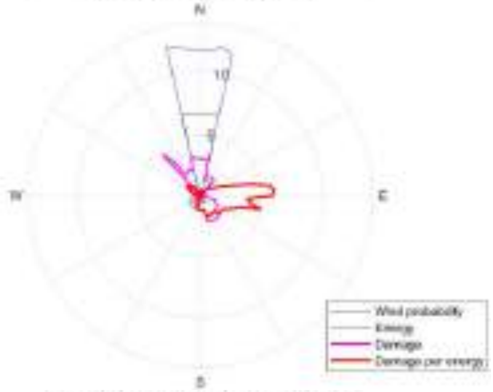
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT26



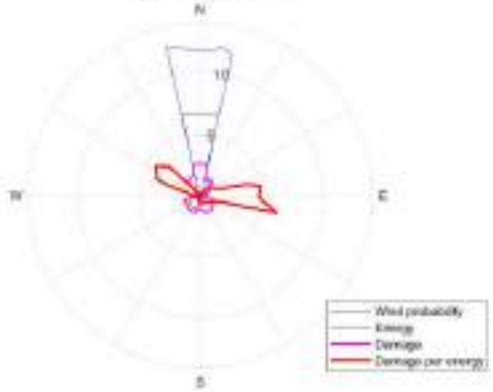
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT26



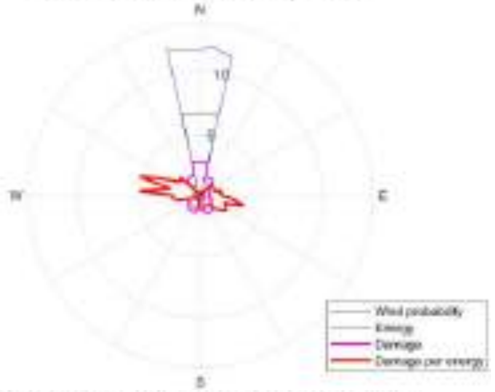
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT26



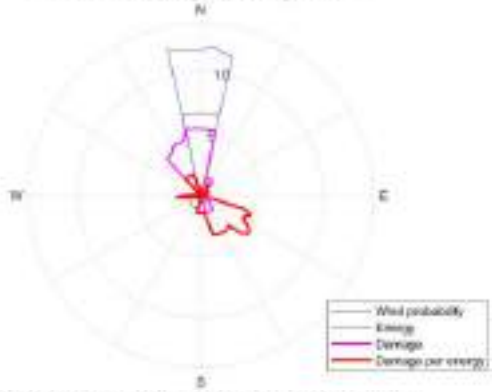
Rose map for the probabilities, energy and LTE in percentage, WT26



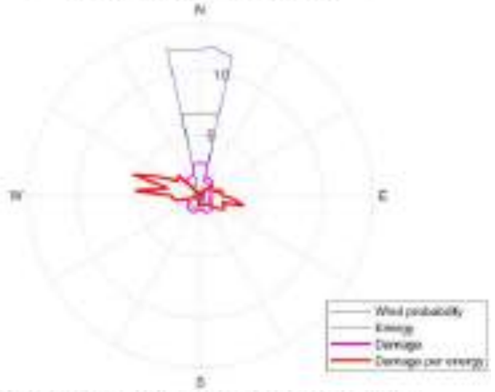
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT27



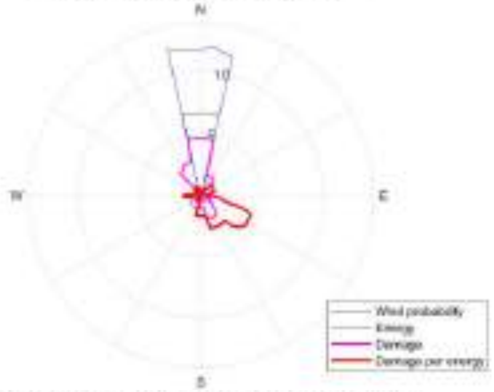
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT27



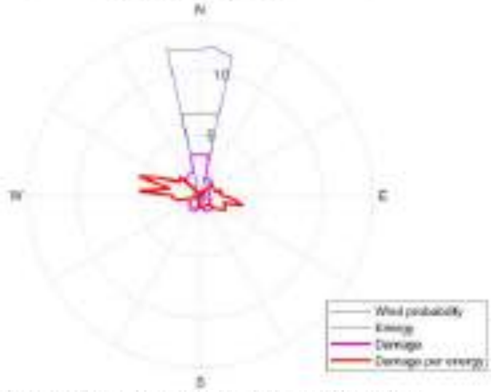
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT27



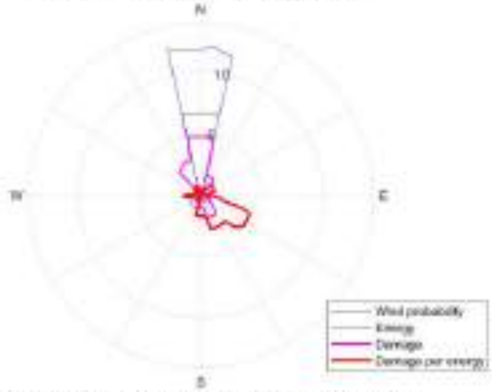
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT27



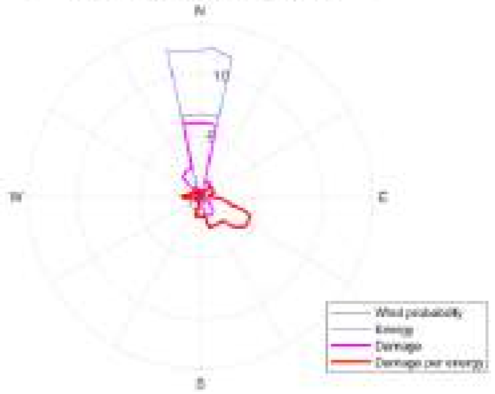
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT27



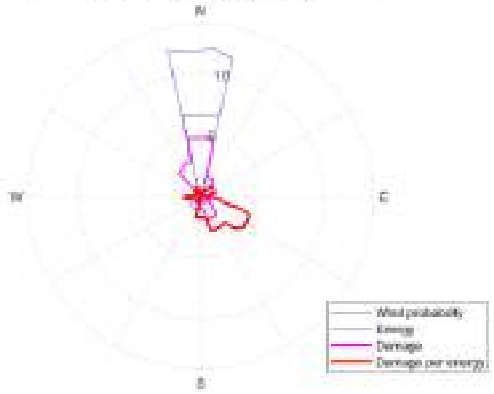
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT27

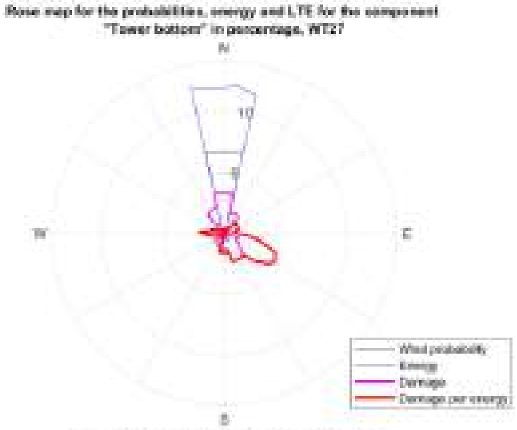


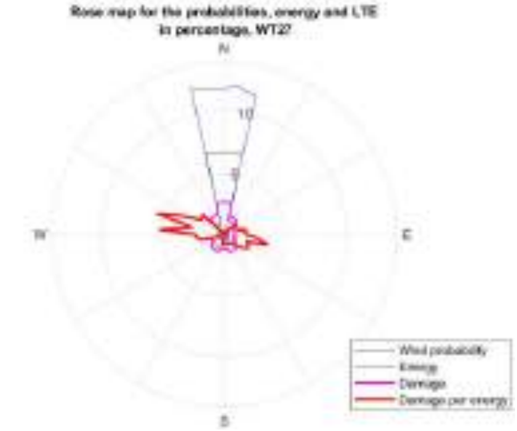
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT27



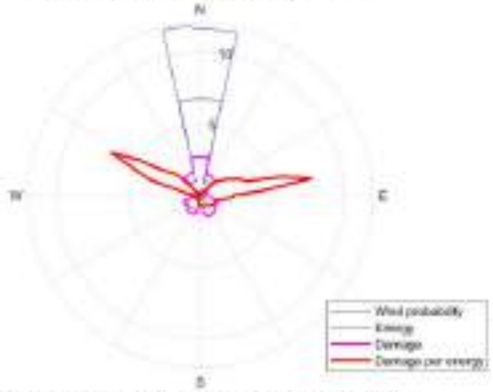
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT27



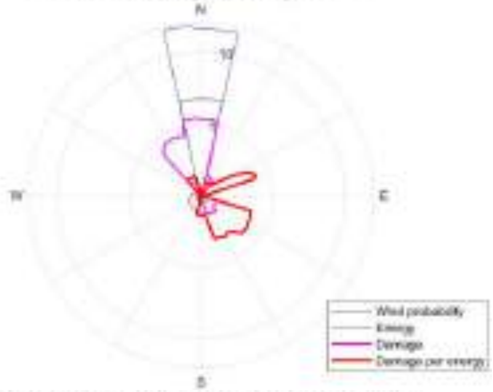

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT27
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT27
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

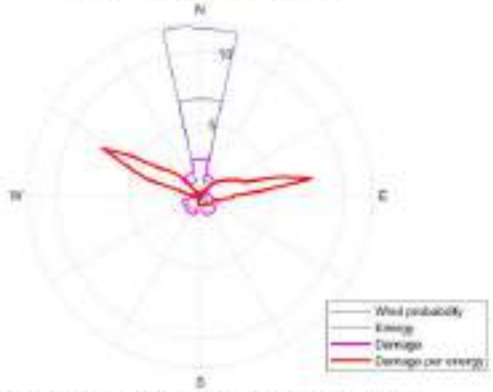
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT28



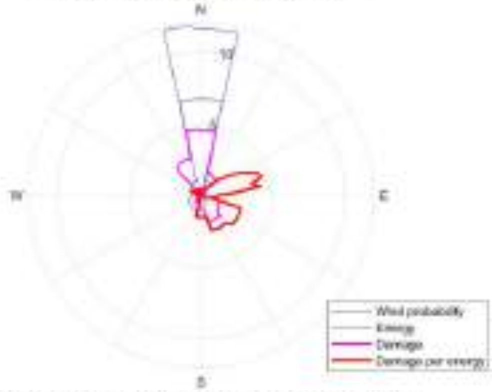
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT28



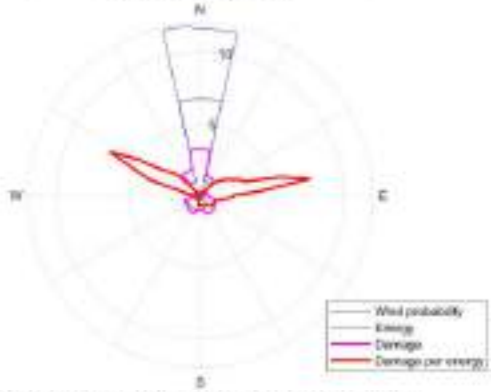
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT28



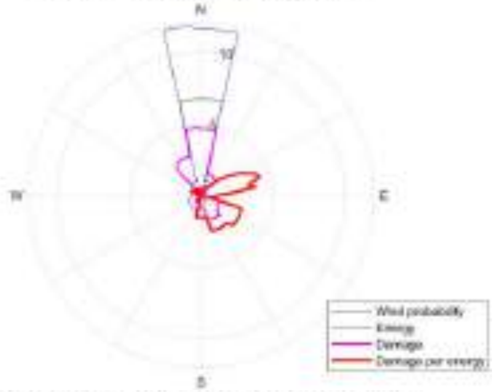
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT28



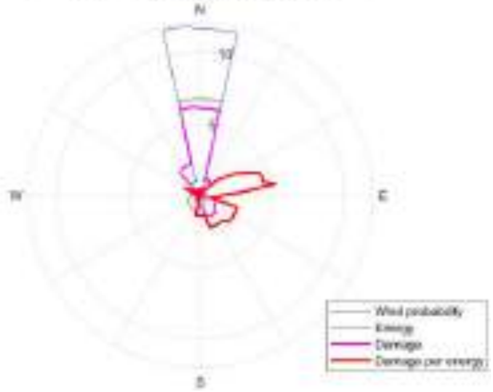
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT28



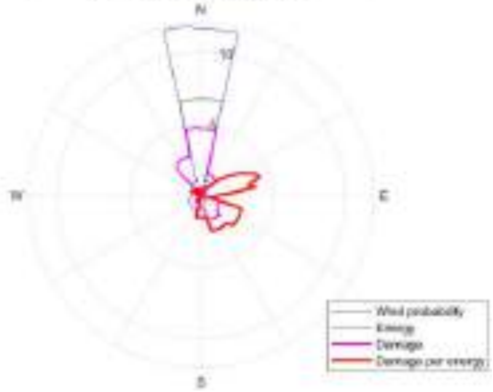
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT28

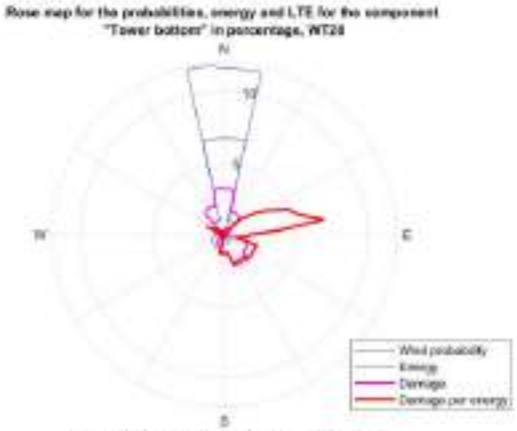


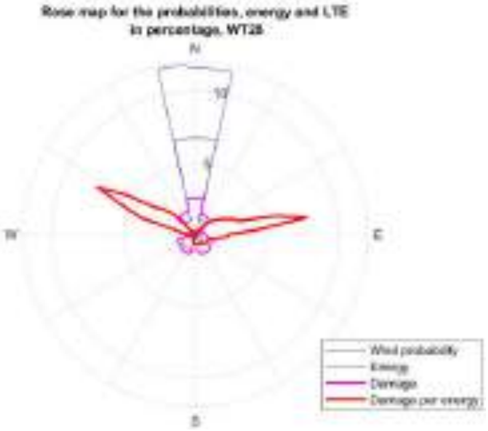
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT28



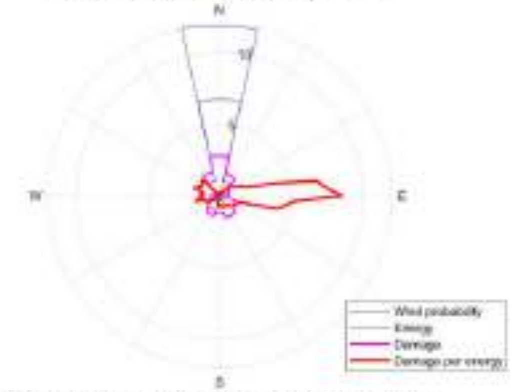
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT28



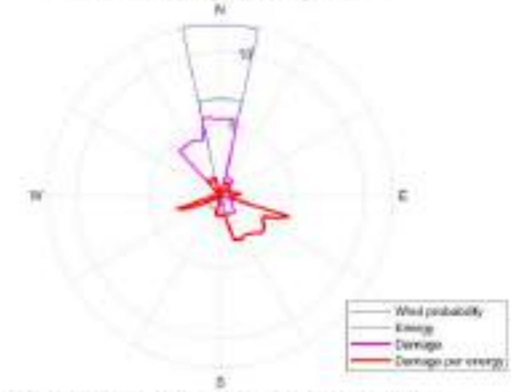

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT28
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT28
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

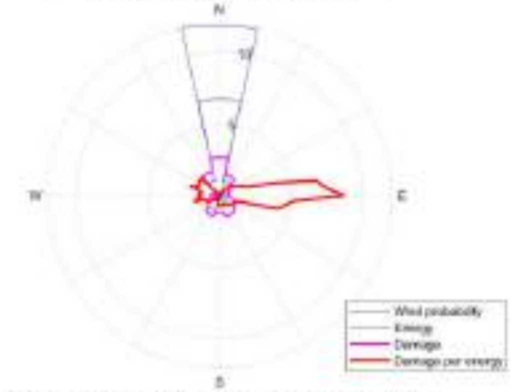
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT29



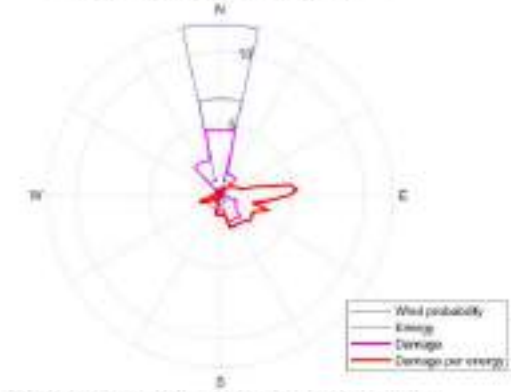
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT29



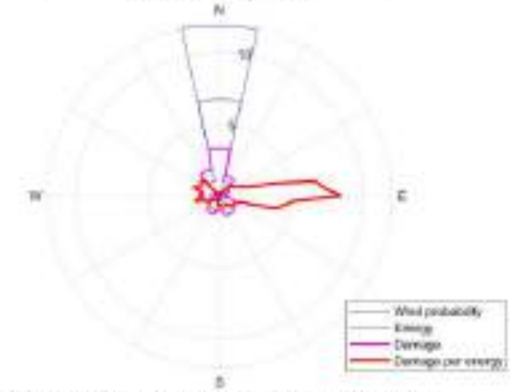
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT29



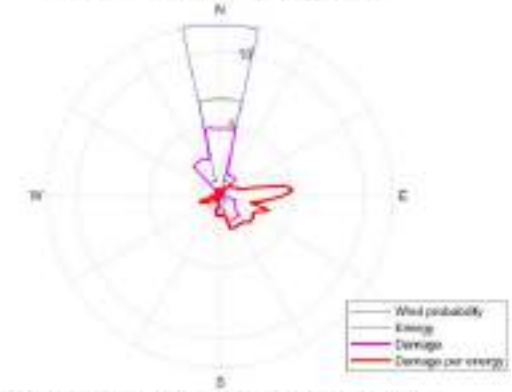
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT29



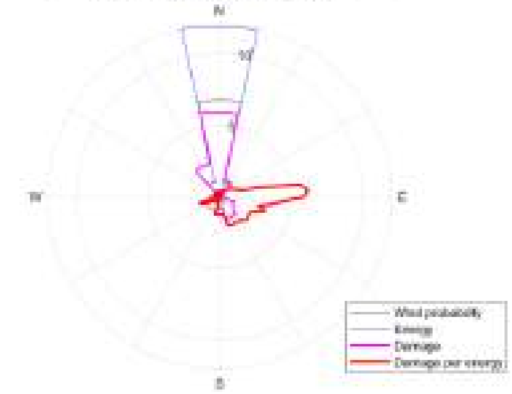
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT29



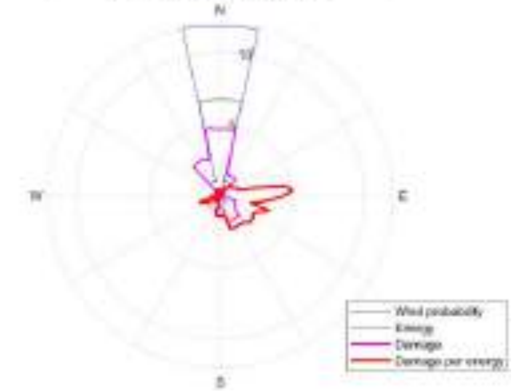
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT29



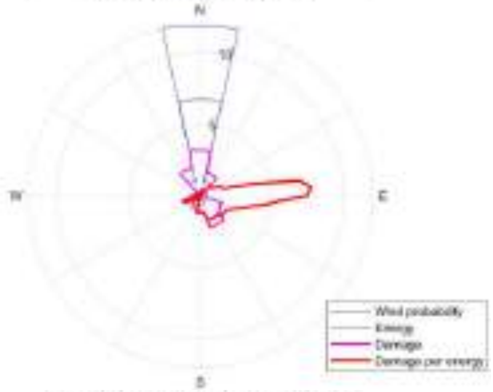
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT29



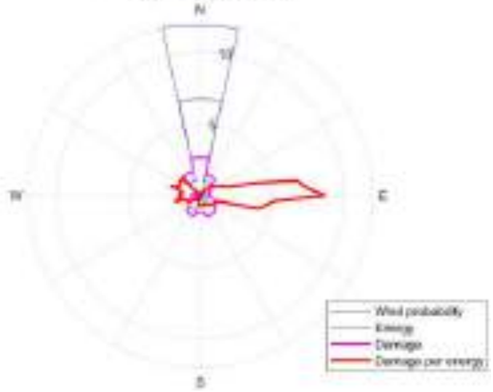
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT29



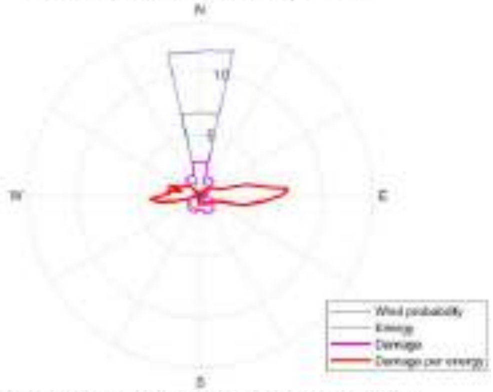
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT29



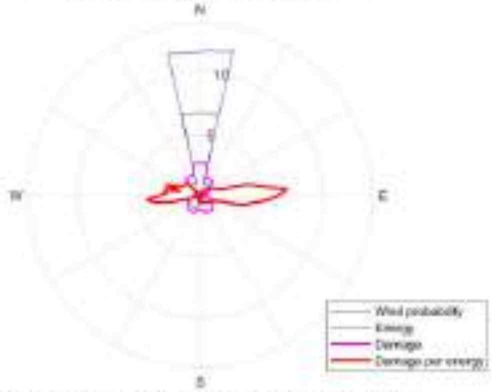
Rose map for the probabilities, energy and LTE in percentage, WT29



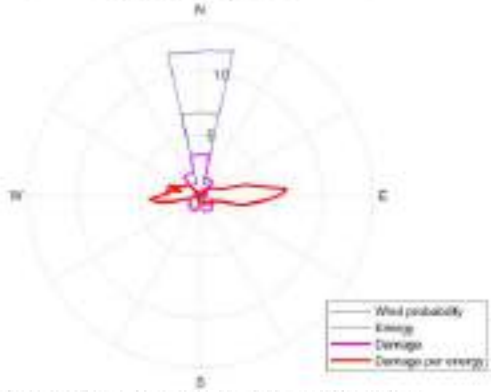
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT38



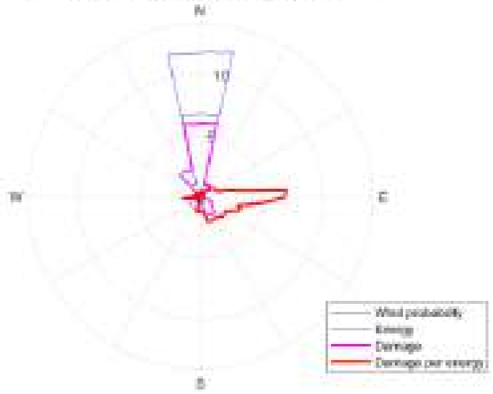
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT38



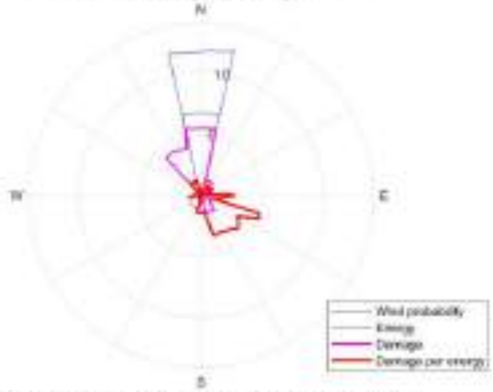
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT38



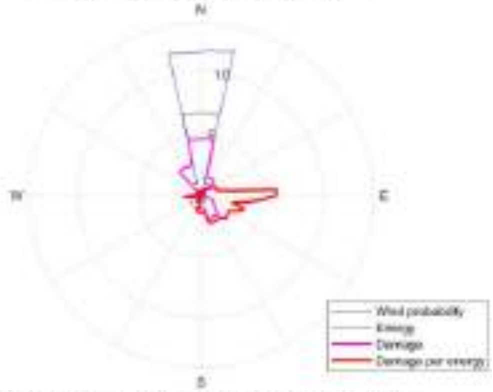
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT38



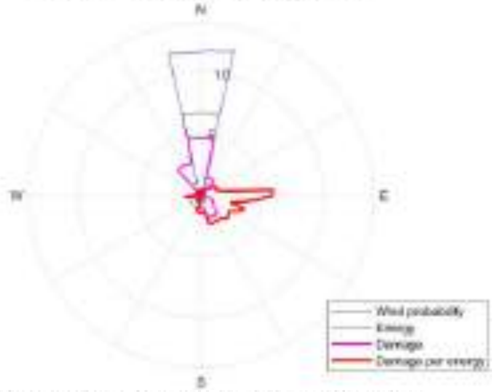
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT38



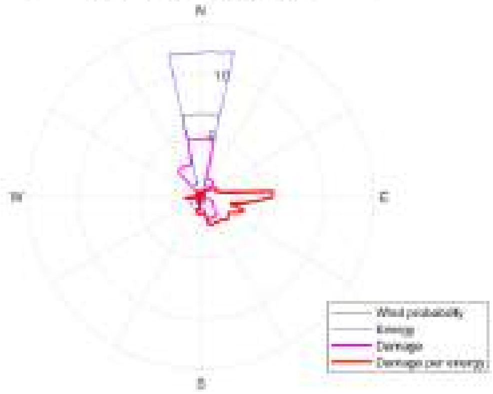
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT38



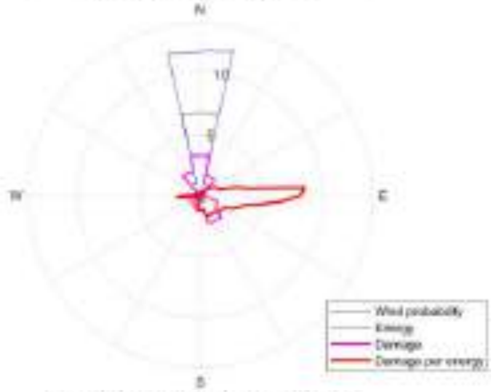
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT38



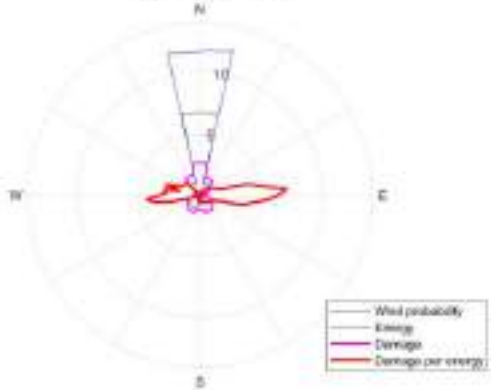
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT38



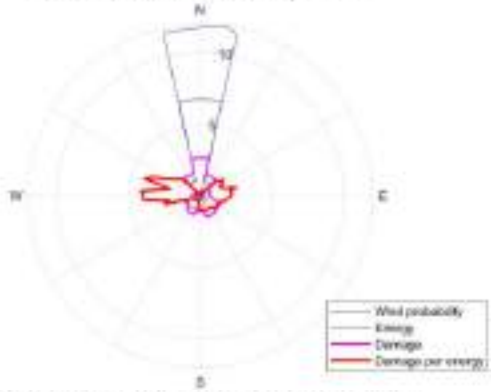
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT30



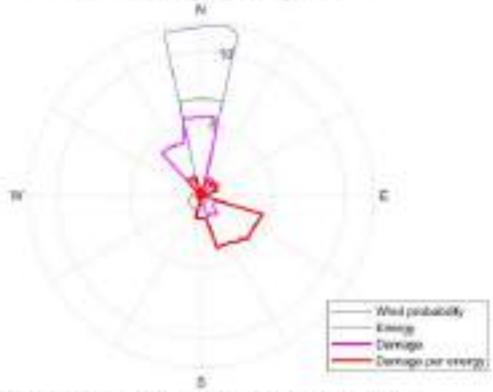
Rose map for the probabilities, energy and LTE in percentage, WT30



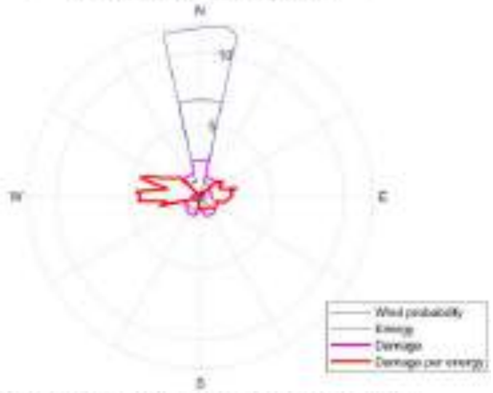
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT31



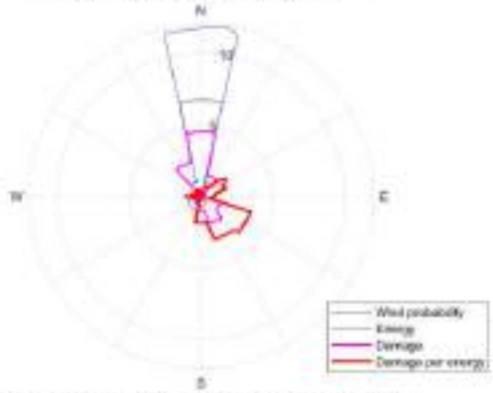
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT31



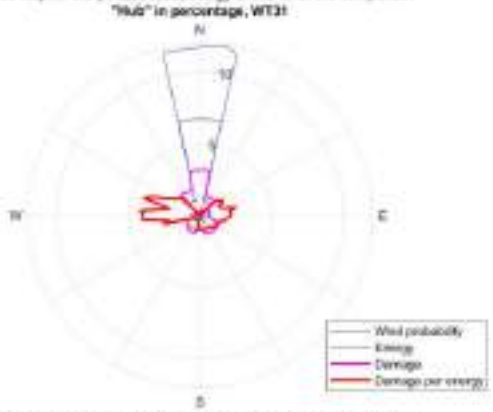
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT31



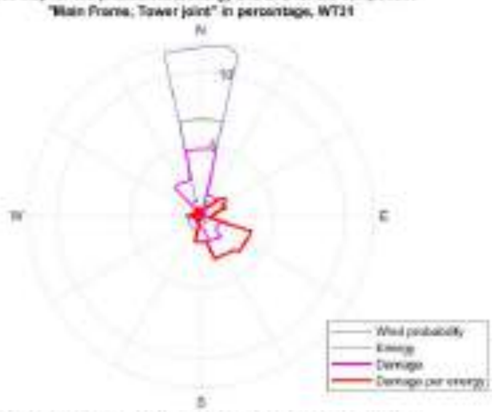
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT31



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT31

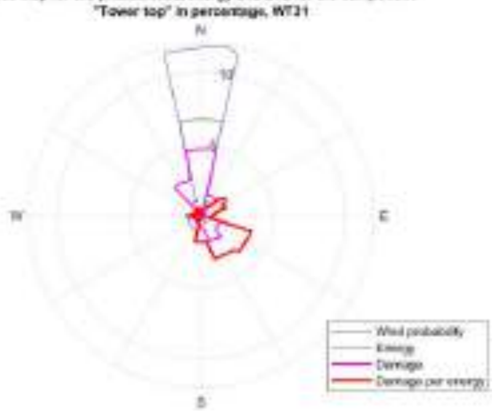


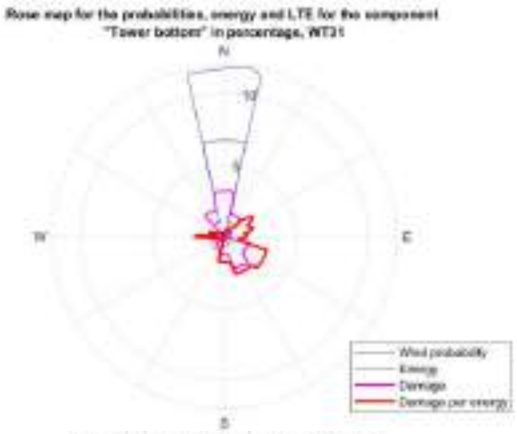
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT31

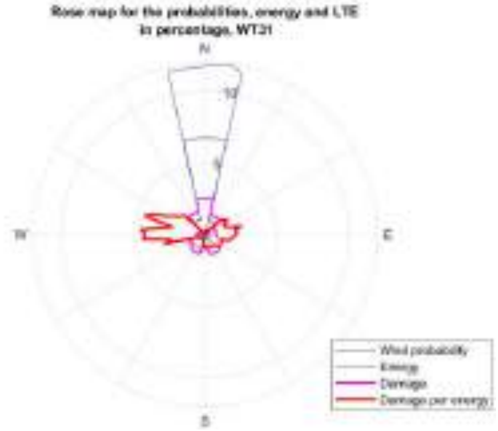


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT31

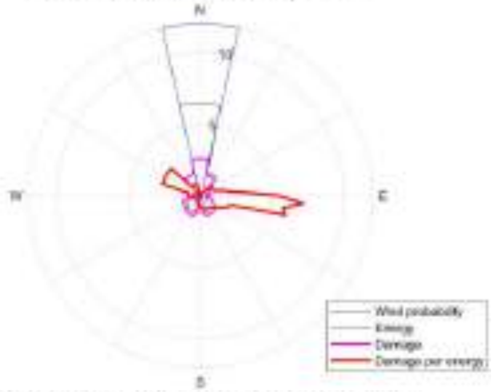
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT31



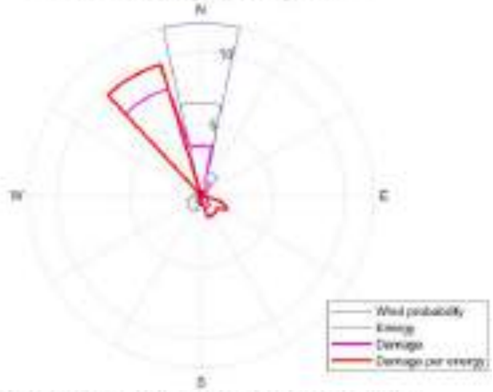

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT31
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT31
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

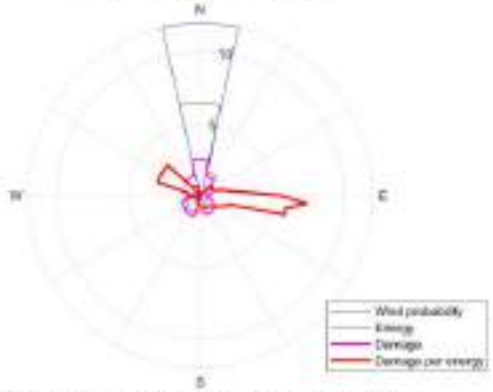
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT32



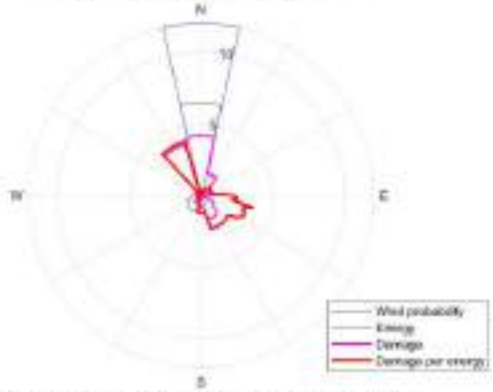
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT32



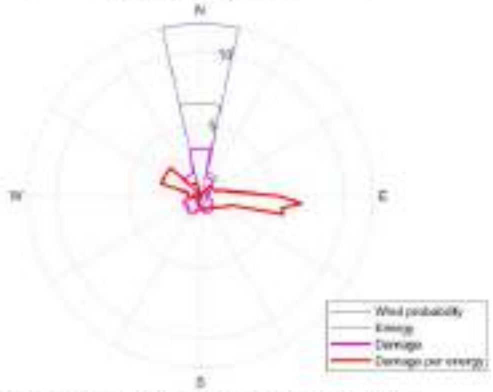
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT32



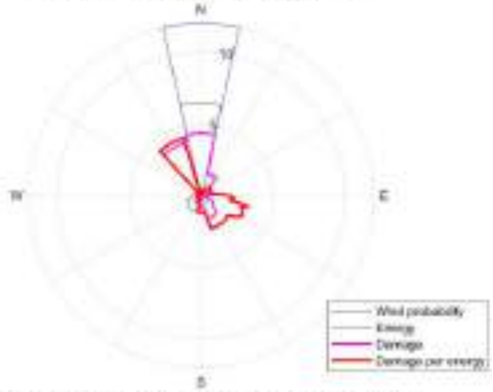
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT32



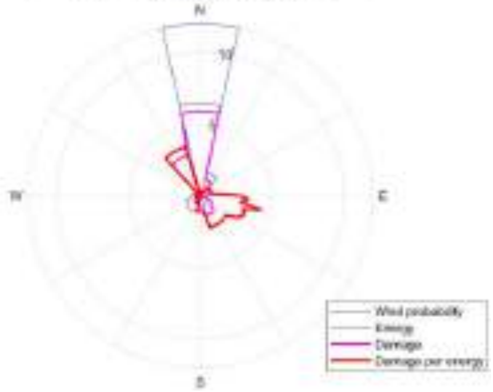
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT32



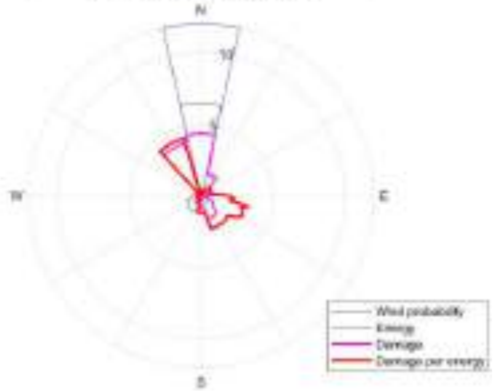
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT32



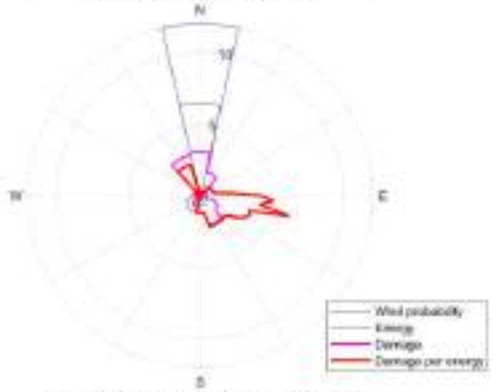
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT32



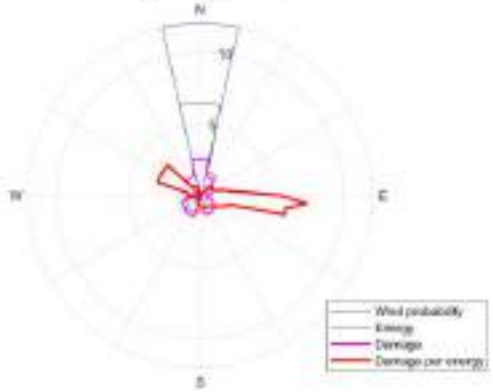
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT32



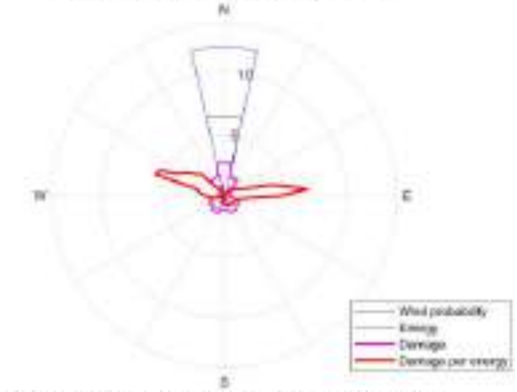
Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT32



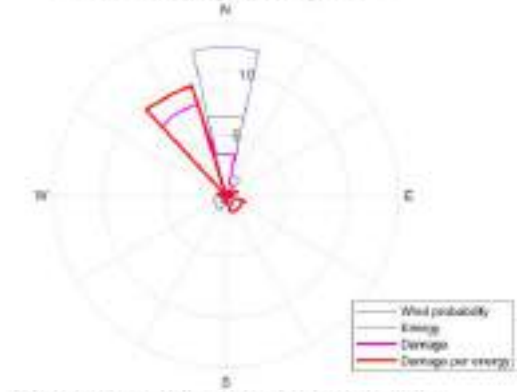
Rose map for the probabilities, energy and LTE
in percentage, WT32



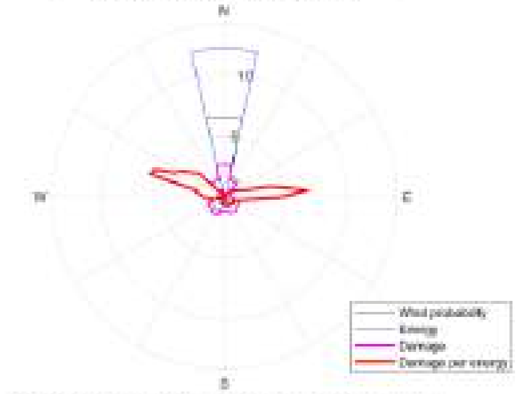
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT33



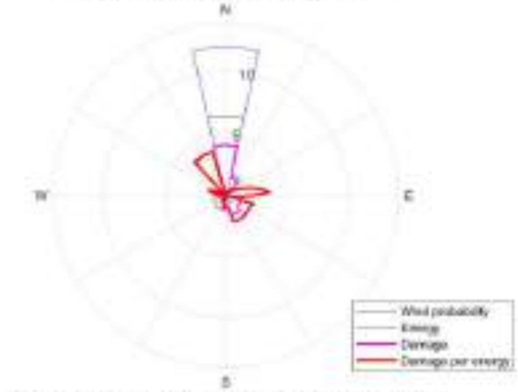
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT33



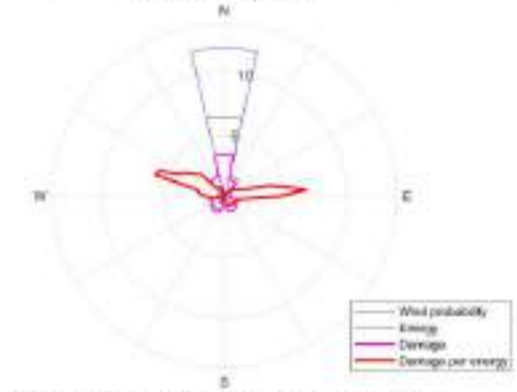
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT33



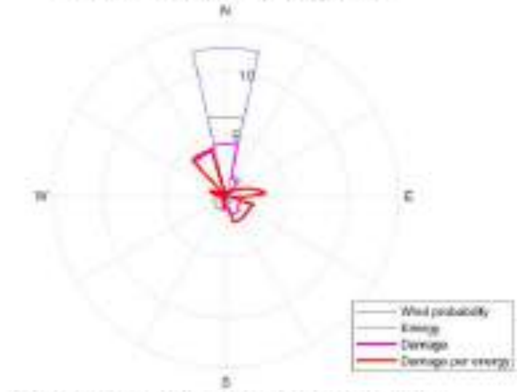
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT33



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT33

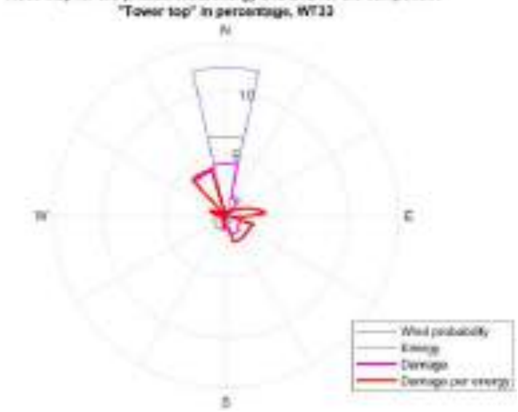


Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT33

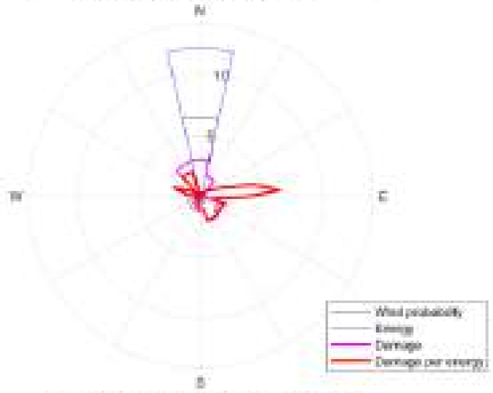


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT33

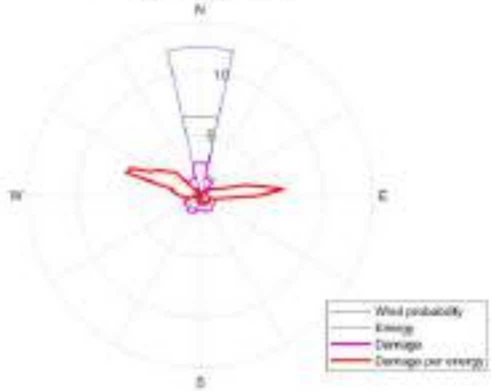
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT33



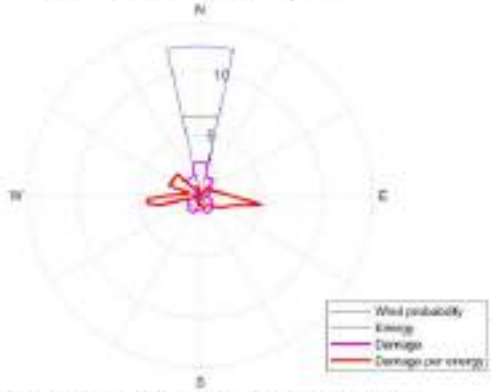
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT33



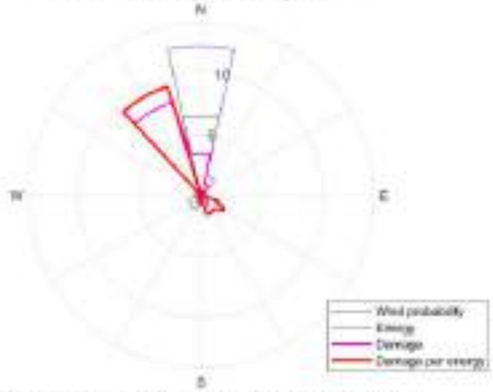
Rose map for the probabilities, energy and LTE in percentage, WT33



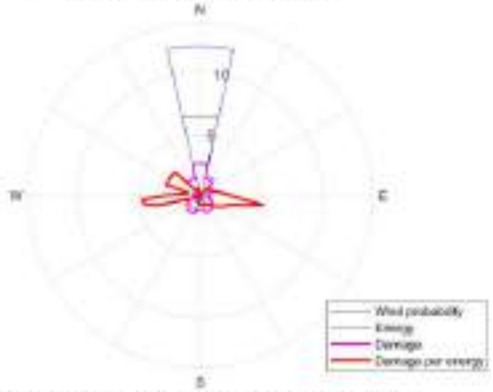
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT34



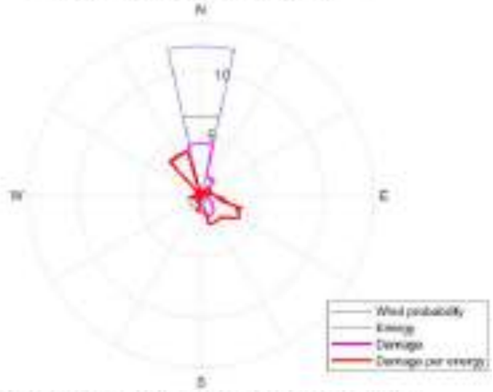
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT34



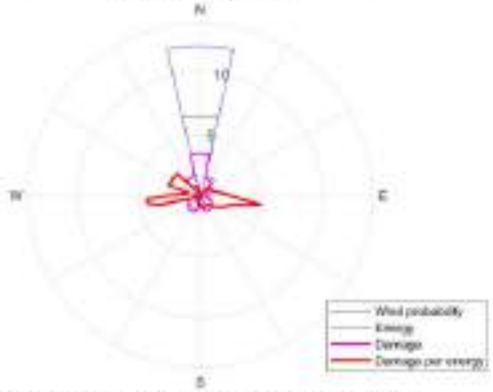
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT34



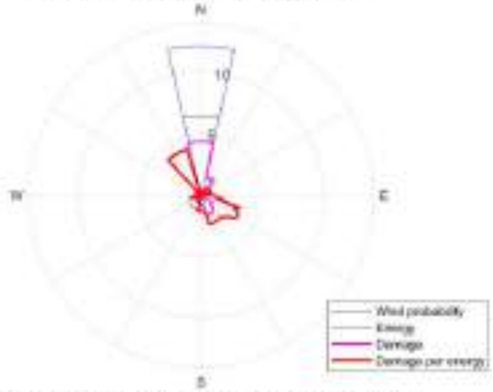
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT34



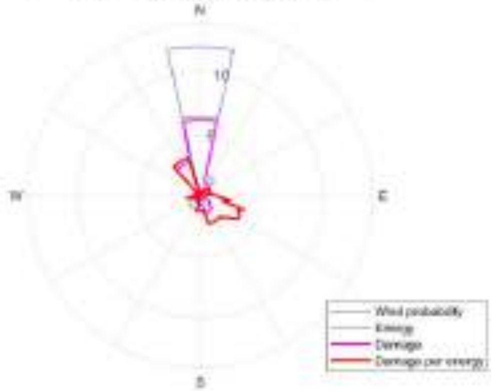
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT34



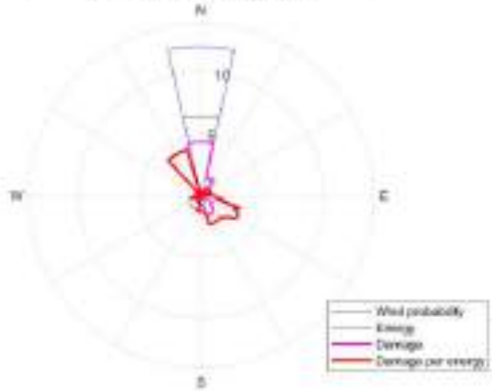
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT34



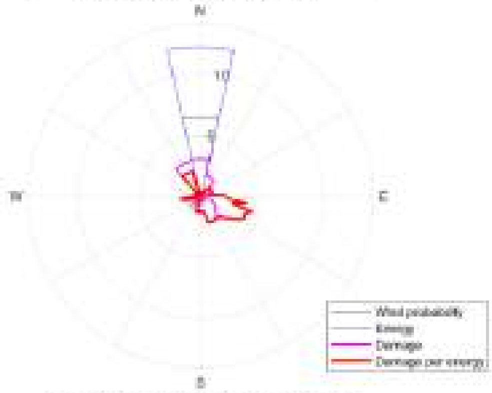
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT34



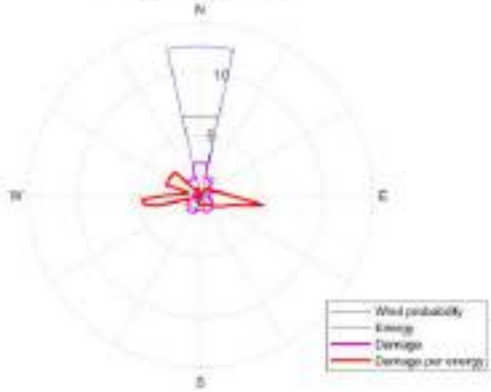
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT34



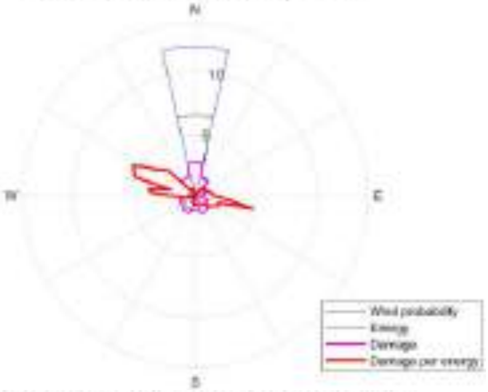
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT34



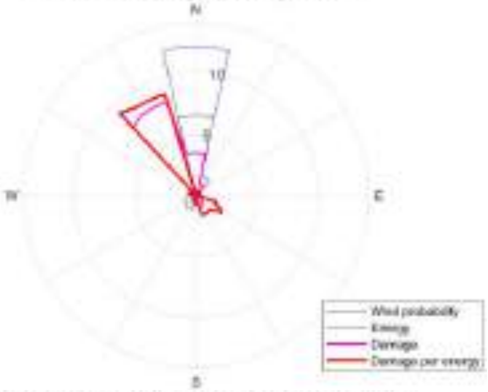
Rose map for the probabilities, energy and LTE in percentage, WT34



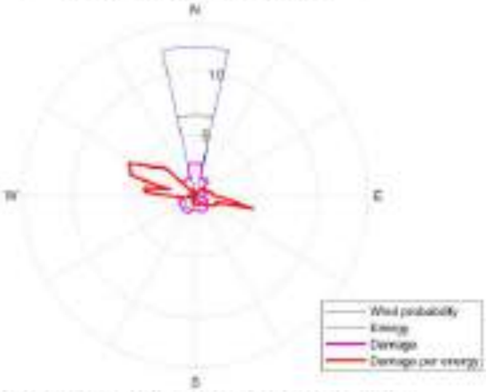
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT35



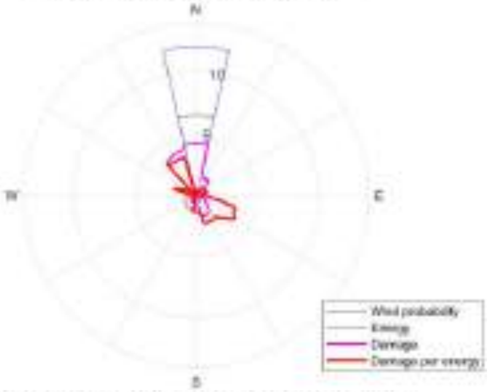
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT35



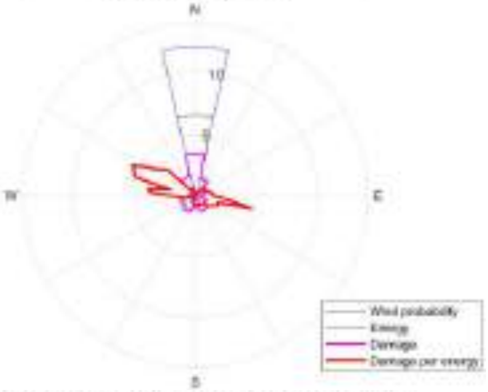
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT35



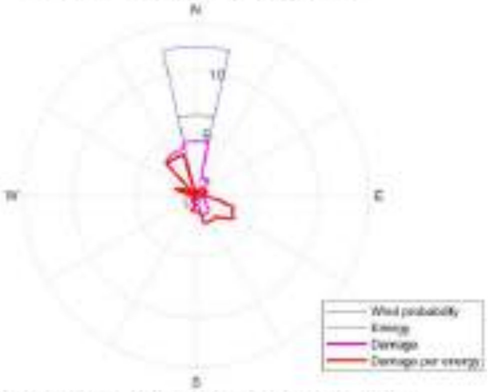
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT35



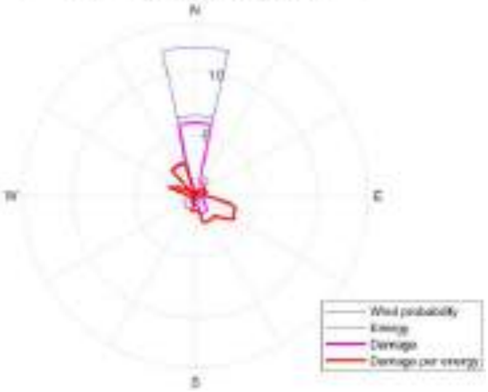
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT35



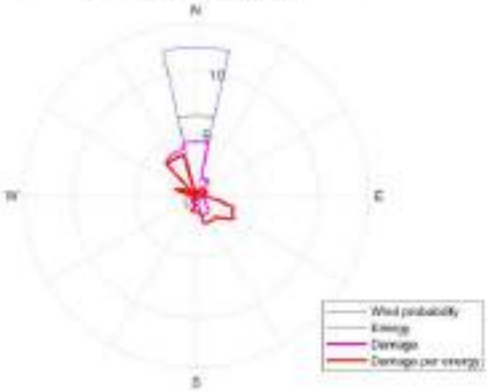
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT35

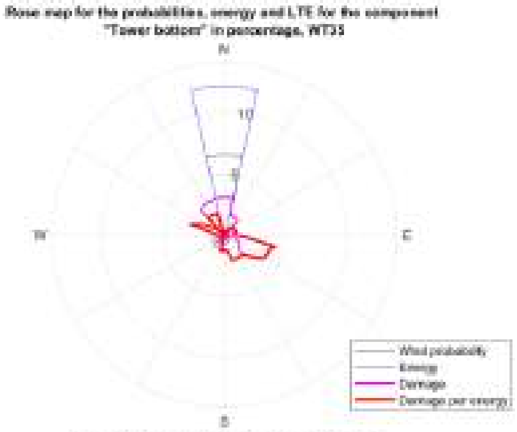


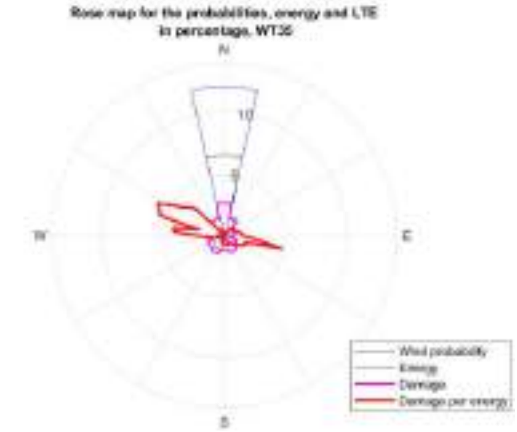
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT35

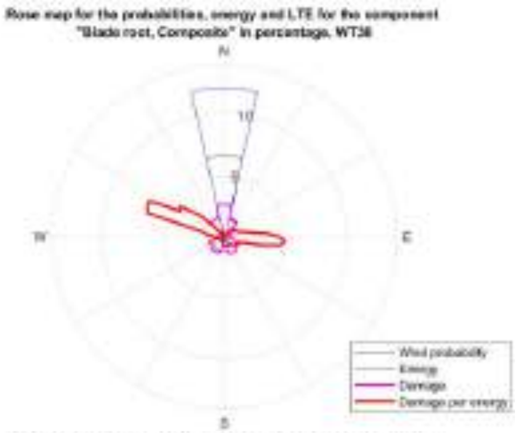


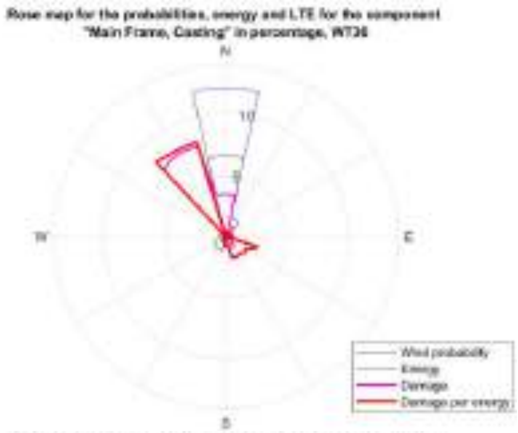
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT35

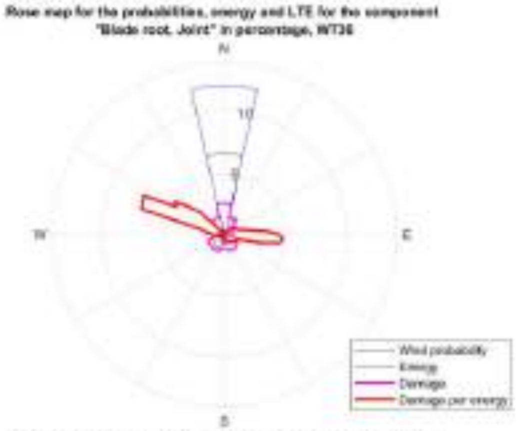


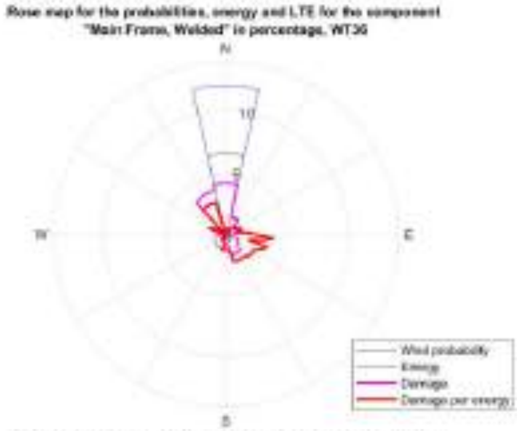

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT35
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

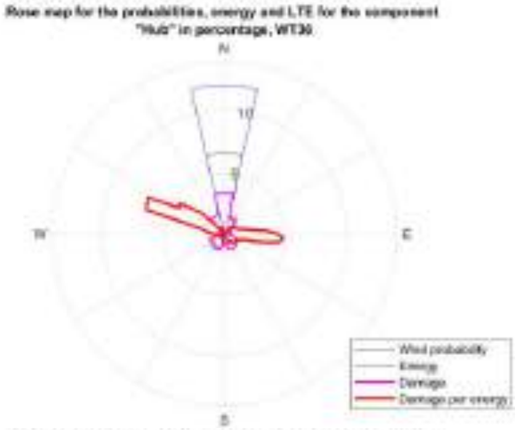

Rose map for the probabilities, energy and LTE in percentage, WT35
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

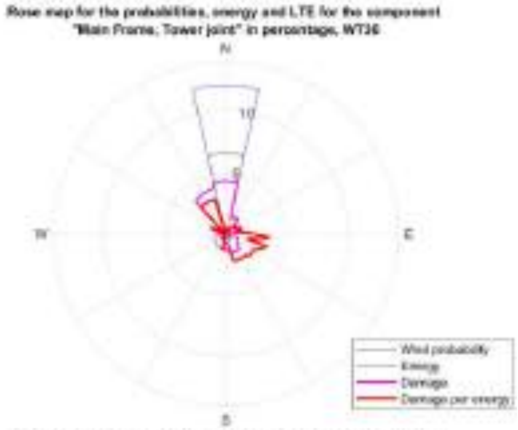

Rose map for the probabilities, energy and LTE for the component
"Blade root, Composite" in percentage, WT36
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

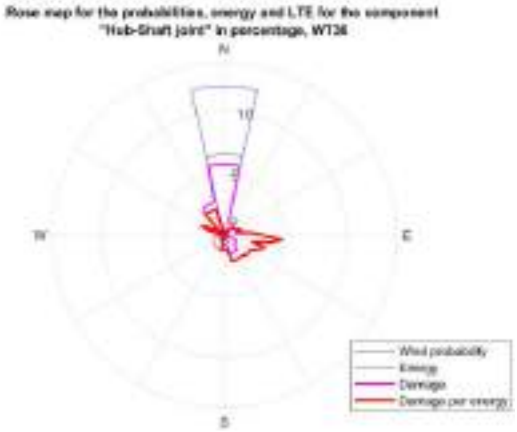

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Casting" in percentage, WT36
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

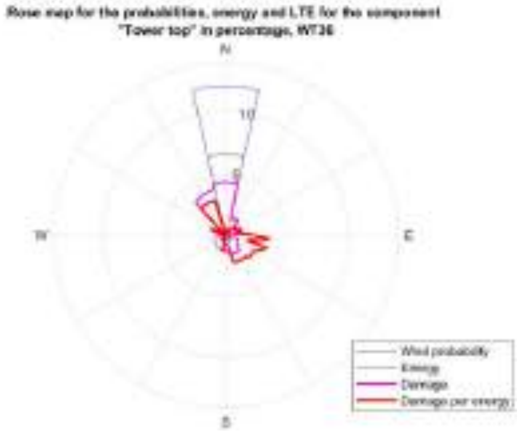

Rose map for the probabilities, energy and LTE for the component
"Blade root, Joint" in percentage, WT36
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Main Frame, Welded" in percentage, WT36
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

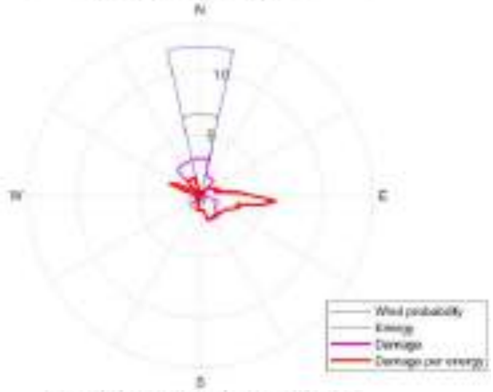

Rose map for the probabilities, energy and LTE for the component
"Hub" in percentage, WT36
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Main Frame; Tower joint" in percentage, WT36
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

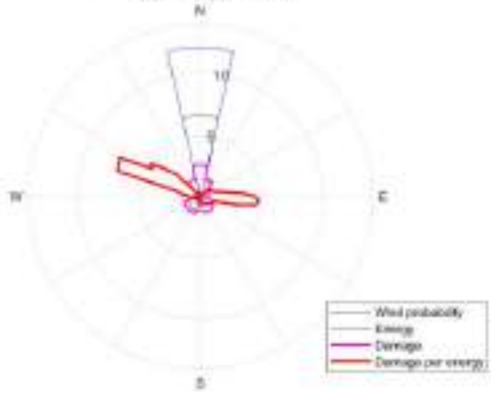

Rose map for the probabilities, energy and LTE for the component
"Hub-Shaft joint" in percentage, WT36
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Tower top" in percentage, WT36
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

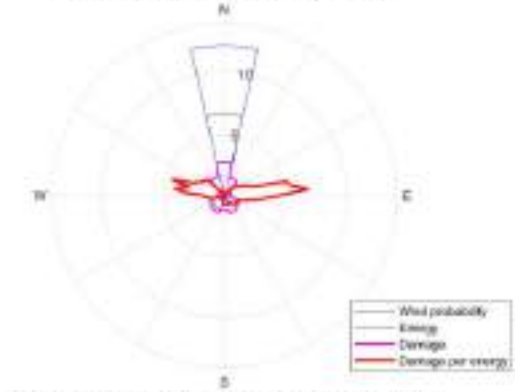
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT36



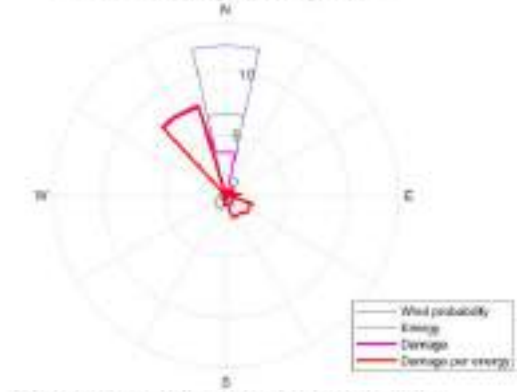
Rose map for the probabilities, energy and LTE in percentage, WT36



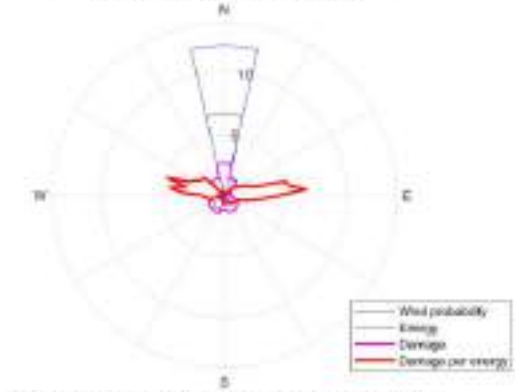
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT37



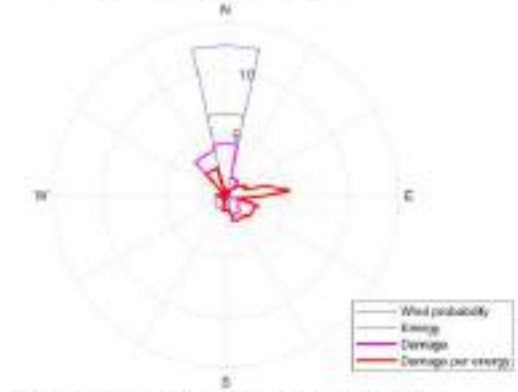
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT37



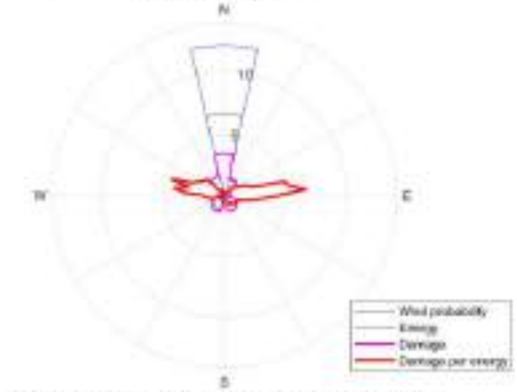
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT37



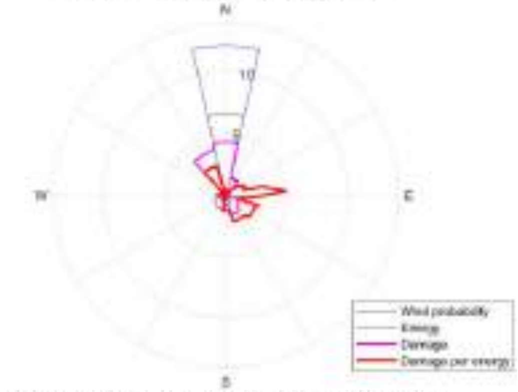
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT37



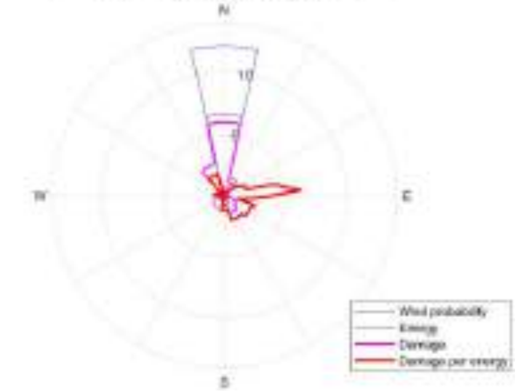
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT37



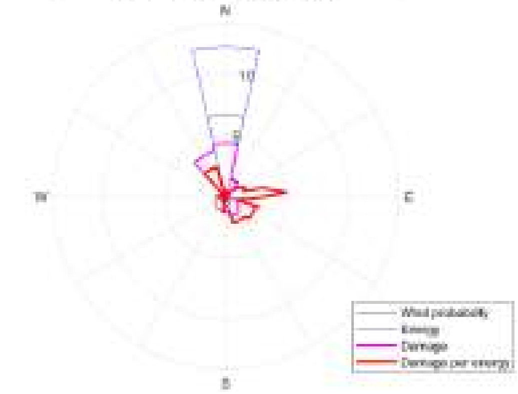
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT37

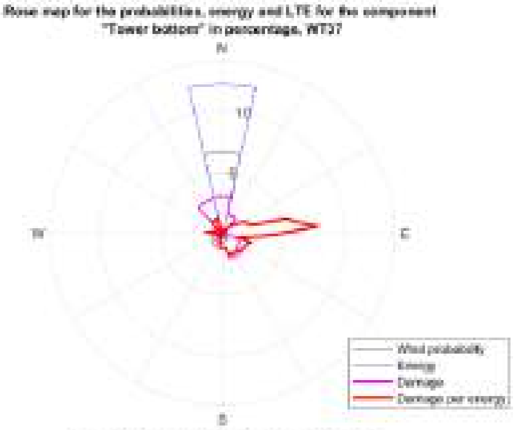


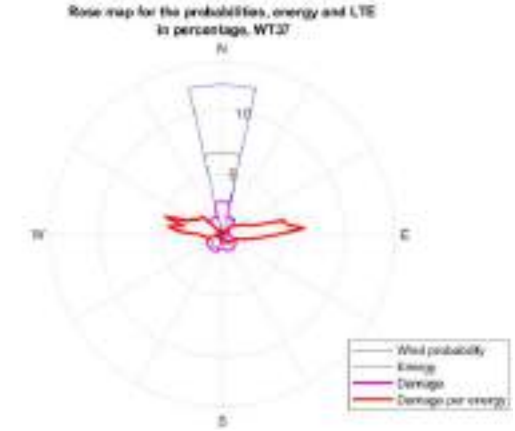
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT37



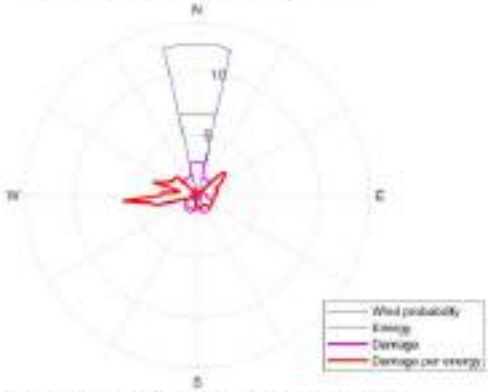
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT37



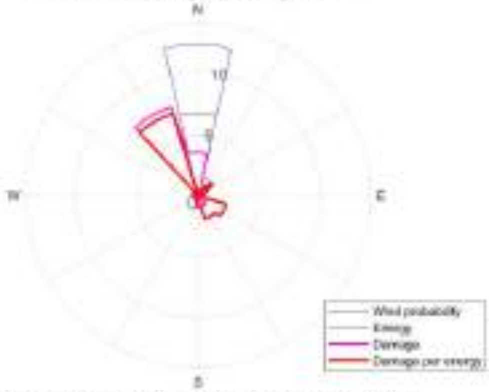

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT37
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT37
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

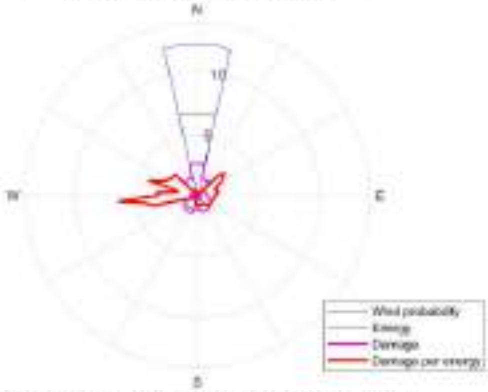
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT38



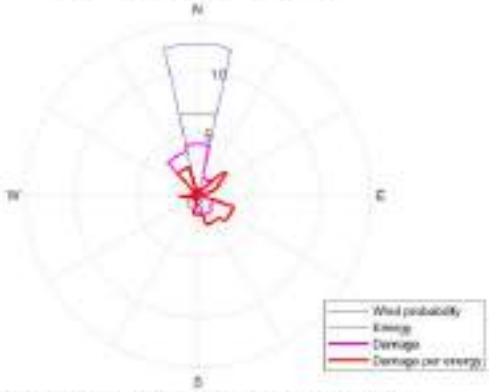
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT38



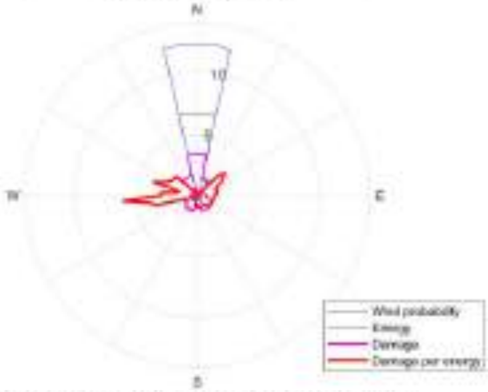
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT38



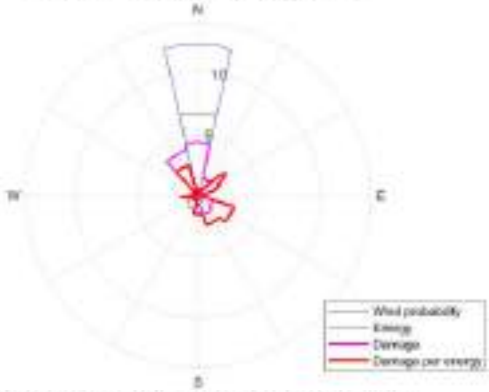
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT38



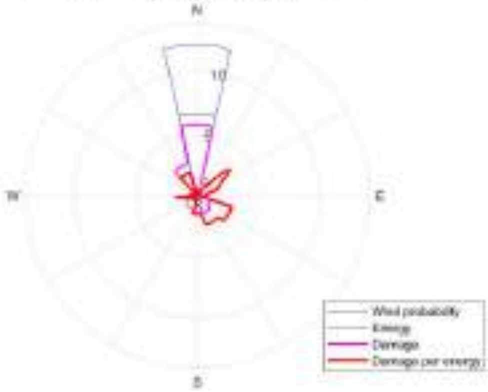
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT38



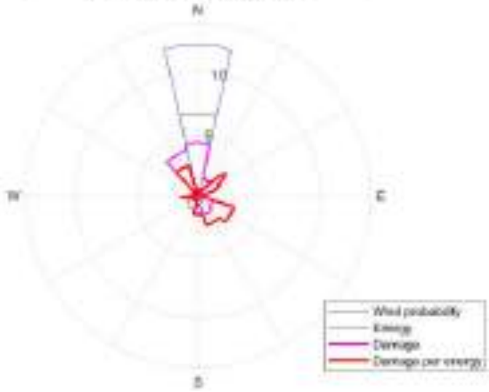
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT38



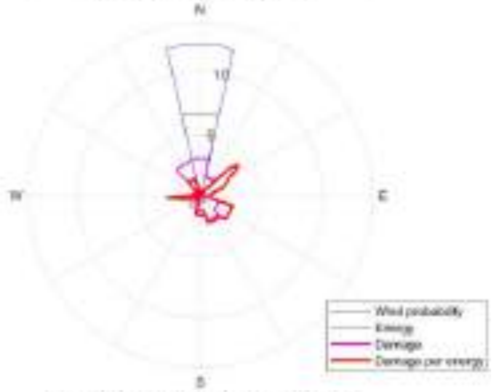
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT38



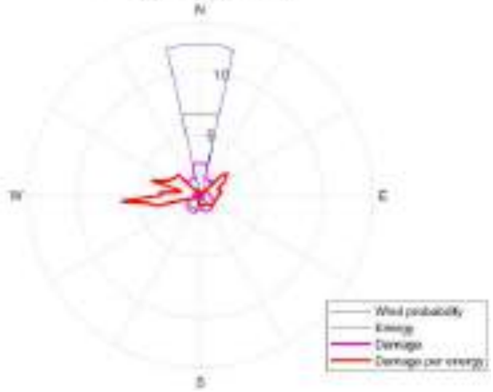
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT38



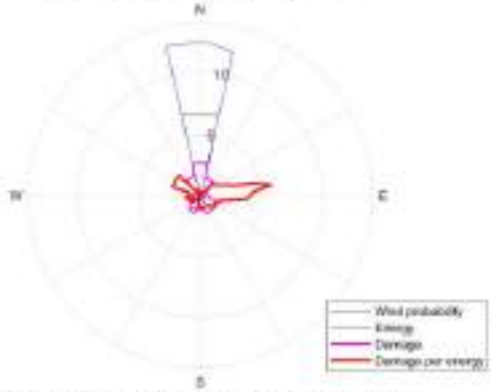
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT38



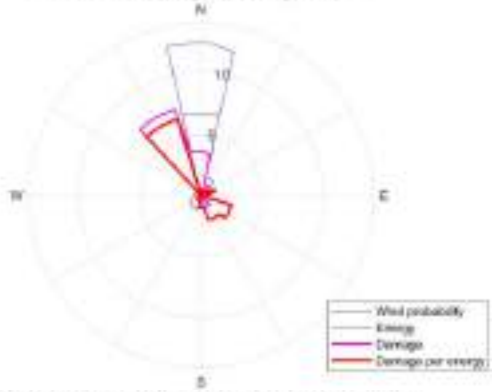
Rose map for the probabilities, energy and LTE in percentage, WT38



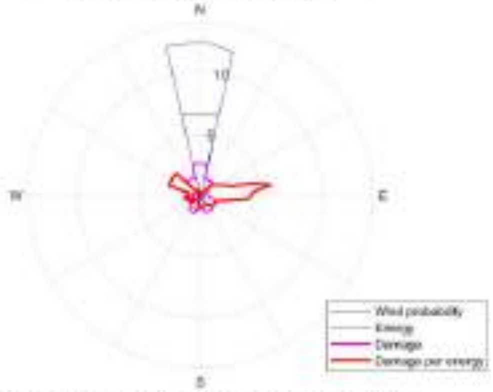
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT39



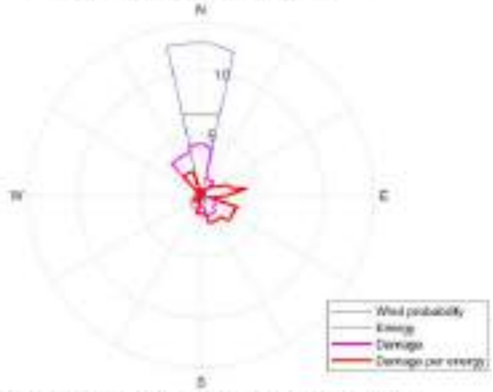
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT39



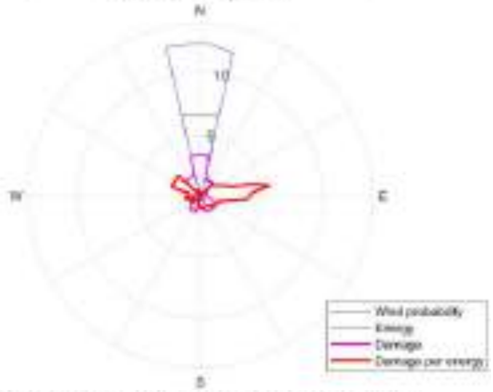
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT39



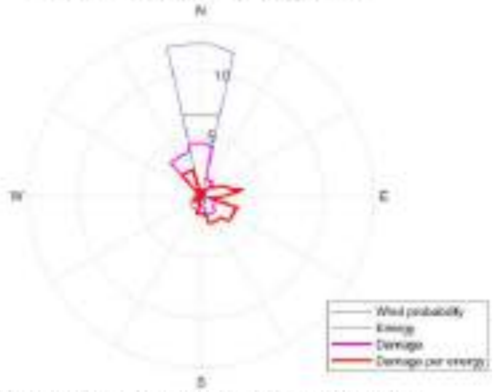
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT39



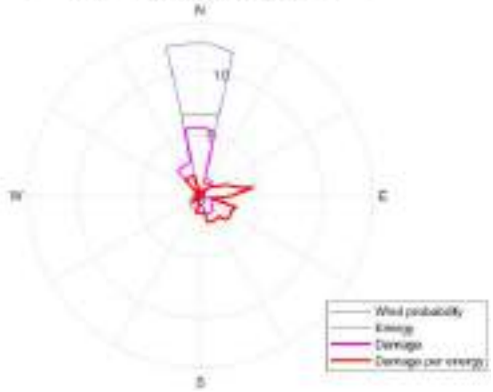
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT39



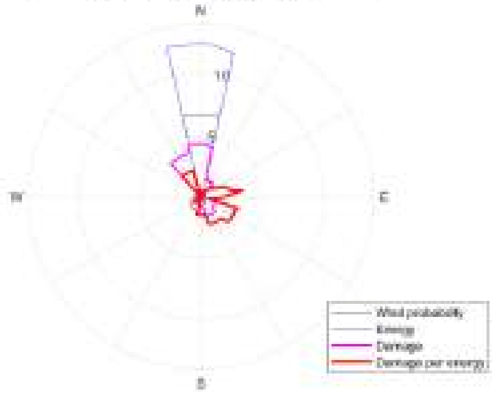
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT39

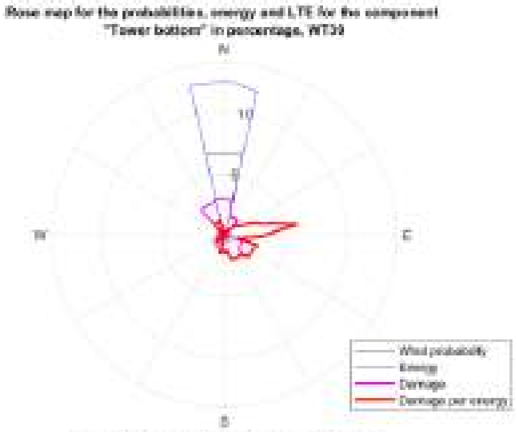


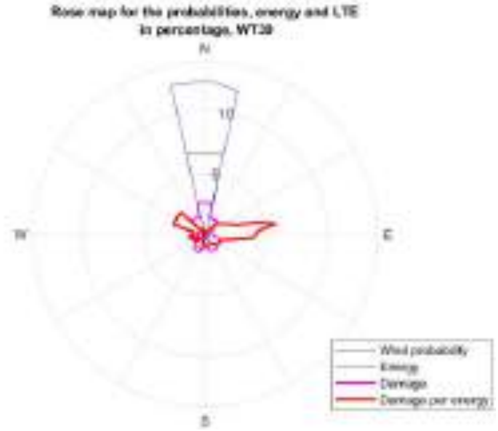
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT39



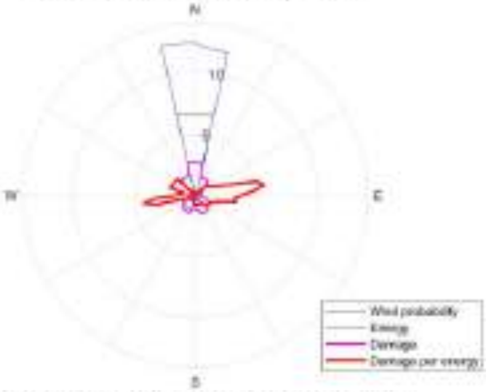
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT39



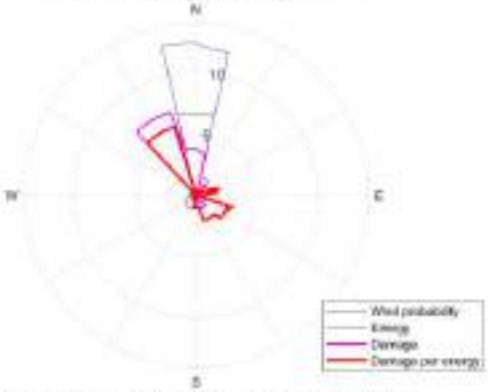

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT39
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT39
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

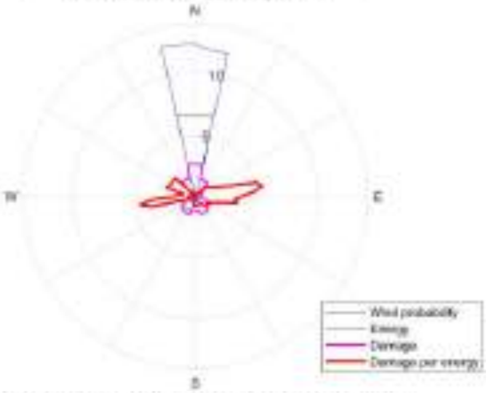
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT40



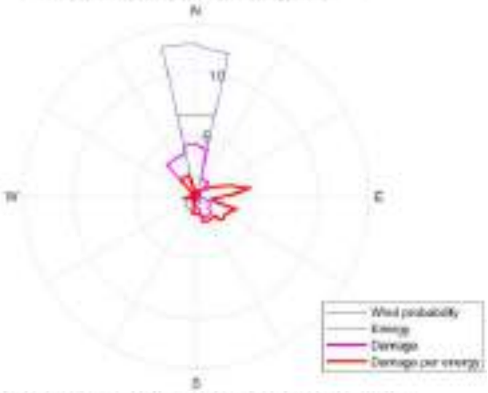
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT40



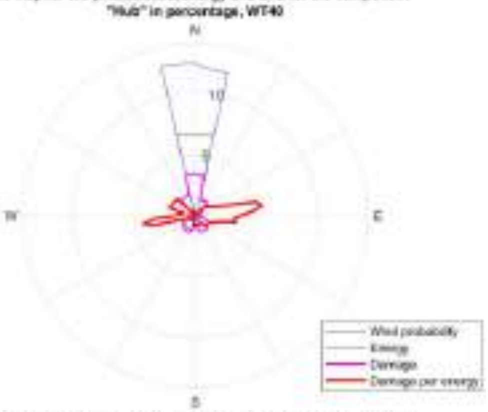
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT40



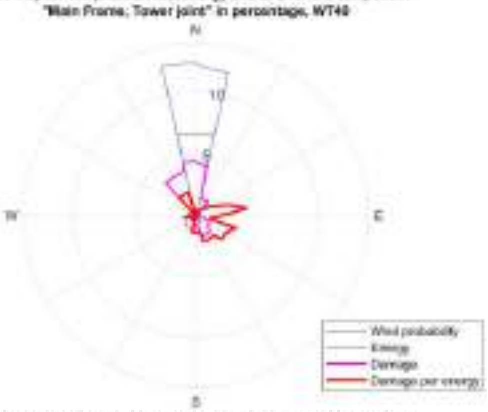
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT40



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT40

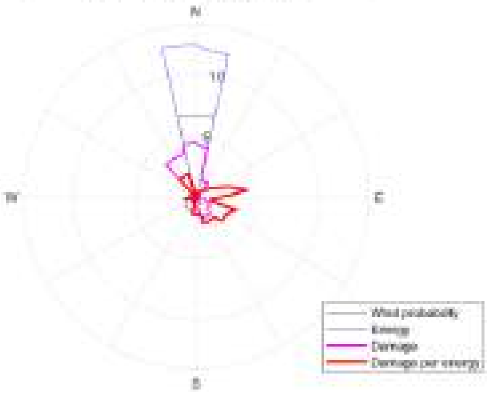


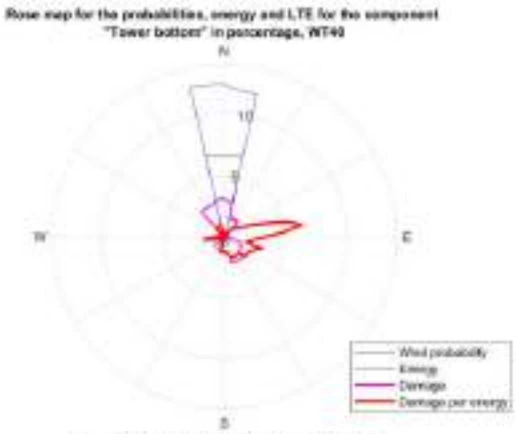
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT40

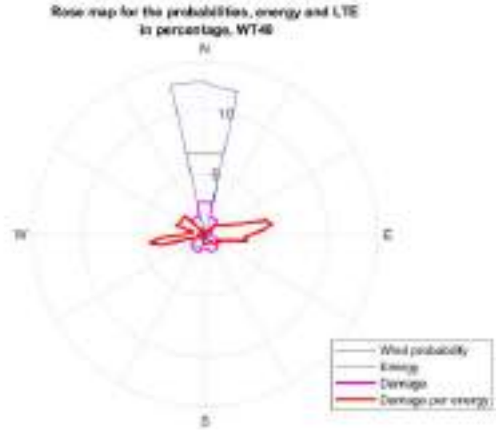


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT40

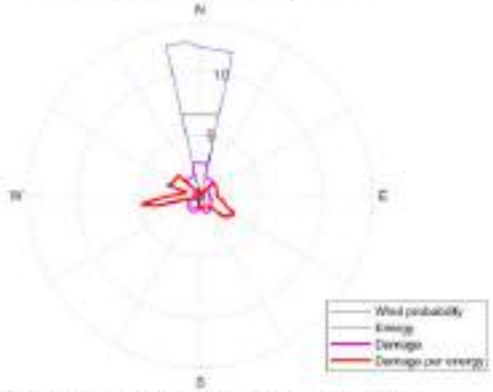
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT40



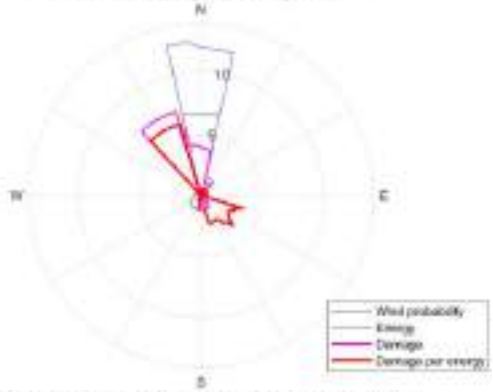

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT40
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT40
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

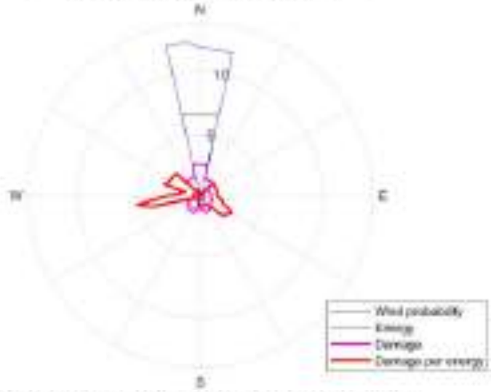
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT41



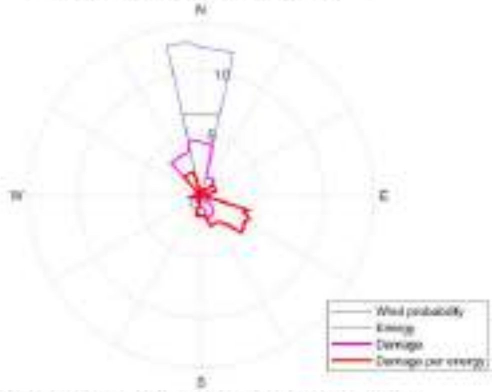
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT41



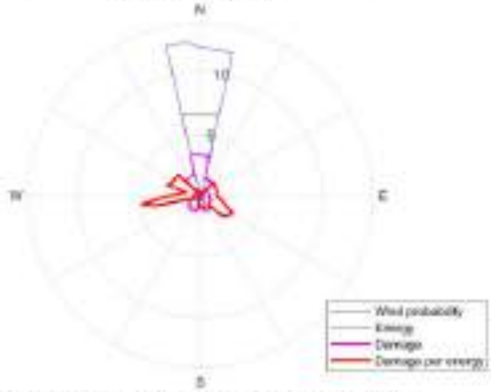
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT41



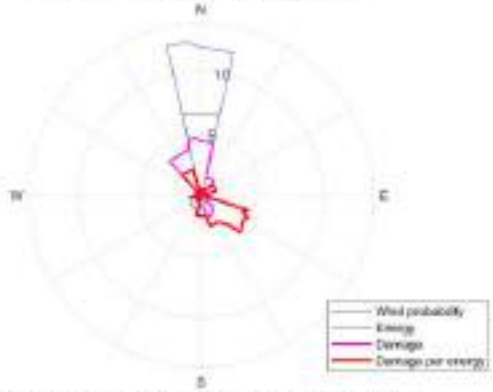
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT41



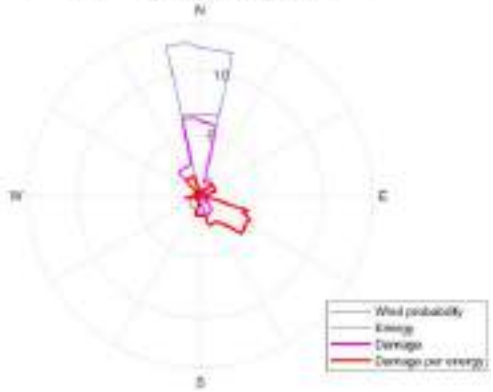
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT41



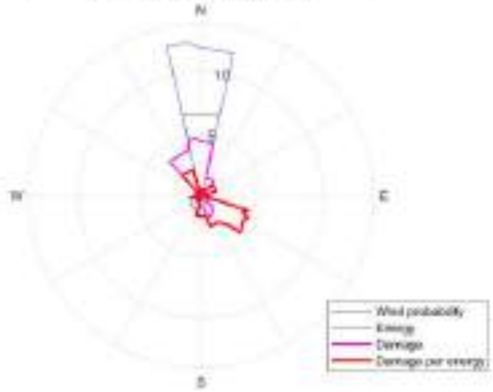
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT41



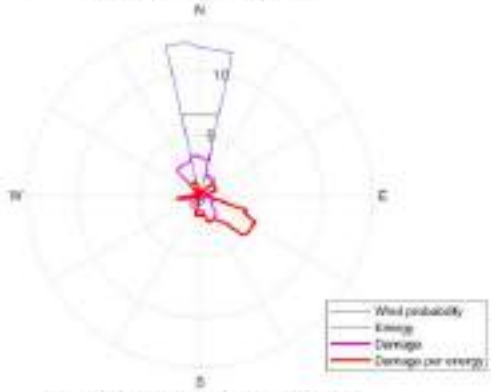
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT41



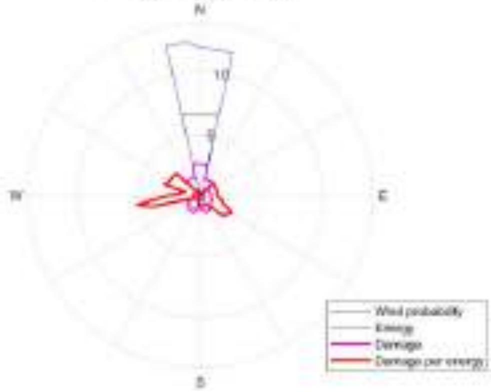
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT41



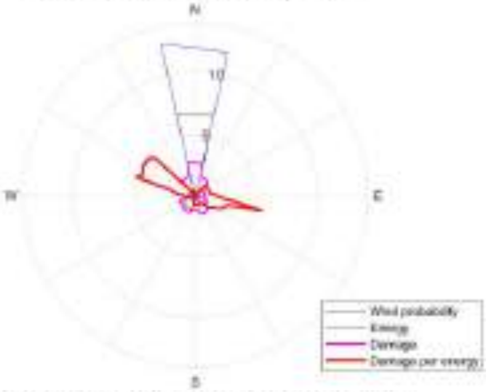
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT41



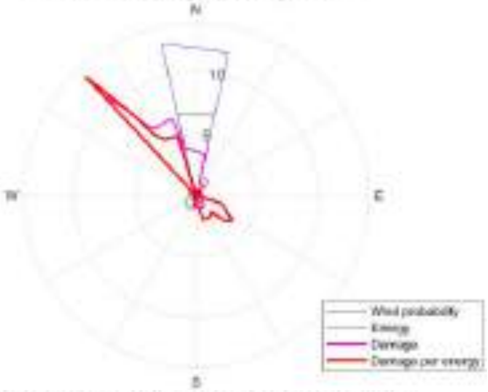
Rose map for the probabilities, energy and LTE in percentage, WT41



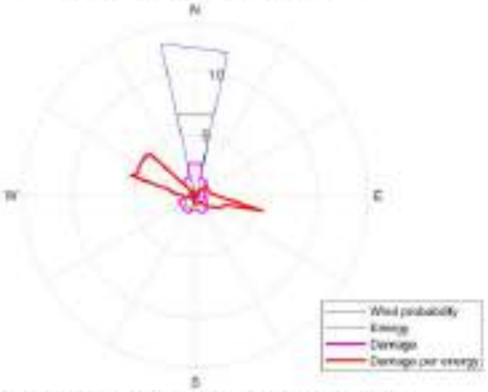
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT42



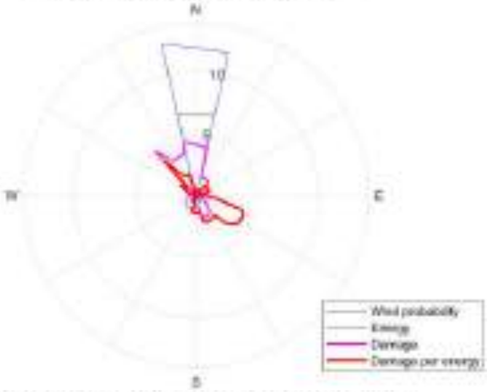
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT42



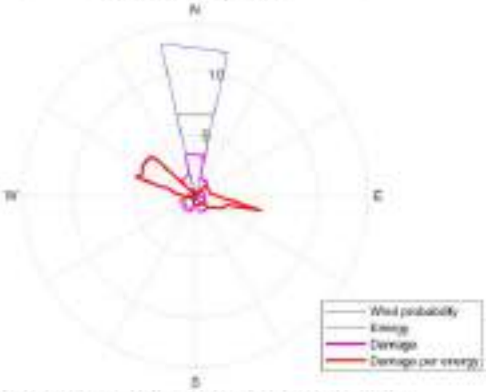
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT42



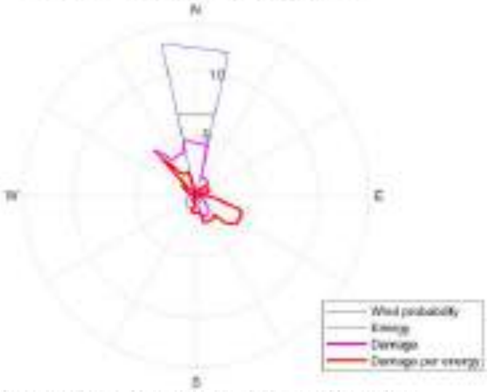
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT42



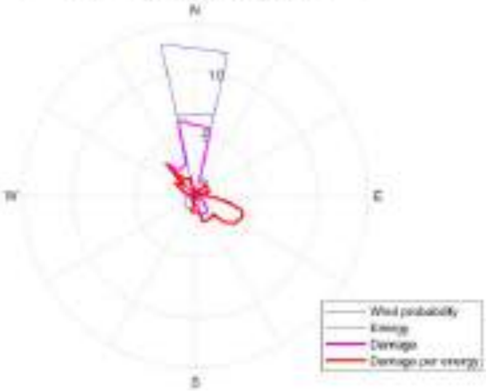
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT42



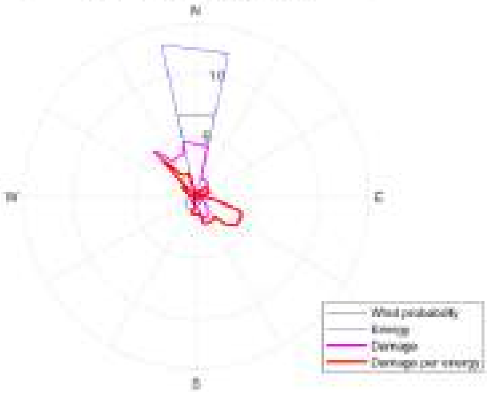
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT42



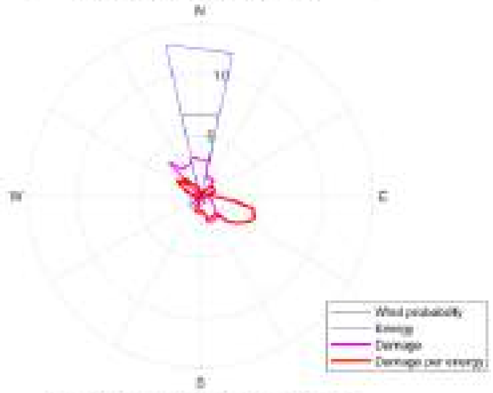
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT42



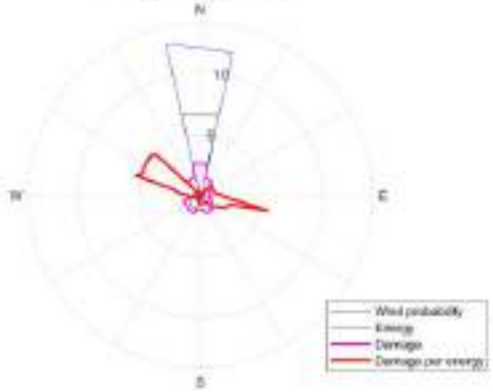
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT42



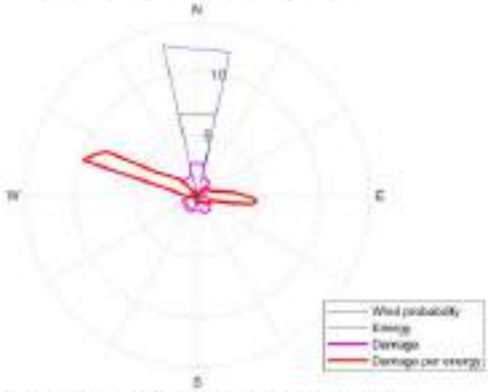
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT42



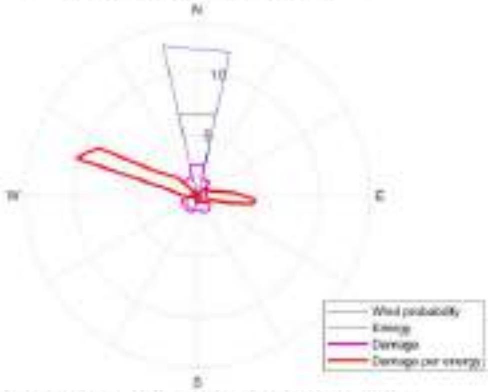
Rose map for the probabilities, energy and LTE in percentage, WT42



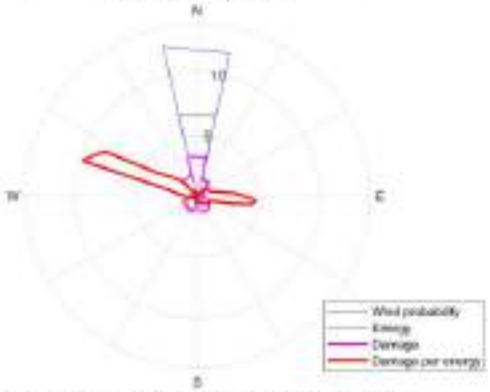
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT43



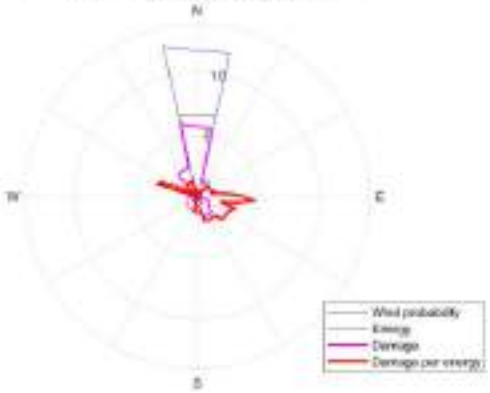
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT43



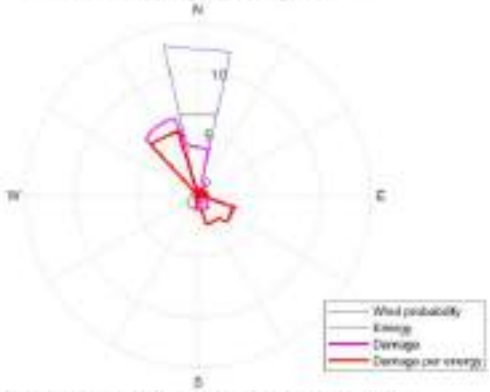
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT43



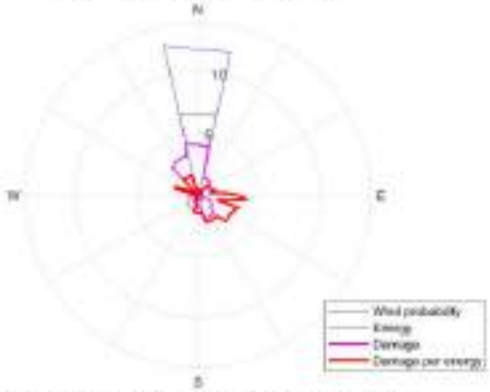
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT43



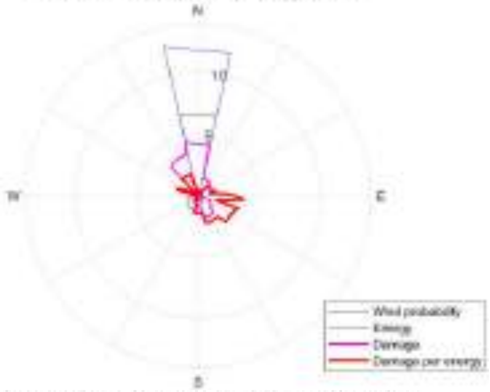
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT43



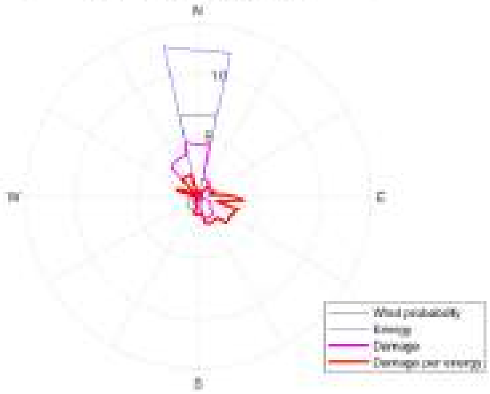
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT43



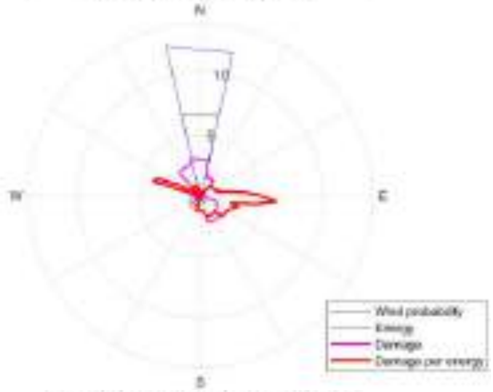
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT43



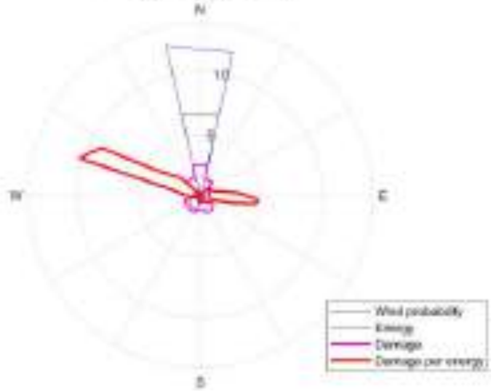
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT43



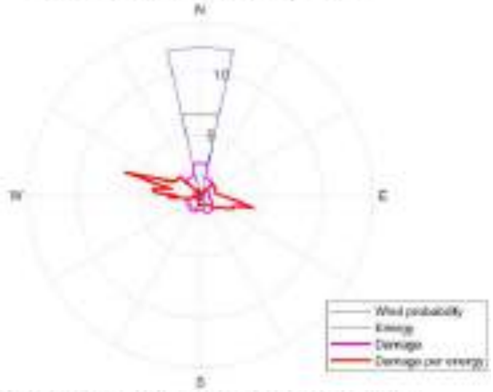
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT43



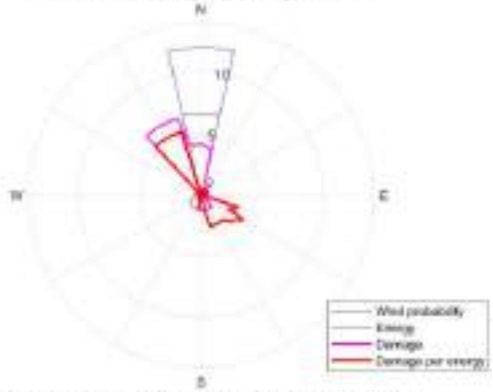
Rose map for the probabilities, energy and LTE in percentage, WT43



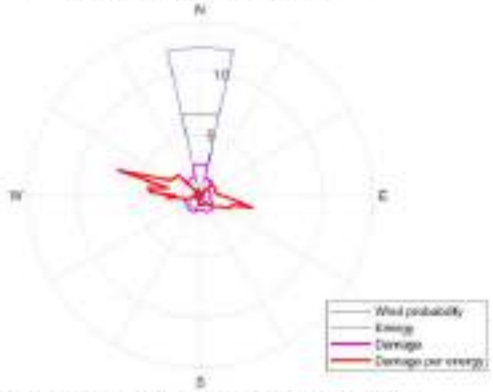
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT44



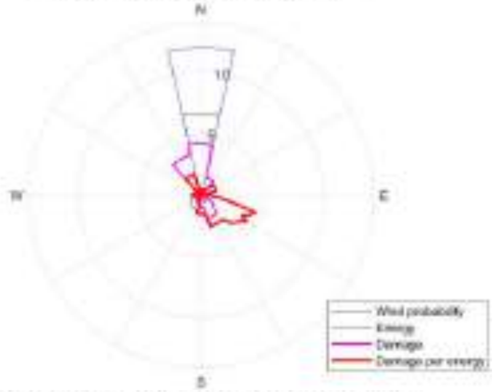
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT44



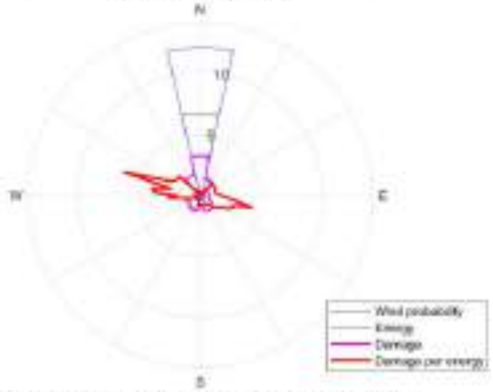
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT44



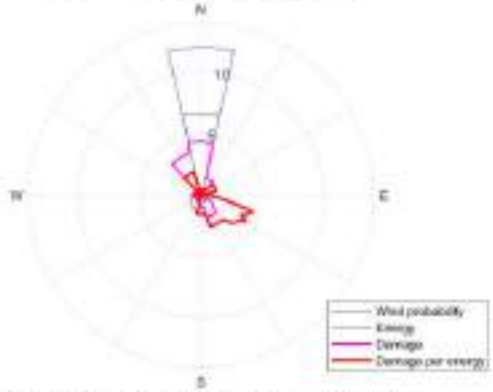
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT44



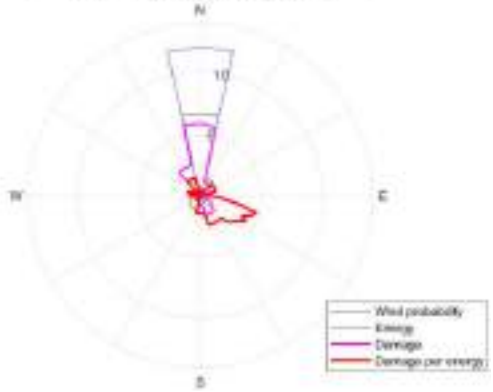
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT44



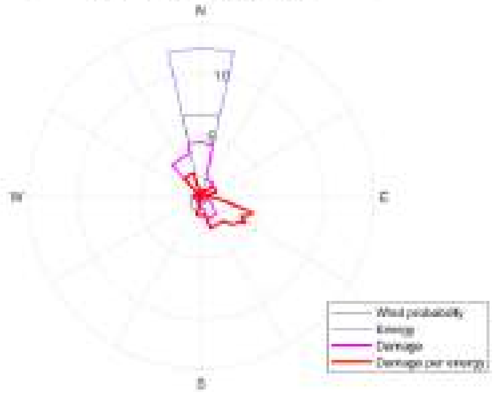
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT44



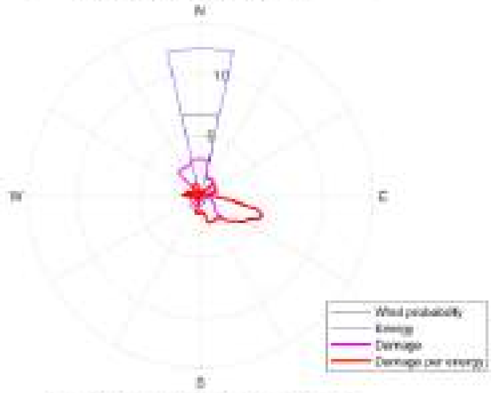
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT44



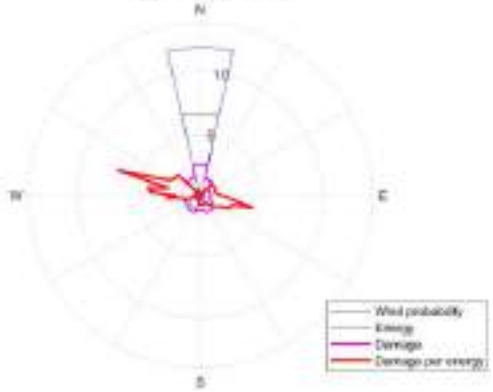
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT44



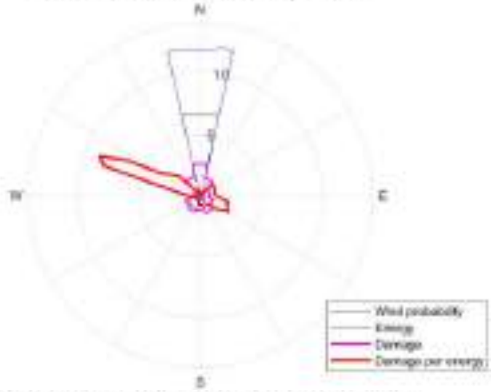
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT44



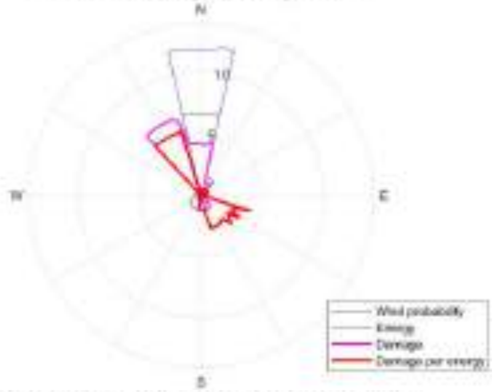
Rose map for the probabilities, energy and LTE in percentage, WT44



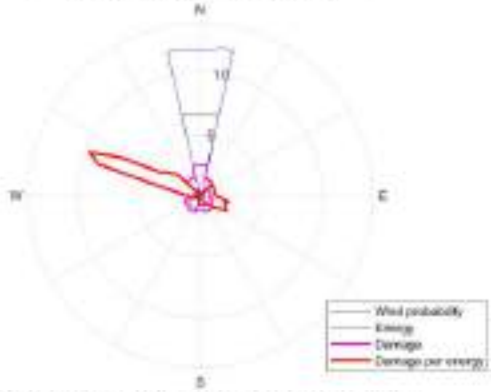
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT45



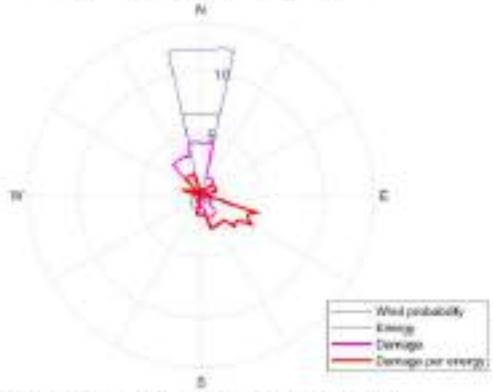
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT45



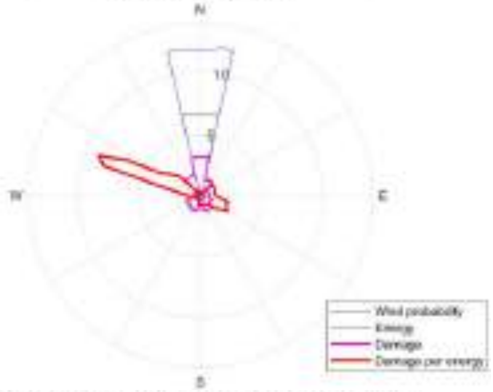
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT45



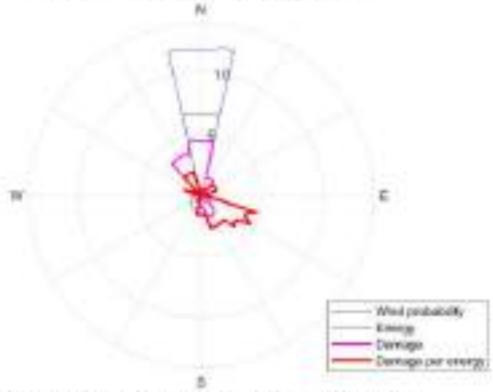
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT45



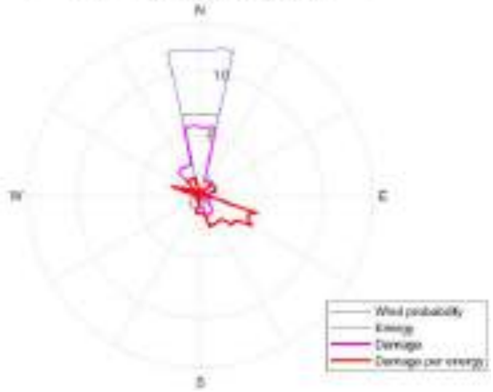
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT45



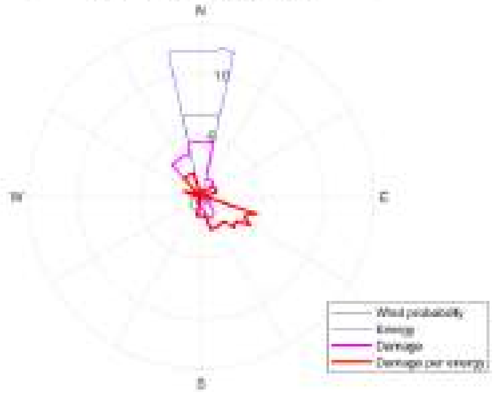
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT45

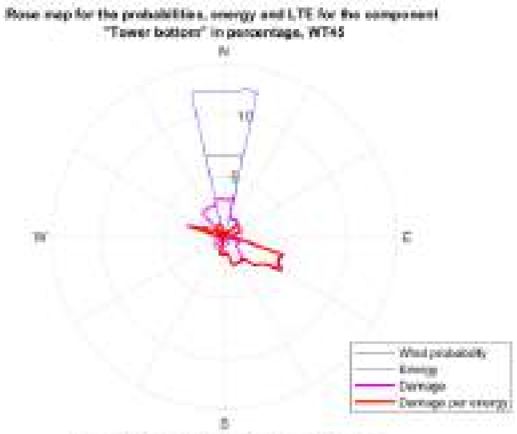


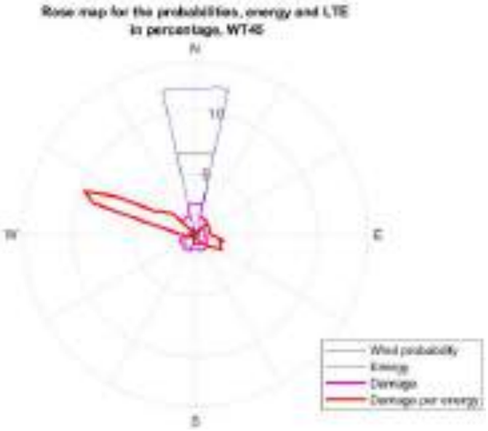
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT45



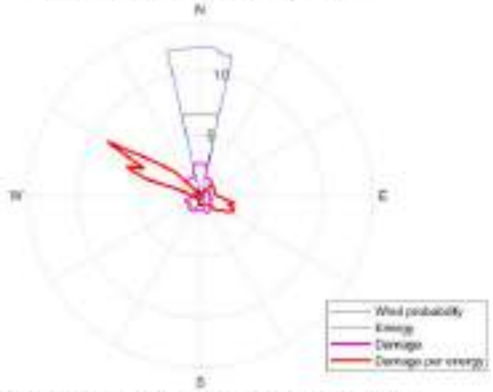
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT45



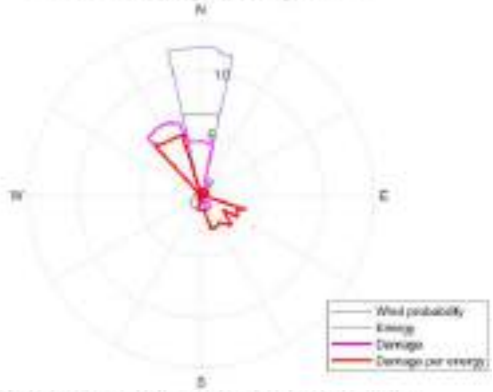

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT45
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT45
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

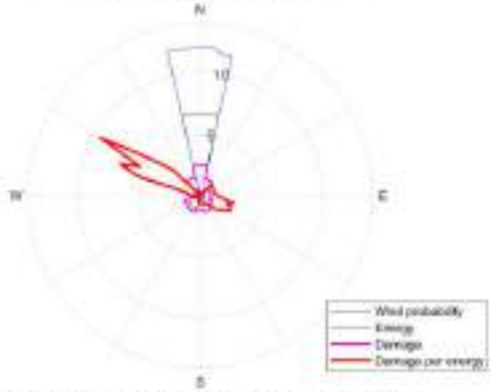
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT46



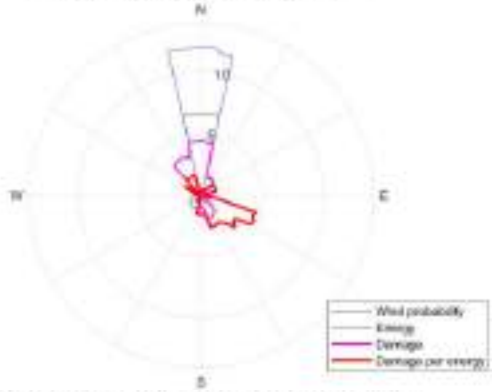
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT46



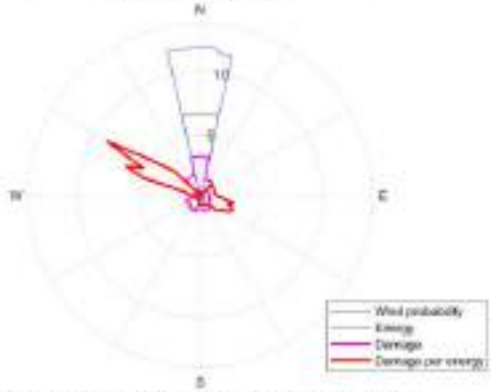
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT46



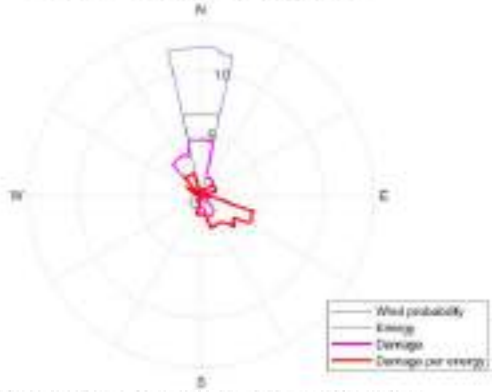
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT46



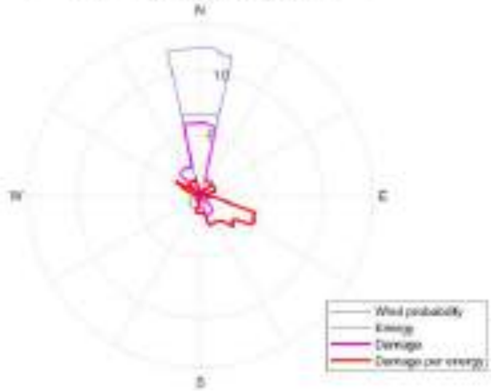
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT46



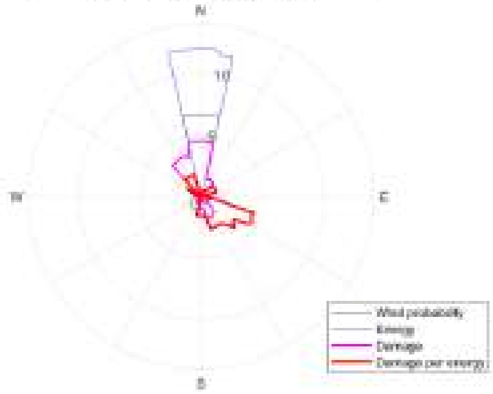
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT46

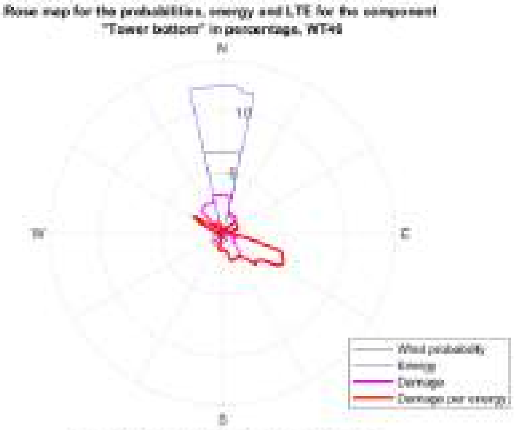


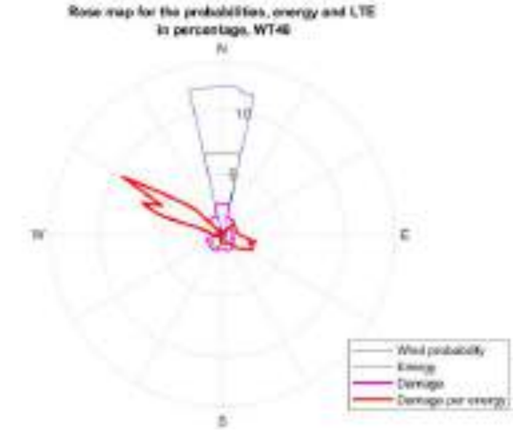
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT46



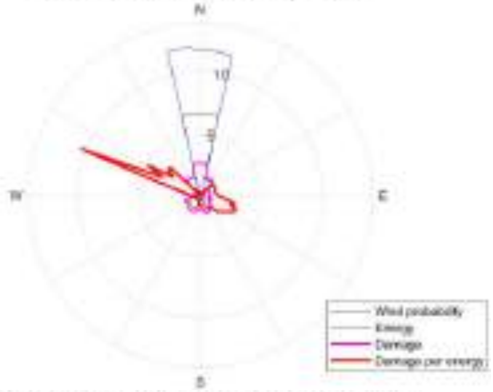
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT46



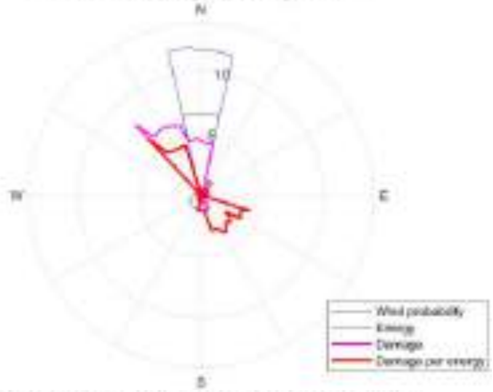

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT46
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT46
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

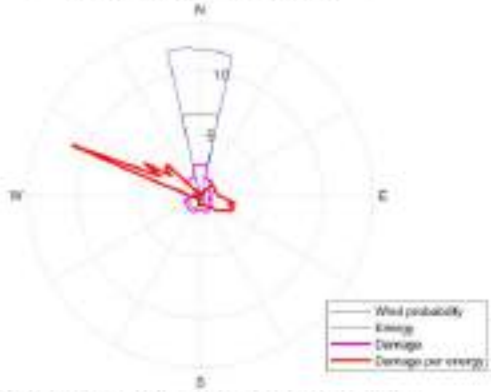
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT47



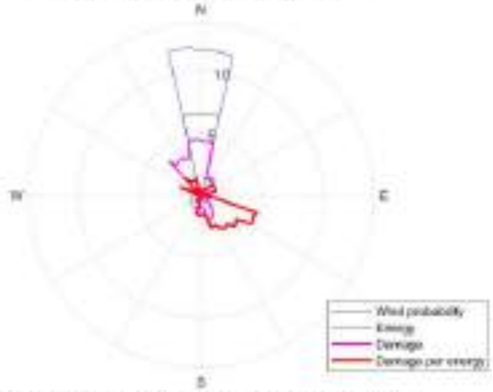
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT47



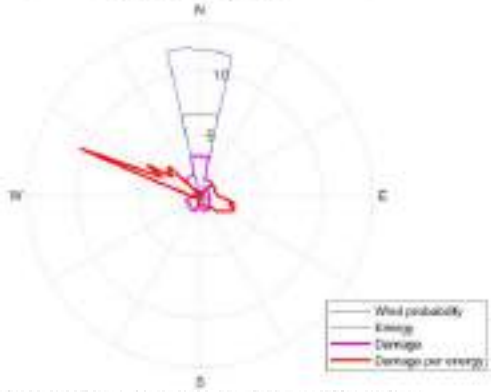
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT47



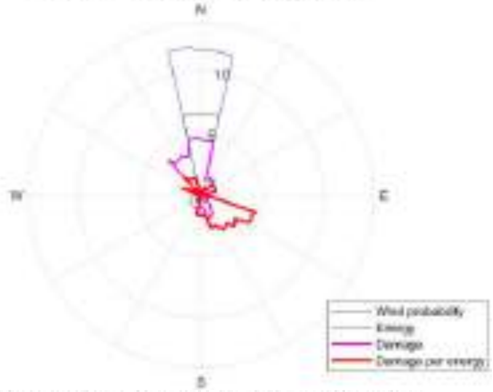
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT47



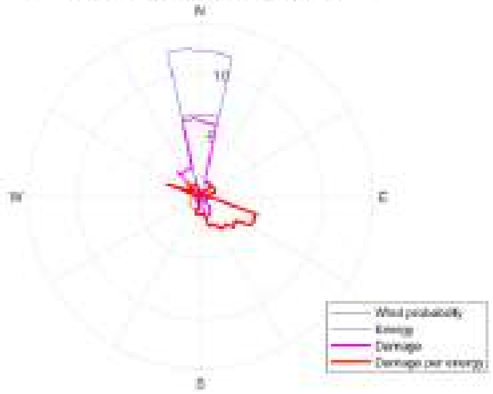
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT47



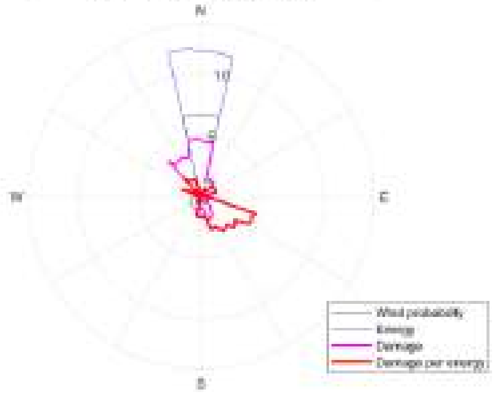
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT47

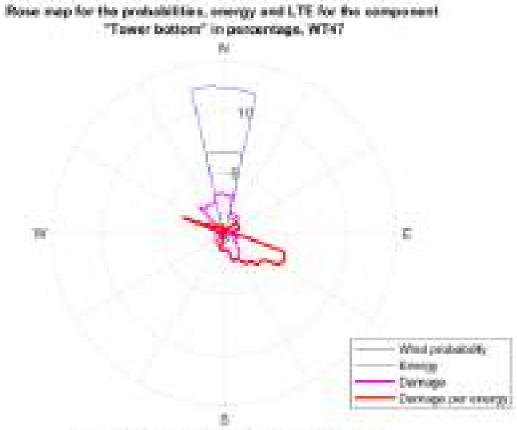


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT47



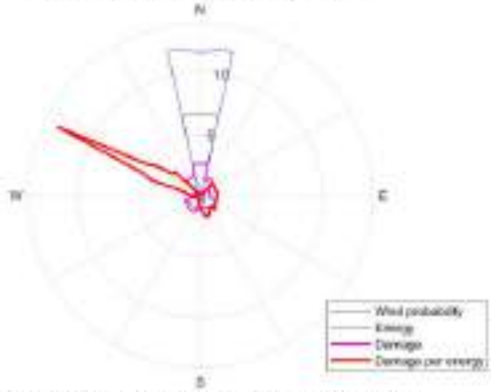
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT47



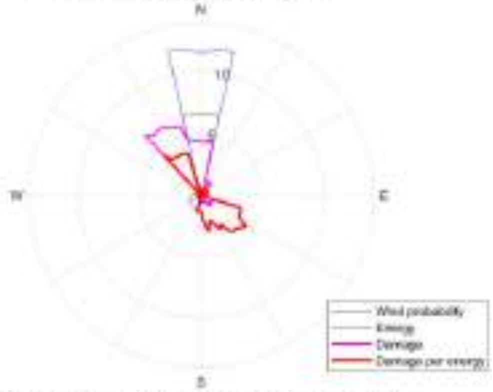

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT47
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT47
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

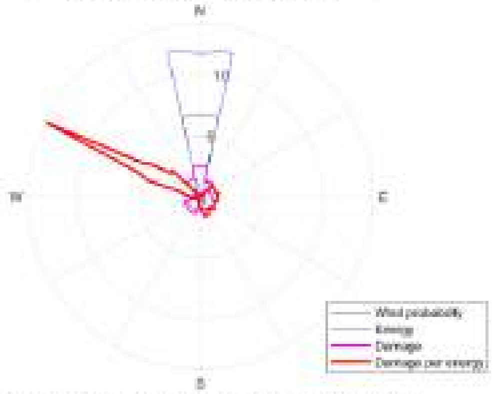
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT48



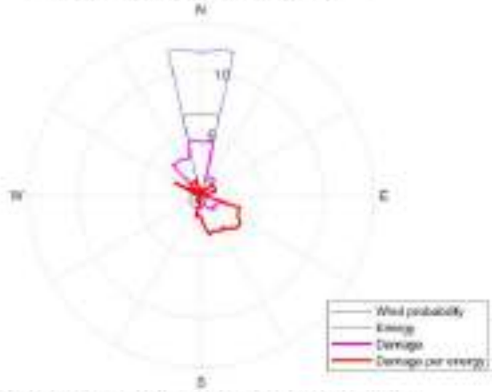
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT48



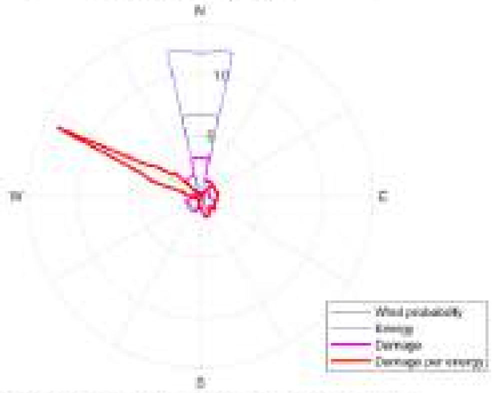
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT48



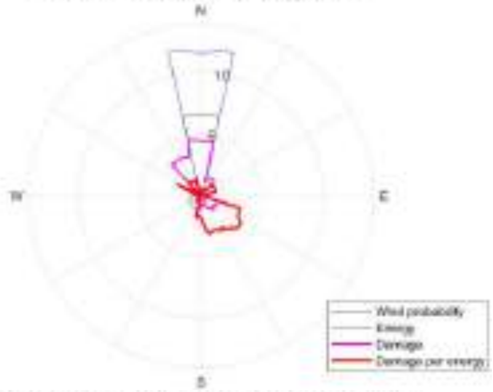
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT48



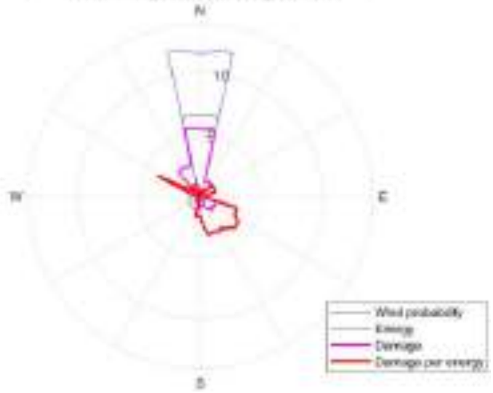
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT48



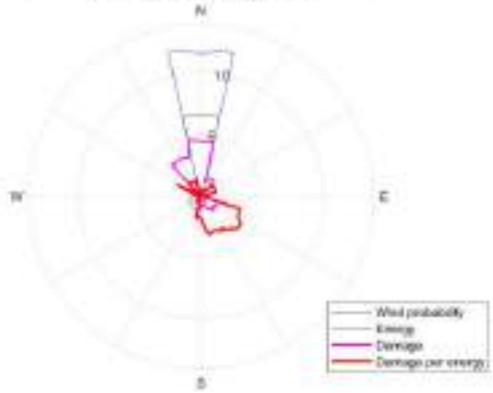
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT48

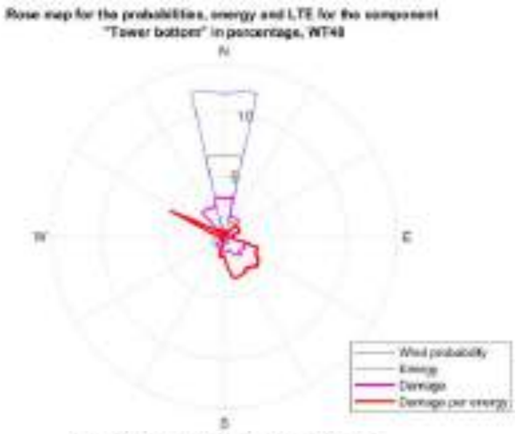


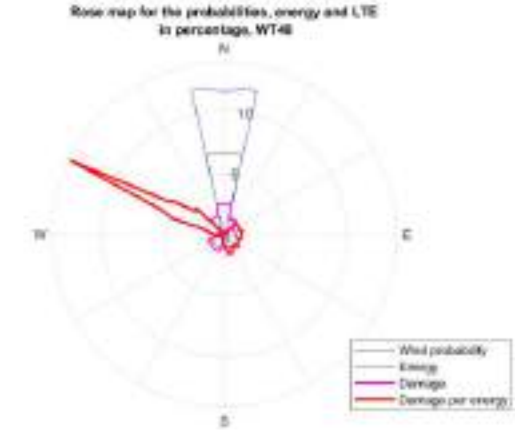
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT48



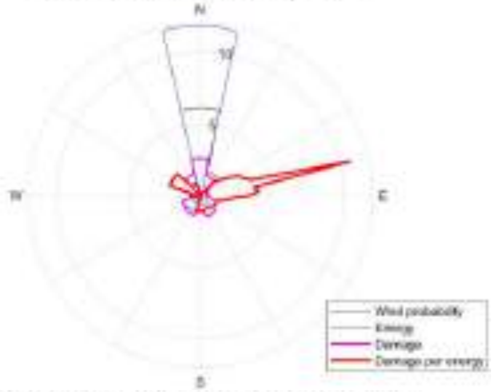
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT48



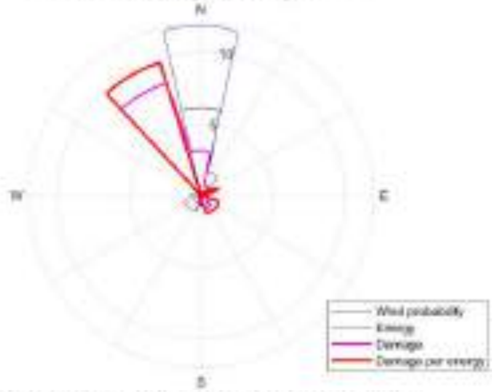

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT48
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT48
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy

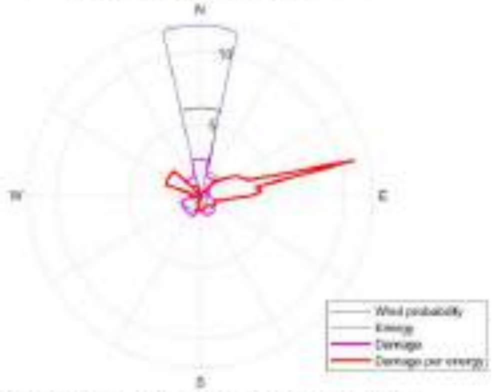
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT49



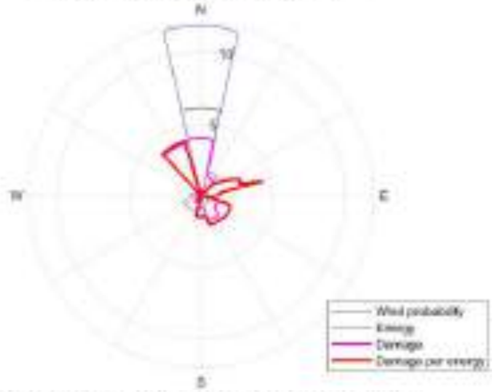
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT49



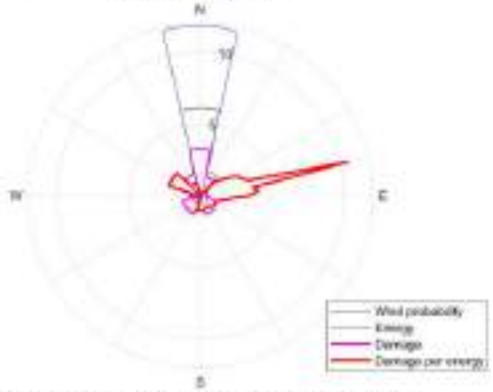
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT49



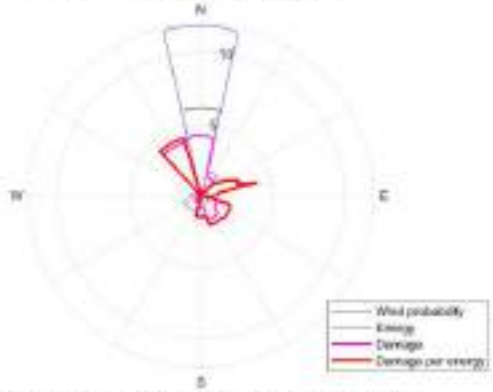
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT49



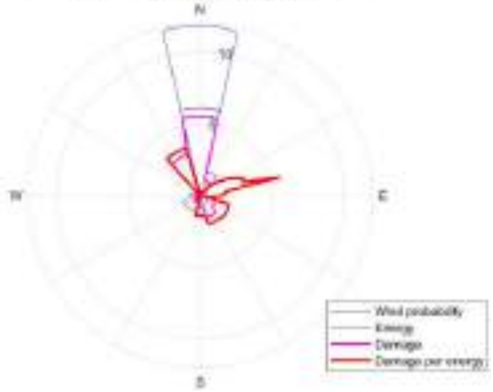
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT49



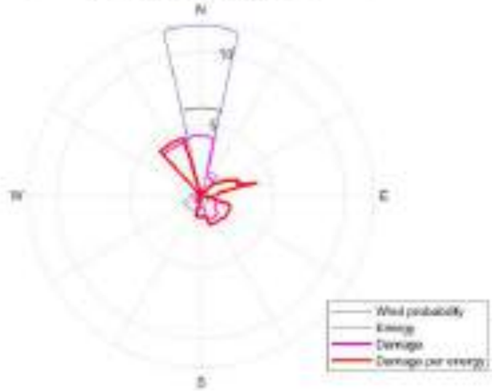
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT49

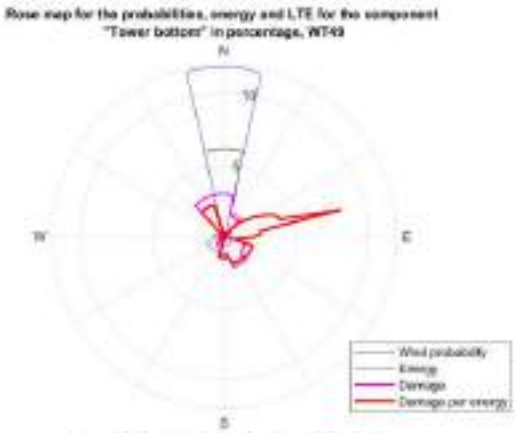


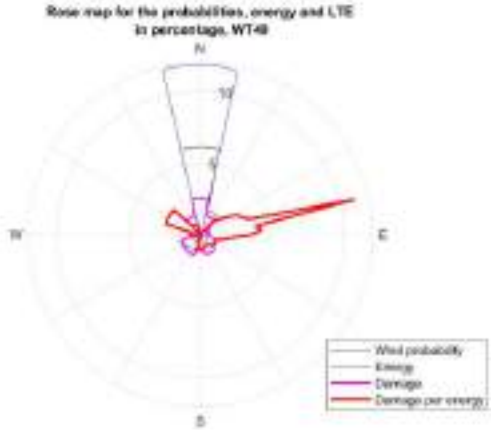
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT49



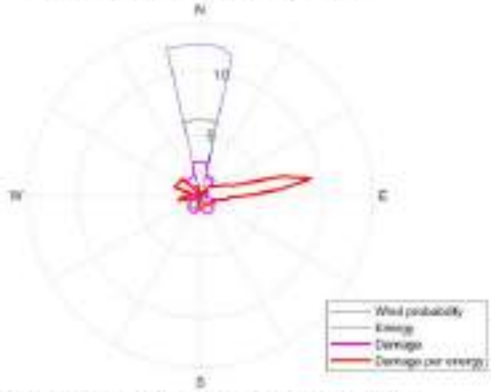
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT49



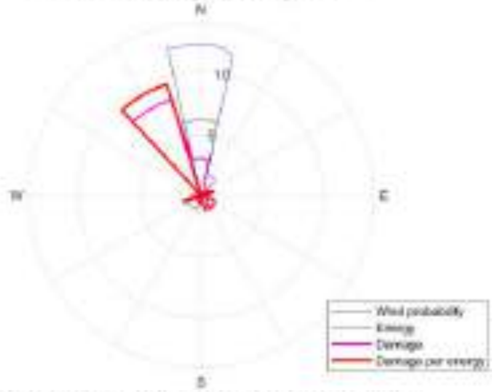

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT49
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT49
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

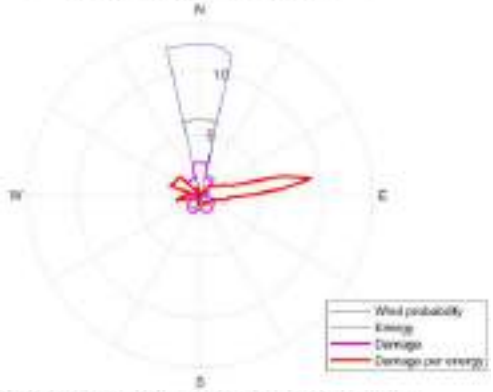
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT58



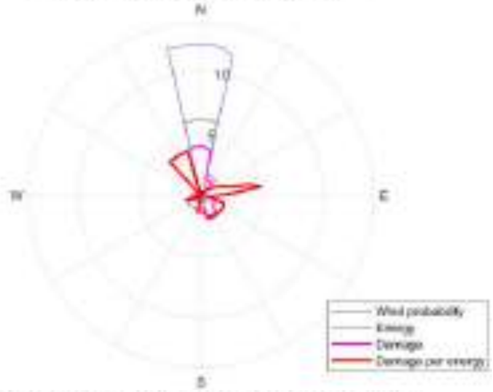
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT58



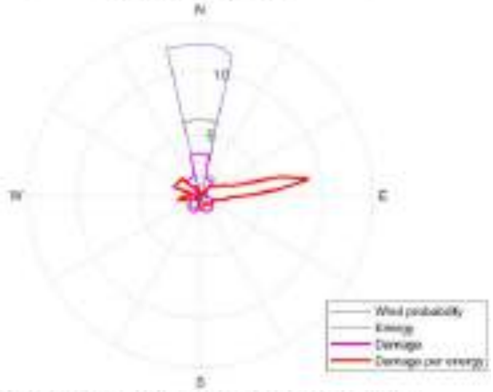
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT58



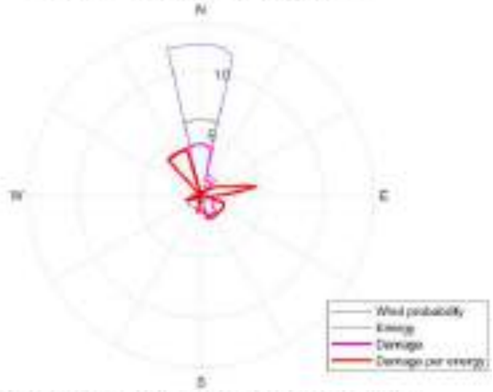
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT58



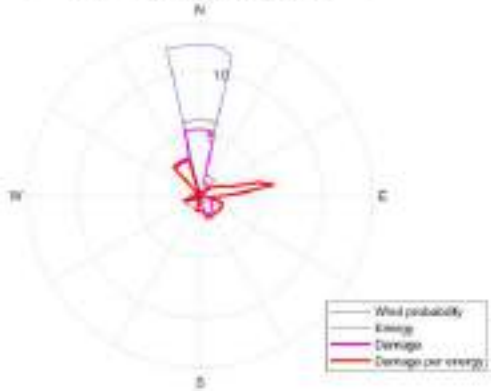
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT58



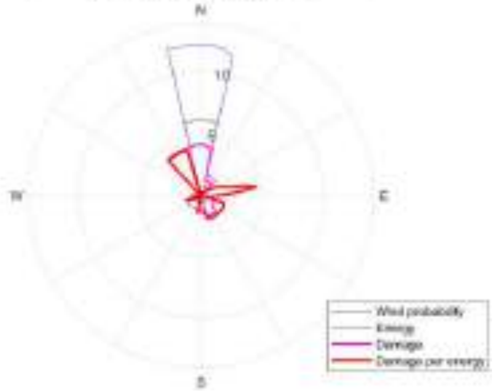
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT58



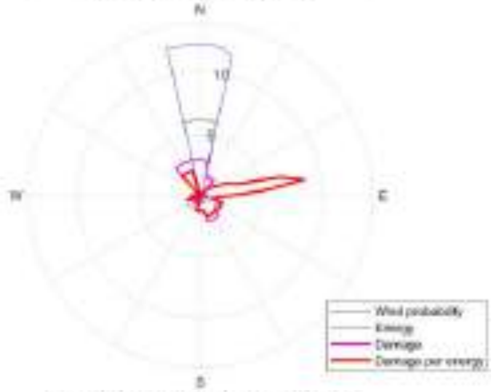
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT58



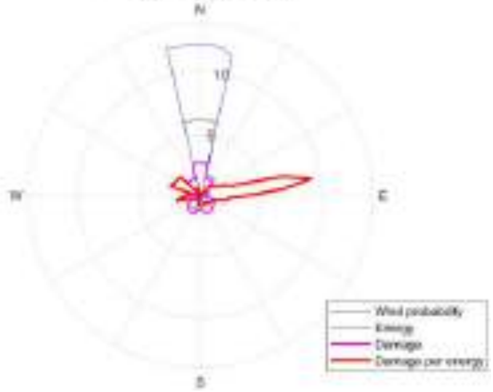
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT58

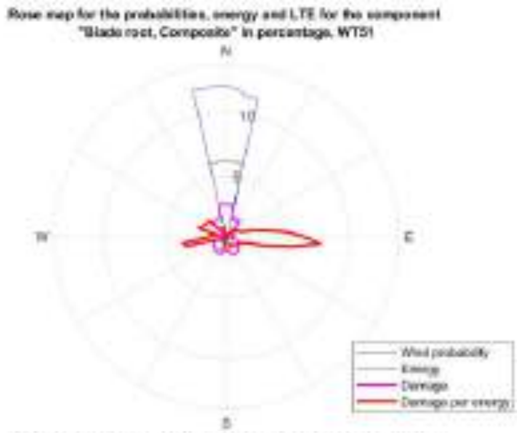


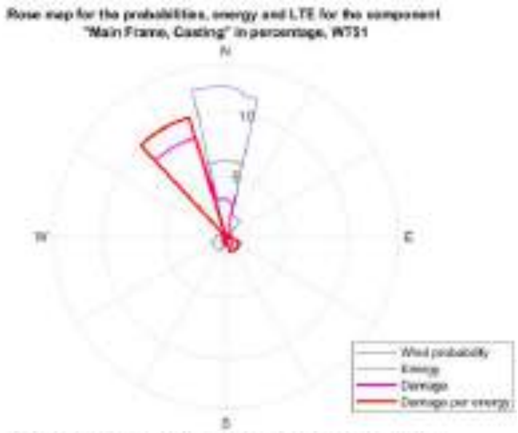
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT50

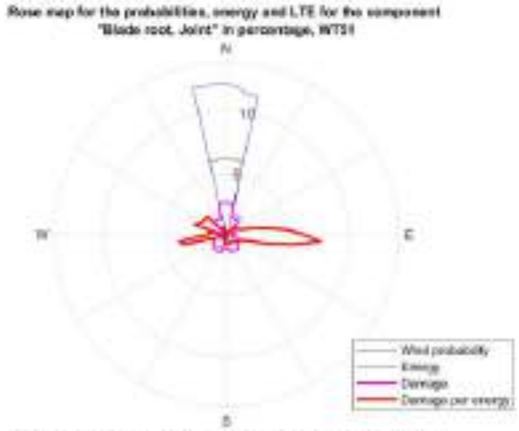


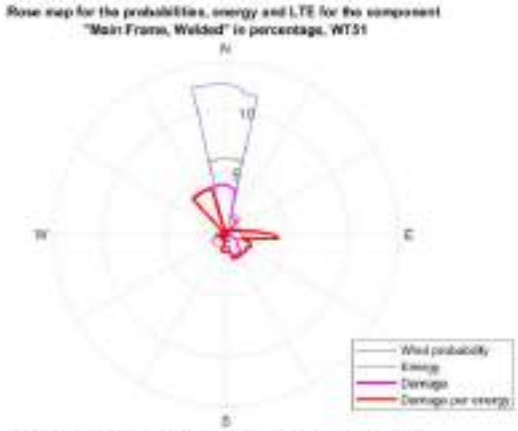
Rose map for the probabilities, energy and LTE in percentage, WT50

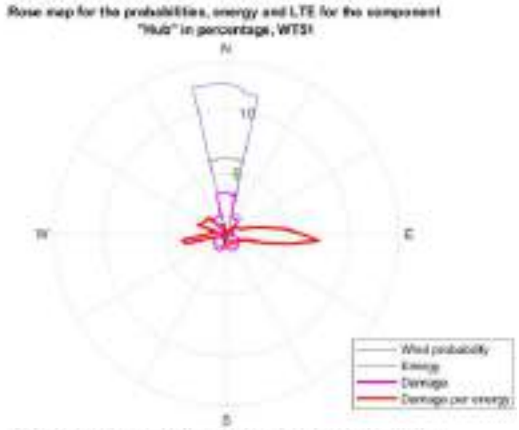


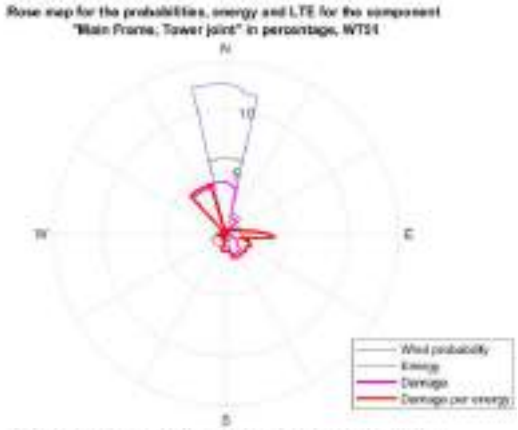

Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WTS1
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

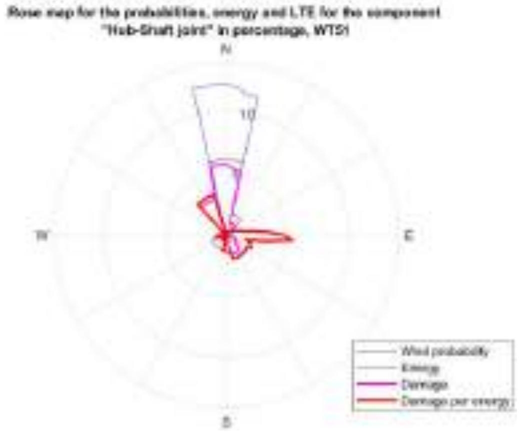

Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WTS1
N
10
5
W
E
Wind probability
Energy
Damage
Damage per energy

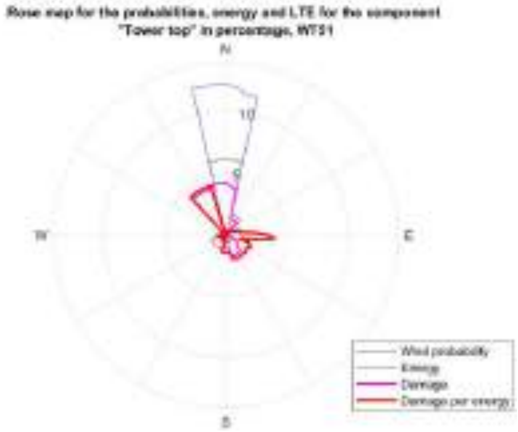

Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WTS1
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

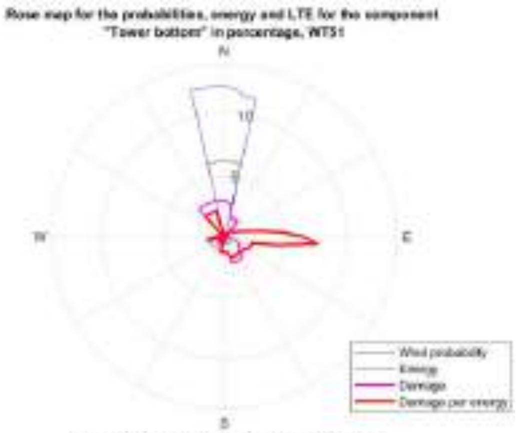

Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WTS1
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

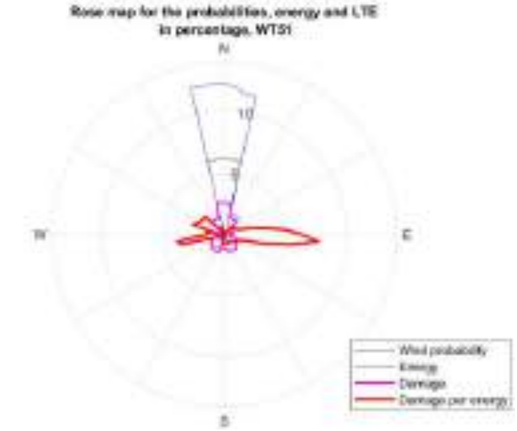

Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WTS1
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WTS1
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

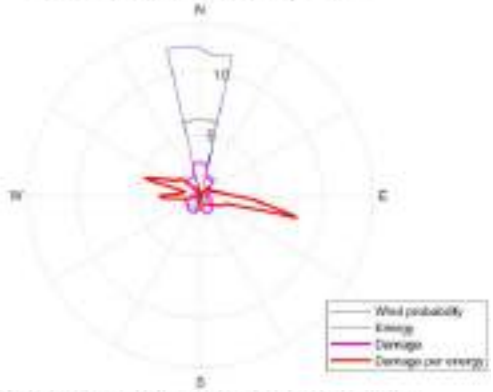

Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WTS1
N
10
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WTS1
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

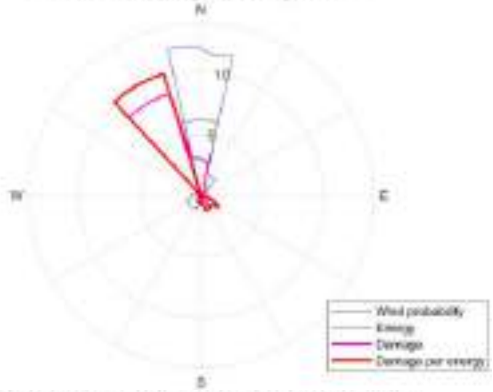

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT51
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT51
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

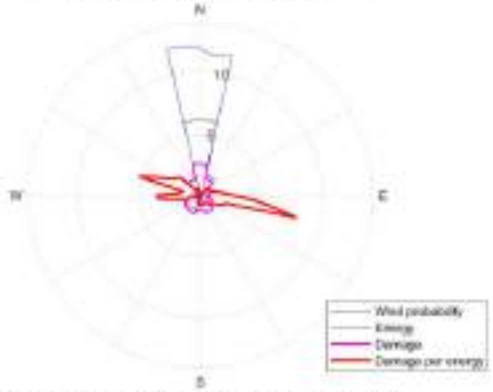
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WTS2



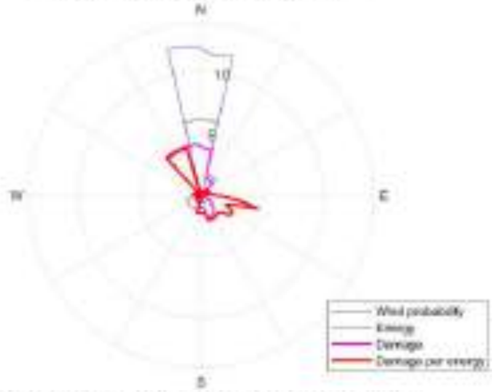
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WTS2



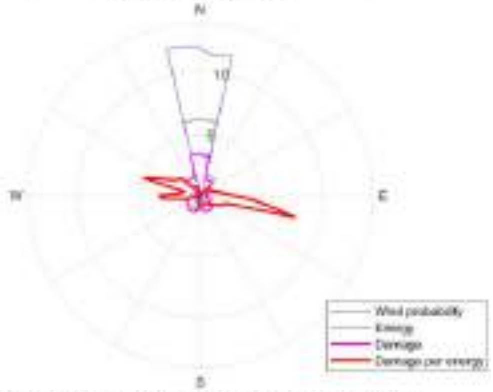
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WTS2



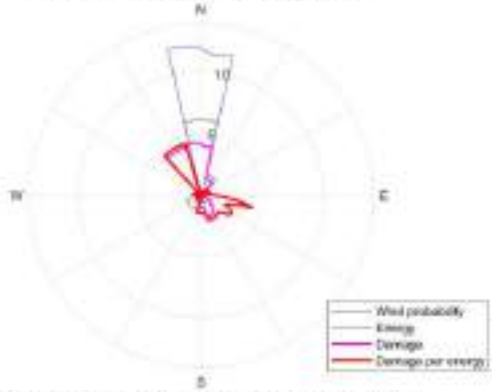
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WTS2



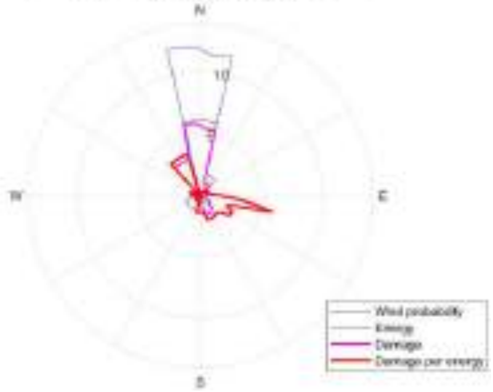
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WTS2



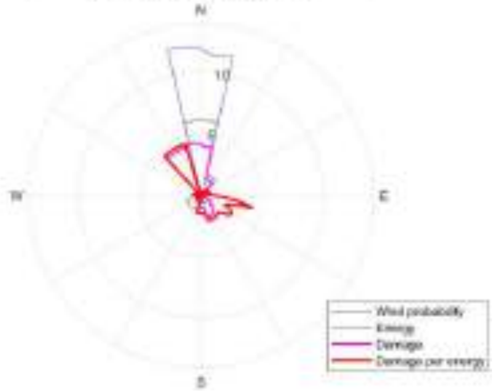
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WTS2

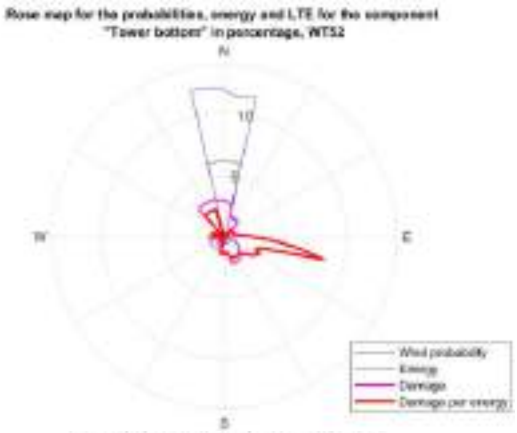


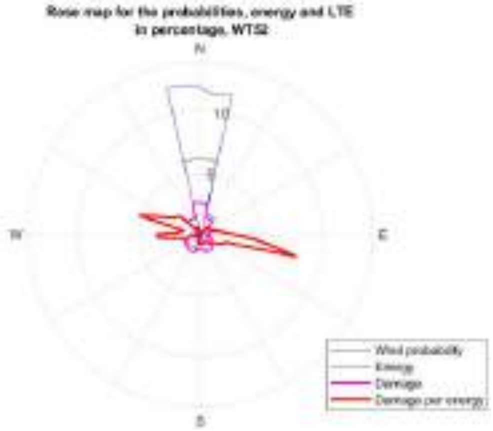
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WTS2



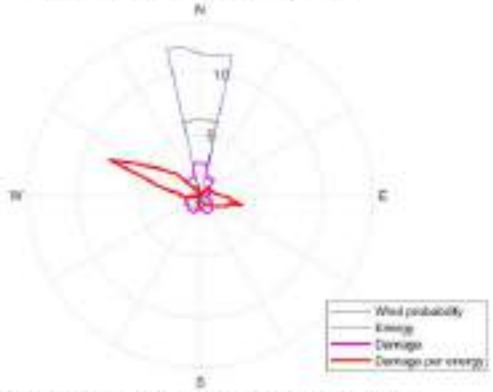
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WTS2



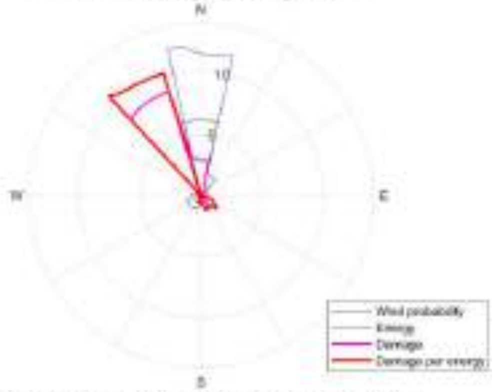

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT52
N
W
E
S
10
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT52
N
W
E
S
10
Wind probability
Energy
Damage
Damage per energy

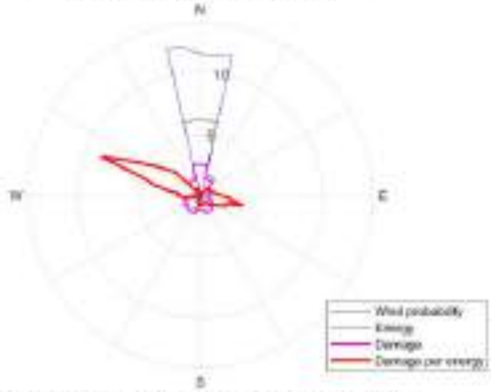
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WTS3



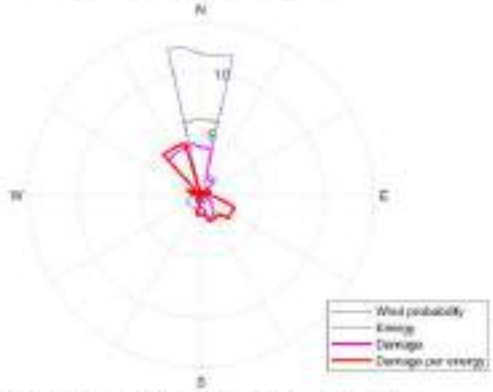
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WTS3



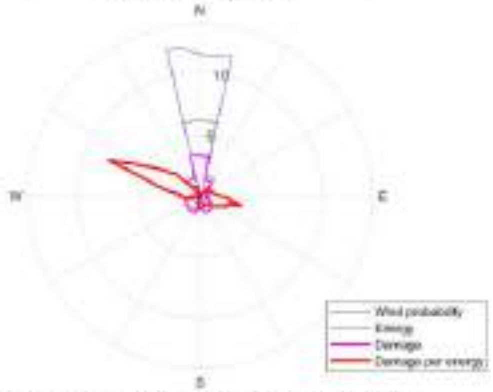
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WTS3



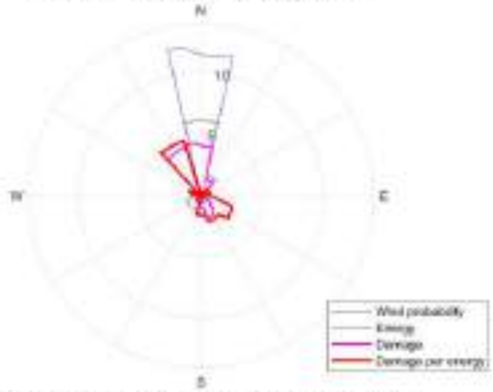
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WTS3



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WTS3

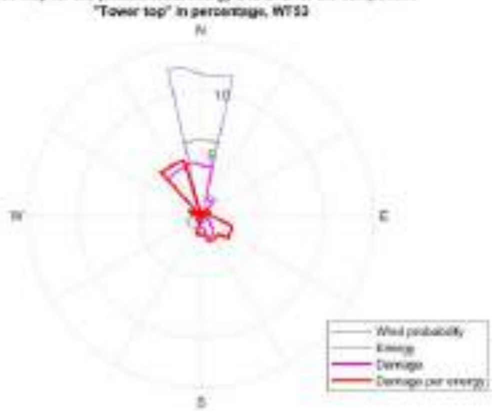


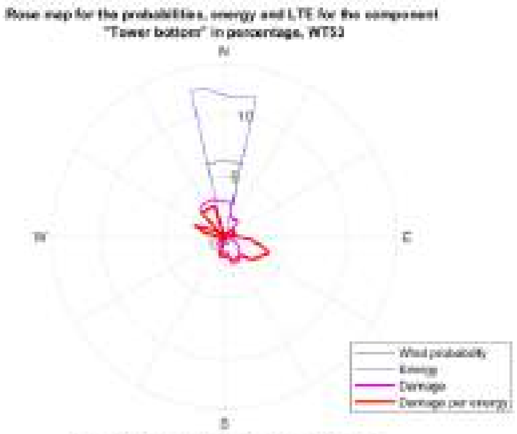
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WTS3

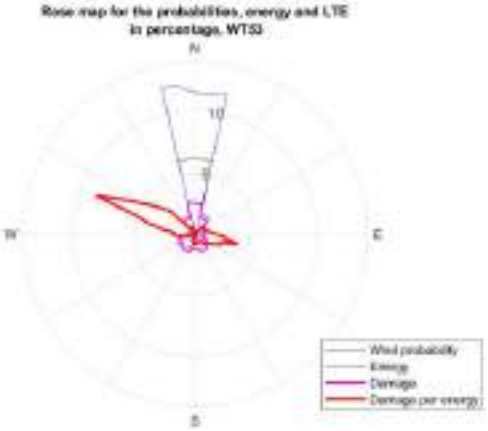


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WTS3

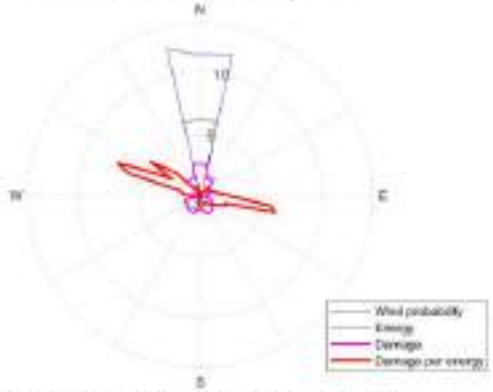
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WTS3



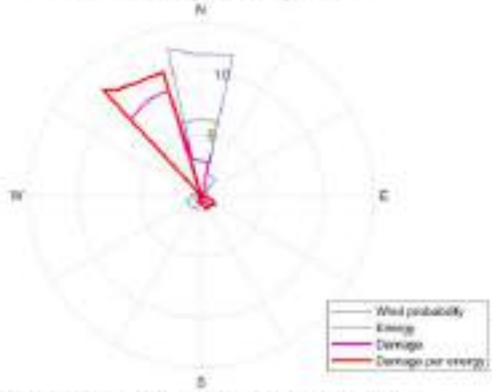

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT53
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT53
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

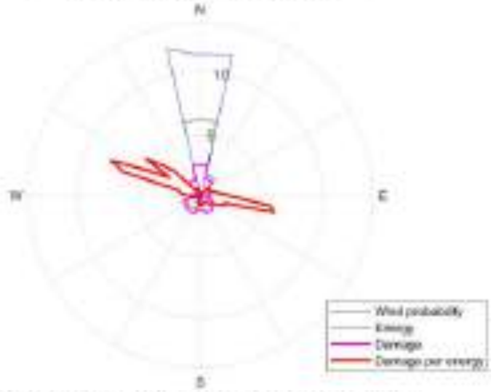
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT54



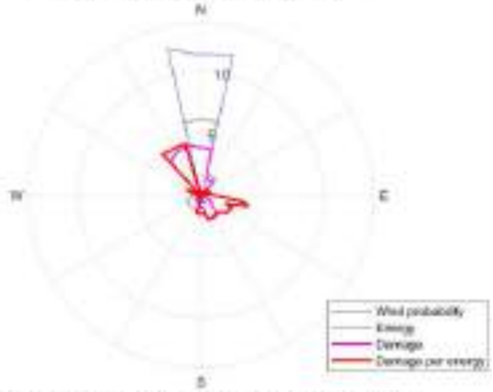
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT54



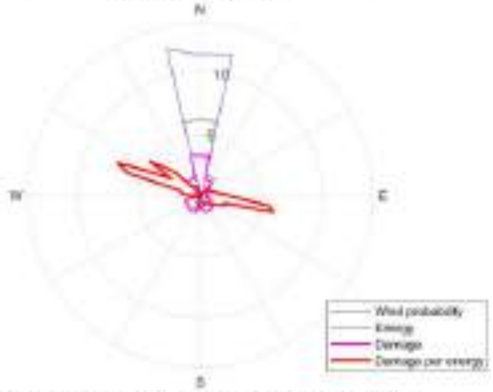
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT54



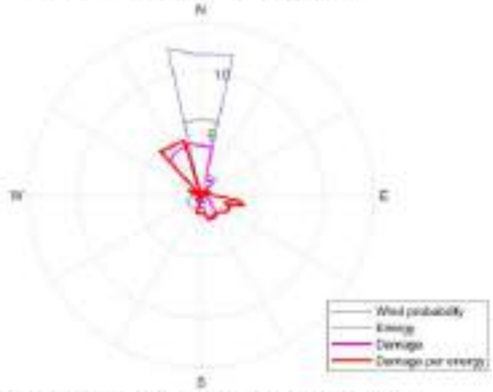
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT54



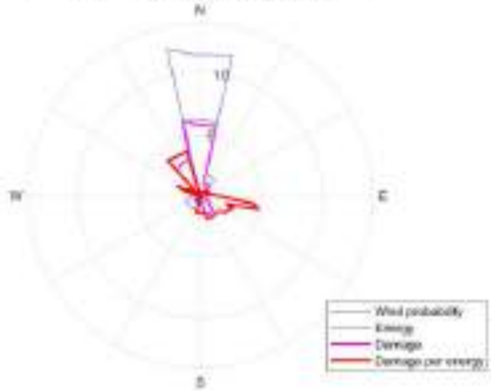
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT54



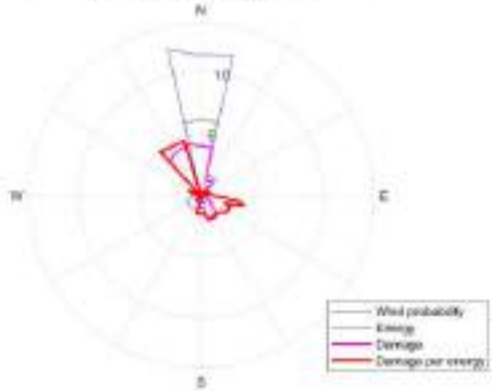
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT54



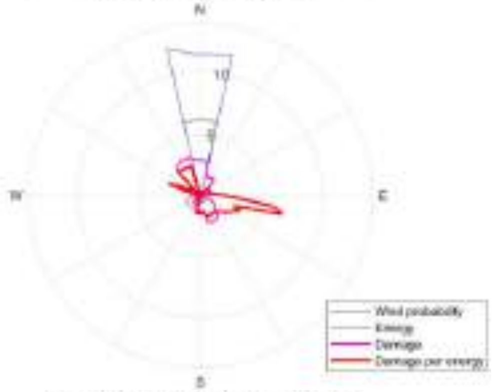
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT54



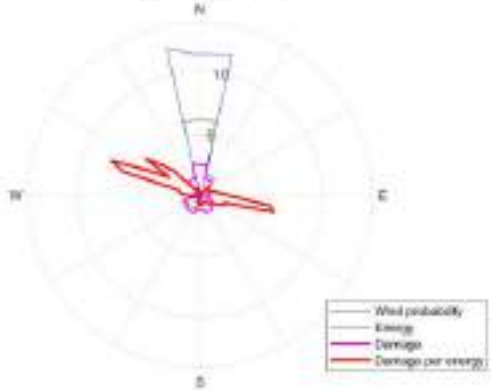
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT54



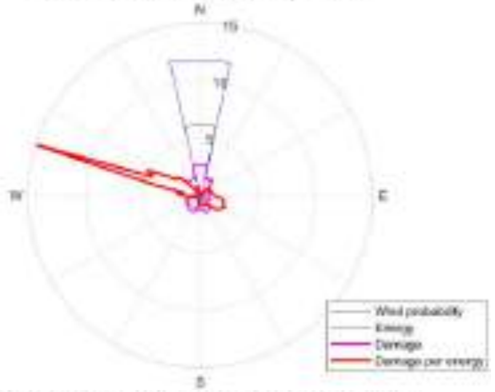
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT54



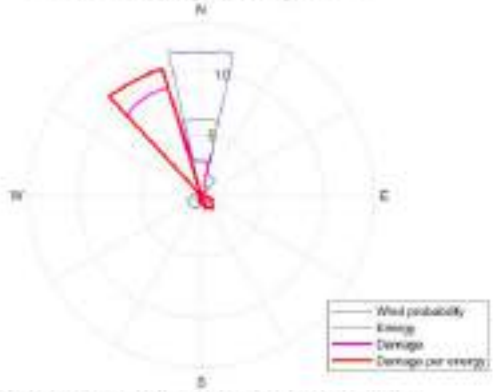
Rose map for the probabilities, energy and LTE in percentage, WT54



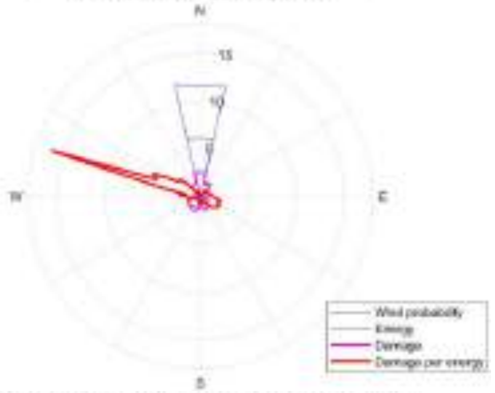
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WTS5



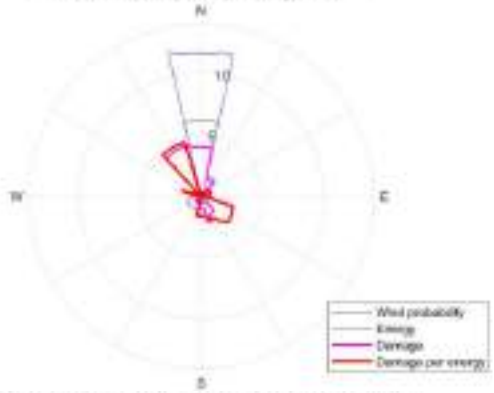
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WTS5



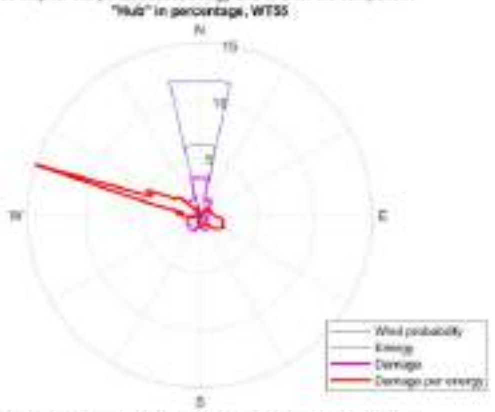
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WTS5



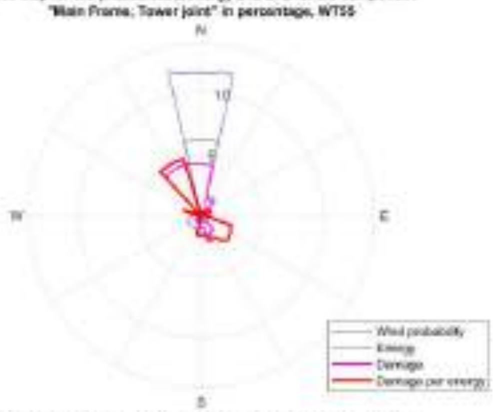
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WTS5



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WTS5

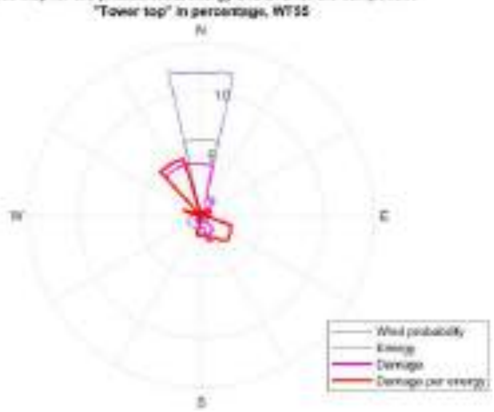


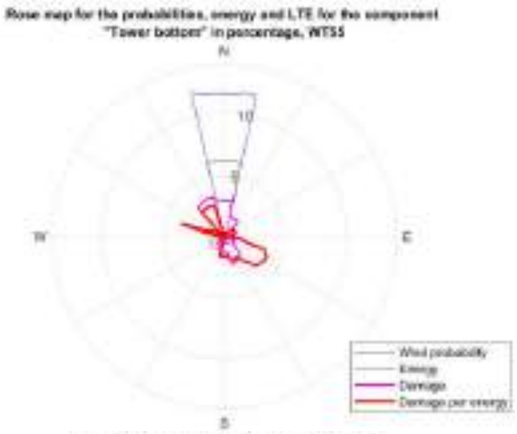
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WTS5

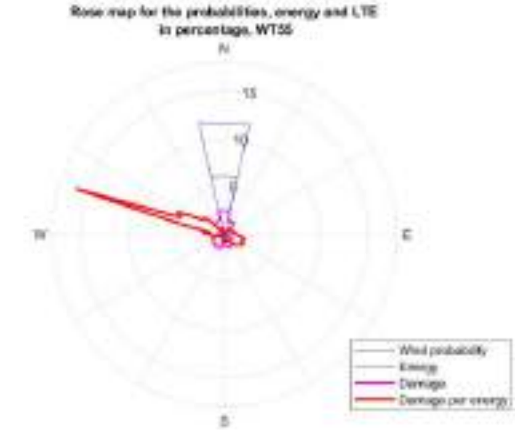


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WTS5

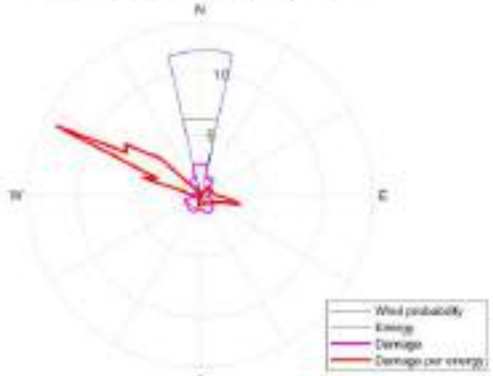
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WTS5



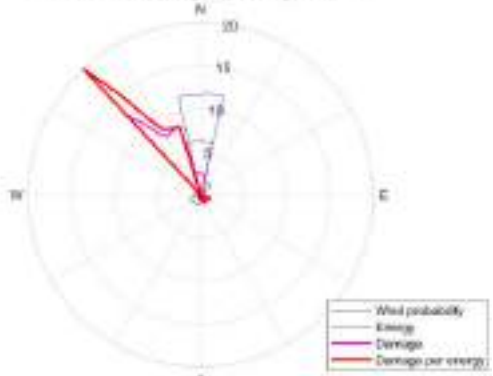

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT55
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT55
N
W
E
S
15
10
5
Wind probability
Energy
Damage
Damage per energy

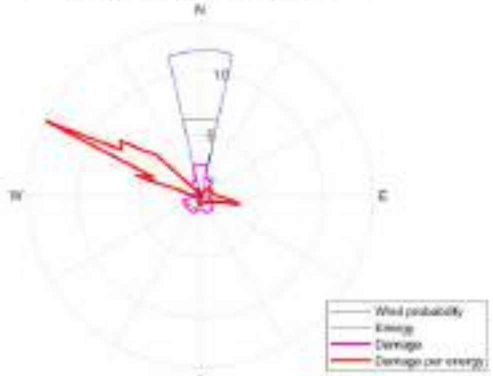
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT56



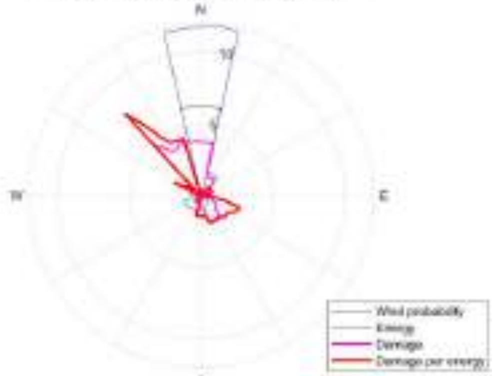
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT56



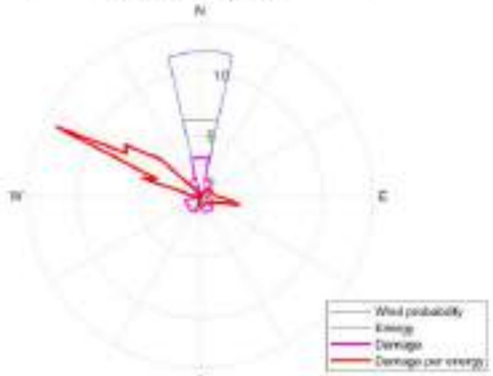
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT56



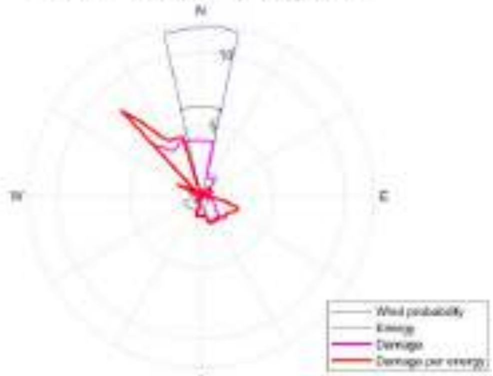
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT56



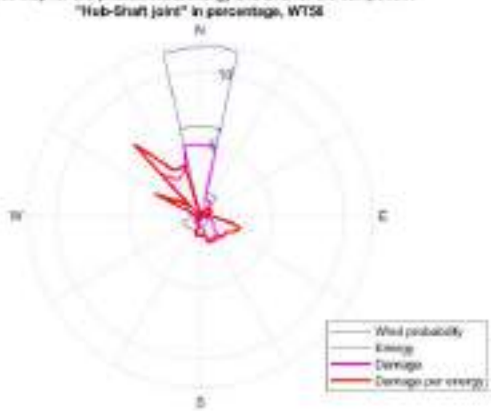
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT56



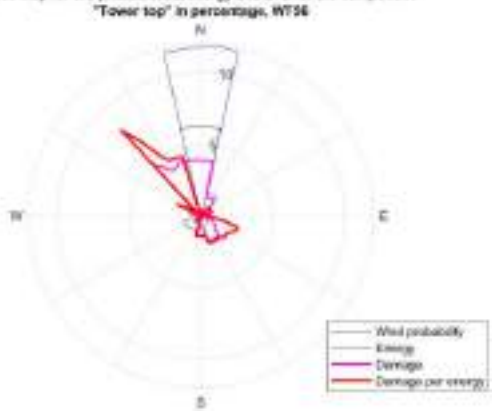
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT56

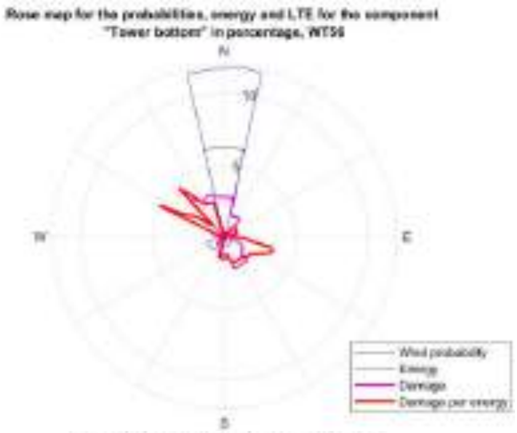


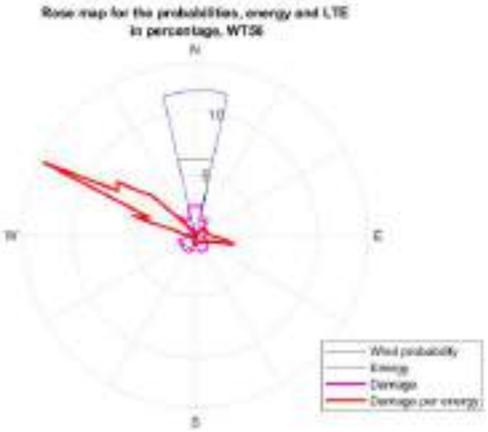
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT56



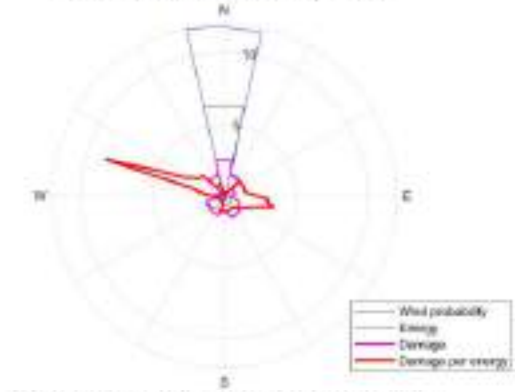
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT56



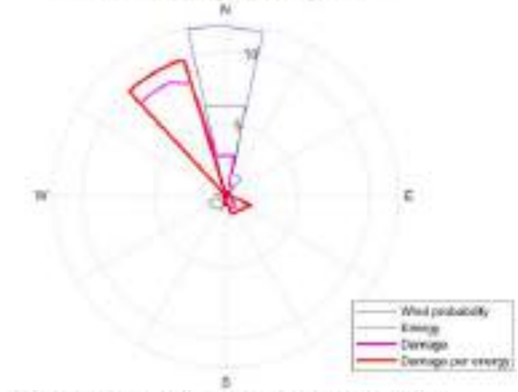

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT56
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT56
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

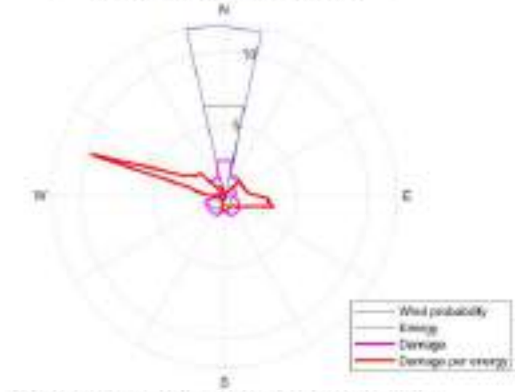
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WTS7



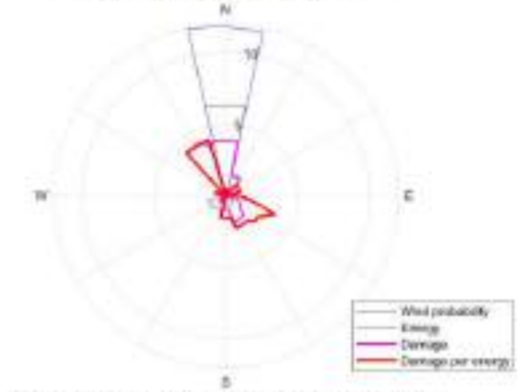
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WTS7



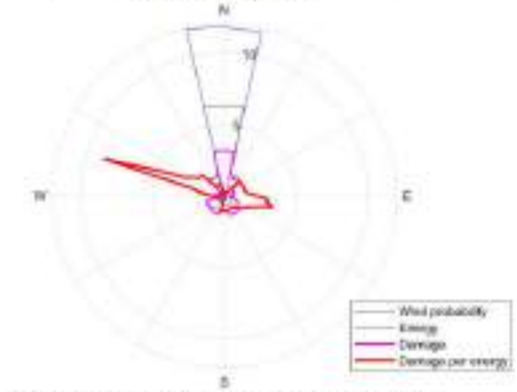
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WTS7



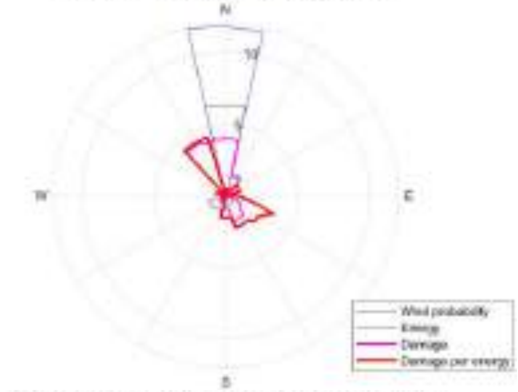
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WTS7



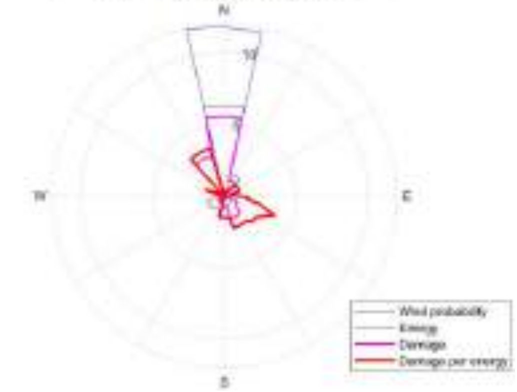
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WTS7



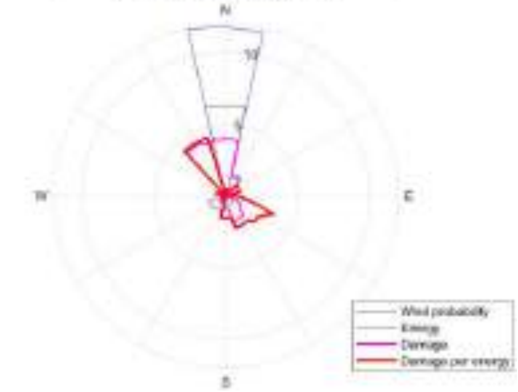
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WTS7



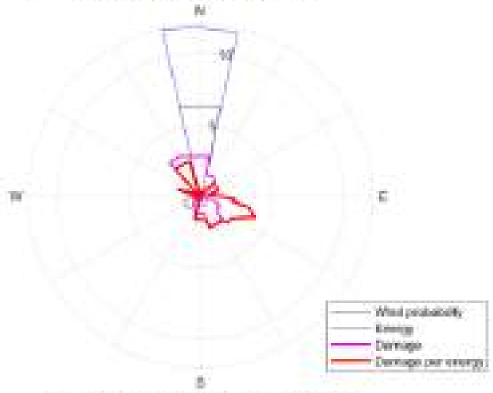
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WTS7



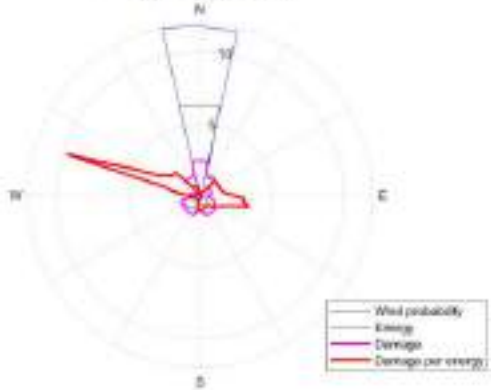
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WTS7

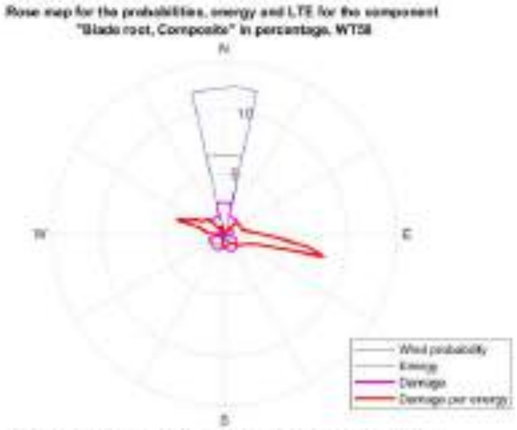


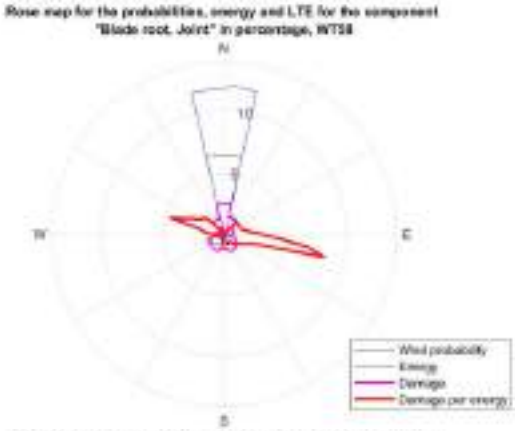
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT57

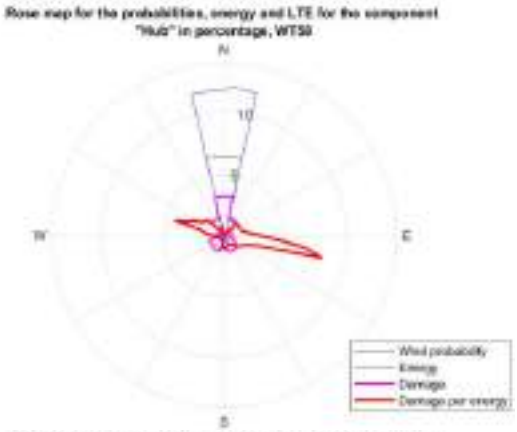


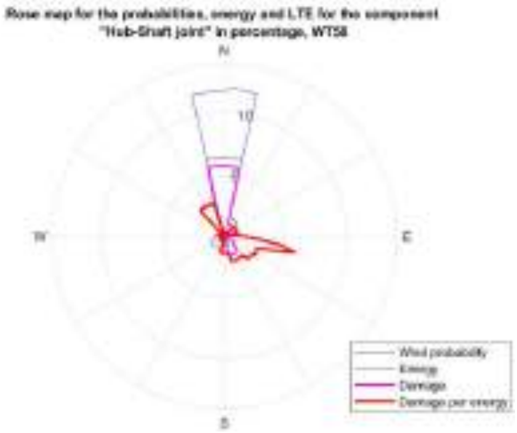
Rose map for the probabilities, energy and LTE in percentage, WT57

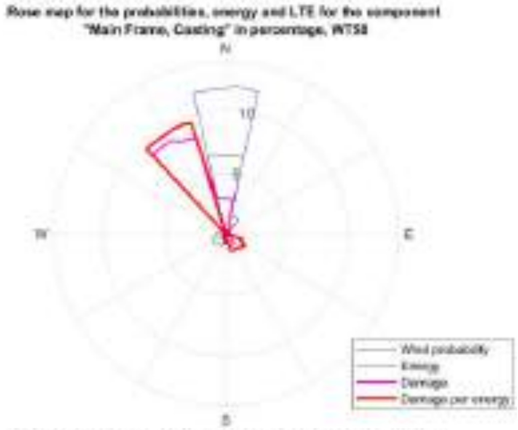


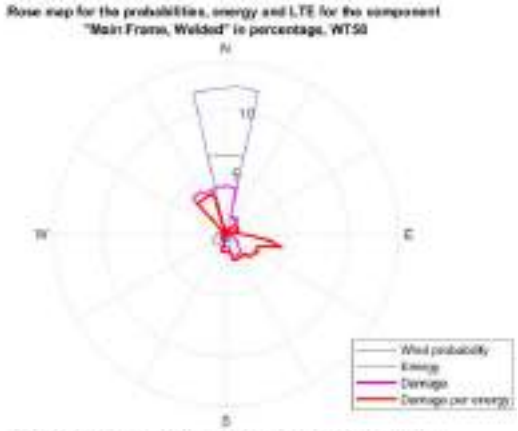

Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT58
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

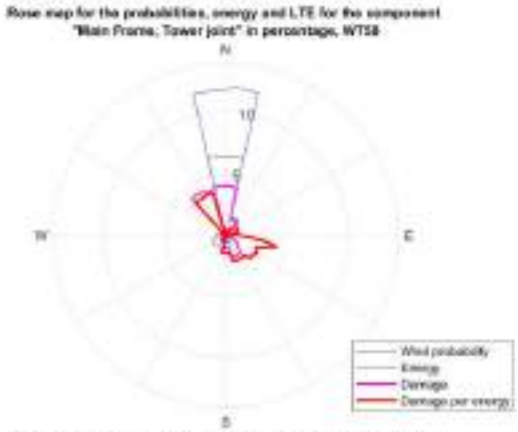

Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT58
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

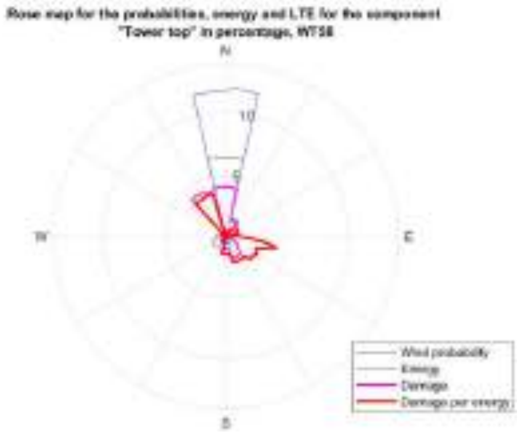

Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT58
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

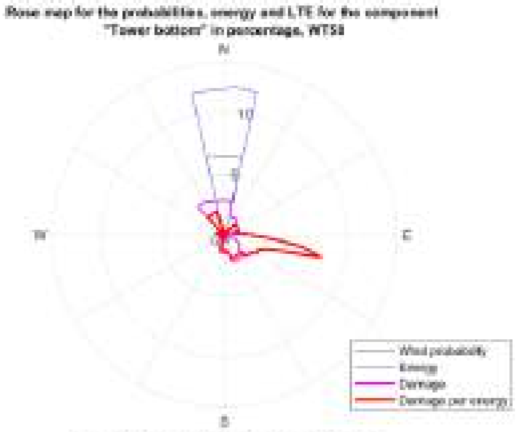

Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT58
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

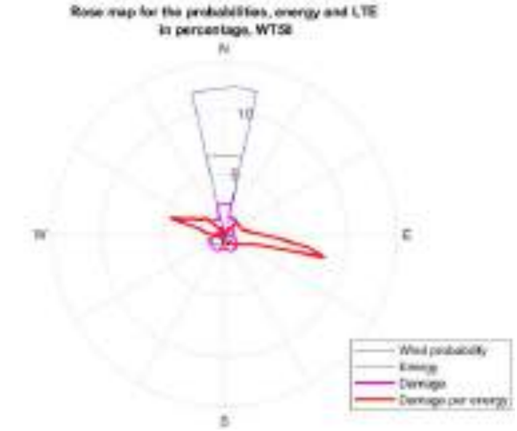

Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT58
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT58
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

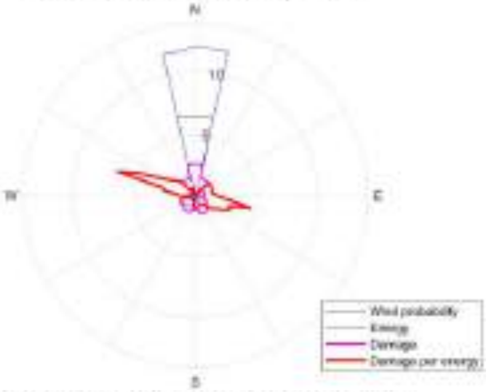

Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT58
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT58
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

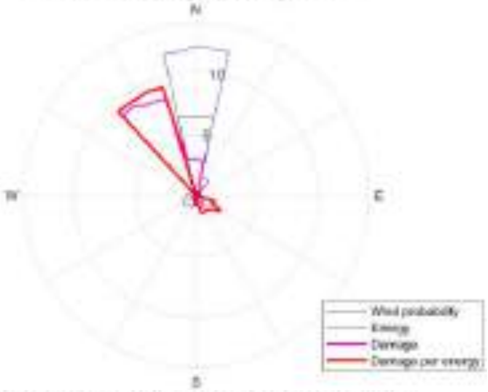

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT58
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT58
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

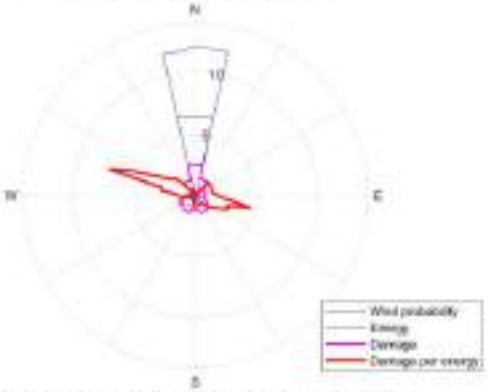
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT59



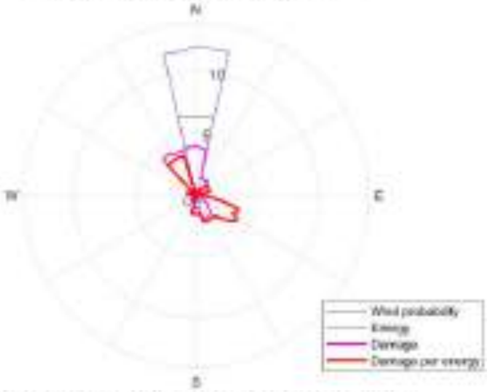
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT59



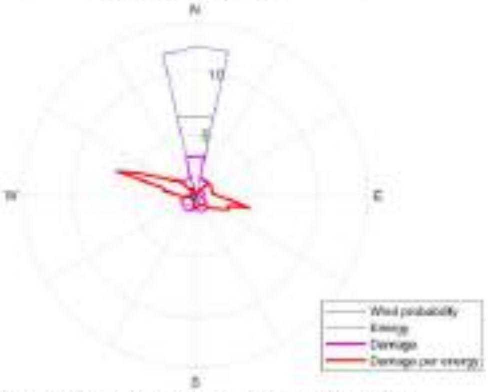
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT59



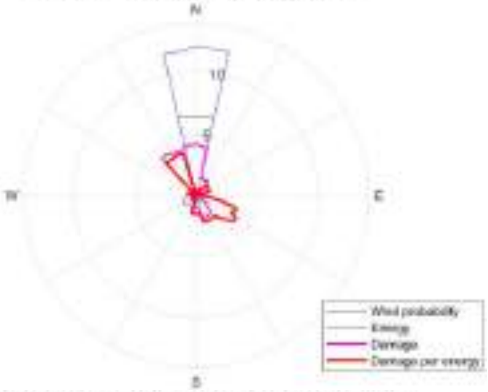
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT59



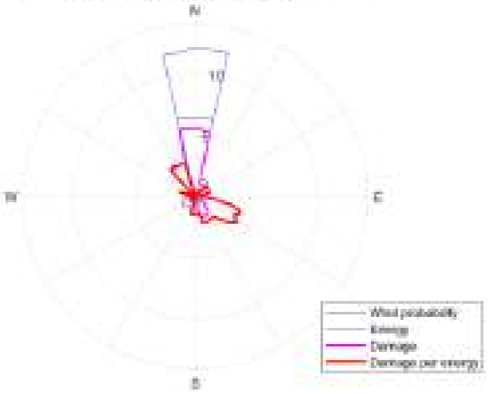
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT59



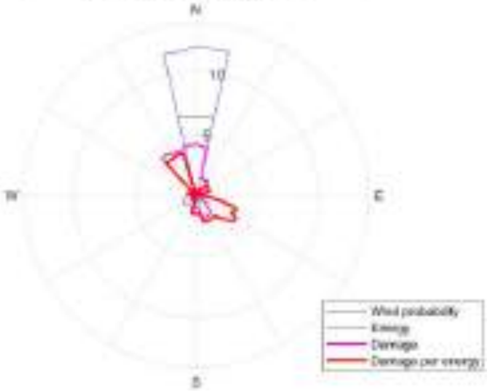
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT59

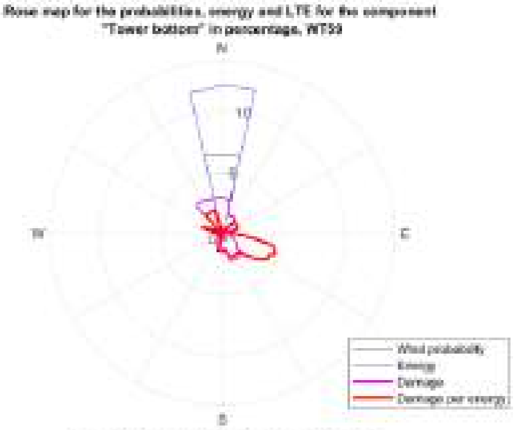


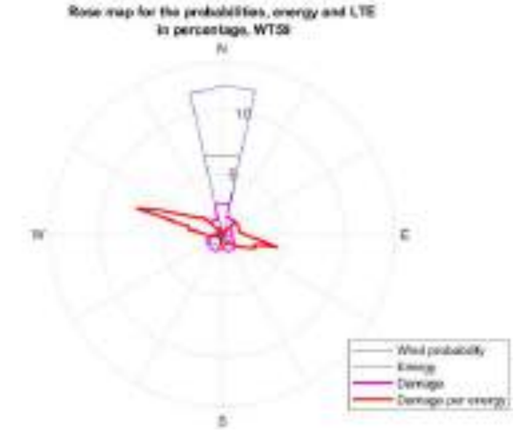
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT59



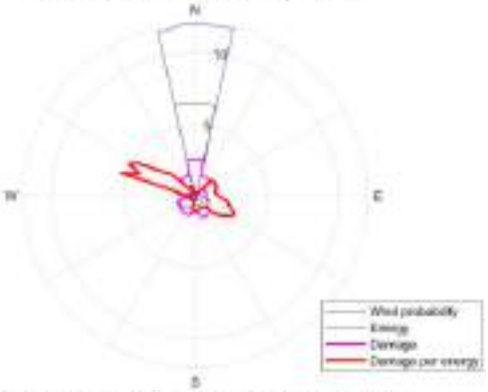
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT59



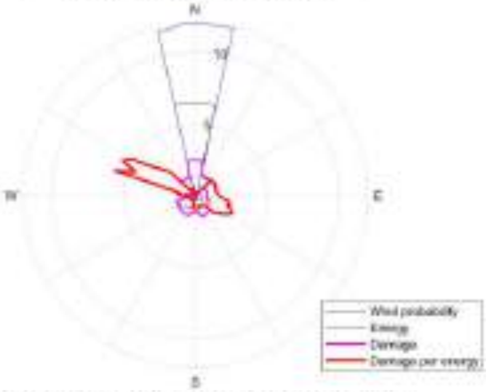

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT59
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE in percentage, WT59
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

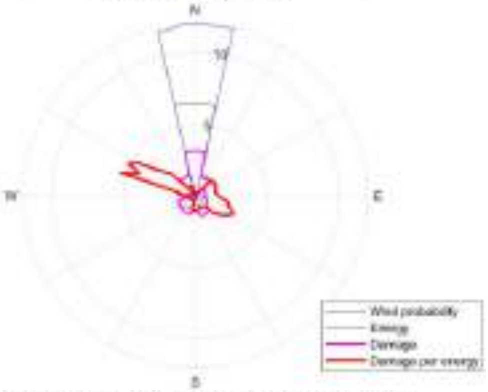
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT60



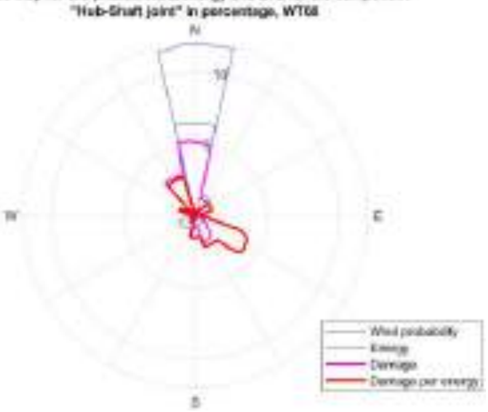
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT60



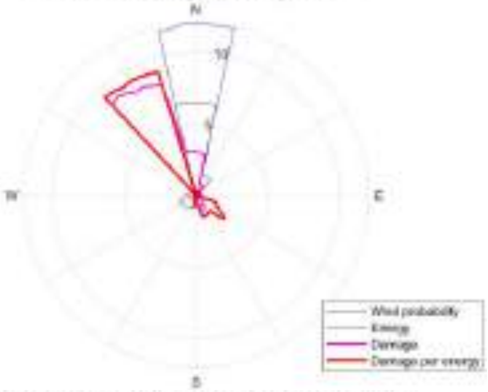
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT60



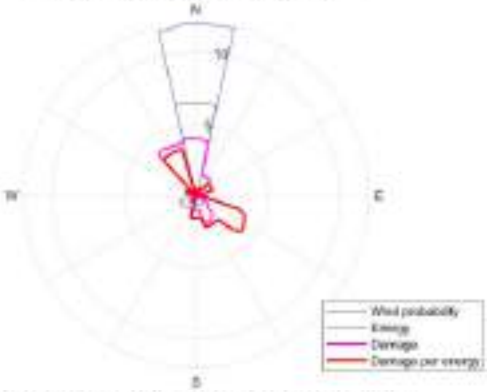
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT60



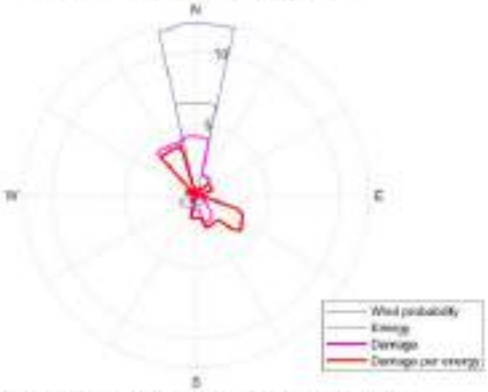
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT60



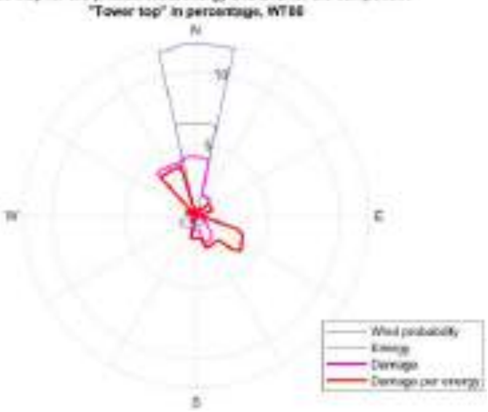
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT60



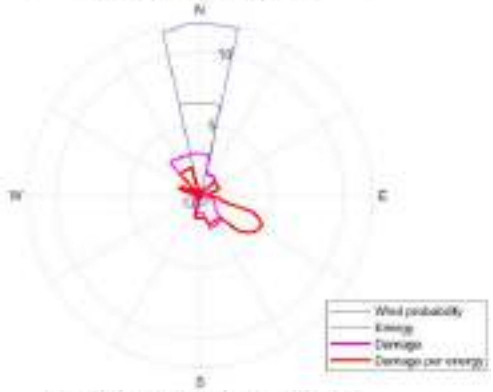
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT60



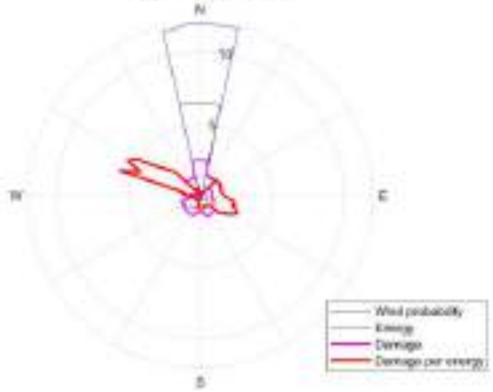
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT60



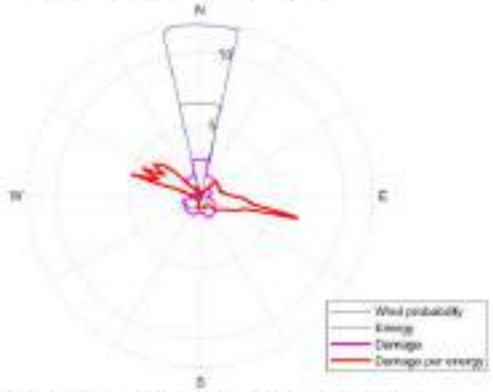
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT60



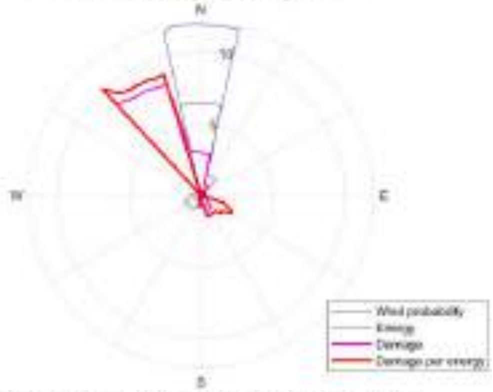
Rose map for the probabilities, energy and LTE in percentage, WT60



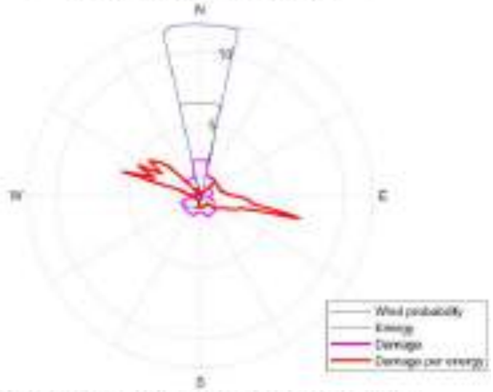
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT01



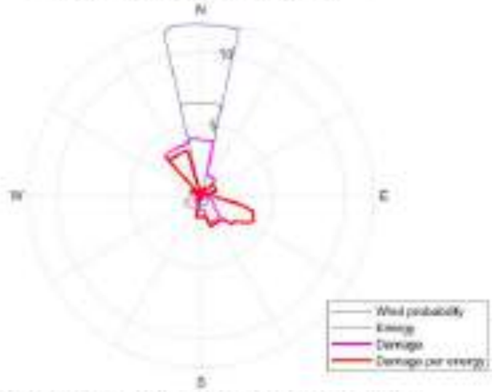
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT01



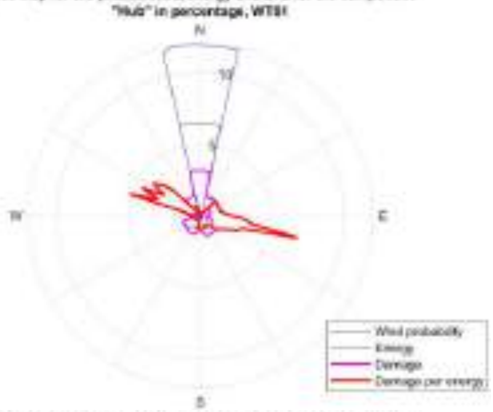
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT01



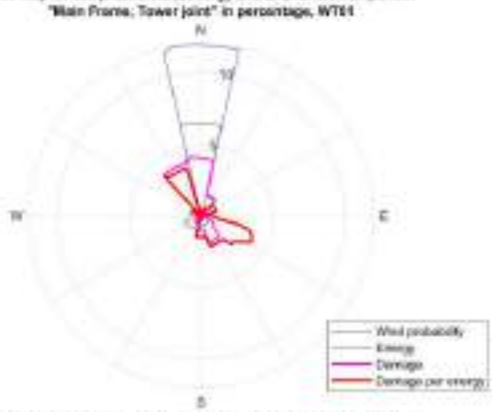
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT01



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT01

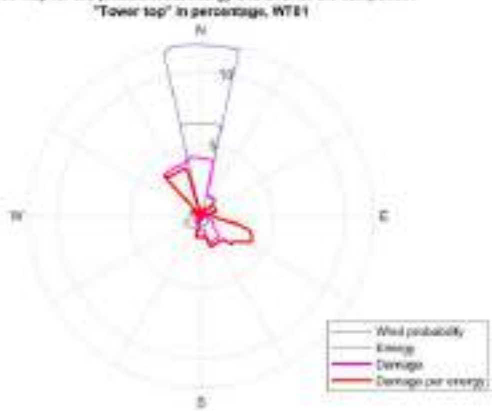


Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT01

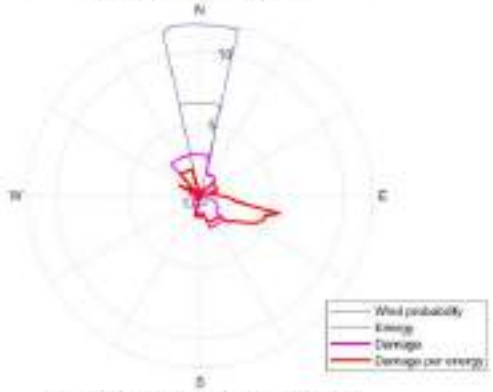


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT01

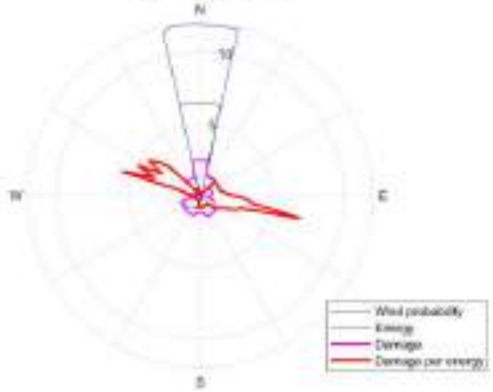
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT01



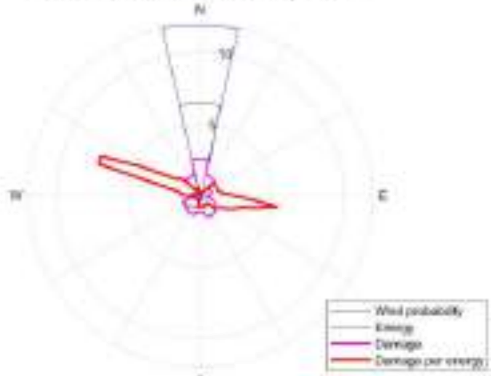
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT01



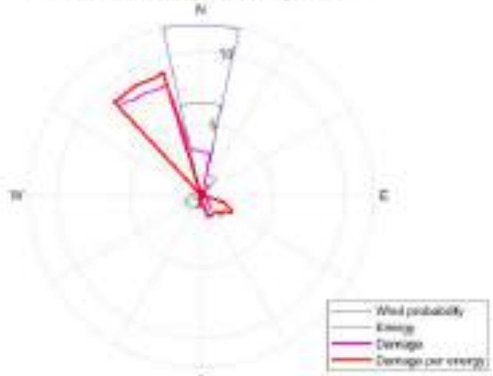
Rose map for the probabilities, energy and LTE in percentage, WT01



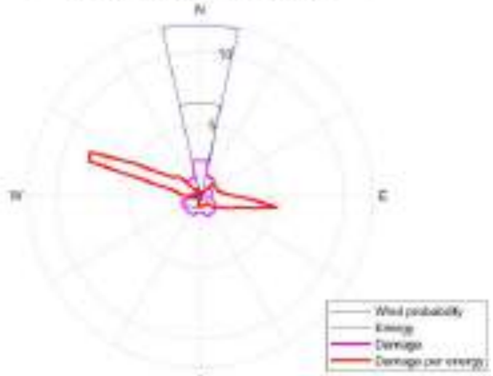
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT62



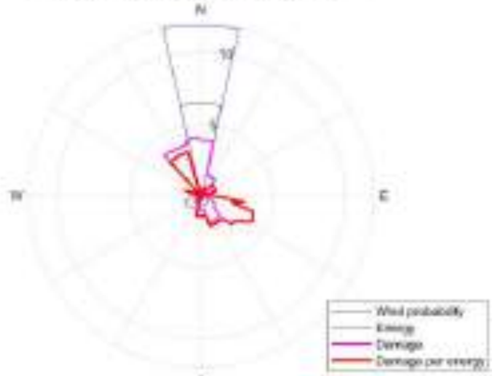
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT62



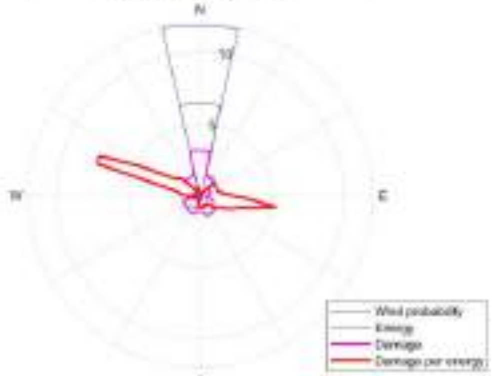
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT62



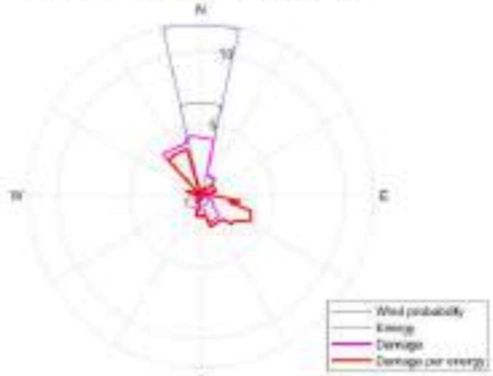
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT62



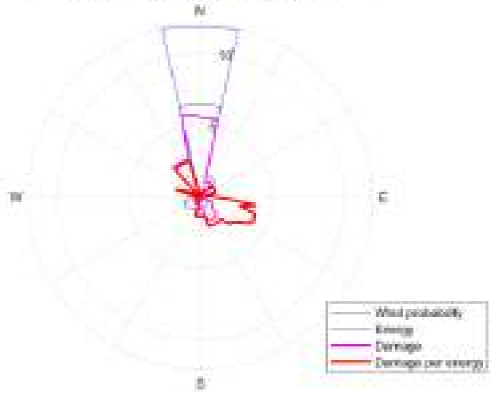
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT62



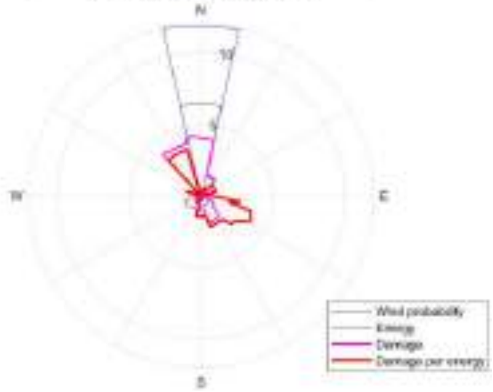
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT62



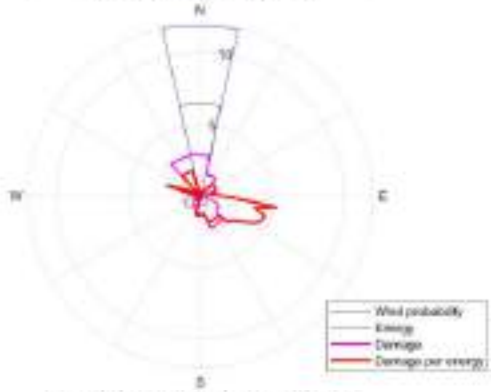
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT62



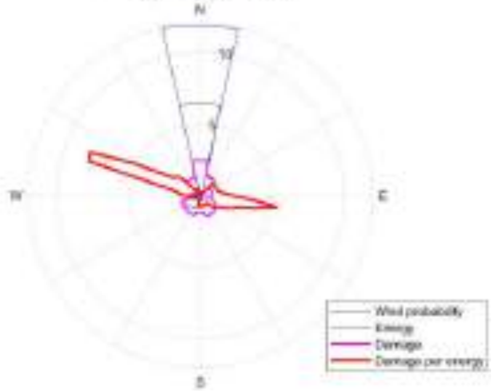
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT62



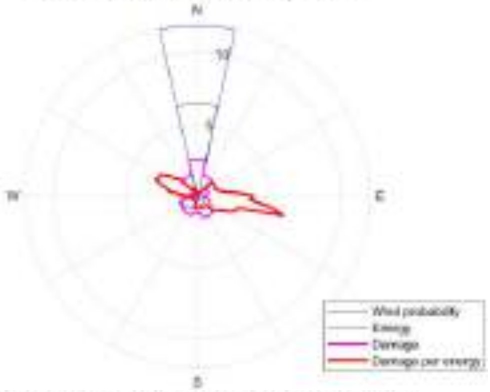
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT62



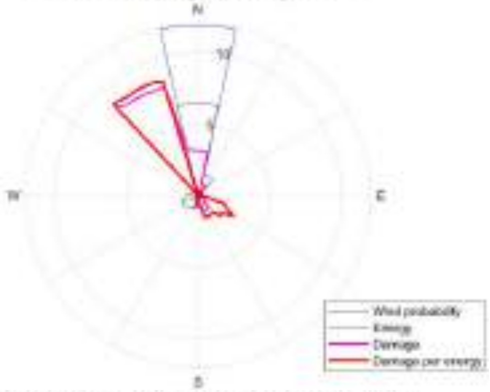
Rose map for the probabilities, energy and LTE in percentage, WT62



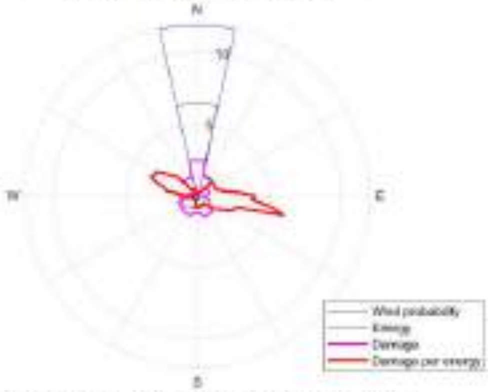
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT63



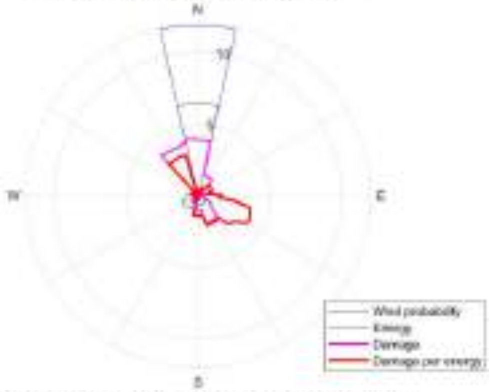
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT63



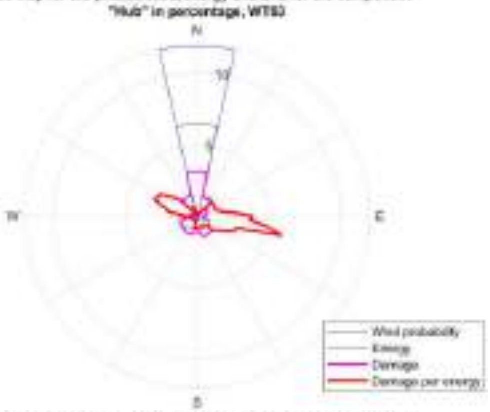
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT63



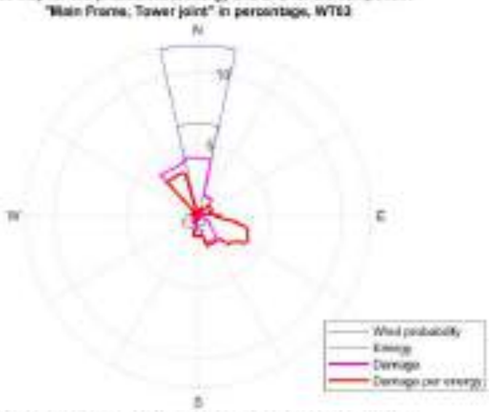
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT63



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT63

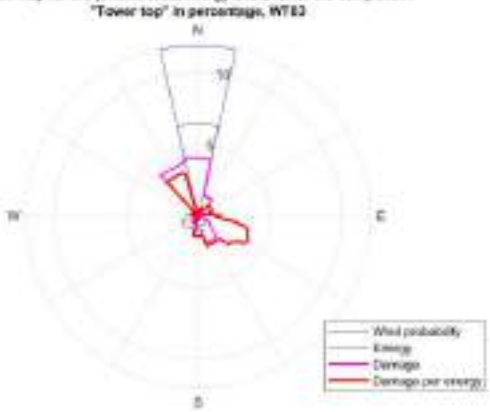


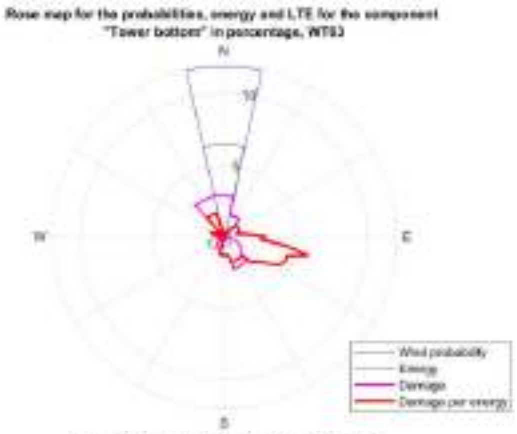
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT63

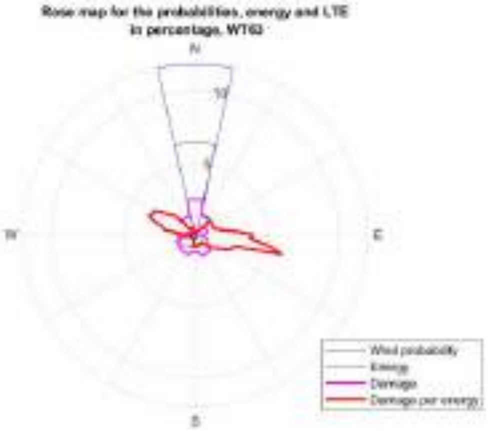


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT63

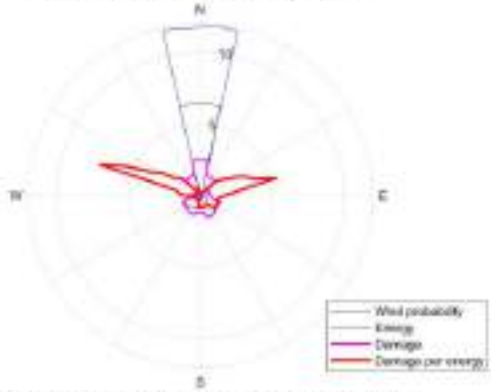
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT63



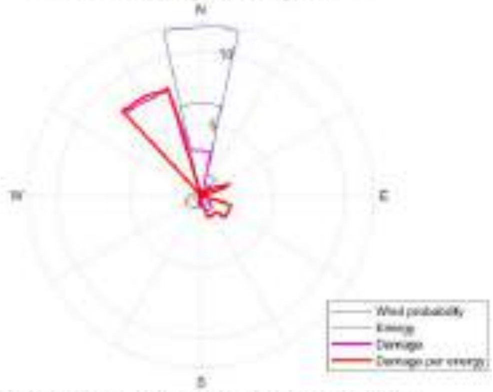

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT63
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT63
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

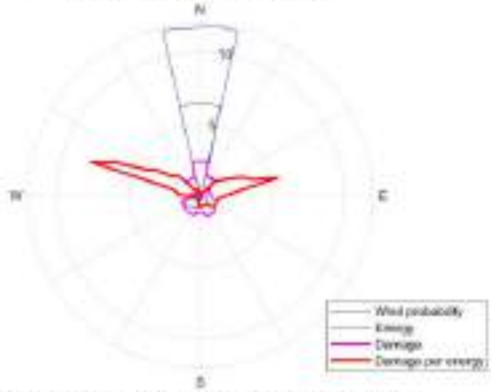
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT64



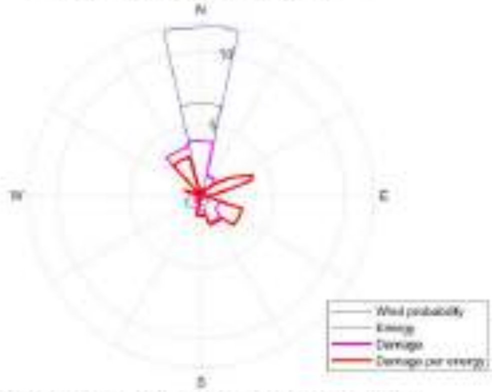
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT64



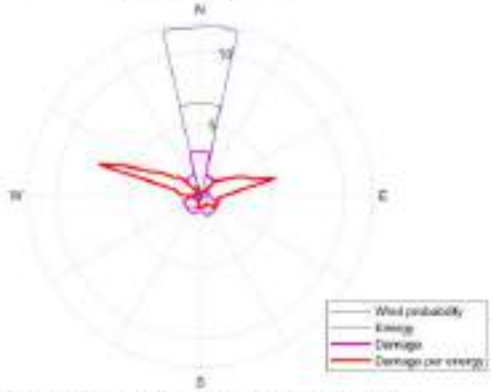
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT64



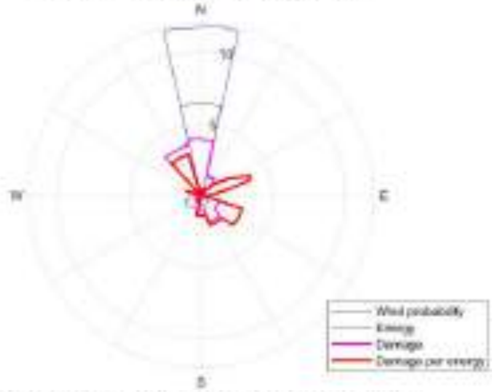
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT64



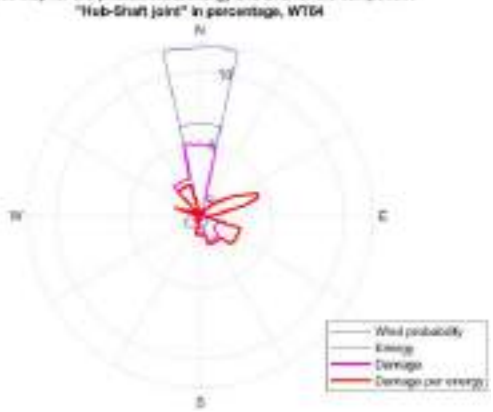
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT64



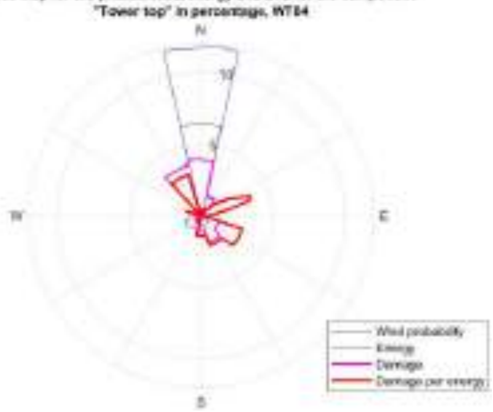
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT64

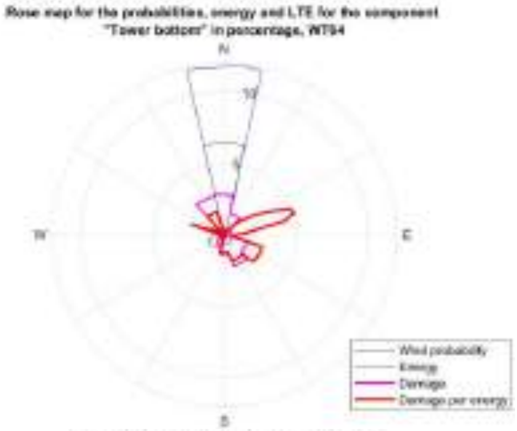


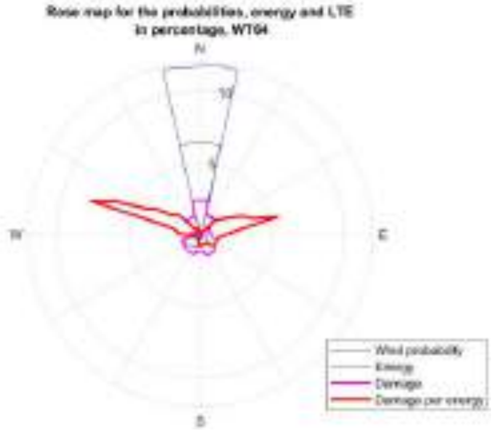
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT64



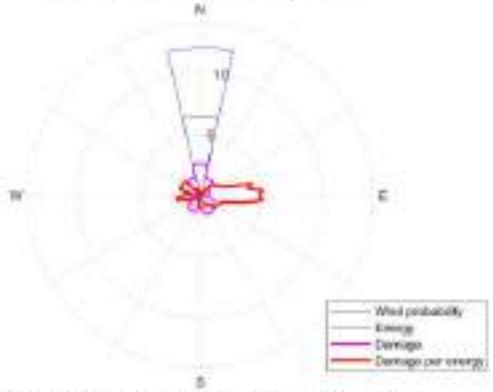
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT64



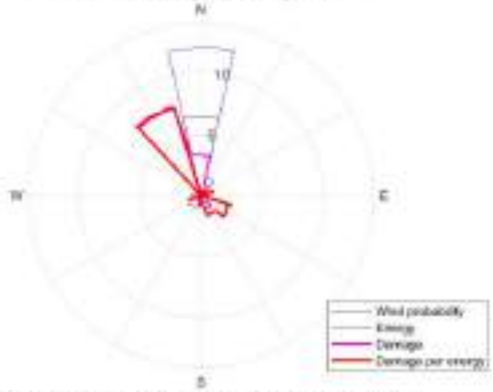

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT64
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT64
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

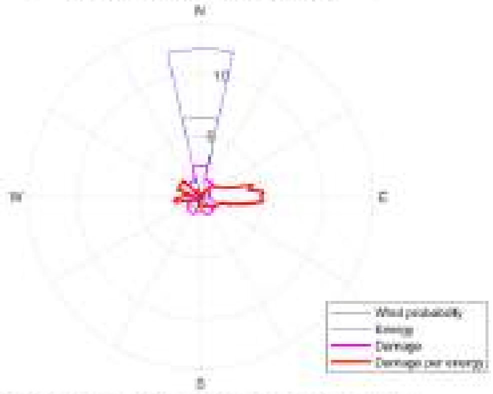
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT65



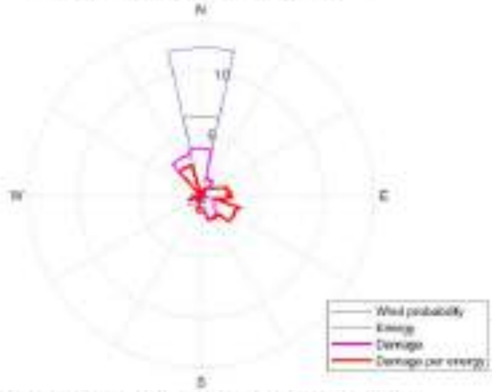
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT65



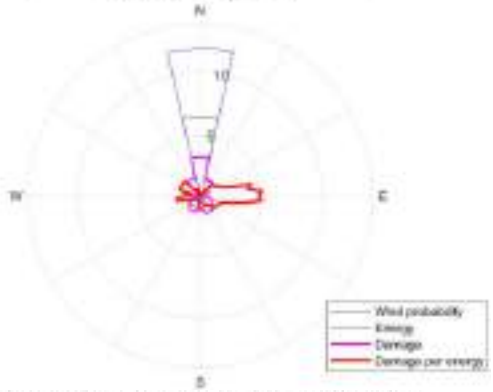
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT65



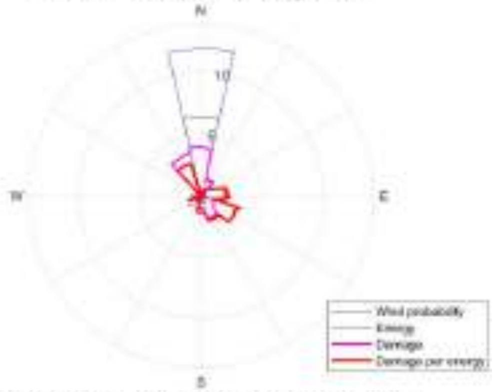
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT65



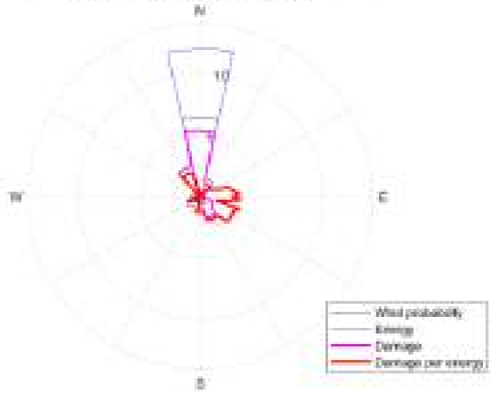
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT65



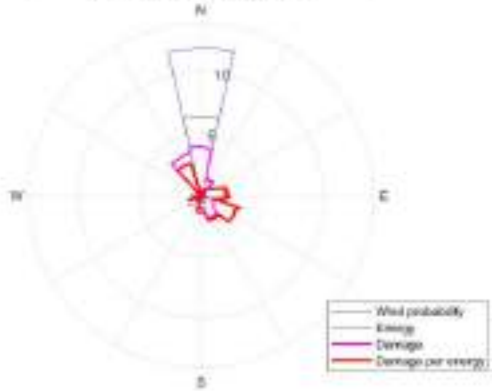
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT65

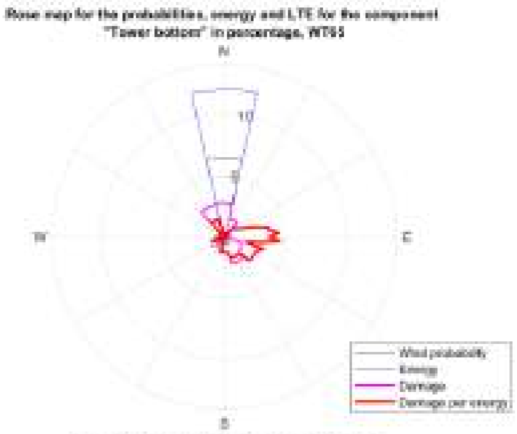


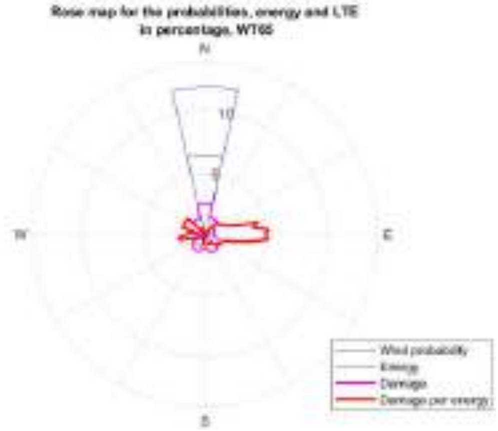
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT65



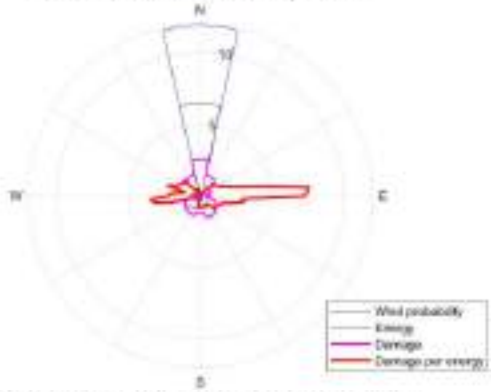
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT65



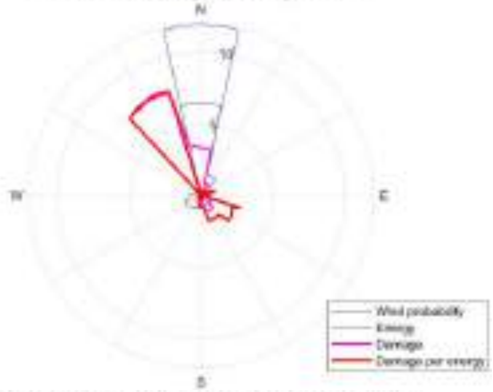

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT65
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT65
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

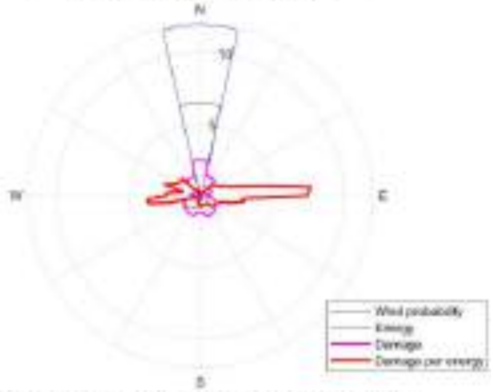
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT66



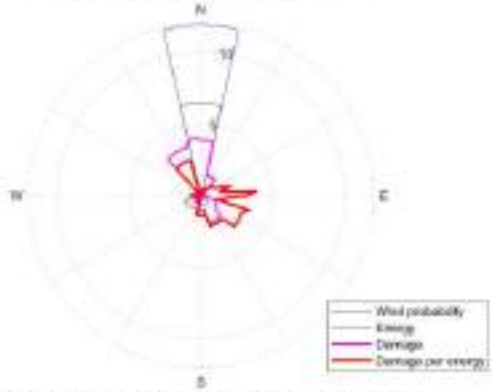
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT66



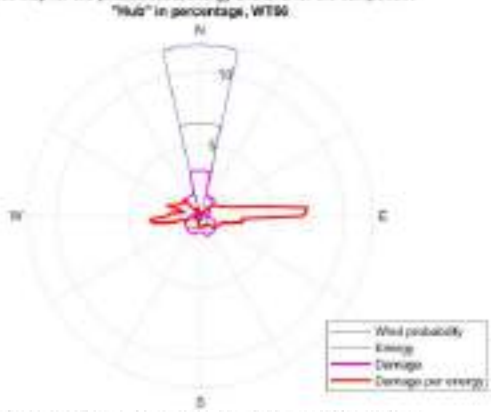
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT66



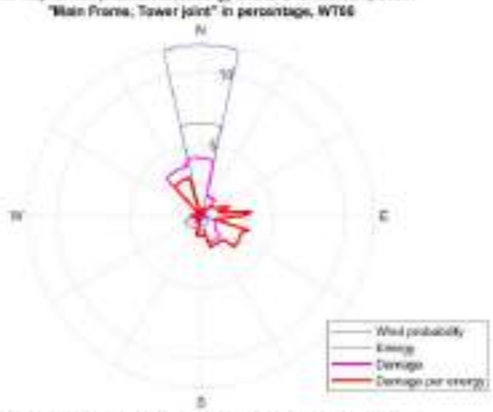
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT66



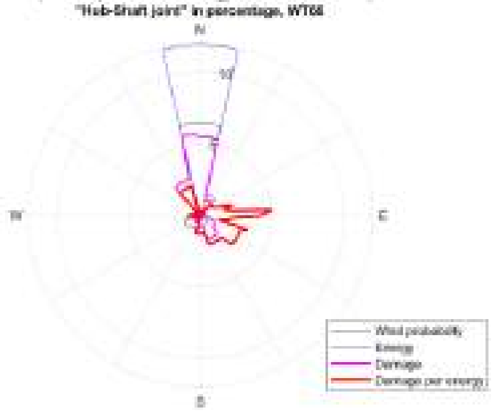
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT66



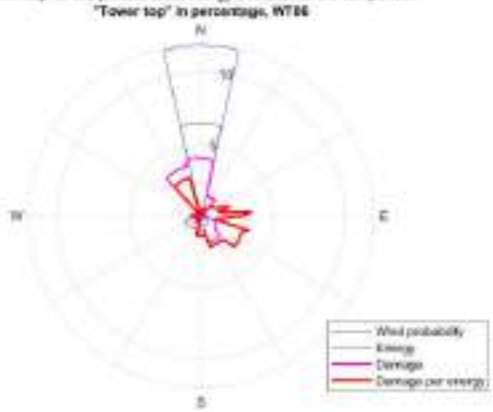
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT66

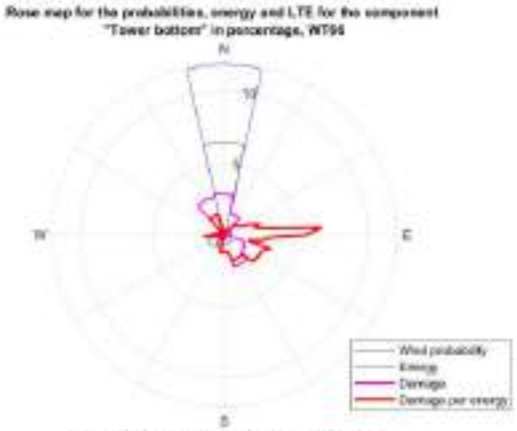


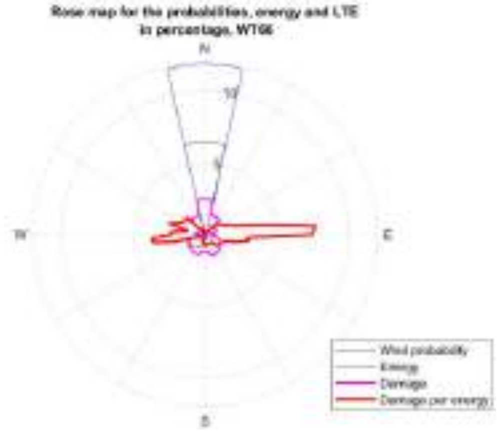
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT66



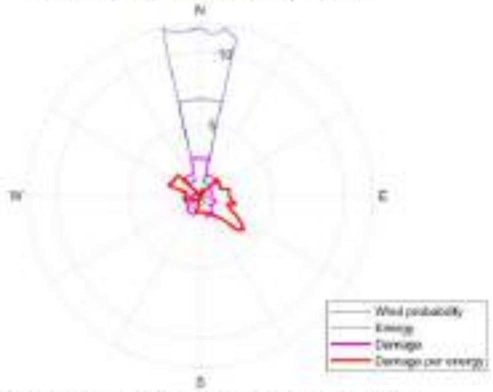
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT66



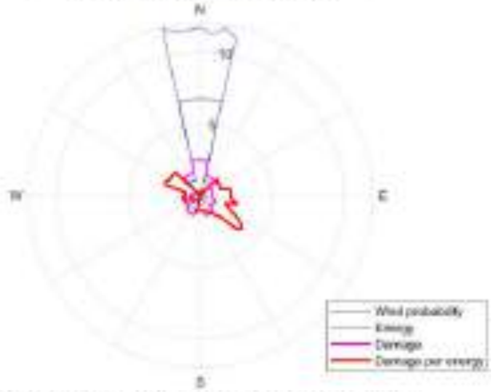

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT56
N
E
S
W
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT66
N
E
S
W
Wind probability
Energy
Damage
Damage per energy

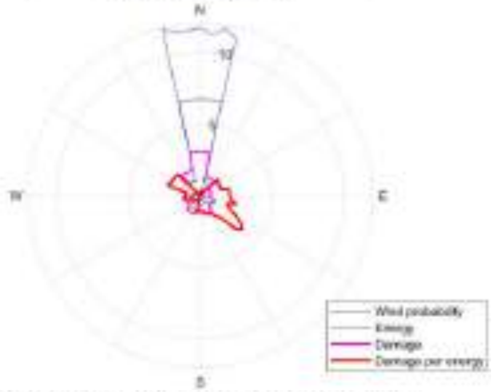
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT67



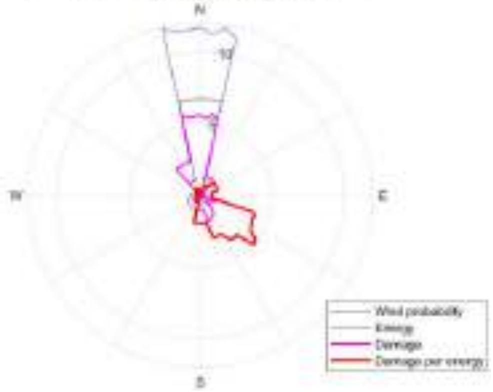
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT67



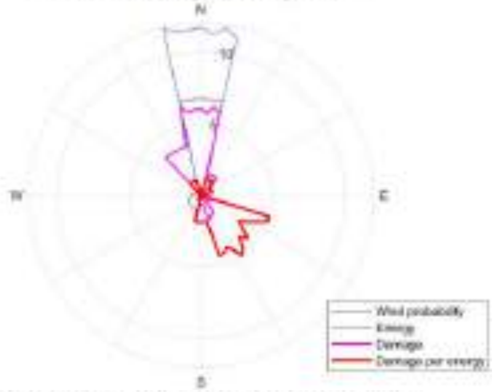
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT67



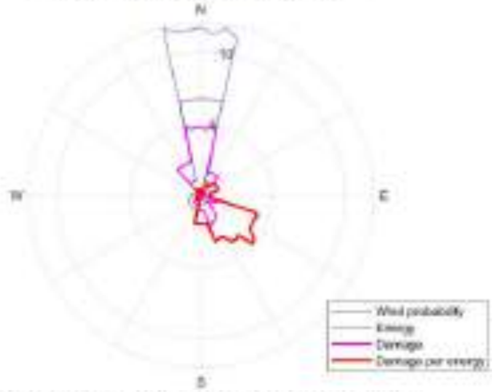
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT67



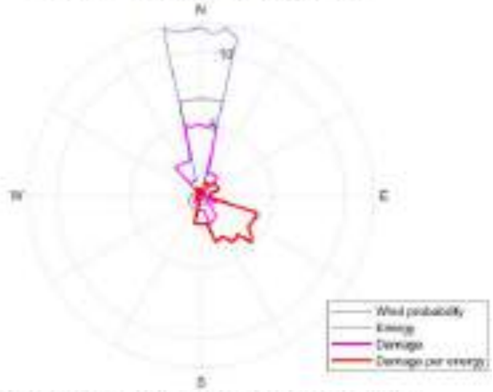
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT67



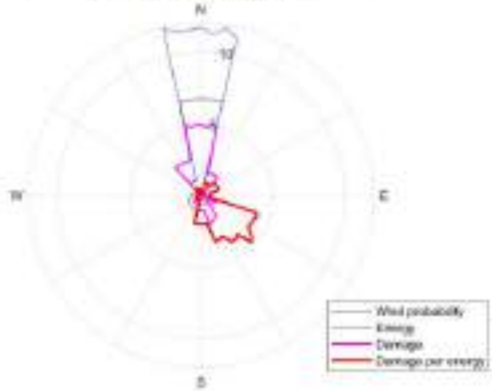
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT67



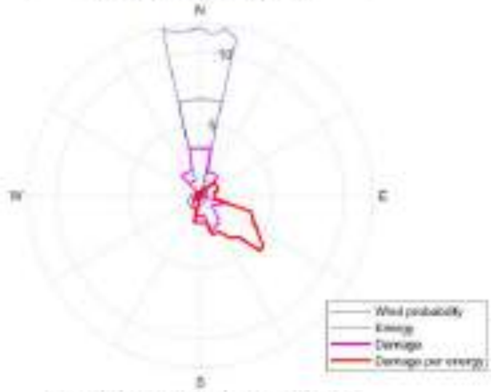
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT67



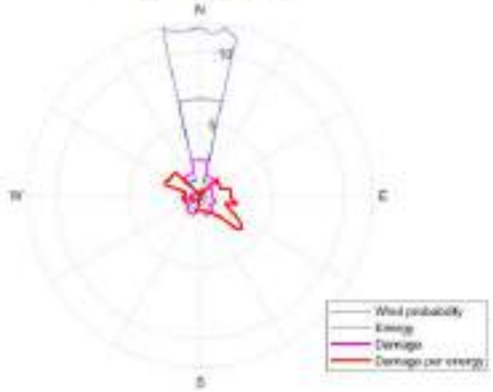
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT67



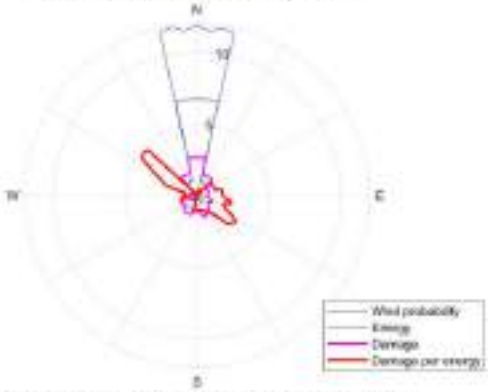
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT67



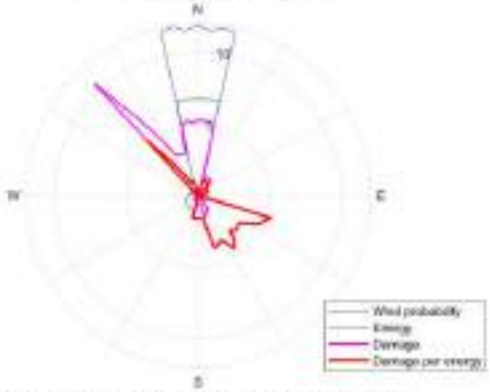
Rose map for the probabilities, energy and LTE in percentage, WT67



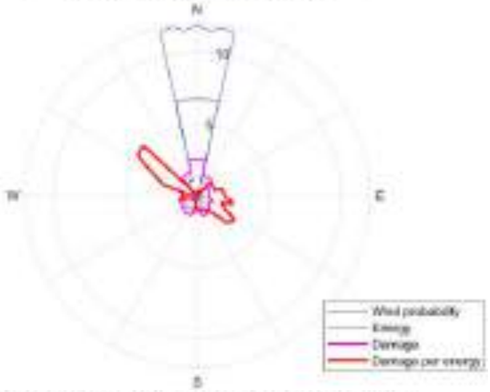
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT68



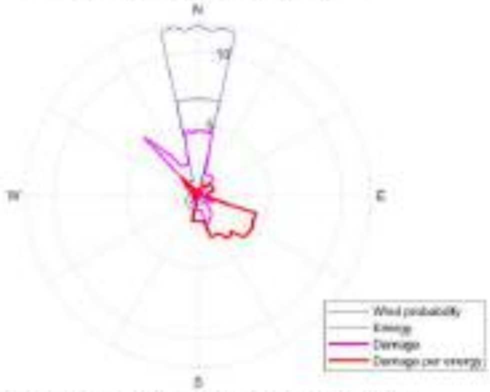
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT68



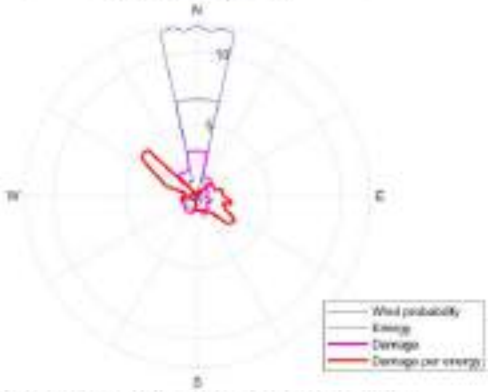
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT68



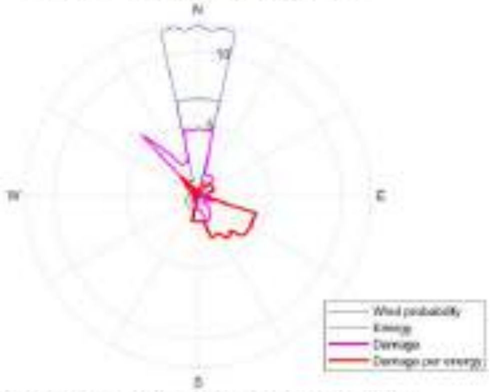
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT68



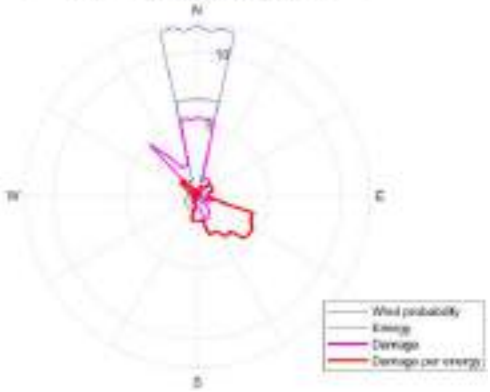
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT68



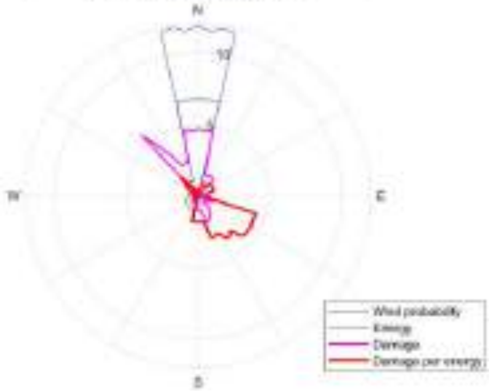
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT68



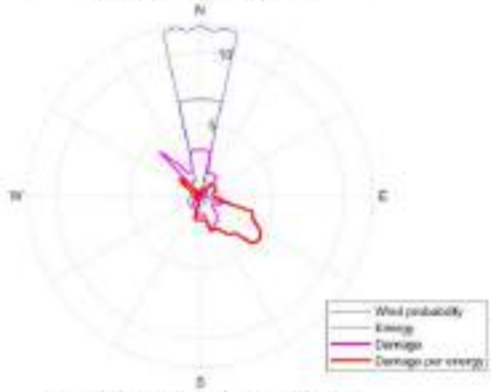
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT68



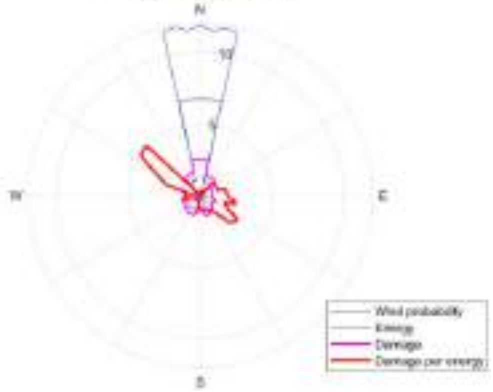
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT68



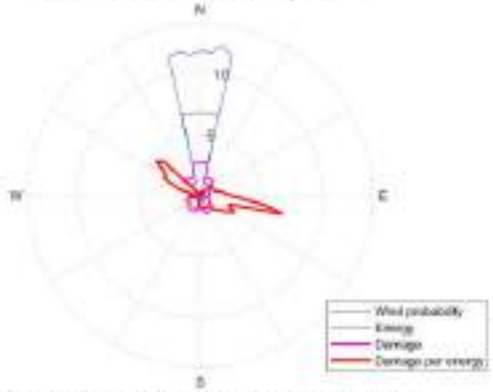
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT68



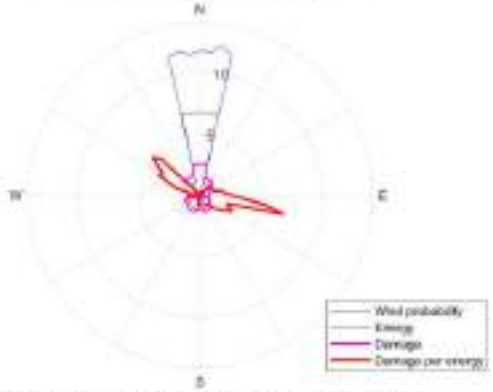
Rose map for the probabilities, energy and LTE in percentage, WT68



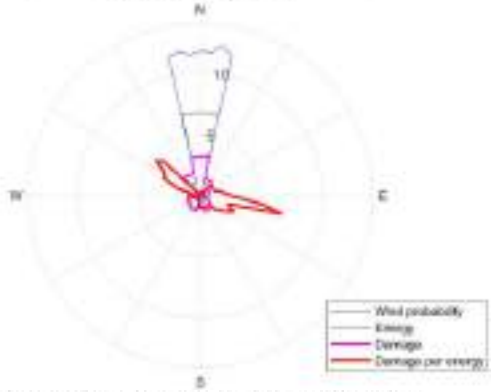
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT69



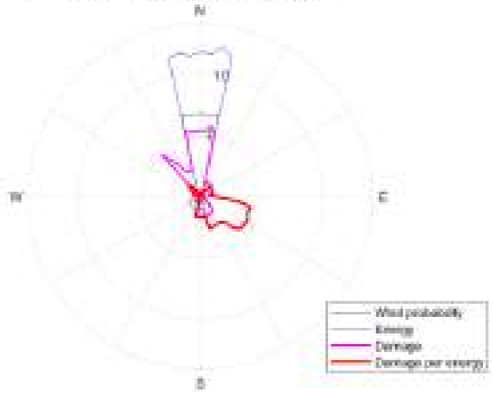
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT69



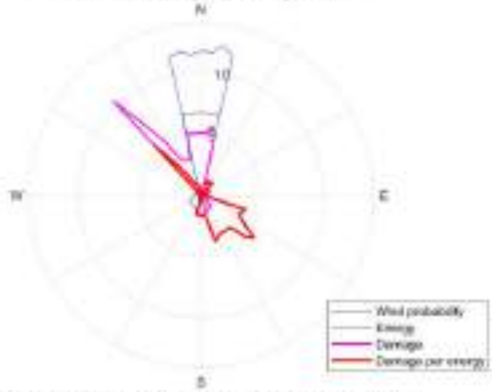
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT69



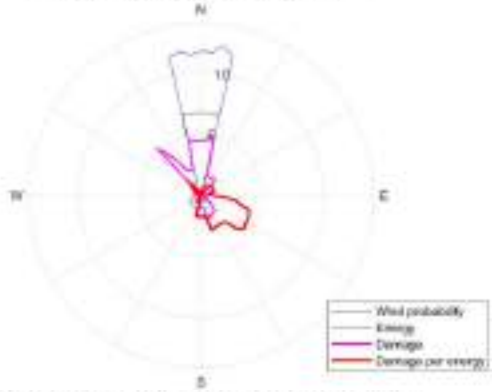
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT69



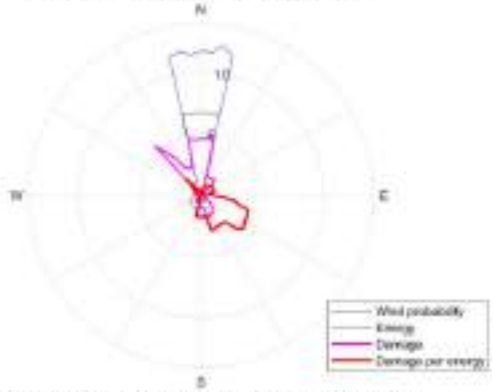
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT69



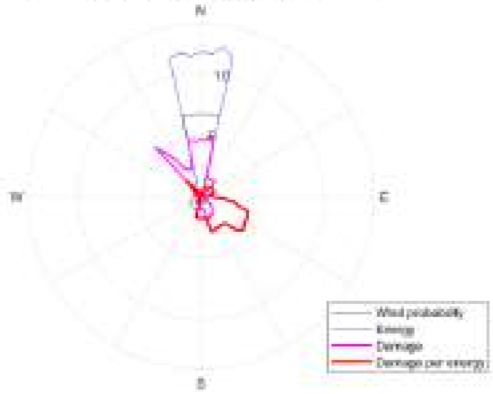
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT69



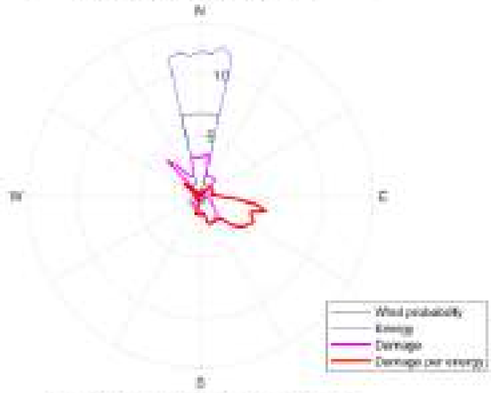
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT69



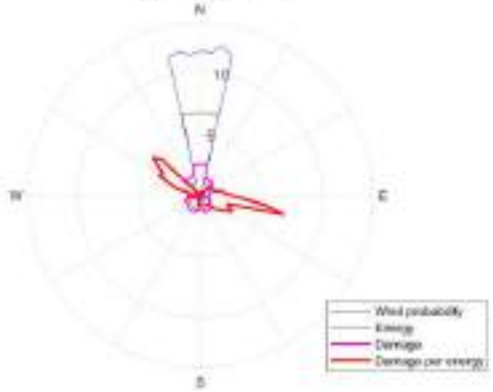
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT69



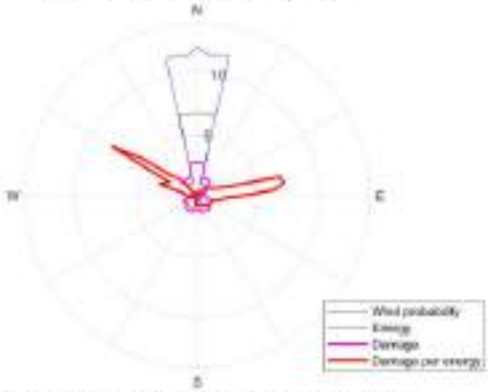
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT59



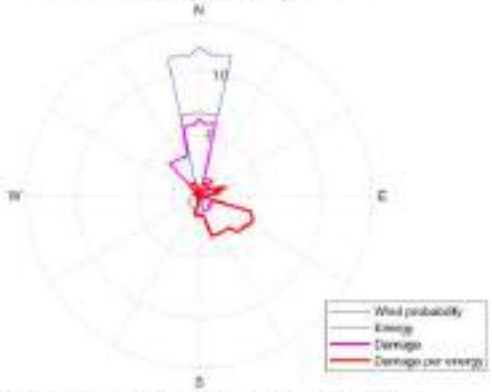
Rose map for the probabilities, energy and LTE in percentage, WT60



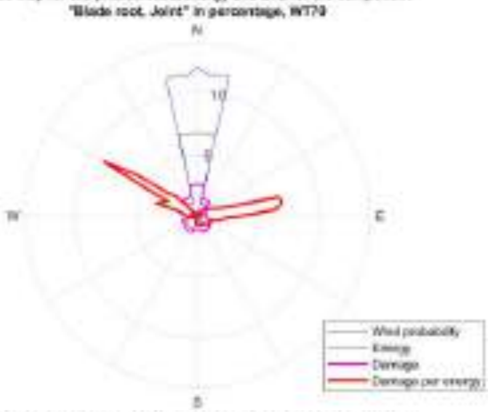
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT70



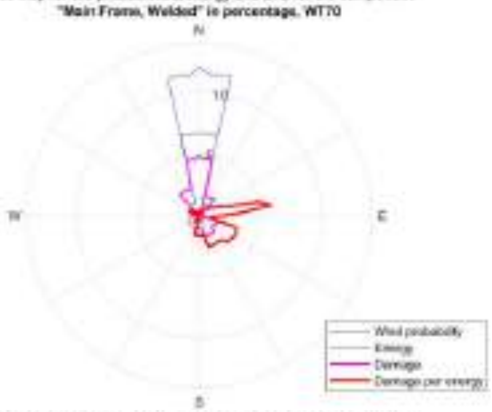
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT70



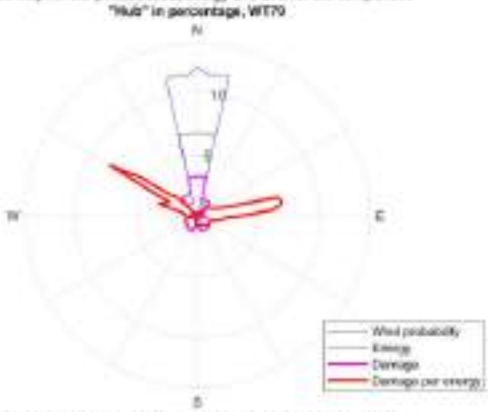
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT70



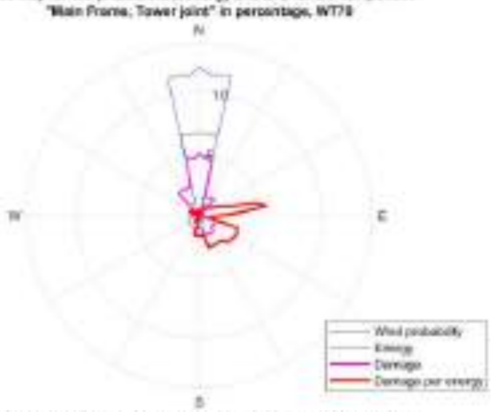
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT70



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT70

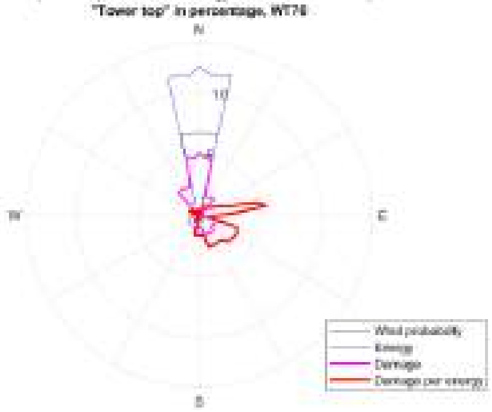


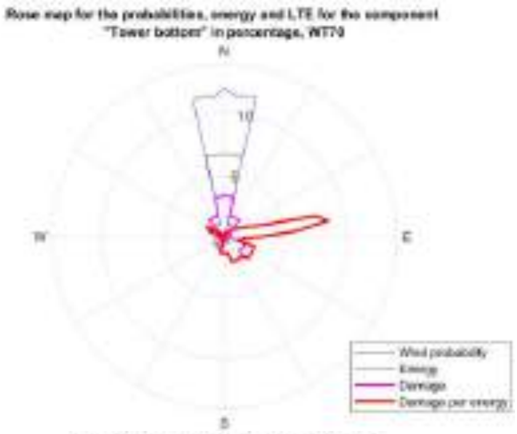
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT70

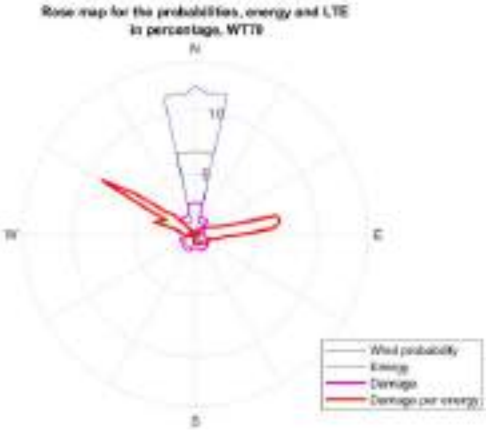


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT70

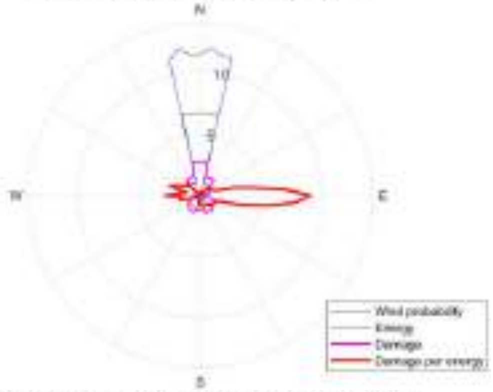
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT70



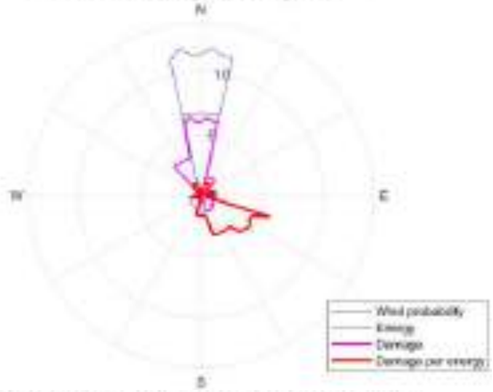

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT70
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT70
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

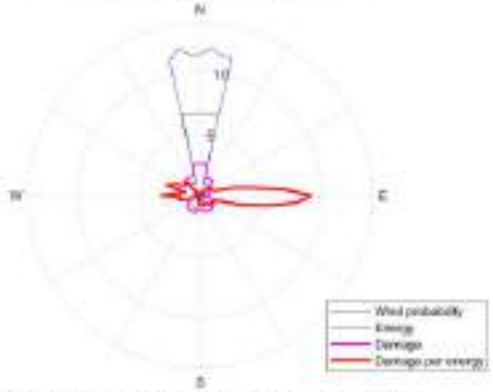
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT71



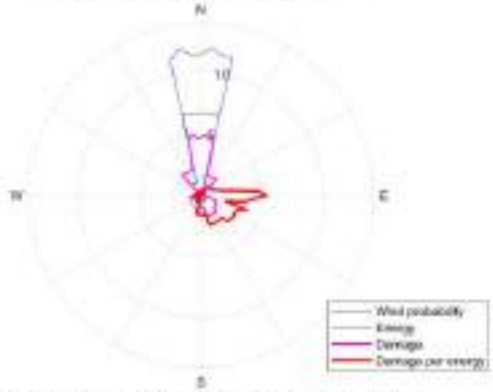
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT71



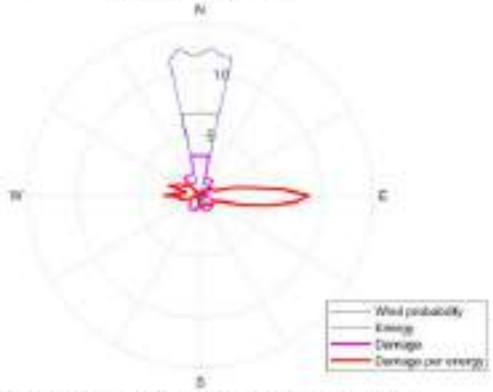
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT71



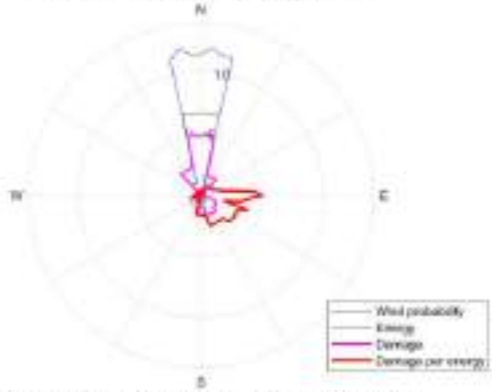
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT71



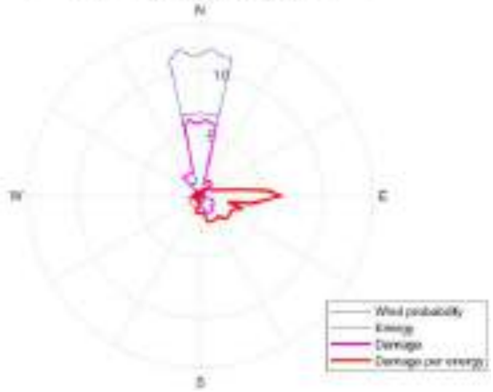
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT71



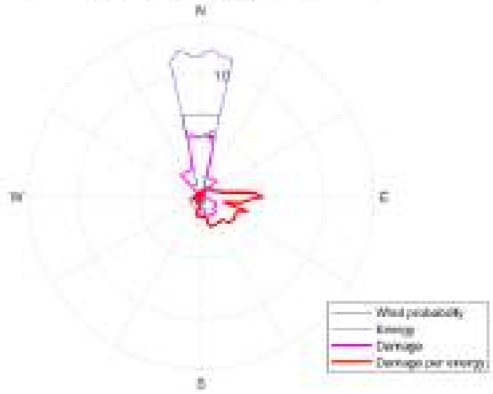
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT71



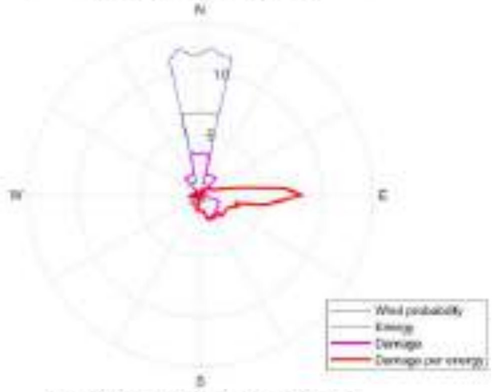
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT71



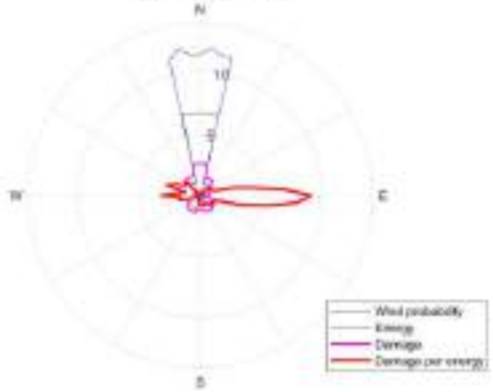
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT71



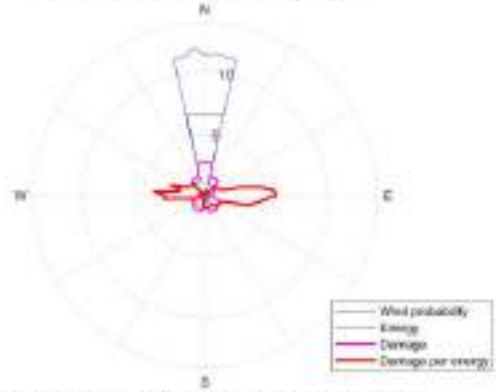
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT71



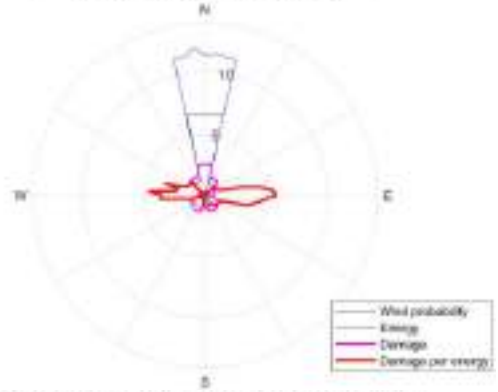
Rose map for the probabilities, energy and LTE in percentage, WT71



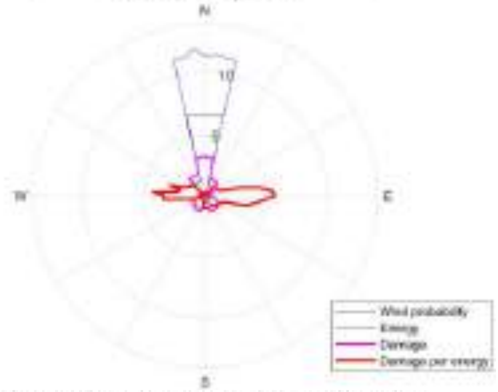
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT72



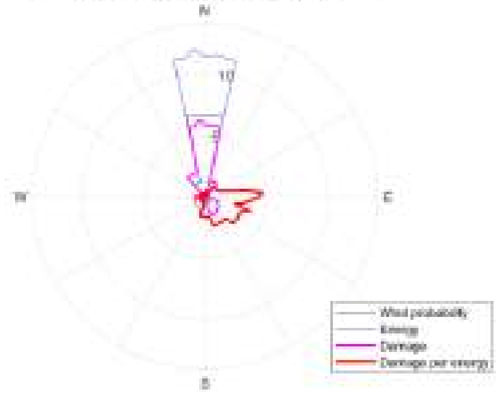
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT72



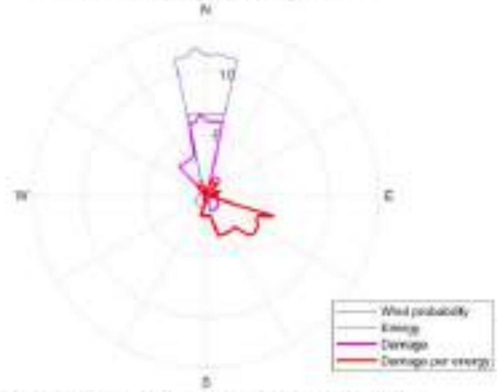
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT72



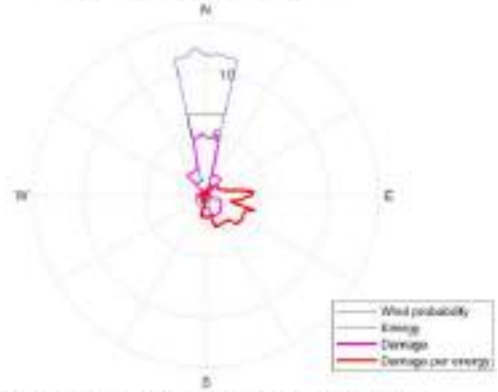
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT72



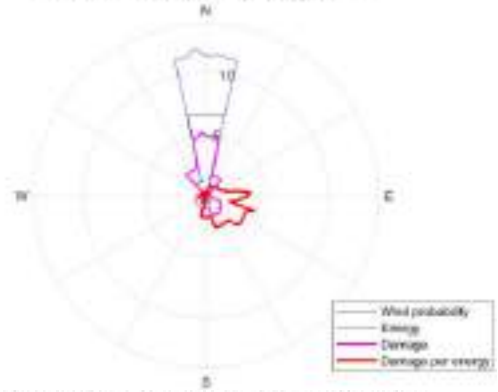
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT72



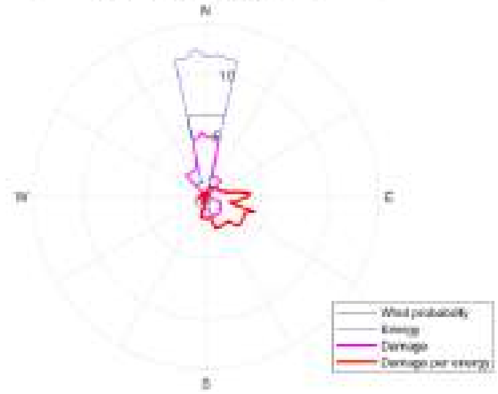
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT72



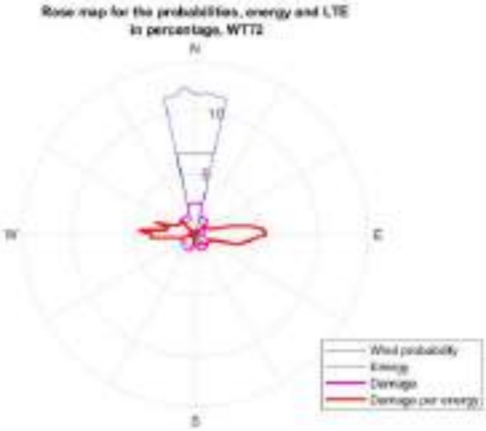
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT72

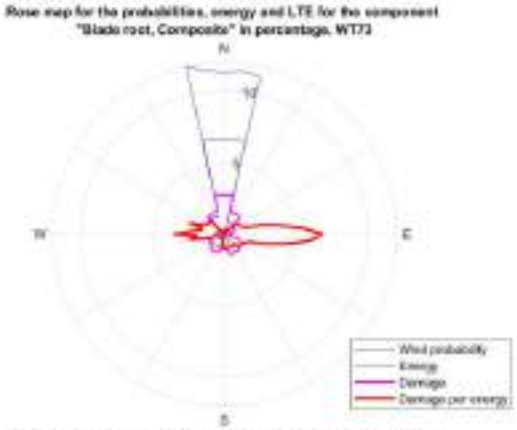


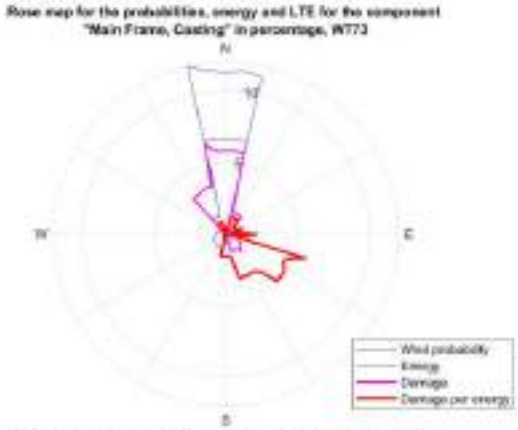
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT72

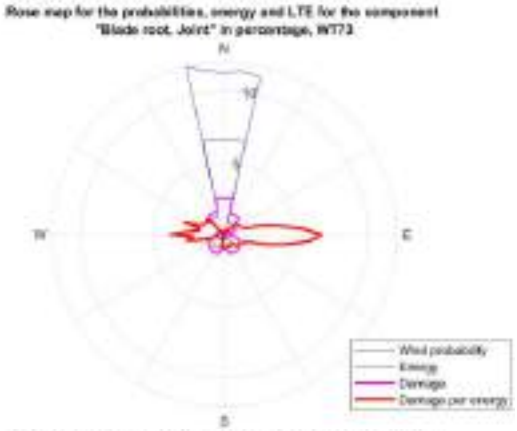


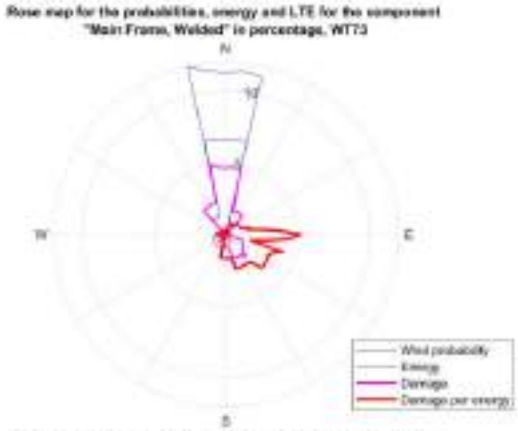

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT72
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

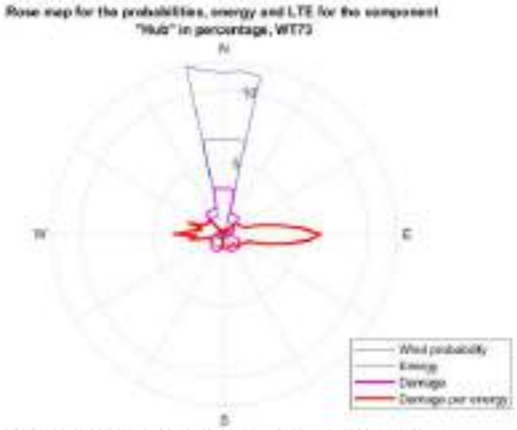

Rose map for the probabilities, energy and LTE
in percentage, WT72
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

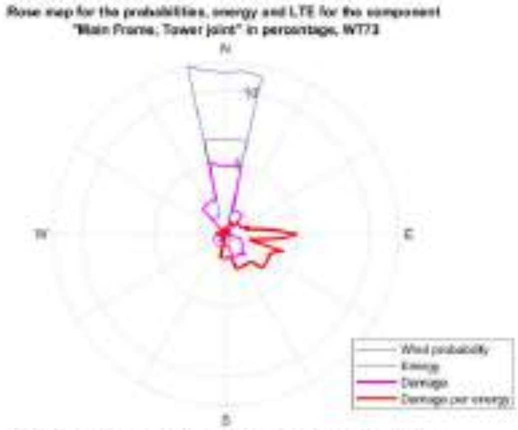

Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT73
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

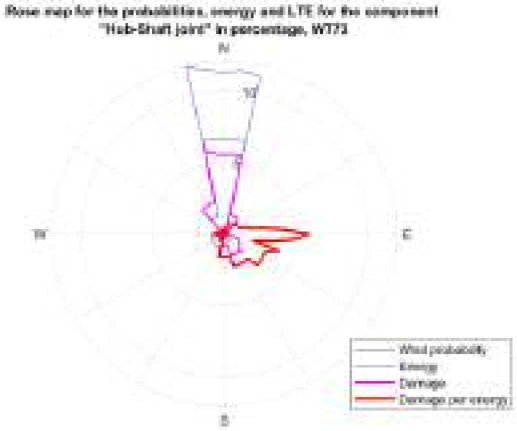

Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT73
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

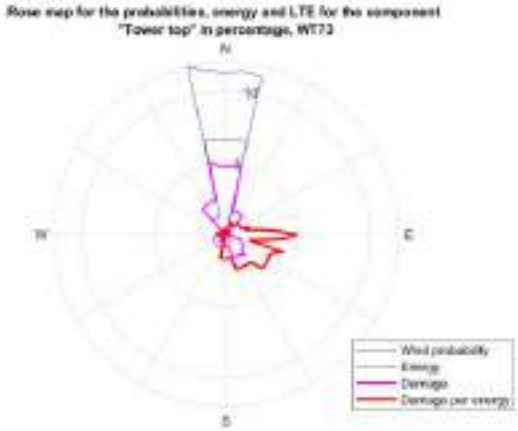

Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT73
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

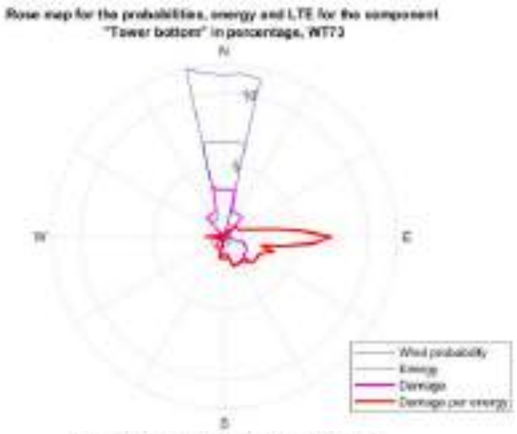

Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT73
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

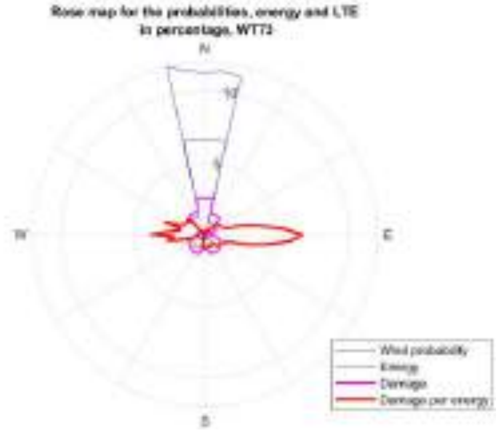

Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT73
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT73
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

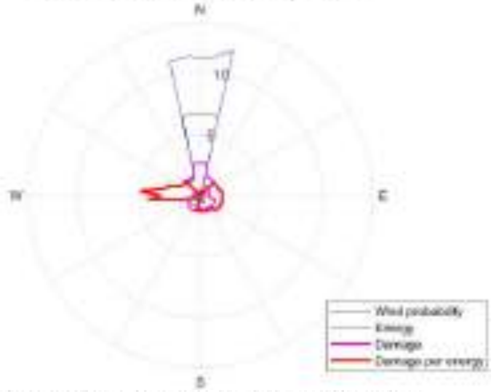

Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT73
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT73
N
E
S
W
10
5
Wind probability
Energy
Damage
Damage per energy

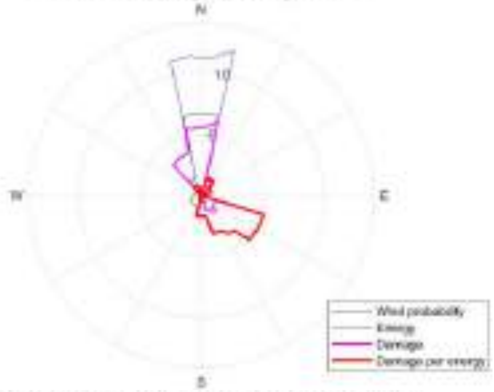

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT73
N
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT73
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

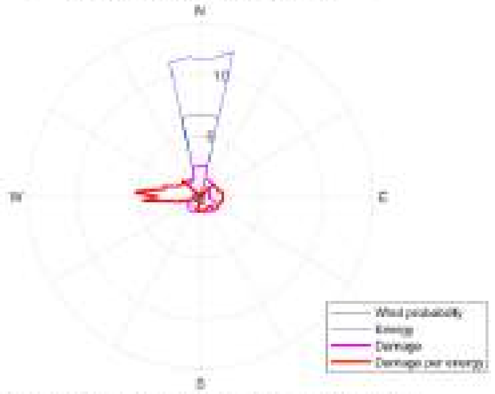
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT74



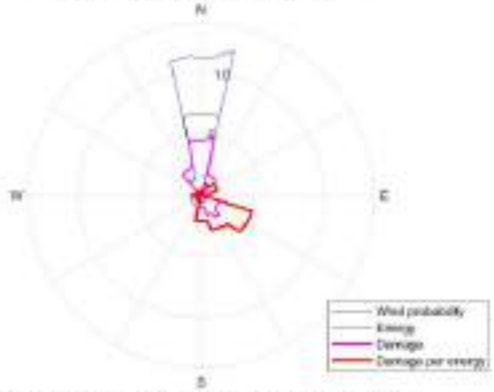
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT74



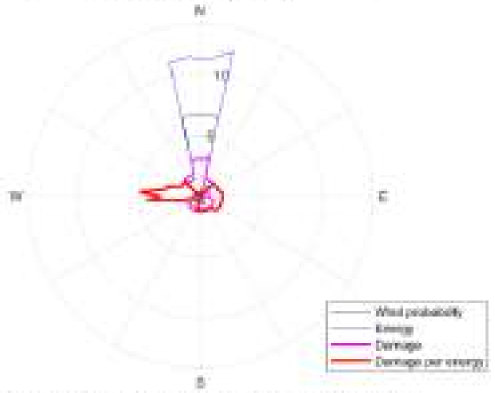
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT74



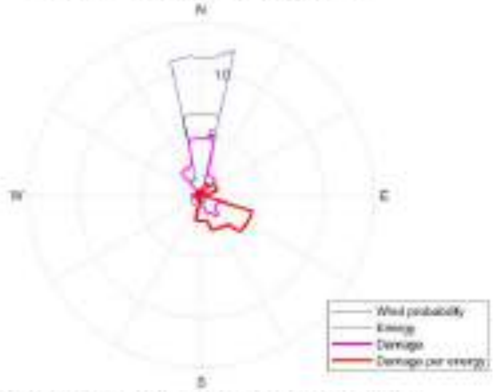
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT74



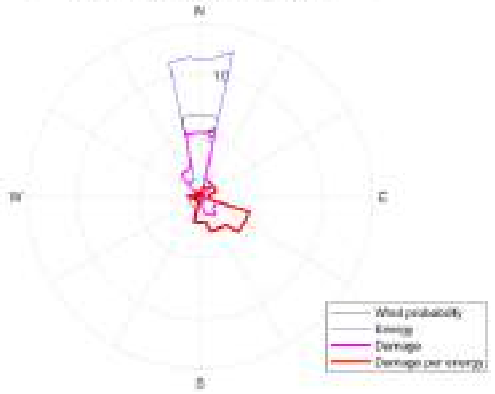
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT74



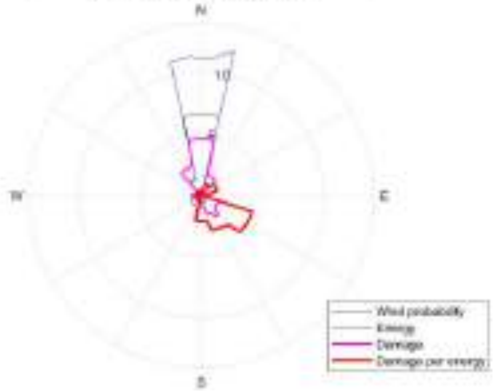
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT74



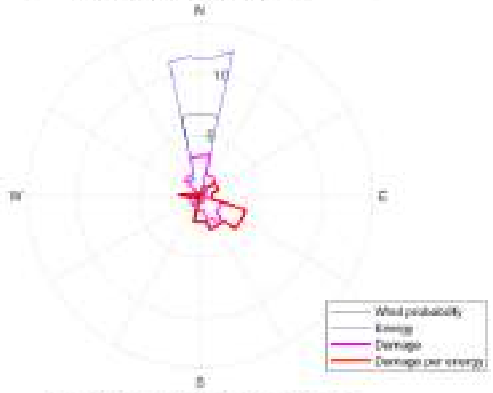
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT74



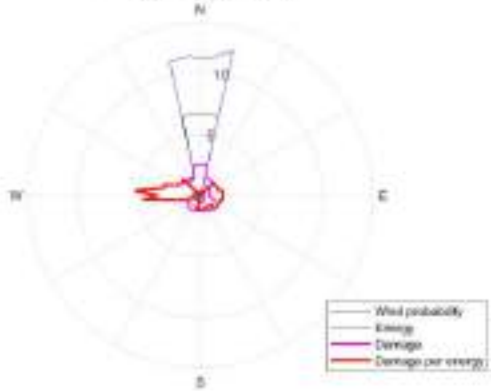
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT74



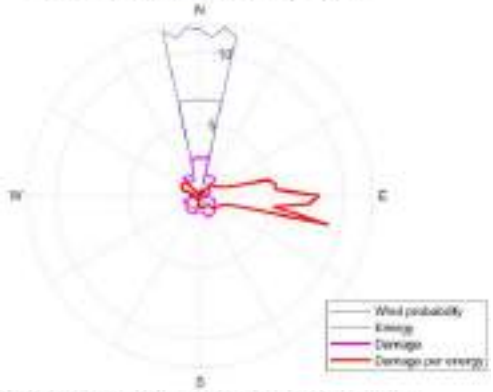
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT74



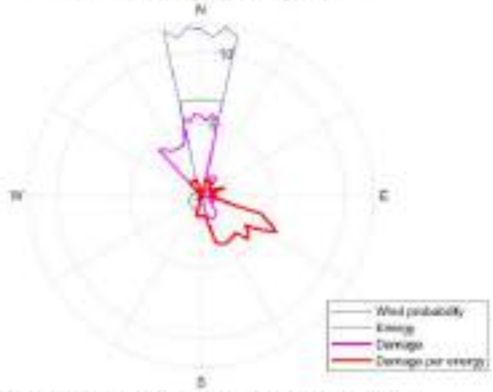
Rose map for the probabilities, energy and LTE in percentage, WT74



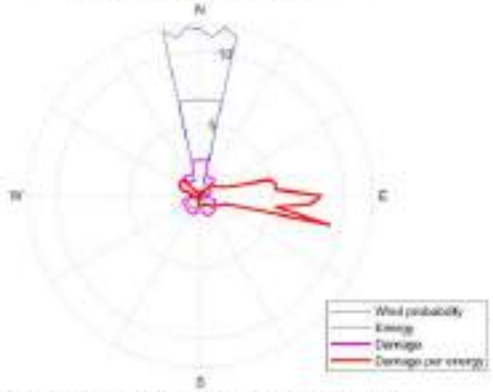
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT75



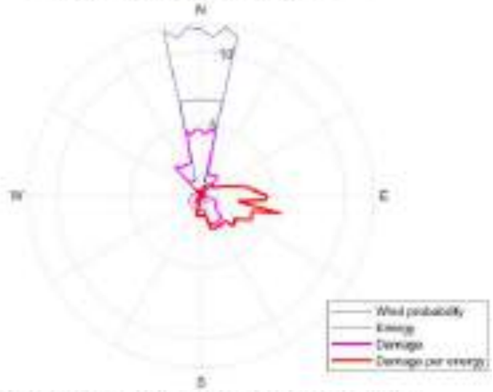
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT75



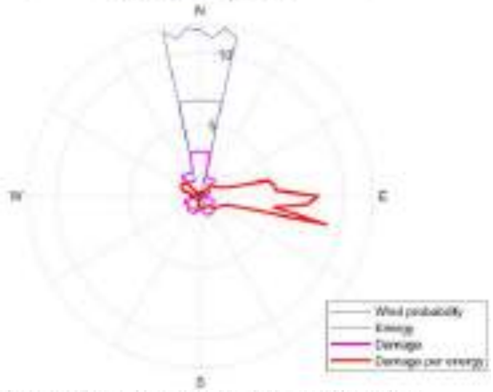
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT75



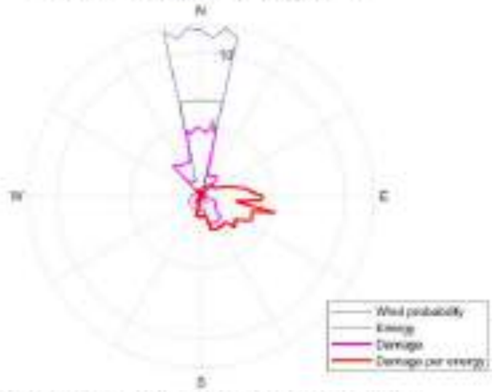
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT75



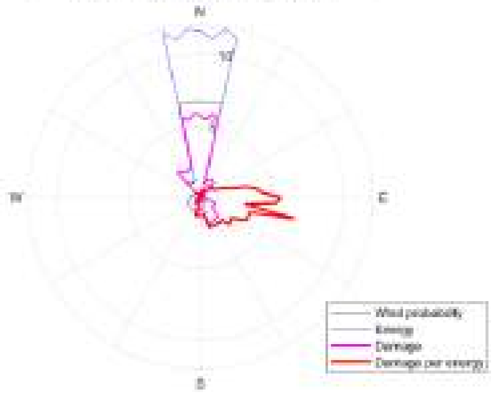
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT75



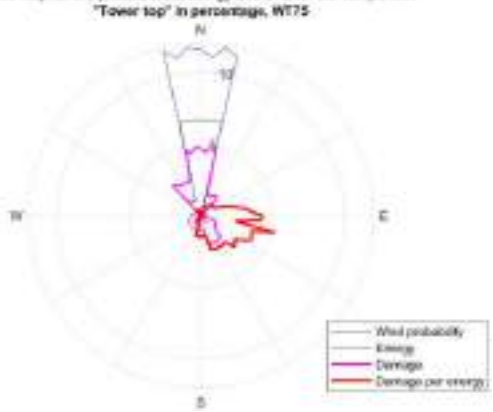
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT75



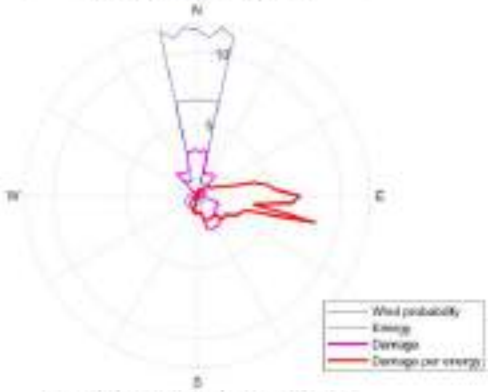
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT75



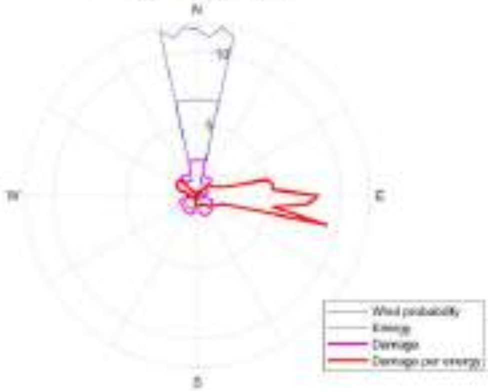
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT75



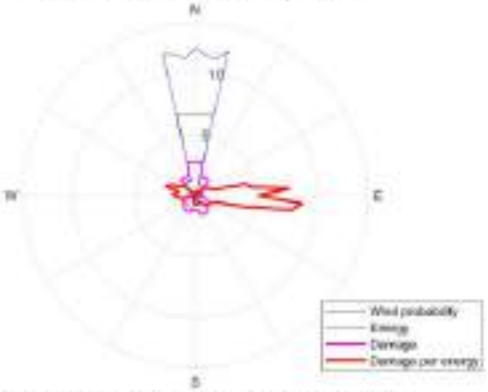
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT75



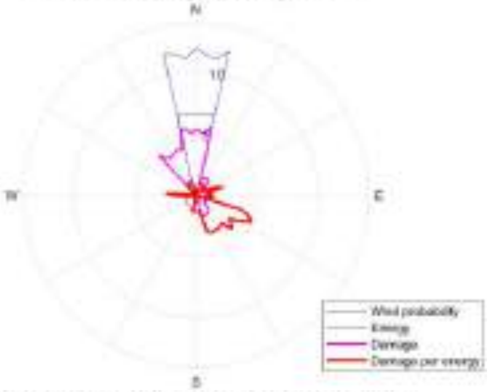
Rose map for the probabilities, energy and LTE in percentage, WT75



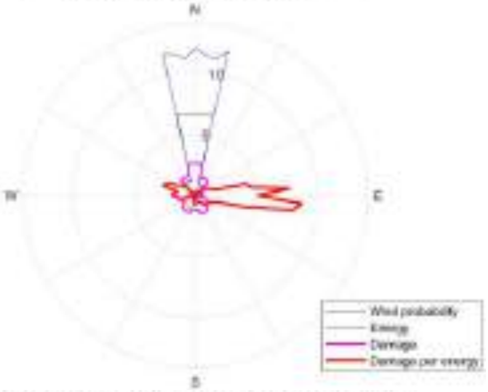
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT76



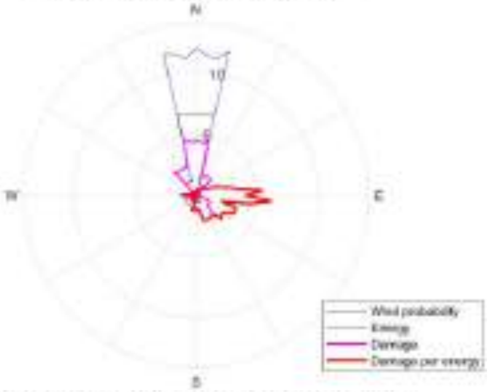
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT76



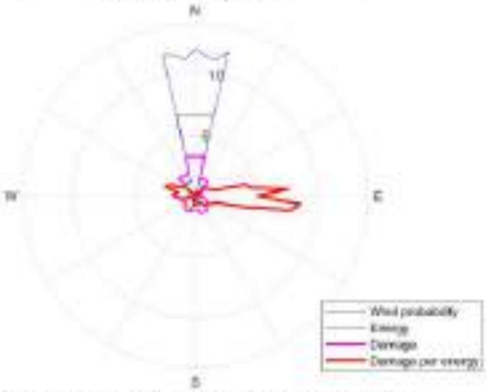
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT76



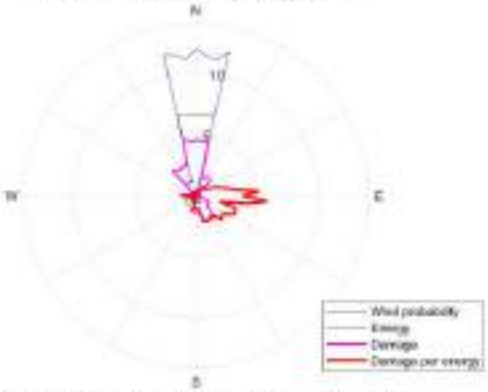
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT76



Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT76

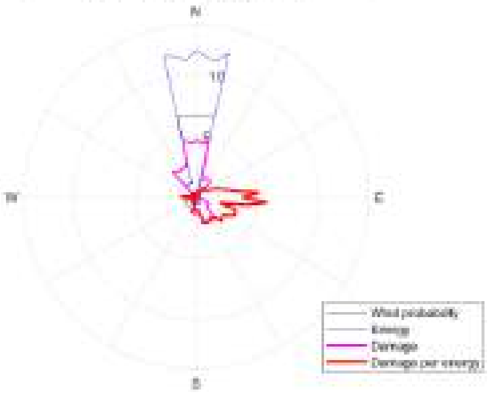


Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT76

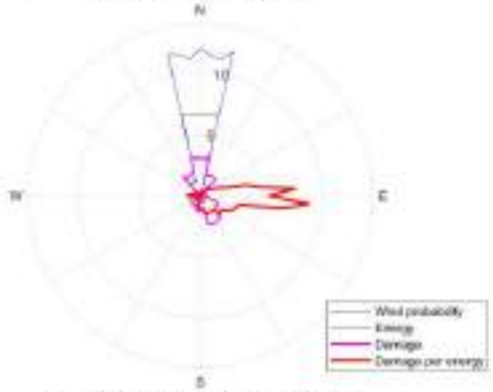


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT76

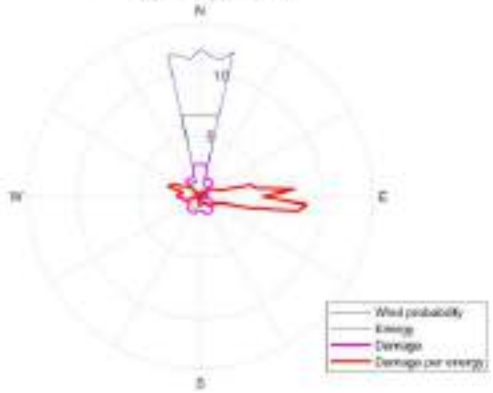
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT76



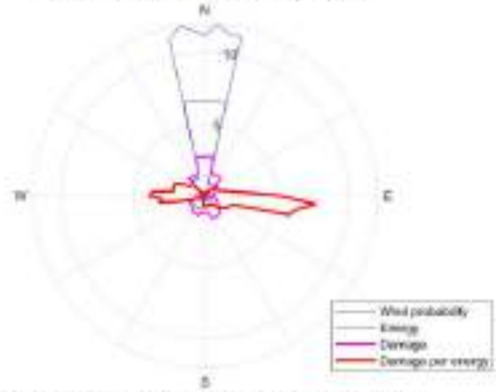
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT76



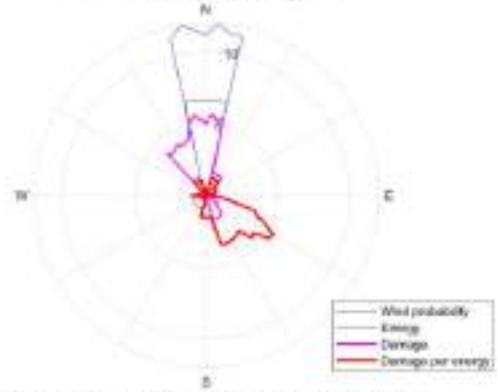
Rose map for the probabilities, energy and LTE in percentage, WT76



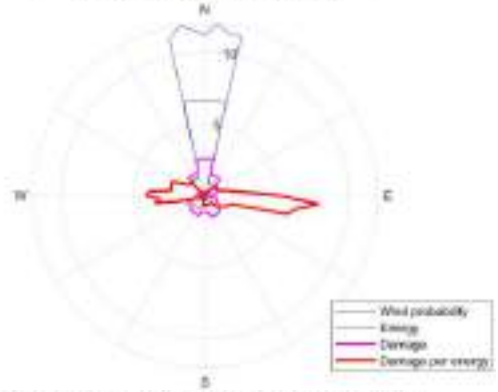
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT77



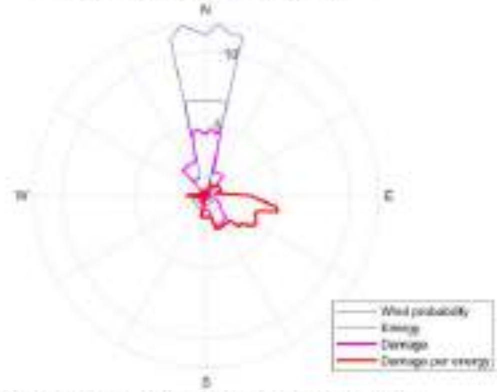
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT77



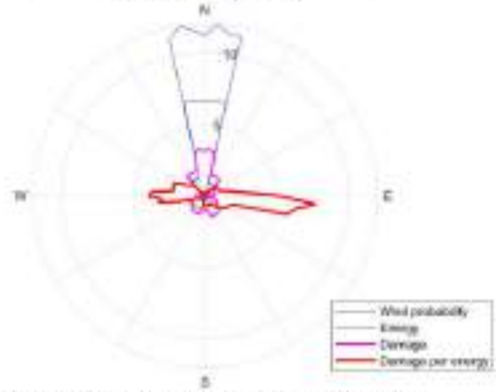
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT77



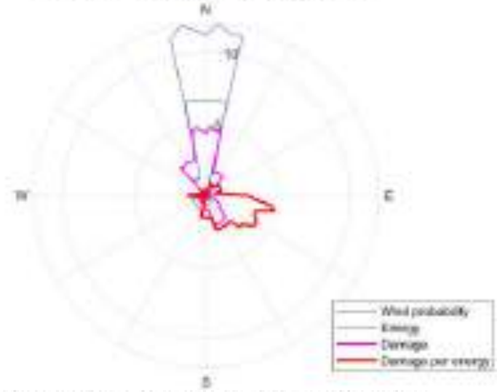
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT77



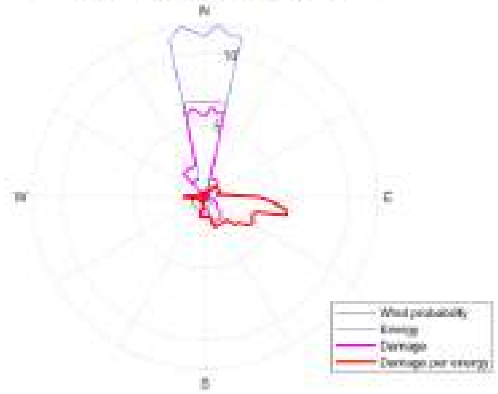
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT77



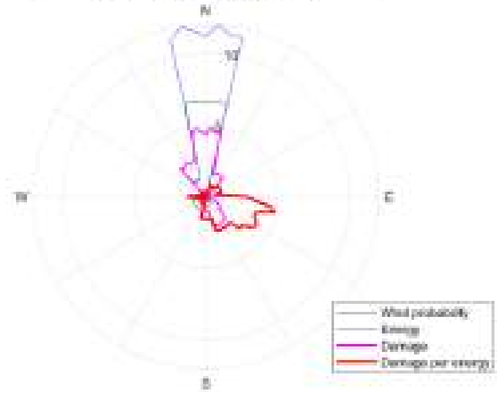
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT77



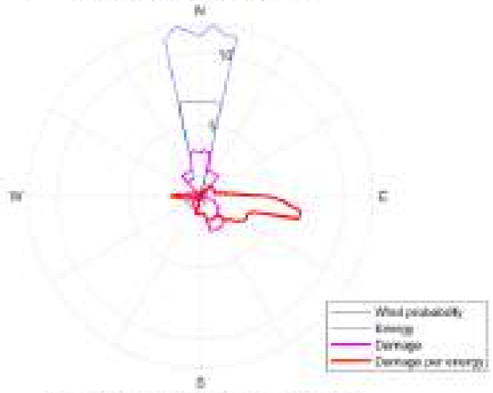
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT77



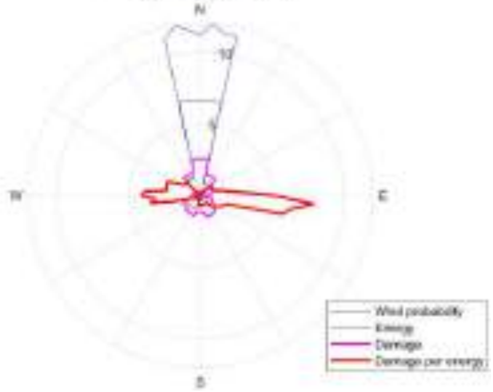
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT77

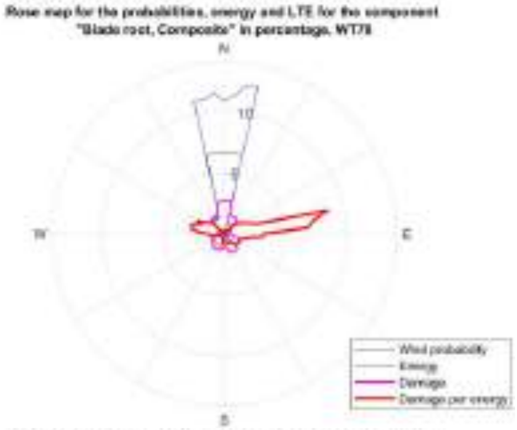


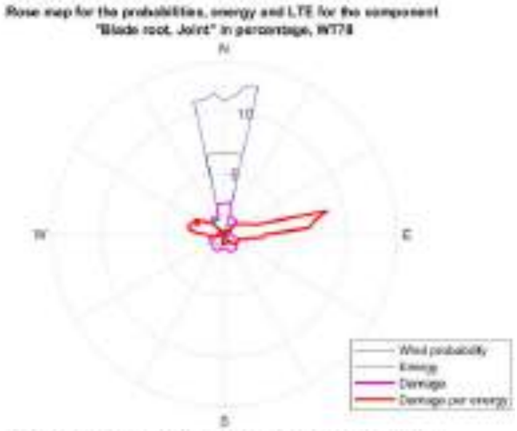
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT77

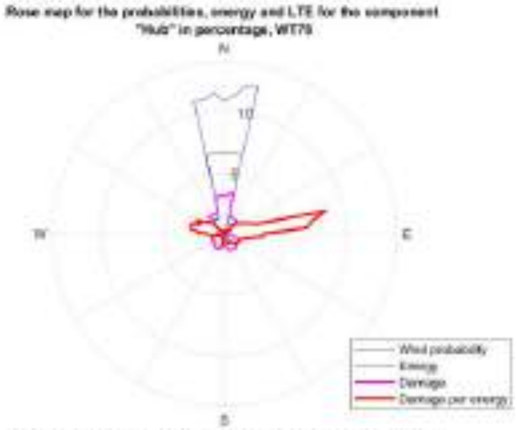


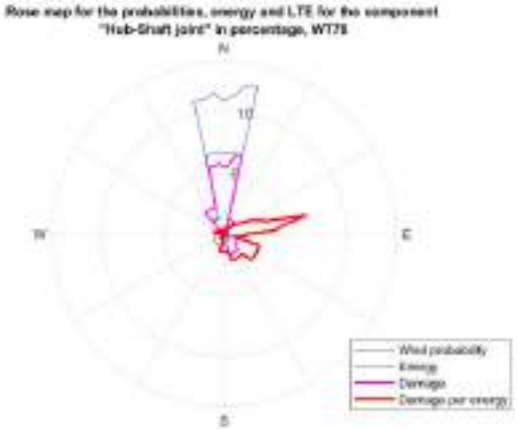
Rose map for the probabilities, energy and LTE in percentage, WT77

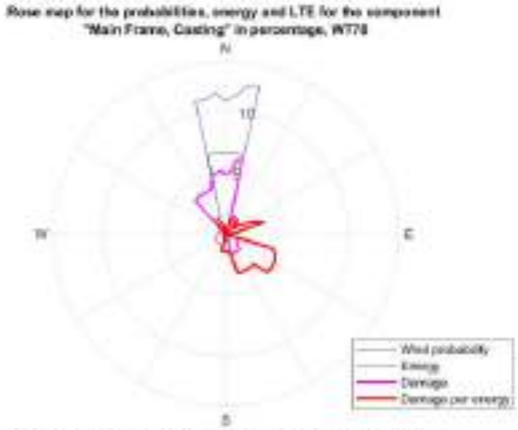


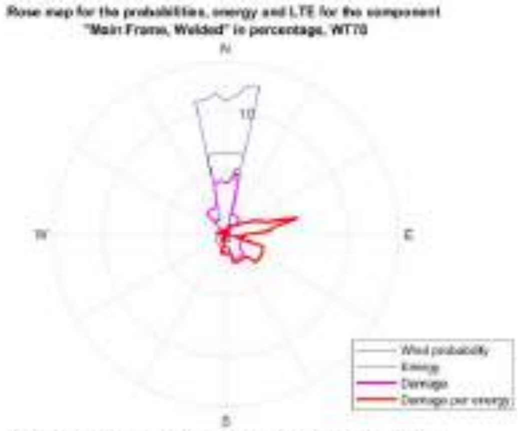

Rose map for the probabilities, energy and LTE for the component
"Blade root, Composite" in percentage, WT78
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

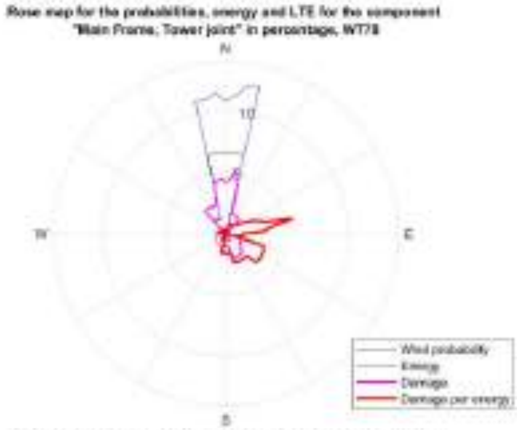

Rose map for the probabilities, energy and LTE for the component
"Blade root, Joint" in percentage, WT78
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

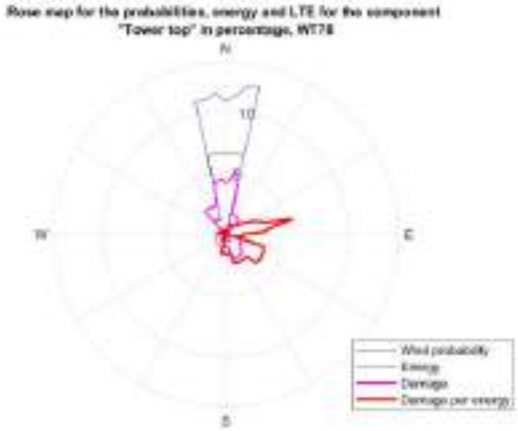

Rose map for the probabilities, energy and LTE for the component
"Hub" in percentage, WT78
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Hub-Shaft joint" in percentage, WT78
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

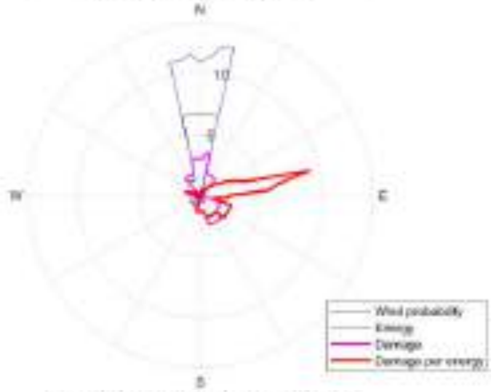

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Casting" in percentage, WT78
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Main Frame, Welded" in percentage, WT78
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

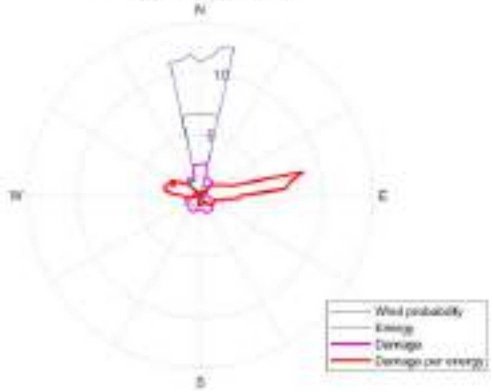

Rose map for the probabilities, energy and LTE for the component
"Main Frame; Tower joint" in percentage, WT78
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

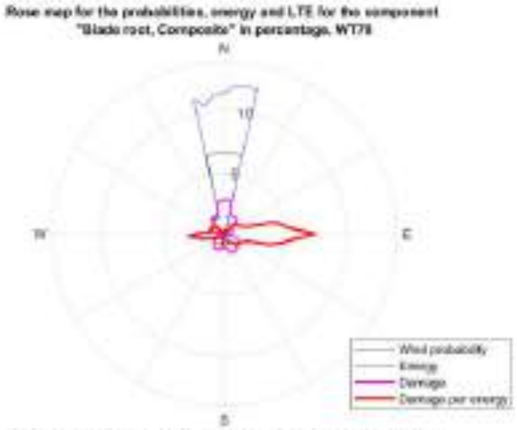

Rose map for the probabilities, energy and LTE for the component
"Tower top" in percentage, WT78
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

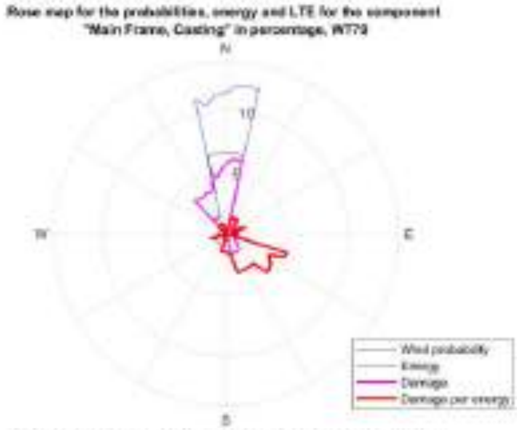
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT78

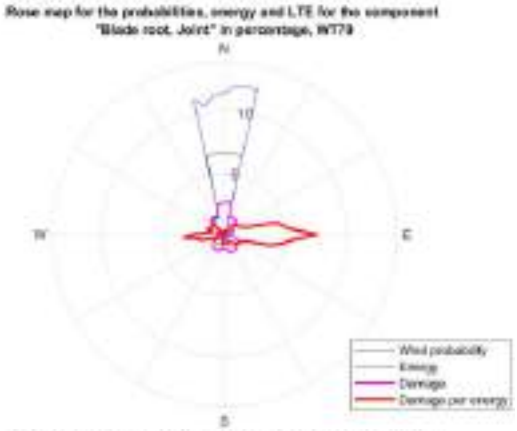


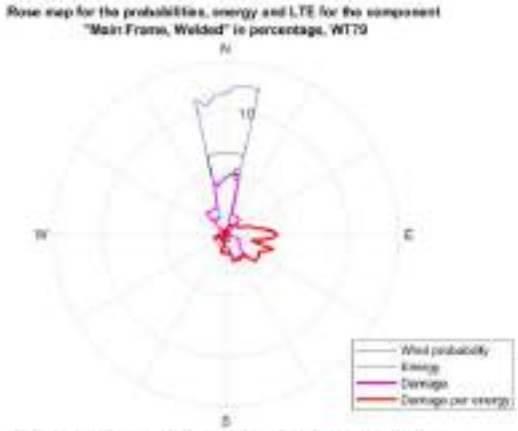
Rose map for the probabilities, energy and LTE in percentage, WT78

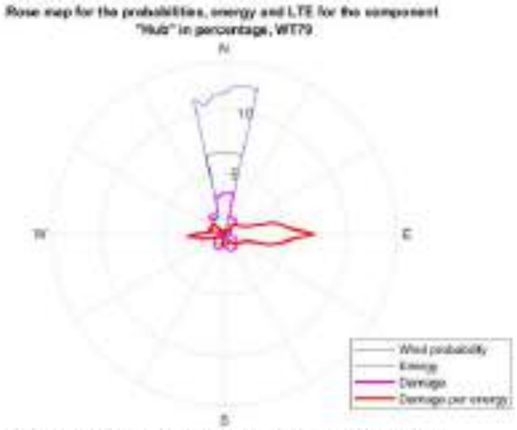


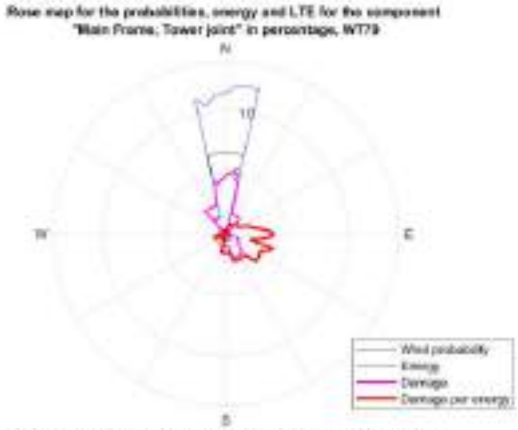

Rose map for the probabilities, energy and LTE for the component
"Blade root, Composite" in percentage, WT79
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

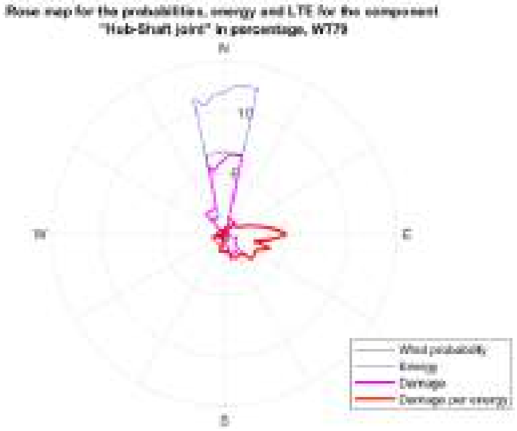

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Casting" in percentage, WT79
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

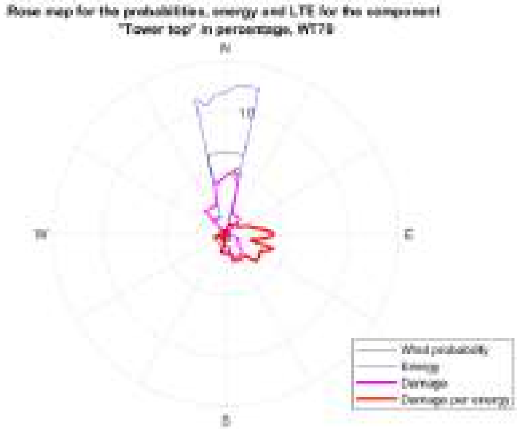

Rose map for the probabilities, energy and LTE for the component
"Blade root, Joint" in percentage, WT79
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Main Frame, Welded" in percentage, WT79
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

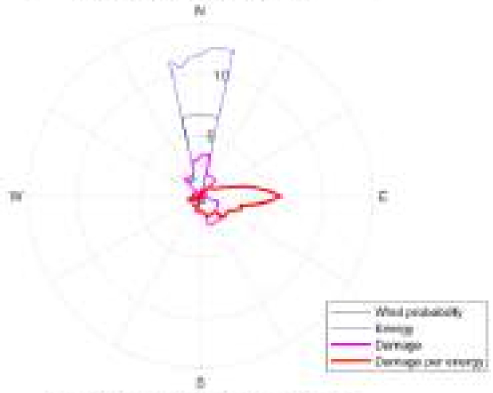

Rose map for the probabilities, energy and LTE for the component
"Hub" in percentage, WT79
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Main Frame; Tower joint" in percentage, WT79
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

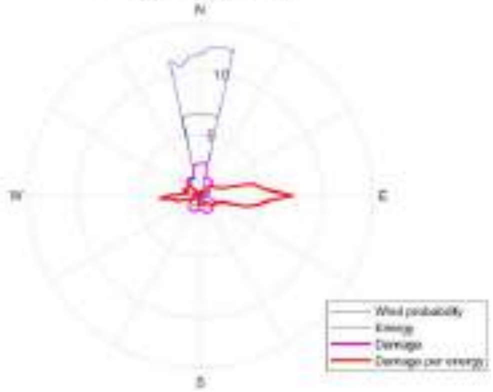

Rose map for the probabilities, energy and LTE for the component
"Hub-Shaft joint" in percentage, WT79
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

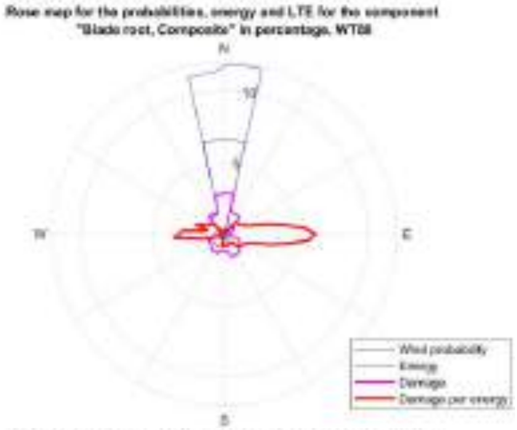

Rose map for the probabilities, energy and LTE for the component
"Tower top" in percentage, WT79
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT79

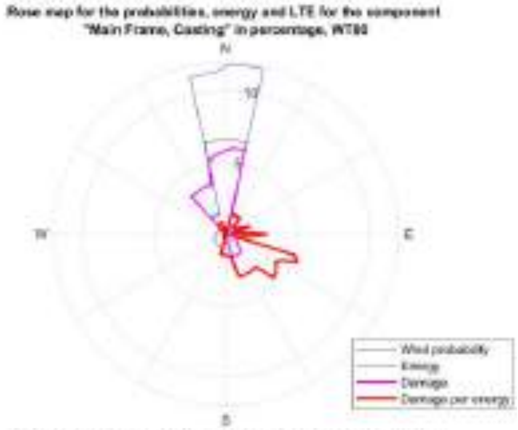


Rose map for the probabilities, energy and LTE in percentage, WT79

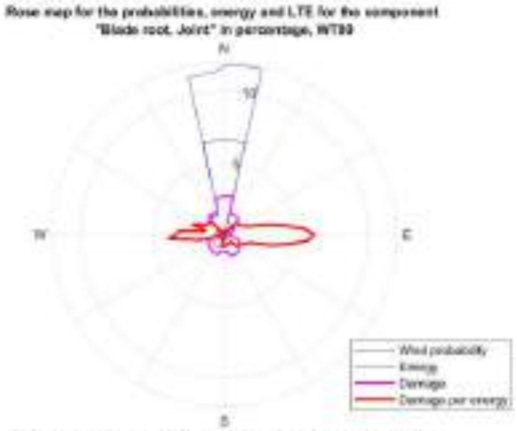




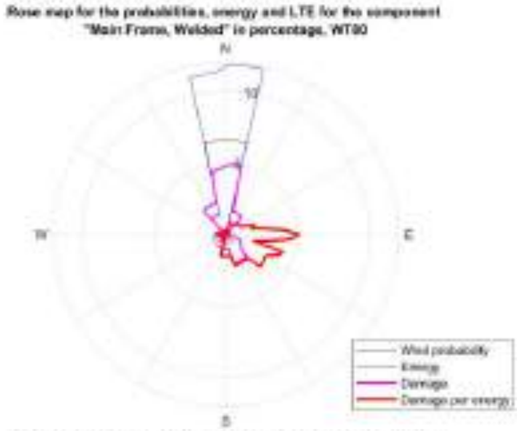
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage
N
W
E
S
Wind probability
Energy
Damage
Damage per energy



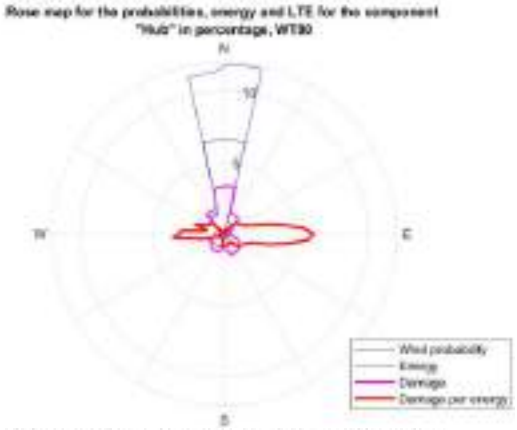
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage
N
W
E
S
Wind probability
Energy
Damage
Damage per energy



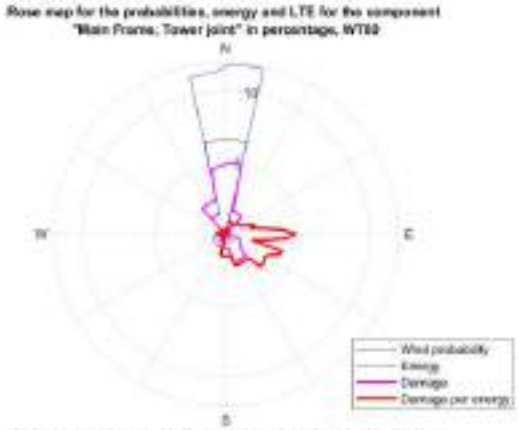
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage
N
W
E
S
Wind probability
Energy
Damage
Damage per energy



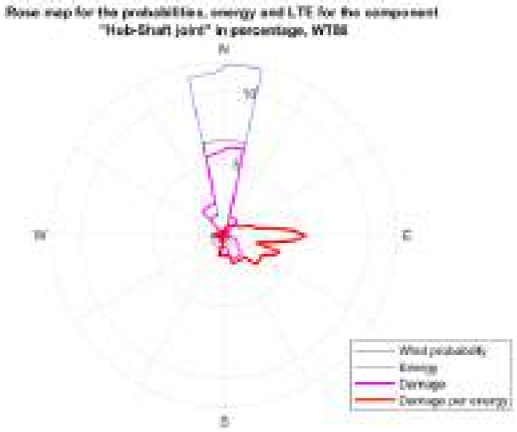
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage
N
W
E
S
Wind probability
Energy
Damage
Damage per energy



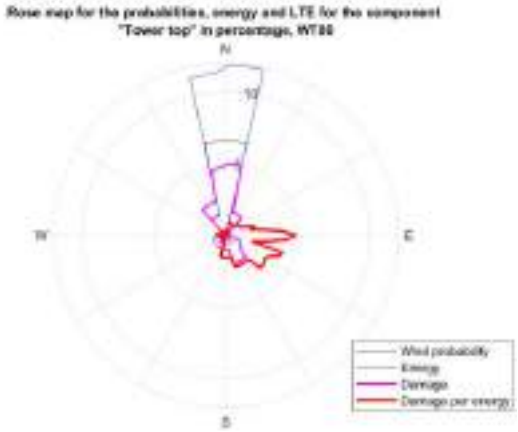
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage
N
W
E
S
Wind probability
Energy
Damage
Damage per energy



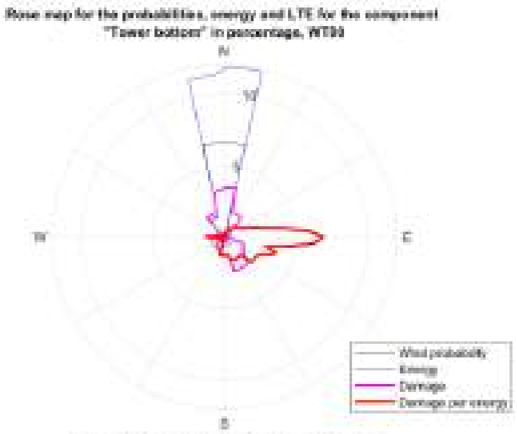
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

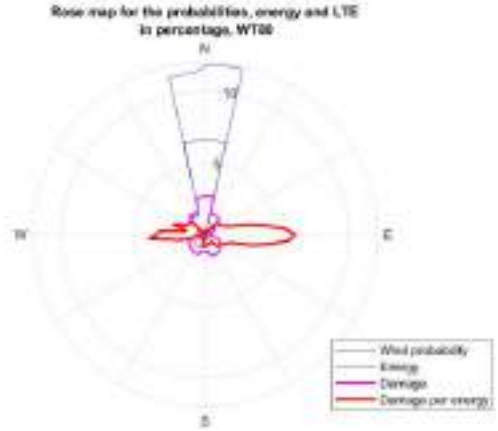


Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

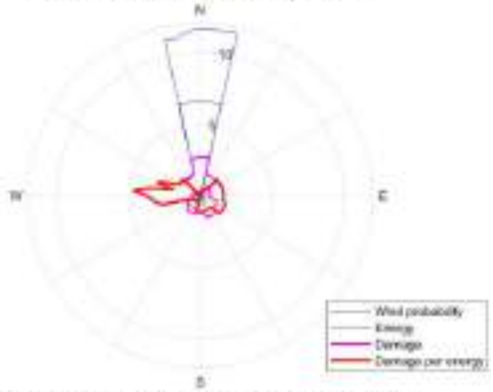


Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage
N
W
E
S
Wind probability
Energy
Damage
Damage per energy

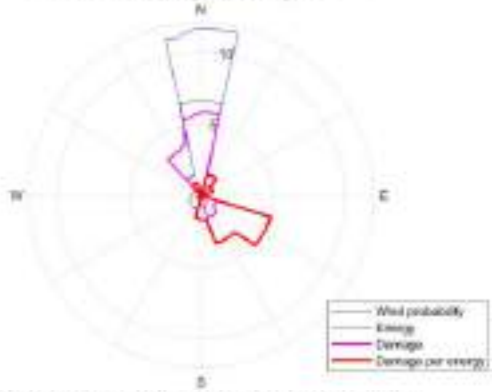

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage,
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage,
N
10
5
W
E
S
Wind probability
Energy
Damage
Damage per energy

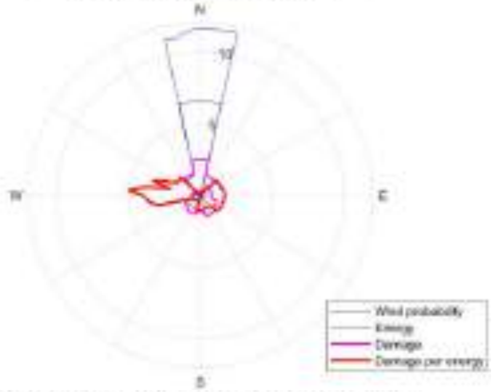
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT01



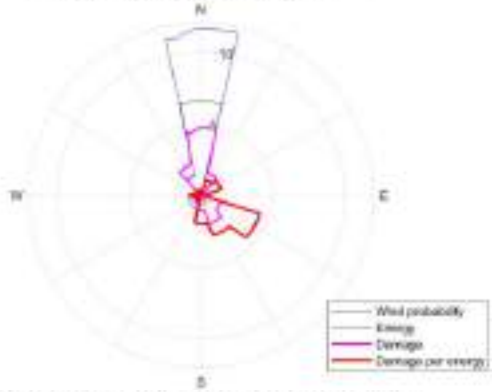
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT01



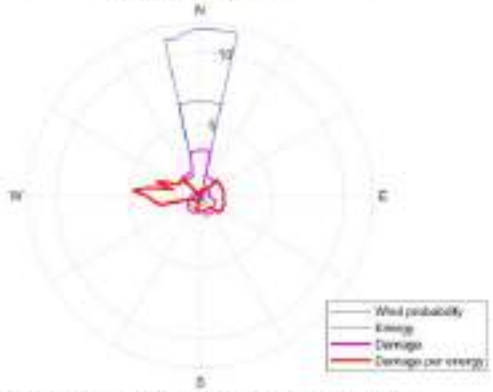
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT01



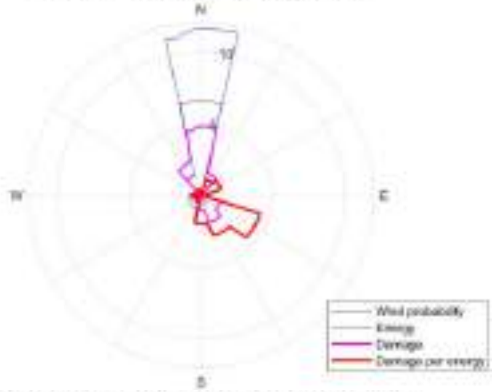
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT01



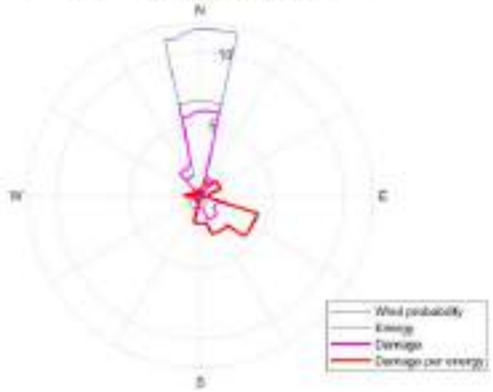
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT01



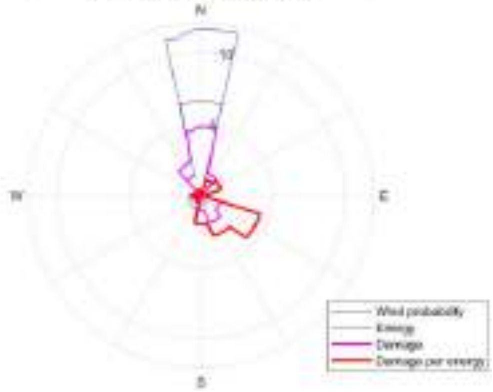
Rose map for the probabilities, energy and LTE for the component "Main Frame; Tower joint" in percentage, WT01



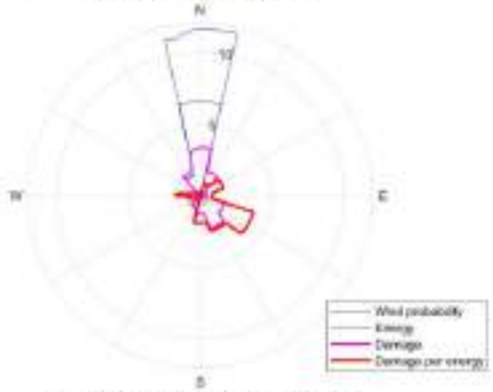
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT01



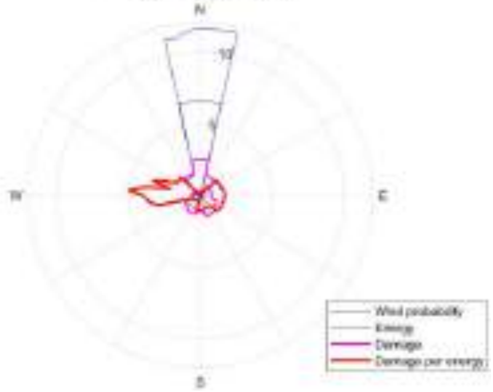
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT01



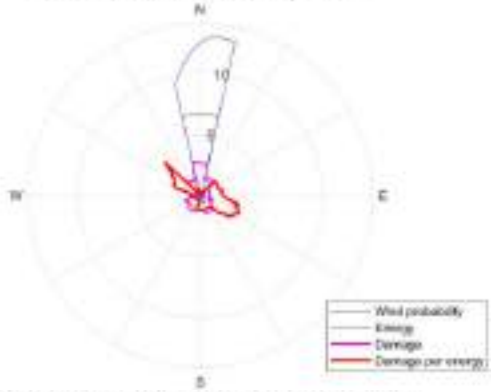
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT01



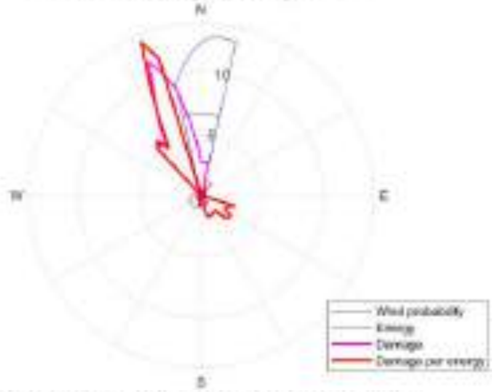
Rose map for the probabilities, energy and LTE in percentage, WT01



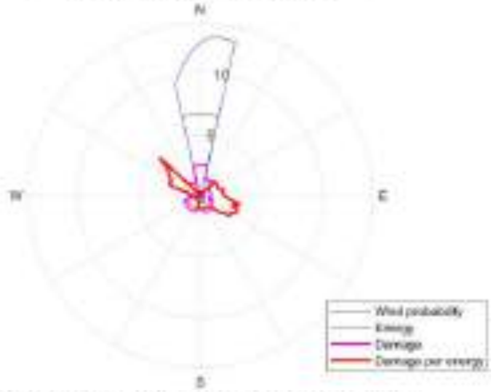
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT82



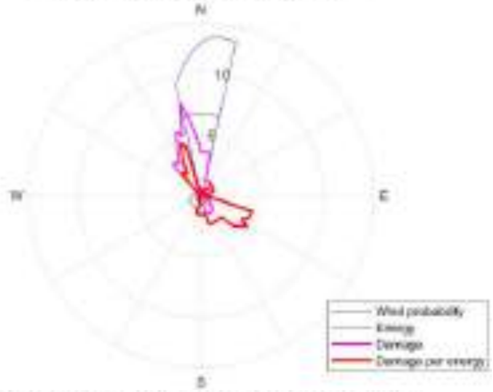
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT82



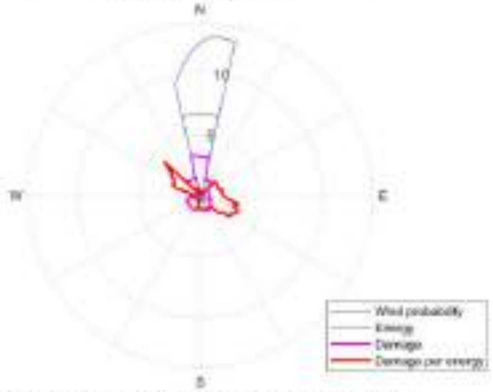
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT82



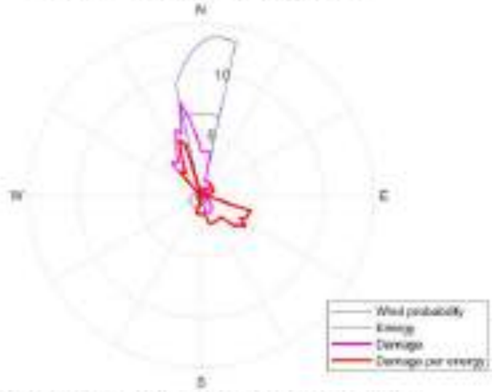
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT82



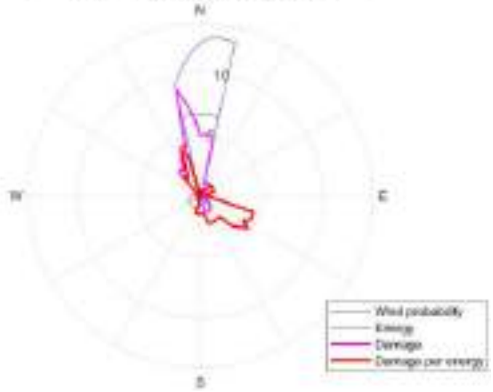
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT82



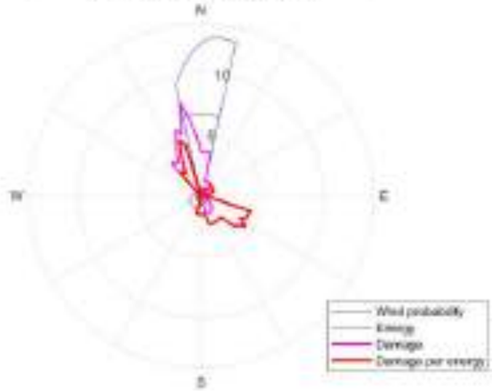
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT82



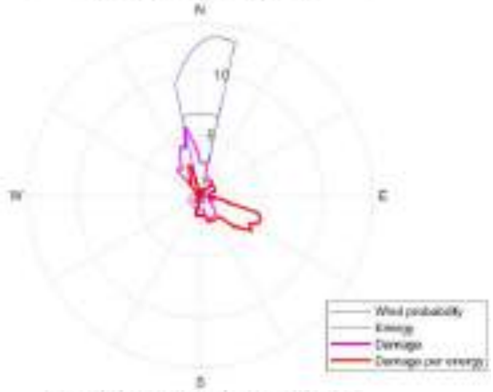
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT82



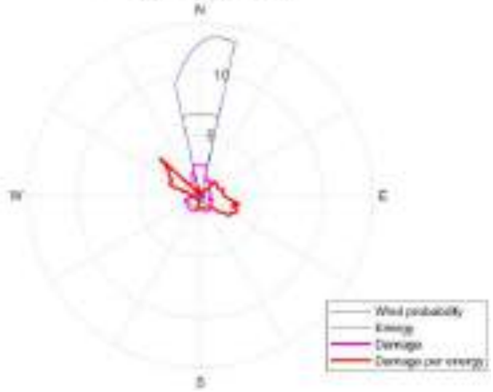
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT82

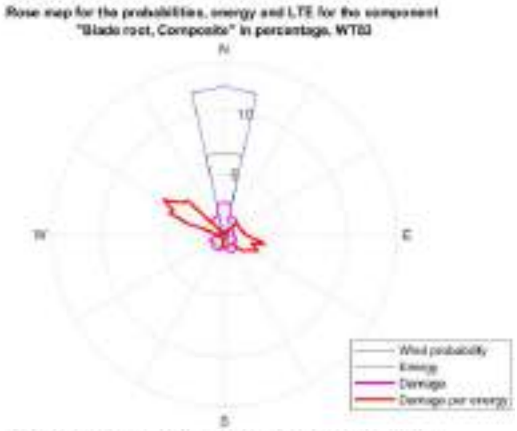


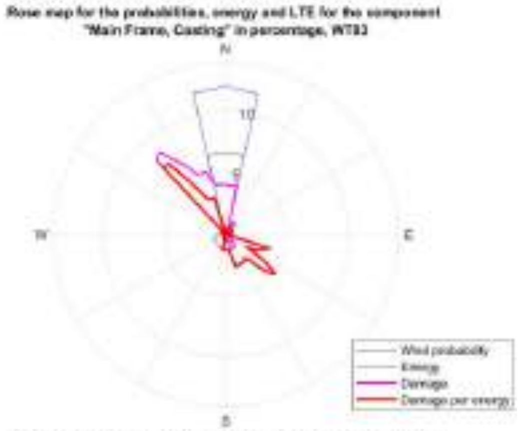
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT82

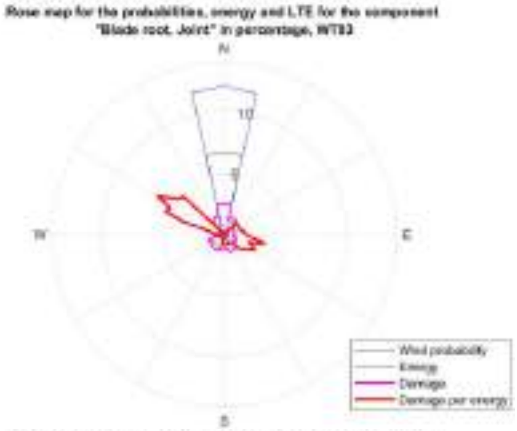


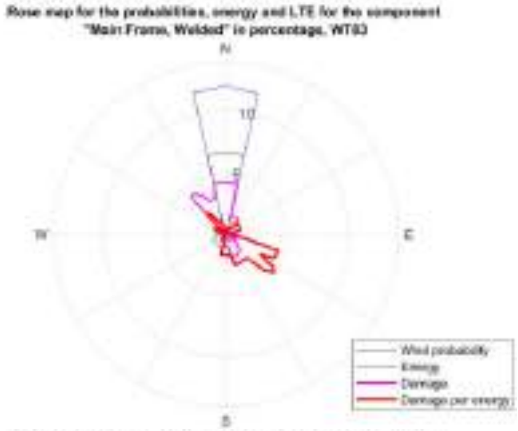
Rose map for the probabilities, energy and LTE in percentage, WT82

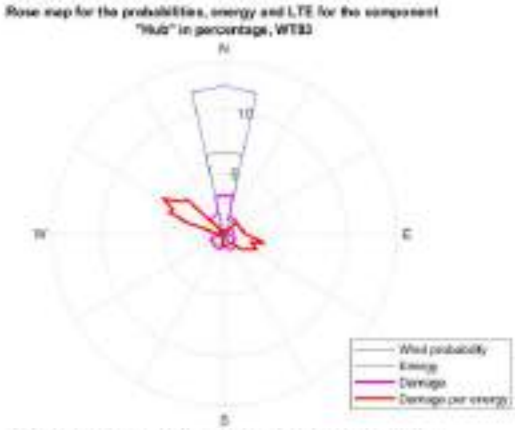


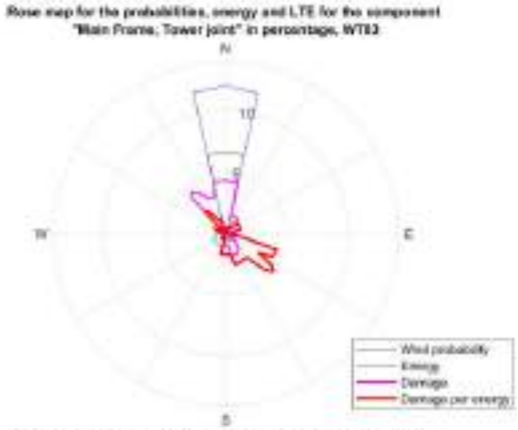

Rose map for the probabilities, energy and LTE for the component
"Blade root, Composite" in percentage, WT83
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

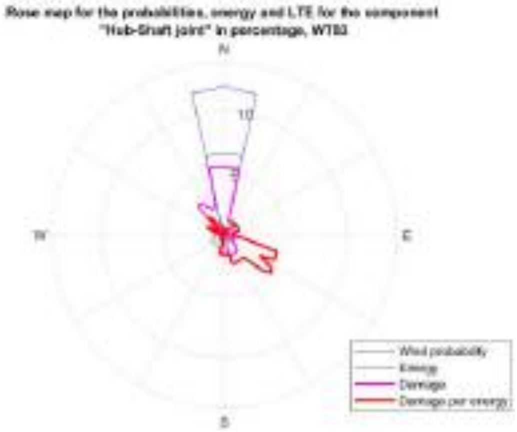

Rose map for the probabilities, energy and LTE for the component
"Main Frame, Casting" in percentage, WT83
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

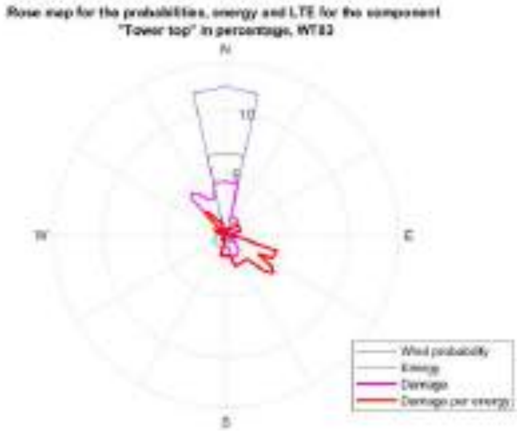

Rose map for the probabilities, energy and LTE for the component
"Blade root, Joint" in percentage, WT83
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Main Frame, Welded" in percentage, WT83
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

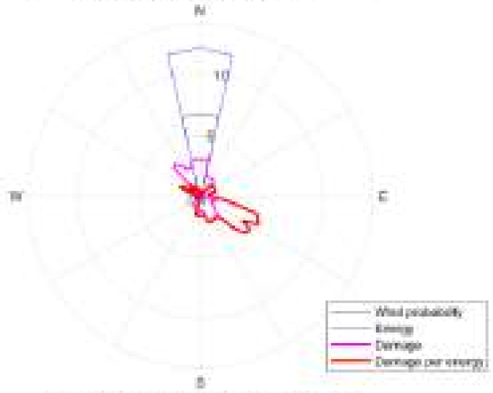

Rose map for the probabilities, energy and LTE for the component
"Hub" in percentage, WT83
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Main Frame, Tower joint" in percentage, WT83
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

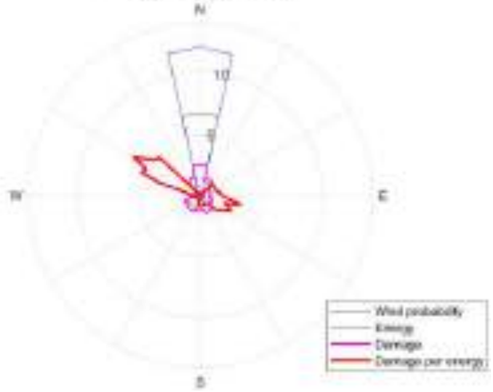

Rose map for the probabilities, energy and LTE for the component
"Hub-Shaft joint" in percentage, WT83
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE for the component
"Tower top" in percentage, WT83
N
W
E
S
10
5
Wind probability
Energy
Damage
Damage per energy

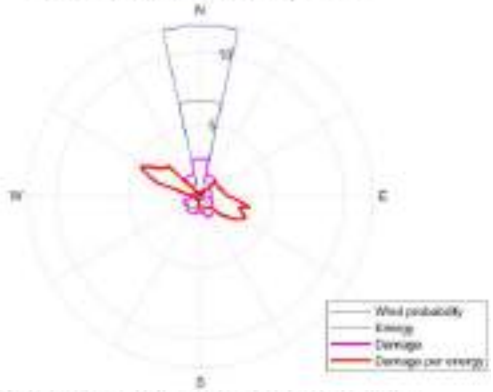
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT83



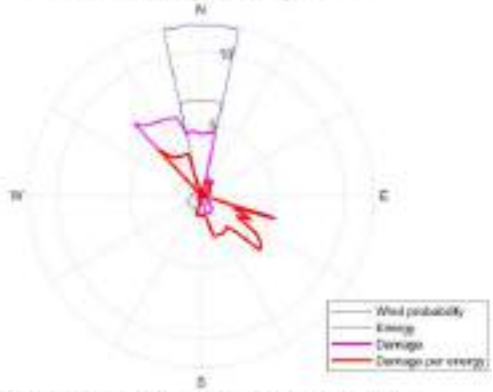
Rose map for the probabilities, energy and LTE in percentage, WT83



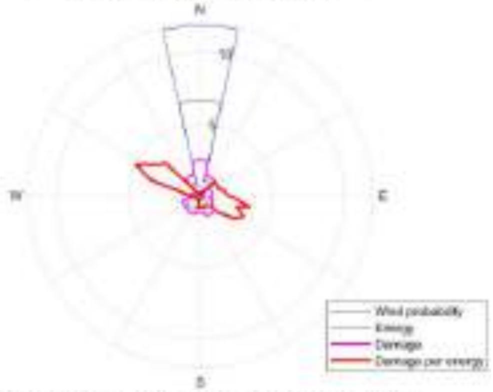
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT84



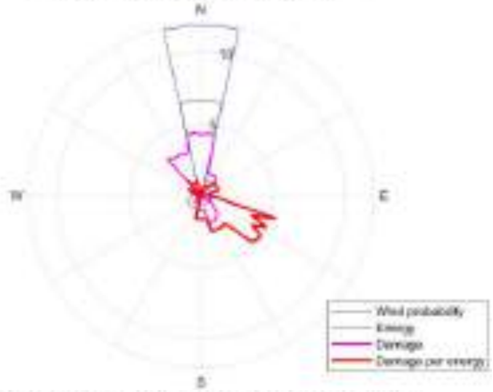
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT84



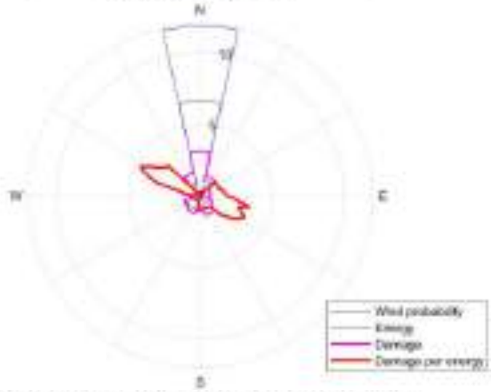
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT84



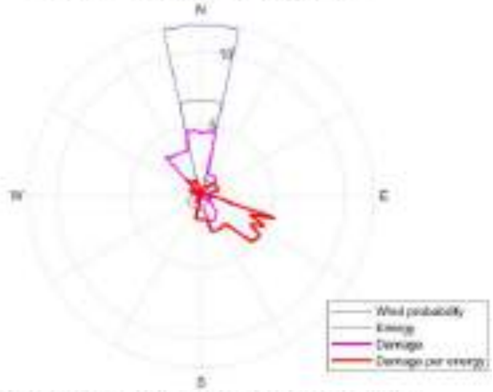
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT84



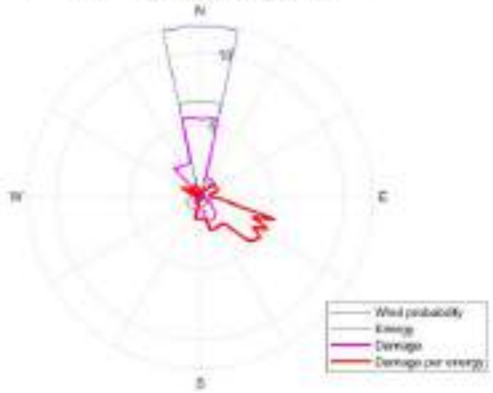
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT84



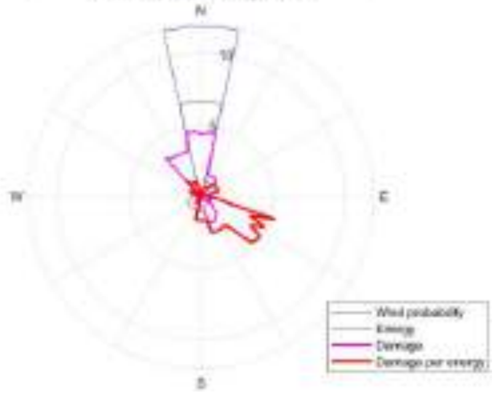
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT84



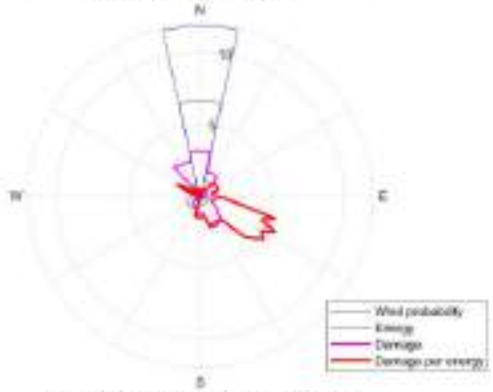
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT84



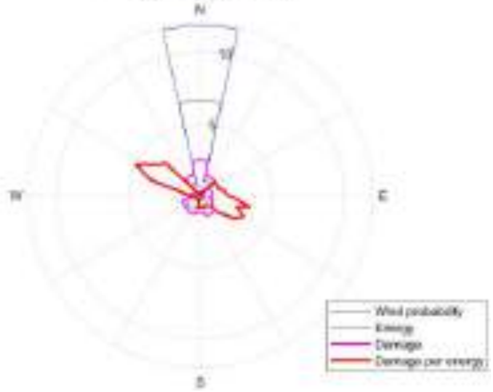
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT84



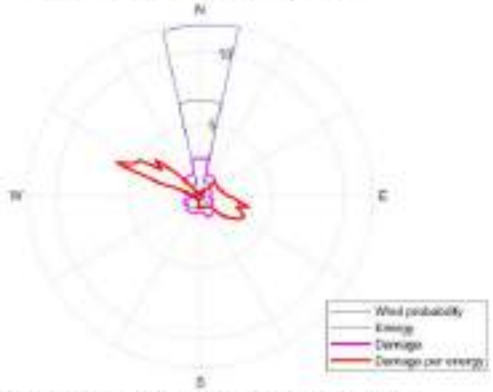
Rose map for the probabilities, energy and LTE for the component "Tower bottom" in percentage, WT04



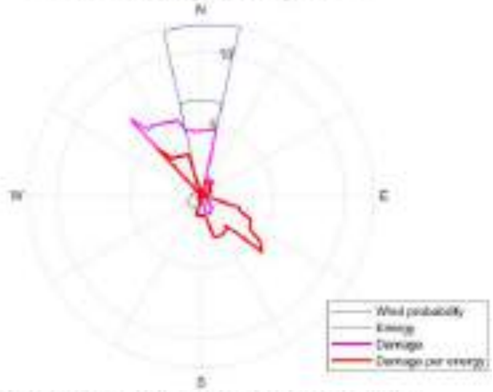
Rose map for the probabilities, energy and LTE in percentage, WT04



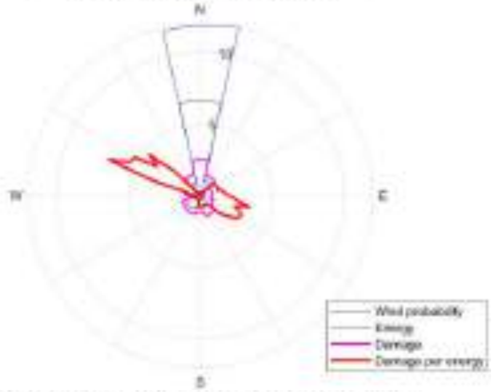
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT85



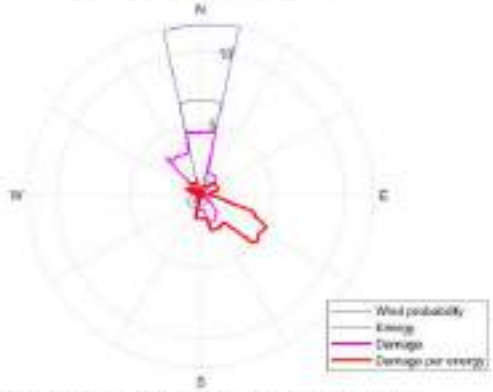
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT85



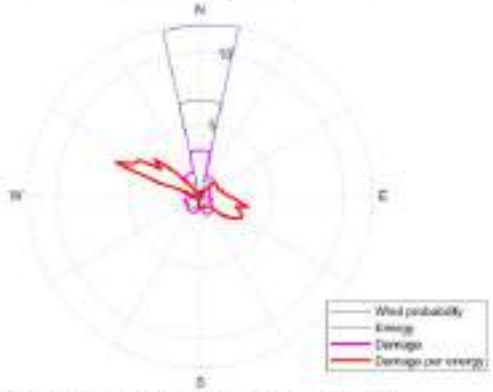
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT85



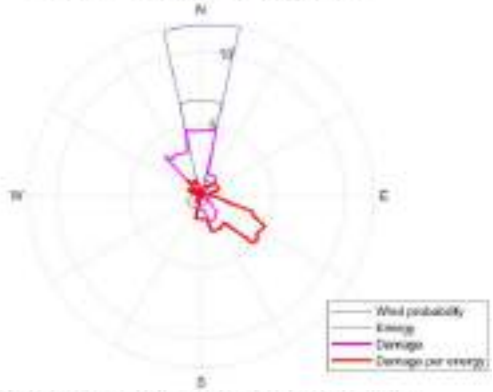
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT85



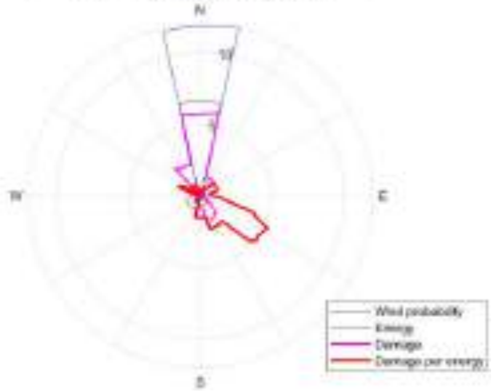
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT85



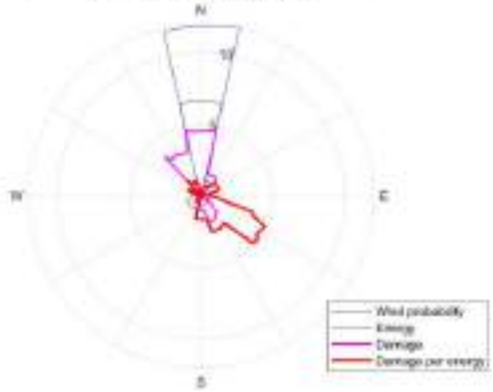
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT85

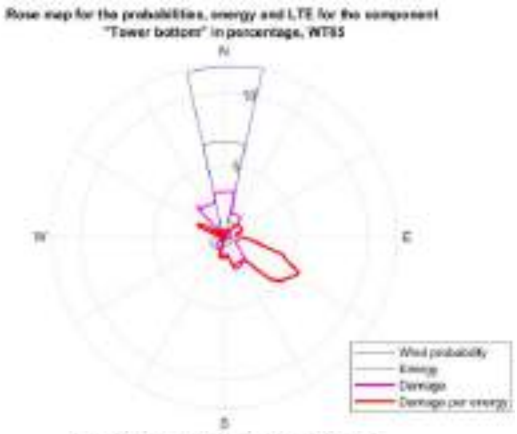


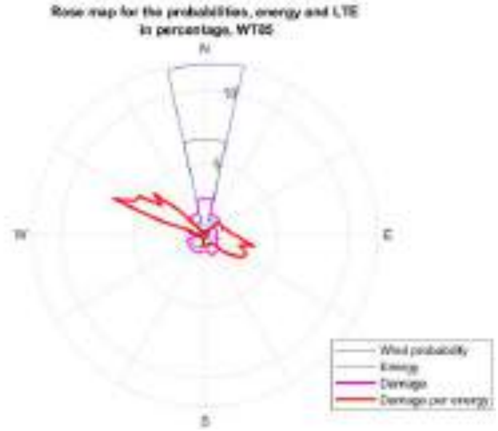
Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT85



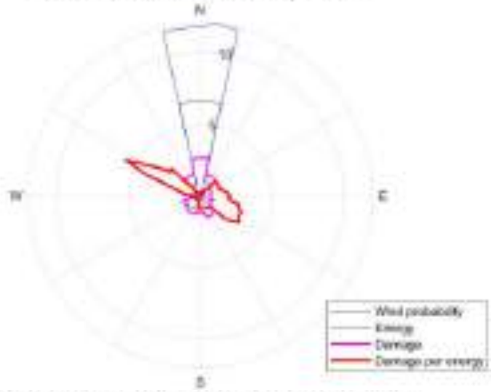
Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT85



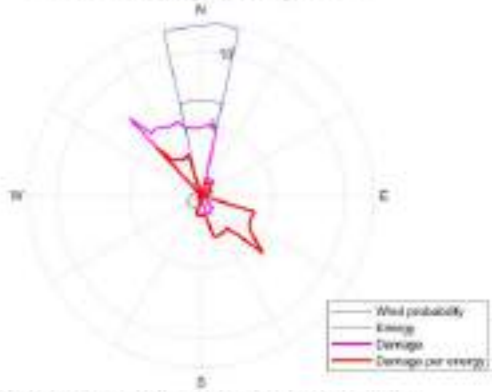

Rose map for the probabilities, energy and LTE for the component
"Tower bottom" in percentage, WT85
N
E
S
W
Wind probability
Energy
Damage
Damage per energy


Rose map for the probabilities, energy and LTE
in percentage, WT85
N
E
S
W
Wind probability
Energy
Damage
Damage per energy

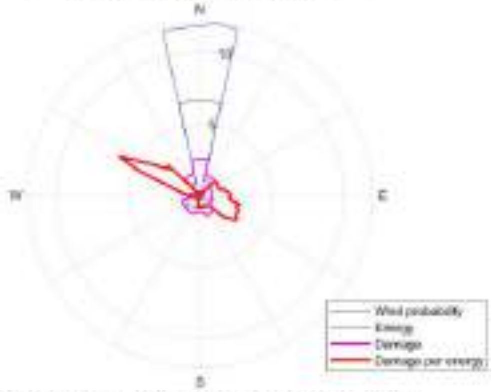
Rose map for the probabilities, energy and LTE for the component "Blade root, Composite" in percentage, WT86



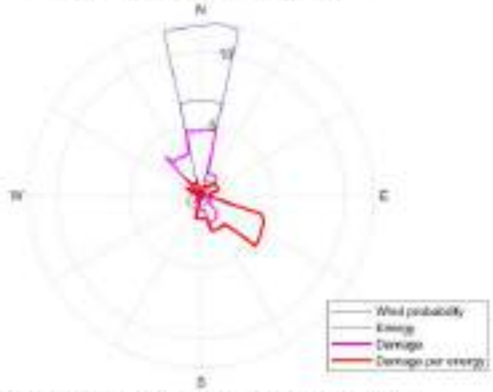
Rose map for the probabilities, energy and LTE for the component "Main Frame, Casting" in percentage, WT86



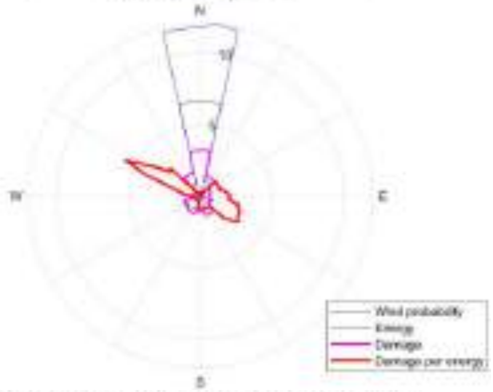
Rose map for the probabilities, energy and LTE for the component "Blade root, Joint" in percentage, WT86



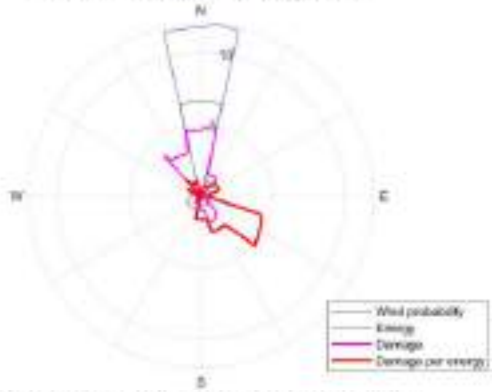
Rose map for the probabilities, energy and LTE for the component "Main Frame, Welded" in percentage, WT86



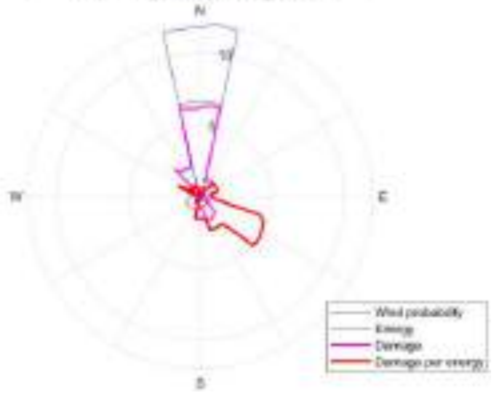
Rose map for the probabilities, energy and LTE for the component "Hub" in percentage, WT86



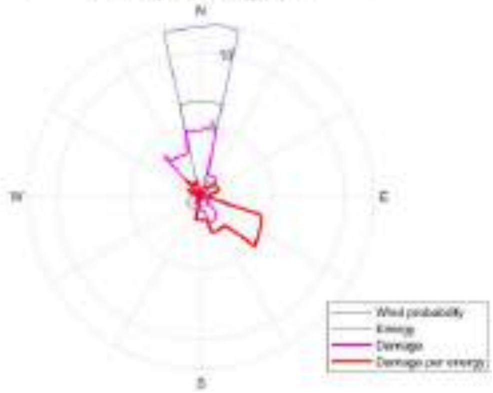
Rose map for the probabilities, energy and LTE for the component "Main Frame, Tower joint" in percentage, WT86



Rose map for the probabilities, energy and LTE for the component "Hub-Shaft joint" in percentage, WT86



Rose map for the probabilities, energy and LTE for the component "Tower top" in percentage, WT86



APPENDIX F—PORTFOLIO BENEFIT ANALYSIS

PORTFOLIO BENEFIT ANALYSIS

Ikakos&PenonoméII

PREPARED FOR:
INTERENERGY

Ref. No.: PR-006385

WIND AND SOLAR OPERATIONAL PORTFOLIO
Panama

01 October 2020

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DOCUMENT HISTORY

ISSUE	DATE	SUMMARY
A	11 August 2020	Draft
B	20 August 2020	Final
C	28 August 2020	Typo Correction

D	24 September 2020	Penonome OEPR update without Ikakos repowering
E	01 October 2020	Penonome OEPR update and Ikakos with repowering

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

UL Services Group LLC, a UL Company ("UL"), was retained by InterEnergy to conduct an evaluation of the portfolio benefit analysis ("PBA") of a portfolio of 2 assets, one operational solar photovoltaic project and one operational wind project. Both assets are located in Panama. The scope of work was conducted in accordance with proposal " 20-04-031026_HY_TA_Ikakos&Penonome_Panama_B_14Aug2020.pdf".

The portfolio has a combined capacity AC capacity of 255 MW. The aggregated annual P50 net energy estimate for the portfolio (standard scenario without Ikakos repowering) was 586.2 GWh/yr, with a net capacity factor (NCF) of 26.2%, based on operational energy reports developed by UL.

Portfolio benefit results when changes in annual energy output from one or more assets in a portfolio are to some extent offset by changes in annual energy output from other assets. The amount of benefit depends on the extent to which uncertainties associated with the energy output estimate for each asset are correlated. In general, accounting for these correlations results in a reduction in the overall uncertainty of the aggregate energy output of the portfolio, and therefore a reduction in investor risk.

The annual and evaluation period probabilities of exceedance for annual energy output for the assets, with and without portfolio benefit, are summarized in Table 0.1 and Table 0.2 for the standard scenario (Ikakos without repowering). For a given probability of exceedance, the portfolio benefit is calculated as the difference in the exceedance value when the portfolio benefit is taken into account and when it is not.

Table 0.1: Annual Portfolio Benefit Summary

Probability of Exceedance	Without Portfolio Benefit		With Portfolio Benefit		Total Benefit	
	Net Energy (GWh/yr)	NCF (%)	Net Energy (GWh/yr)	NCF (%)	(%)	(GWh)
P50	586	26.2%	586	26.2%	0.0%	0.0
P75	544	24.4%	548	24.5%	0.6%	3.5
P90	507	22.7%	513	23.0%	1.3%	6.7
P95	484	21.7%	493	22.0%	1.8%	8.6
P99	442	19.8%	454	20.3%	2.7%	12.1

Table 0.2: Evaluation Period[1] (15-year) Portfolio Benefit Summary

Probability of Exceedance	Without Portfolio Benefit		With Portfolio Benefit		Total Benefit	
	Net Energy (GWh/yr)	NCF (%)	Net Energy (GWh/yr)	NCF (%)	(%)	(GWh)
P50	586	26.2%	586	26.2%	0.0%	0.0
P75	568	25.4%	571	25.6%	0.5%	3.1
P90	552	24.7%	558	25.0%	1.1%	5.9
P95	542	24.3%	550	24.6%	1.4%	7.6
P99	524	23.4%	535	23.9%	2.1%	10.8

The portfolio benefit associated with this portfolio equated to 10.8 GWh (2.1 %) at the annual P99 level. The overall portfolio uncertainties when considering no portfolio benefit were 10.6% and 4.6% for annual and 15-year evaluation periods respectively. These uncertainties were reduced to 9.7% and 3.8% when considering the portfolio benefit.

[1] Solar preconstruction EPR evaluation period is 25 years, however, UL adopted the analysis for the PBA to 15-year evaluation period.. Wind operational assessment is for 15 years from now, 20 from COD in 2015. The effective evaluation period is based on the shorter of the two studies, or 15 years.

1. INTRODUCTION

UL Services Group LLC, a UL Company (UL) was retained by InterEnergy (the "Client") to conduct an evaluation of the portfolio benefit analysis ("PBA") of a portfolio of 2 assets, one operational solar photovoltaic project and one operational wind project. Both assets are located in Panama. The scope of work was conducted in accordance with proposal "20-04-031026_HY_TA_Ikakos&Penonome_Panama_B_14Aug2020.pdf". This report presents a summary of the data used, the methodology, and the results of the portfolio benefit analysis. Table 1.1 provides a summary of the assets in the portfolio. Figure 1.1 shows the locations of the assets in the portfolio.

For asset uncertainties associated with future variability (e.g. resource variability), the magnitude of uncertainty decreases in proportion to the number of years in the evaluation period (e.g. 25-year evaluation period uncertainty is lower than a 15-year evaluation period uncertainty). A 15-year evaluation period was used in this analysis based on the evaluation period considered on the Wind Project operational energy estimate ("OEPR"). Table 1.1 is a summary of the assets in the portfolio,

Table 1.1: Portfolio Summary

Asset	Status	Energy Estimate Performed	Capacity (MW)[2]	COD	Evaluation Period (years)
Ikakos PV	Operational	Pre-Constructive Assessment solar	40	2018	15
Penonomé II	Operational	Operational Assessment wind	215	2015	15

This analysis is based on the following UL OEPR and EPE Uncertainty calculations.

Interenergy_Penonome_II_AnnexA-ClientAvail_OEPR_20200930.xlsxPR-005231_IkakosPV_2020-08-11_EPE_Summary~ Repowering.xlsxUL notes that although the PV Project has been operation since August 2018, UL could not perform an operational energy analysis due to DC cabling issue which could not be quantified on a monthly basis. In the absence of an OEPR, UL has performed a pre-constructive ("PreconSolar") independent energy estimate ("EPE") to evaluate the long-term solar resource and energy at the Ikakos PV asset.

[2] Capacity is based on the sum of the turbine nameplate ratings. For Solar plant, the grid connected capacity has been considered as the plant capacity

Figure 1.1: Asset Locations

2. BACKGROUND AND METHODS

In any renewable energy asset investment, there is a risk that the plant will not perform as expected. This risk is generally expressed as the uncertainty in the expected production (the standard error for a normal distribution, for example), or as the probability of exceedance at different exceedance levels ranging from 50% (P50) to 99% (P99).

The uncertainty in annual energy output is usually assessed for individual assets without regard to other assets in the portfolio. Specifically, the probability distribution of annual energy output is estimated for each asset, and the probability distribution for the portfolio as a whole is assumed to be the sum of the distributions of the individual assets. This approach is generally conservative. In reality, changes in annual energy output at any particular asset may at times be offset by changes in output at other assets in the portfolio. As a result, the probability distribution for the aggregate energy output of a portfolio is generally narrower (i.e. has lower uncertainty) than the summed probability distributions of energy for the individual assets. This reduced uncertainty (and reduced risk to the investor) is generally referred to as the portfolio benefit. The goal of a portfolio benefit analysis is to quantify this benefit in a systematic and robust manner.

Portfolio benefit results from two main mechanisms. The first relates to inter-annual variability (IAV) in the wind resource as well as plant losses (e.g. availability, curtailment). For example, two wind plants in the same geographical area would be expected to have highly correlated IAV in energy output. Conversely, two wind plants on different continents would be expected to have largely uncorrelated (or possibly negatively correlated) IAV in energy output. The second mechanism relates to measurement error and modeling assumptions in both pre-construction and operational assessments. For example, if identical anemometers are used to measure wind speeds for different wind assets, then measurement error between assets would likely be highly correlated (e.g. a tendency to overestimate or underestimate wind speeds). Conversely, the use of different anemometers for different wind assets would result in largely uncorrelated (or possibly negatively correlated) measurement errors.

Portfolio benefit is quantified using the following steps. First, various sources of uncertainty for the different assets in a portfolio are identified and estimated from the pre-construction or operational energy assessments. Second, for each uncertainty category, correlation coefficients between different assets are calculated or estimated. These uncertainty values and correlation coefficients are then input to a Monte Carlo simulation[3] to generate probability distributions of aggregate annual energy output for the portfolio. Probabilities of exceedance (P50, P99, etc.) are then calculated from the resulting probability distribution and compared to the same values obtained when considering aggregate energy output based on the simple sum of individual asset probabilities of exceedance (i.e. no portfolio benefit):

Portfolio Benefit at Exceedance Level XX = [PXX with portfolio effect] – [PXX without portfolio effect]

The R open-source programming language[4] was used to conduct the Monte Carlo simulation. It was assumed that the relationships of the different uncertainty parameters modeled are linearly correlated

[3] A Monte-Carlo simulation refers to the random generation of data (bounded to a prescribed domain and often by inter-data relationships) for the purposes of generating a representative distribution of data from which robust statistics can be calculated. These simulations are generally used when it is difficult or impossible to use other mathematical methods to generate a distribution.

[4] R Core Team (2013). R: A language and environment for statistical computing. R Foundation for Statistical Computing, Vienna, Austria. URL http://www.R-project.org/. Version 3.4.2 (2017-09-28) -- "Short Summer" Copyright (C) 2017 The R Foundation for Statistical Computing Platform: x86_64-w64-mingw32/x64 (64-bit)

between assets, and so can be represented in a correlation matrix with the Pearson coefficient, commonly denoted as r.

Several uncertainty categories in this analysis require long-term historical estimates of the annual wind resource at each project, as well as the correlation coefficient of the annual resource values between different projects. For this analysis, UL utilized the following reference data sources:

- MERRA2 reanalysis dataset[2.5]
- SolarGIS remote sensing reanalysis dataset[6]

In addition to the reference datasets UL utilized the MODIS Land Cover dataset[7] to categorize land cover at each asset location. Other inter-project correlations were estimated by considering similarities between project equipment, methods used in the energy assessment, as well as meteorological and geographical characteristics. In most cases, robust estimates of correlation coefficients are lacking as they depend on differences or similarities in project characteristics or parameters. Therefore, most of the prescribed correlation coefficients in this report were qualitative and subjective in nature and reflect UL's experience and engineering judgment. Correlation coefficients used in this analysis are described in the following section.

[2.5] The Modern-Era Retrospective Analysis for Research and Applications-2 (MERRA-2) dataset was developed by the National Aeronautics and Space Administration (NASA). MERRA utilizes a variety of observing systems which have been assimilated into a global three-dimensional grid by numerical atmospheric models at a horizontal resolution of 1/2° latitude and 2/3° longitude. Multiple interpolated data points as well as the 4 surrounding grid points were assessed. MERRA-2 was released in 2016 and replaced the previous version, MERRA..

[6] https://solargis.com/docs/product-guides/time-series-and-tmy-data.

[7] The MODIS Land Cover Type product is a global land cover classification data layer produced annually from 2001 through 2013 Data are distributed by the USGS at 500m resolution in standard MODIS grid tiles. These tiles use the sinusoidal projection and cover approximately 1200 x 1200 km (~10° x 10° at the equator).

3. SOURCES OF UNCERTAINTY AND CORRELATION COEFFICIENTS

The uncertainties associated with annual energy output for both operational and pre-construction wind plants fall into several categories. These categories are summarized in Table 3.1. Uncertainty categories can differ significantly between pre-construction and operational energy assessments due to the nature of the analysis and the available data.

For the most part, different technologies (e.g. operational wind, pre-construction solar) have uncorrelated uncertainty categories. However, there are some uncertainty categories where some degree of correlation (or negative correlation) exists, such as inter-annual variability (IAV) of the resource. Table 3.1 has been organized such that uncertainty categories in the same row may exhibit some degree of correlation under certain conditions. Uncertainty categories in different rows are considered uncorrelated in this analysis.

Table 3.1: Uncertainty Categories for Different Project Types and Technologies

Applicability	Operational Wind	Pre-Construction Wind	Operational Solar	Pre-Construction Solar
All	(3.1.1) Energy and Resource Measurement	(3.1.1) Energy and Resource Measurement	(3.1.1) Energy and Resource Measurement	(3.1.1) Energy and Resource Measurement
All	(3.1.2) Representativeness of historical period	(3.1.2) Representativeness of historical period	(3.1.2) Representativeness of historical period	(3.1.2) Representativeness of historical period
All	(3.1.3) IAV of Resource	(3.1.3) IAV of Resource	(3.1.3) IAV of Resource	(3.1.3) IAV of Resource
All	(3.1.4) Future Availability and Curtailment Losses	(3.1.4) Future Availability and Curtailment Losses	(3.1.4) Future Availability and Curtailment Losses	(3.1.4) Future Availability and Curtailment Losses
All	(3.7) Other	(3.7) Other	(3.7) Other	(3.7) Other
All Wind/ Solar	(3.1.5) Degradation	(3.1.5) Degradation	(3.1.5) Degradation	(3.1.5) Degradation
All Wind	(3.2.1) Wind Speed and Direction Frequency Distribution	(3.2.1) Wind Speed and Direction Frequency Distribution	N/A	N/A
Op Wind	(3.3.1) Air Density Adjustment	N/A	N/A	N/A
Precon Wind	N/A	(3.4.1) Environmental Losses (Other than Deg)	N/A	Environmental losses
Precon Wind	N/A	(3.4.2) Site Documentation and Verification	N/A	N/A
Precon Wind	N/A	(3.4.3) Wind flow modeling	N/A	N/A
Precon Wind	N/A	(3.4.4) Wind shear	N/A	N/A
Precon Wind	N/A	(3.4.5) Wake & Electrical losses	N/A	N/A
Precon Wind	N/A	(3.4.6) Turbine performance	N/A	N/A
Precon Solar	N/A	N/A	N/A	(3.6.1) Simulation
Precon Solar	N/A	N/A	N/A	(3.6.2) Plane of Array (POA) Transposition Uncertainty

Some uncertainty categories in Table 3.1 can be combined provided that their associated correlation relationships depend on equivalent asset parameters or characteristics. For example, correlation relationships for both energy measurement and adjustment (operational wind plants) and resource measurement accuracy (pre-construction wind plants) depend only on the device used to make those measurements (revenue meter for energy data, anemometer for wind speed measurements). In such cases, these uncertainty categories can be combined (i.e. Energy and Resource Measurement; Wake and Electrical Losses) by assigning a correlation coefficient of 0 (i.e. uncorrelated) between assets of different technologies. Such an approach is based on propagation of uncertainty theory and simplifies the Monte Carlo simulation while causing no change to the results of the portfolio benefit analysis.

Although the portfolio analyzed here is comprised of only operational wind and solar assets, the discussion of operational wind and solar assets provide useful references in the context of explaining portfolio benefit.

The 'Other' category is used on occasion to hold uncertainty values needed in the analysis to balance total uncertainty and individual uncertainties mathematically, a result of some consultants using less robust modelling methods, or when a consultant uses a category that doesn't adhere to UL's assumptions. This category is always perfectly correlated so it contributes no benefit.

3.1 All Assets

3.1.1 Energy and Resource Measurement

This category includes energy measurement and adjustment uncertainty (operational plants) and resource measurement uncertainty (pre-construction plants). Correlation between assets depends on asset type and the device used to make those measurements. Assets that use the same device are assumed to have a correlation coefficient of 0.5. Assets that use different devices are assumed to have a correlation coefficient of 0.25 provided the asset technology is the same. Different asset technologies or operational vs preconstruction reports are assumed to be uncorrelated. The correlation used in this analysis is zero.

3.1.2 Representativeness of Historical Period

In both pre-construction and operational energy assessments, a measure-correlate-predict (MCP) method is used to adjust the short-term resource measurements at each site to those recorded at reference sources with much longer periods of record. Uncertainty in the MCP adjustment depends on three factors: the length of the on-site data record, the length of the reference source period of record, and the correlation between the concurrent on-site and reference data.

To the extent that resource variations at two assets are correlated, then errors in the MCP adjustment may also be correlated if either the site period or the long-term reference period, or both, overlap in time. Correlations in the MCP adjustment error between assets were calculated directly using rolling averages of the annual resource data. The correlation used in this analysis is zero.

3.1.3 Inter-annual Variability (IAV) of Resources

The uncertainty due to IAV in the future resource is reported or estimated for both the annual and the 15-year evaluation period. Correlation coefficients between assets are calculated directly based on the relationships between the asset annual resource data.

Table 5.3 summarizes the correlation matrix for this category. The correlation between wind and solar resource at these assets is 0.24.

3.1.4 Future Availability and Curtailment Losses

Correlation of future availability and curtailment losses between assets depends on the turbine or solar panel manufacturer, model, the COD year of the asset and the distance between projects. The most closely correlated assets share all these attributes while the least correlated share none. These categories are selected as assets using the same technology in a similar meteorological condition (as distinguished by distance) will likely be significantly correlated. Common factors include, turbine or panel model, maintenance practices, specific component failures, grid interconnection and downtime related to severe weather. Assets which do not have these factors in common are likely to have uncorrelated availability losses.

For assets with common attributes described above and within proximity of one another, a maximum correlation coefficient of 0.75 is assumed. Assets that differ in all categories are assumed to be uncorrelated. Assets with some common attributes are assigned correlation in the range specified according to an UL derived logical algorithm. The correlation used in this analysis is zero.

3.1.5 Degradation

Solar panels are assumed to degrade at a known rate annually and wind turbines also exhibit annual degradation, but at a much smaller rate which can be mitigated and approximated based on maintenance schedules. The uncertainty associated with this degradation rate is typically correlated if the manufacturer and model as well as the climate are all common within a given technology. If this is the case the correlation between assets is equal to 0.75. If assets differ in these three variables, then the correlation between assets is zero. Assets with some common attributes are assigned correlation in the range specified according to an UL derived logical algorithm. The correlation used in this analysis is zero.

There may also be a small amount of real correlation between wind and solar technologies as sandy environments may cause damage to both wind and solar in a manner that degrades performance. The magnitude of the loss and associated uncertainty is suspected of being very small and not modeled in this simulation.

3.2 All Wind Assets

UL considers one uncertainty categories applicable to both preconstruction and operational assets.

3.2.1 Wind Speed and Direction Frequency Distribution

Uncertainty in wind speed and direction frequency distribution will be correlated for assets that are located in the same topography. Correlations between assets are therefore determined based on the distance between assets.

As there is only a single wind asset, there are no correlations to consider.

3.3 Operational Wind Estimates

UL considers a single category of uncertainty for operational wind assets separate from the categories listed under the other groupings above.

3.3.1 Air Density Adjustment

Errors in air density estimates can be caused by errors in temperature and/or pressure readings from the asset site or reference data, as well as in the formulas used (e.g. deviations of the atmospheric density profile from standard assumptions). Correlation between assets depends on the consultant who performed the energy assessment. As there is only a single wind asset, there are no correlations to consider.

3.4 Pre-Construction Wind Estimates

The categories of uncertainty specific to this asset type are described below. There are no preconstruction wind assets considered in this assessment thus descriptions are informative only.

3.4.1 Environmental (other than Degradation)

Projects in geographic proximity to each other are likely to be exposed to similar weather features and would most likely experience similar environmental losses such as lightning and icing. In the case of solar, similar soiling and snow cover production losses. Given similar land cover evolves under similar environmental conditions, land cover is used as a proxy for these conditions. Therefore, correlation between assets is based on the distance between assets as well as land cover at the asset as determined from MODIS. Correlation coefficients range between 0.75 (for geographically close assets with the same land cover classification) to 0 (for geographically far assets with different land cover classifications). Note that while MODIS provides a unique landcover type for each asset location, for this analysis solar and wind landcover types are assumed to be distinct sub-categories of the MODIS classification. As there is only a single operational wind asset, this category does not apply.

3.4.2 Site Documentation and Verification

Correlation of site documentation and verification uncertainty between projects depends on the consultant who performed the energy assessment. Projects that include this uncertainty category and use the same consultant are assumed to have a correlation coefficient of 0.25. Otherwise, the projects are assumed to be uncorrelated. As there is only a single operational wind asset, this category does not apply.

3.4.3 Wind Flow Modeling

Estimating the hub-height wind resource at the turbine locations, relative to the observed resource at measurement locations, requires a model of some kind (typically a numerical wind flow model). The errors in this process depend largely on the complexity of the terrain and vegetation cover as well as the type (and corresponding accuracy) of the wind flow model. Therefore, correlation between projects is determined based on distance between projects (proxy to distinguish terrain complexity) as well as the consultant who performed the energy assessment (proxy to distinguish wind flow model). Correlation coefficients can be 0.75 for the same consultant and projects within close proximity, 0.25 for the same consultants and projects not within close proximity or 0 for estimates from different consultants. As there is only a single operational wind asset, this category does not apply.

3.4.4 Wind Shear

The wind shear exponent is used to extrapolate wind speeds from the height of the top anemometer(s) on a monitoring mast to the proposed hub height according to the power law. Usually the shear exponent is calculated from measurements between two heights on a meteorological mast but can also be measured or adjusted using data from LIDAR or SODAR systems, where available. Errors in the measurements (of both speed and height) can produce errors in the shear exponent. Furthermore, there may be a change in the shear profile above the top monitoring height, which creates further uncertainty in the hub-height wind speed. Typically, these factors amount to between 10 and 20 percent of the estimated shear exponent. The lower end of the range applies to configurations with redundant sensors and relatively simple terrain, where abrupt changes in the shear profile are unlikely to occur; in complex terrain, the estimates are towards the higher end of the range.

Correlation of wind shear uncertainty between projects depends on the distance between projects (proxy to distinguish terrain complexity and wind climatology). Projects within close proximity are assumed to have a correlation coefficient of 0.75. Otherwise, the correlation coefficient is zero. As there is only a single operational wind asset, this category does not apply.

3.4.5 Wake and Electrical Losses

The uncertainty of wake losses is primarily driven by the wake modeling software used. The electrical loss uncertainty accounts for the collection system design and loss estimates used in the preconstruction assessment. Both factors are related to the consultant who performed the energy assessment. Projects that use the same consultant are assumed to have a correlation coefficient of 0.5. Otherwise, the projects are assumed to be uncorrelated. As there is only a single operational wind asset, this category does not apply.

3.4.6 Turbine Performance

Uncertainty in wind turbine performance accounts for the actual performance of turbines on the wind plant sites, including suboptimal operation, power curve adjustment, and high wind hysteresis. Correlation between projects is determined based on the turbine model and the environment in which the turbine is operating (e.g. desert, forest, agricultural, etc.). Correlation coefficients range between 0.75 (for the same turbine model and same climate) to 0 (for different turbine models and different climate). As there is only a single operational wind asset, this category does not apply.

3.5 All Solar Projects

Degradation is common to wind and solar assets and described in section 3.1. There are no other uncertainties specific to operational solar assets as the Ikakos asset was treated as pre-construction in this analysis.

3.6 Pre-Construction Solar Estimates

The portfolio includes one operational solar asset. Though the plant is operational it has been evaluated as a pre-construction asset due to reporting challenges. The categories of uncertainty specific to this asset type are described below.

3.6.1 Simulation Uncertainty

Energy assessments that make use of the same energy modeling software (e.g. PVsyst), are performed by the same consultant, and are based on the same land use will likely have correlated errors in energy modeling. Correlation coefficients range between 1 (same PV model software, same consultant, same land use as determined by MODIS) to 0 (all factors different).

Simulation uncertainty was provided and is considered in energy production analysis, but as there is only one preconstruction solar asset, there is no correlation between assets to consider.

3.6.2 Plane of Array (POA) Transposition Uncertainty

The POA Uncertainty category addresses the uncertainty associated with converting GHI irradiance to the planned installation angle and orientation of the PV module array. The estimated correlation can be as high as 1.0 when the same transposition algorithm is used and the array configuration is the same (tilt angle, tracker config), 0.5 if either is the same between two solar assets, or 0.25 if both are different.

POA uncertainty was included in the energy production analysis, but as there is only a single preconstruction solar asset, there is no correlations to consider.

3.7 Other Uncertainty

There is variation in the treatment of uncertainty across the industry by different consultants. The categories described in sections 3.1 to 3.6 above are generally consistently defined between consultants or at least overlap between the varying methodologies. When consultants consider other sources of uncertainty, these categories are combined and moved to an 'other uncertainty' category that is assigned perfect correlation and thus does not contribute to portfolio benefit. As UL is the consultant on for both assets no uncertainty is included in this category.

4. RESULTS

4.1 PBA Results

4.1.1 Overall Portfolio Benefit

The uncertainty values and correlation coefficients defined in the previous section, along with the P50 values for each asset, were used in the Monte Carlo simulation to randomly generate aggregate annual energy output for the portfolio. A total of 300,000 iterations were used to generate a robust probability distribution. From this distribution, energy output at various probabilities of exceedance was calculated. These results were compared to those calculated from the aggregate probability distribution when assuming no portfolio benefit (i.e. the sum of distributions from individual assets).

Table 4.1 and Table 4.2 show results for annual and 15-year evaluation period cases, respectively. Plots of the aggregate probability distribution with and without benefit are shown in Figure 4.1 and Figure 4.2. Also included in the plots are the 'best case' probability distributions for which uncertainty categories are completely uncorrelated across assets. This case is included to show the possible range of portfolio benefit; the associated values are not used elsewhere in the analysis. The 15-year period is the period common to both solar and wind energy production analyses.

Table 4.1: Portfolio Benefit for the annual Evaluation Period

Probability of Exceedance	Without Portfolio Benefit		With Portfolio Benefit		Total Benefit	
	Portfolio Energy without Benefit (GWh/yr)	NCF without Benefit (%)	Portfolio Energy with Benefit (GWh/yr)	NCF with Benefit (%)	Portfolio Benefit (%)	Portfoli o Benefit (GWh)
P50	586	26.2%	586	26.2%	0.0%	0.0
P75	544	24.4%	548	24.5%	0.6%	3.5
P90	507	22.7%	513	23.0%	1.3%	6.7
P95	484	21.7%	493	22.0%	1.8%	8.6
P99	442	19.8%	454	20.3%	2.7%	12.1

Table 4.2: Portfolio Benefit for the 15-year Evaluation Period

Probability of Exceedance	Without Portfolio Benefit		With Portfolio Benefit		Total Benefit	
	Net Energy (GWh/yr)	NCF (%)	Net Energy (GWh/yr)	NCF (%)	(%)	(GWh)
P50	586	26.2%	586	26.2%	0.0%	0.0
P75	568	25.4%	571	25.6%	0.5%	3.1
P90	552	24.7%	558	25.0%	1.1%	5.9
P95	542	24.3%	550	24.6%	1.4%	7.6
P99	524	23.4%	535	23.9%	2.1%	10.8

The portfolio benefit associated with this portfolio equated to 12.1 GWh (2.7 %) at the annual P99 level. The overall portfolio uncertainties when considering no portfolio benefit were 10.6% and 4.6% for annual and 15-year evaluation periods respectively. These uncertainties were reduced to 9.7% and 3.8% when considering the portfolio benefit.

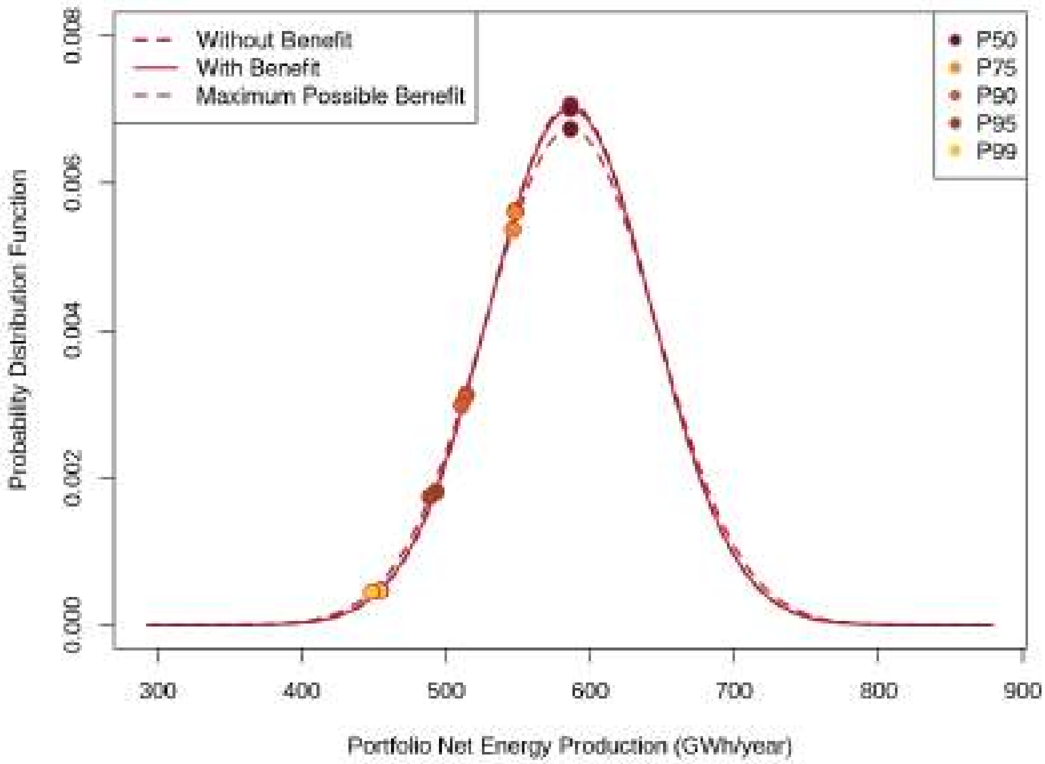

Figure 4.1: annual Portfolio Benefit

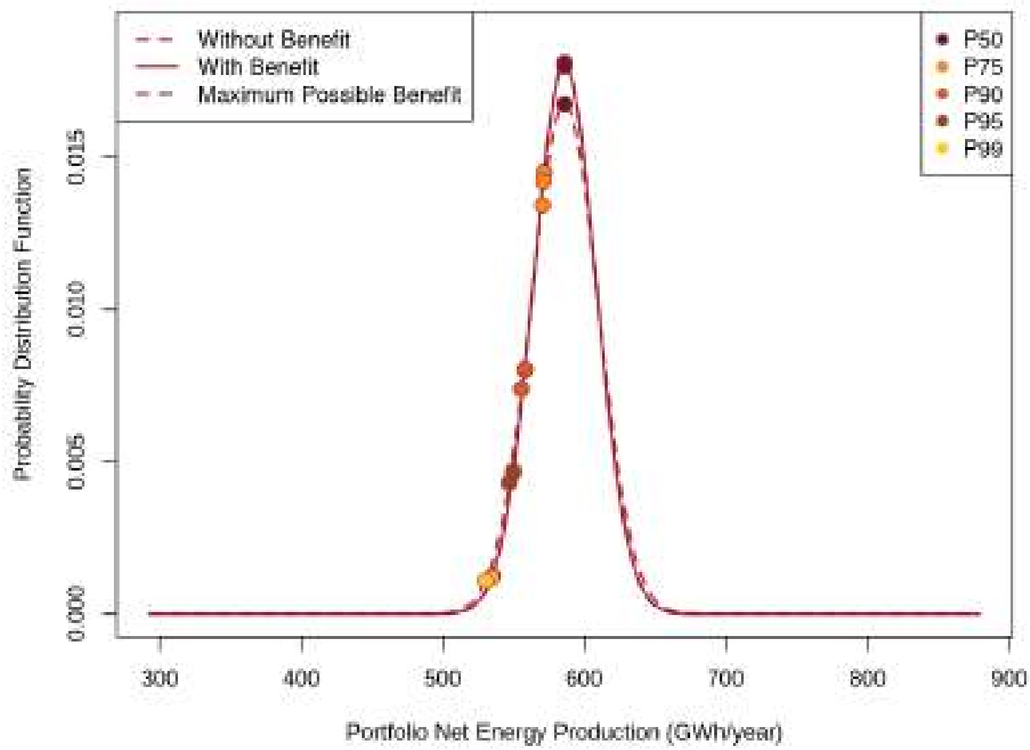

Figure 4.2: Evaluation Period Portfolio Benefit

4.1.2 Asset Contributions to Portfolio Benefit

It is understood that the uncertainty is reduced for the portfolio as a whole, and not for any individual wind plant. It is the investor in the portfolio that benefits from this reduction, not the investor in an individual asset that is held in a portfolio. Some financial models may not be structured to account for financial impacts at the portfolio level, however, and so it may be necessary to allocate estimates of portfolio benefit to the individual assets.

When a portfolio has 3 or more assets, one can assess the relative contribution by comparing the magnitude of the impact of removing each asset in turn from the portfolio. When there are only 2 assets, the contribution is weighted based on a combination of annual energy and uncertainty. Table 4.3 shows the asset contributions and recommended allocation for the annual and 15-year evaluation periods.

Table 4.3: Asset Contributions to Portfolio Benefit

Asset	Energy Estimate Performed	Capacity (MW)	P50 Annual Contribution (%)	P50 15-year Evaluation Period Contribution (%)
Ikakos PV	Pre-Constructive Assessment	40.0	14.93%	14.93%
PENONOME II	Operational - Wind	215.0	85.07%	85.07%

The relative allocations can be applied to the portfolio benefit at each probability of exceedance, and the benefit distributed among the assets to aid in financial modeling. Again, UL emphasizes that the benefit is only actually realized at the aggregate portfolio level.

Table 4.4: Asset Probabilities of Exceedance with Portfolio Benefit, annual Estimates, Yearly Breakdown - Penonomé+Ikakos

Asset	P75 (GWh/year)		P90 (GWh/year)		P95 (GWh/year)		P99 (GWh/year)	
	Without Benefit	With Benefit	Without Benefit	With Benefit	Without Benefit	With Benefit	Without Benefit	With Benefit
Ikakos (EP Average)PV	83.4	84.0	79.8	80.8	77.6	78.9	73.5	75.5
PENONOME II	460.9	463.9	426.9	432.5	406.5	413.7	368.3	378.4
Annual Results – Ikakos&Penonome								
PENONOME II+Ikakos PV Yr 1	544.5	548.0	506.9	513.5	484.3	492.9	442.0	454.2
PENONOME II+Ikakos PV Yr 2	544.1	547.6	506.4	513.1	483.9	492.5	441.6	453.7
PENONOME II+Ikakos PV Yr 3	543.5	547.0	505.9	512.6	483.4	491.9	441.1	453.2
PENONOME II+Ikakos PV Yr 4	542.9	546.5	505.3	512.0	482.8	491.4	440.6	452.7
PENONOME II+Ikakos PV Yr 5	545.5	549.0	507.8	514.5	485.2	493.8	442.9	455.0
PENONOME II+Ikakos PV Yr 6	544.9	548.4	507.2	513.9	484.7	493.2	442.3	454.5
PENONOME II+Ikakos PV Yr 7	544.3	547.9	506.7	513.3	484.1	492.7	441.8	453.9
PENONOME II+Ikakos PV Yr 8	543.8	547.3	506.1	512.8	483.6	492.1	441.3	453.4
PENONOME II+Ikakos PV Yr 9	543.2	546.7	505.5	512.2	483.0	491.6	440.7	452.9
PENONOME II+Ikakos PV Yr 10	545.7	549.2	507.9	514.6	485.3	493.9	442.9	455.1

Table 4.4: Asset Probabilities of Exceedance with Portfolio Benefit, annual Estimates, Yearly Breakdown - Penonomé+Ikakos

Asset	P75 (GWh/year)		P90 (GWh/year)		P95 (GWh/year)		P99 (GWh/year)	
	Without Benefit	With Benefit	Without Benefit	With Benefit	Without Benefit	With Benefit	Without Benefit	With Benefit
PENONOME II+Ikakos PV Yr 11	545.1	548.6	507.4	514.0	484.8	493.3	442.4	454.5
PENONOME II+Ikakos PV Yr 12	544.5	548.0	506.8	513.4	484.2	492.8	441.8	453.9
PENONOME II+Ikakos PV Yr 13	543.9	547.4	506.2	512.9	483.6	492.2	441.2	453.4
PENONOME II+Ikakos PV Yr 14	543.3	546.8	505.6	512.3	483.0	491.6	440.7	452.8
PENONOME II+Ikakos PV Yr 15	545.8	549.3	508.0	514.6	485.3	493.9	442.8	455.0
Annual Average	544.3	547.9	506.6	513.3	484.1	492.7	441.7	453.9

Note* Annual average estimation for Penonome II corresponds to the annual average for a 15-evalutation period, not for a specific year over the evaluation period.
Note** Annual average benefit is to be assumed only considering the Portfolio project (not individually)

Table 4.5: Asset Probabilities of Exceedance with Portfolio Benefit, Evaluation Period Estimates

Asset	P75 (GWh/year)		P90 (GWh/year)		P95 (GWh/year)		P99 (GWh/year)	
	Without Benefit	With Benefit	Without Benefit	With Benefit	Without Benefit	With Benefit	Without Benefit	With Benefit
Ikakos PV Ann Avg	83.8	86.8	80.5	81.5	78.5	79.8	74.8	76.7
PENONOME II	484.3	487.3	471.4	477.0	463.6	470.9	449.1	459.3

5. APPENDIX

The following figures and tables are referenced throughout the body of this report.

Table 5.1: Annual Period Uncertainty

Project	Energy and Resource Measurement	IAV in Resource	Representativeness of Historical Period	Future Availability and Curtailment Losses	Spatial Uncertainty	PV Plant Energy Model Simulation	Annual PV Degradation	Air Density Adjustment	Wind speed and direction frequency distribution	Future Blade degradation Loss
PENONOME II	1.1%	10.6%	2.5%	2.2%	0.0%	0.0%	0.0%	0.1%	1.6%	0.1%
Ikakos PV	5.0%	3.0%	0.6%	0.0%	0.1%	3.5%	0.8%	0.0%	0.0%	0.0%

Table 5.2: Evaluation Period Uncertainty

Project	Energy and Resource Measurement	IAV in Resource	Representativeness of Historical Period	Future Availability and Curtailment Losses	Spatial Uncertainty	PV Plant Energy Model Simulation	Annual PV Degradation	Air Density Adjustment	Wind speed and direction frequency distribution	Future Blade degradation Loss
PENONOME II	1.1%	3.0%	2.5%	1.1%	0.0%	0.0%	0.0%	0.1%	0.8%	0.1%
Ikakos PV	5.0%	0.7%	0.6%	0.0%	0.1%	3.5%	0.8%	0.0%	0.0%	0.0%

Table 5.3: IAV Correlation

Project	Ikakos PV	PENONOME II
Ikakos PV	1	0.24
PENONOME II	0.24	1

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Panama, Republic of Panama

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US$262,664,000

UEP Penonomé II, S.A.

6.500% Senior Secured Notes due 2038

Guaranteed by

Tecnisol I, S.A., Tecnisol II, S.A., Tecnisol III, S.A. and Tecnisol IV, S.A.

OFFERING MEMORANDUM

Sole Global Coordinator and Book-Running Manager

Citigroup

December 9, 2020

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's Assigns First-Time Ba3 Rating to UEP Penonomé II, S.A.; Outlook Stable

30 Nov 2020

New York, November 30, 2020 -- Moody's Investors Service, ("Moody's") today assigned first-time Ba3 debt rating to UEP Penonome II, S.A. ("Issuer" or "UEP II") and its proposed $275 million Reg S / 144 A Senior Secured Notes due 2038 ("Notes"). The outlook on the rating is stable.

UEP II owns 5 wind farms with a combined capacity of 215 MW located in the Cócle Province, Republic of Panama, which began operations in January 2015. Tecnisol I, S.A., Tecnisol II, S.A., Tecnisol III, S.A. and Tecnisol IV, S.A. (together "Tecnisol" or "Guarantors") are four integrated solar farms which began operations in August 2018 and are also located in Panama, with a combined capacity of 40 MW (10 MW each). Tecnisol will be guarantors of the transaction. UEP II and Tecnisol are majority and fully owned by InterEnergy Group Ltd., respectively.

Assignments:

..Issuer: UEP Penonome II, S.A.

....Gtd Senior Secured Regular Bond/Debenture, Assigned Ba3

Outlook Actions:

..Issuer: UEP Penonome II, S.A.

....Outlook, Assigned Stable

RATINGS RATIONALE

The Ba3 rating assigned consider the material contracted cash flows from UEP II's creditworthy counterparties, the Panamanian distribution companies, stemming from the public auctioned PPAs. In addition, the ratings reflect the competitiveness of UEP II and Tecnisol assets as well as the role of non-hydro renewables that complement Panama's energy matrix. In addition, our assessment considers the project finance features embedded in the transaction and the fully amortizing debt profile.

The strengths mentioned above are partially mitigated by the transaction's exposure to the energy market, particularly the 5-year merchant tail. While InterEnergy will seek to renew or close new PPAs to mitigate the merchant tail, the company will be exposed to market prices at the time of renewal. According to Panamanian energy market regulation, distribution companies are required to contract 100% of their yearly projected energy and capacity needs through public tenders organized by ETESA (Empresa de Transmision Electrica, S.A., Baa1 negative), the transmission company and dispatch center operator. As such, UEP II's PPAs with the distribution companies could be extended in the future.

In addition, the rating considers that the debt service reserve of 6-months that steps up to 12-months in March 2034, at the start of the merchant tail, is below the 12-month standard for wind projects. The Issuer and Guarantors have faced some technical issues in the past, although InterEnergy has been able to implement action plans to address and correct them. The technical issues had an impact on wind generation of the Issuer but have been partially mitigated with the availability guarantee of Goldwind under the Service and Maintenance Agreement ("SMA"). In the case of the Guarantors, the corrections have been 100% completed as of now, and are expected to partially address the weaker than expected generation performance of the solar assets.

Our rating also recognizes that the transaction has a non-standard structure, where Tecnisol acts as Guarantor instead of co-issuer, mainly explained as InterEnergy is a majority shareholder of UEP II (83.78%) while sole owner of Tecnisol. The rating also considers that the SMA is signed with an experienced counterparty, Goldwind International Holdings (HK), albeit it will expire in December 2023, which generates uncertainty regarding the scope and price of the agreement renewal.

Under Moody's Base Case, projected Moody's Debt Service Coverage Ratio ("DSCR", Cash Flow Available for Debt Service / Debt Service) over the life of the debt averages 1.14x, consistent with our B score under our methodology. Moody's Base Case considers a P95 generation scenario for wind farms given that the 5 wind farms are contiguous and exposed to the same resource, consistent with our rating methodology, and a P99 scenario for the solar assets to incorporate the lack of a track record of adequate generation performance although the technical issues have been resolved by the company. Moody's Base Case also considers a haircut in projected spot prices of 20% and an increase in O&M costs of 10%. We recognize that under P90 generation scenarios for wind and solar, with the haircut in projected spot prices of 20% and an increase in O&M costs of 10%, DSCR improves to an average of 1.22x, consistent with a Ba score.

The Ba3 rating assigned considers that the transaction benefits from project finance features including restrictions on additional indebtedness, distributions and change of control and a security package.

ENVIRONMENTAL, SOCIAL, GOVERNANCE CONSIDERATIONS

No material effects related to environmental issues have been highlighted in the Independent Engineer report for the issuer. Given that the issuer owns wind and solar assets, we do not expect any environmental considerations that would affect the rating.

Social Considerations component is not considered material in the sector. A number of power generation projects in the region have been interrupted as a result of social issues such as the Ituango power project in Colombia. No material effects related to social issues have been highlighted in the Independent Engineer report for the Issuer.

Given that the transaction benefits from a project finance structure, that considers covenants, additional indebtedness and distribution tests, governance risks are not considered material.

The outlook is stable, reflecting our expectation of visible and stable cash flows derived from long term PPAs in the next 12-18 months.

FACTORS THAT COULD LEAD TO AN UPGRADE OR DOWNGRADE OF THE RATING

The rating could face upward pressure if recorded DSCRs are expected to be sustained above 1.3x with little volatility, a generation profile closer to P50 and more predictability over operation and maintenance costs in the middle term.

Generation issues leading to a generation profile lower than P95 volumes for the wind project and/or cost increases that lead to DSCRs below 1.10x on a sustained basis could trigger downward pressure on the rating.

The principal methodology used in this rating was Power Generation Projects Methodology published in July 2020 and available at https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_1236893 . Alternatively, please see the Rating Methodologies page on www.moodys.com for a copy of this methodology.

REGULATORY DISCLOSURES

For further specification of Moody's key rating assumptions and sensitivity analysis, see the sections Methodology Assumptions and Sensitivity to Assumptions in the disclosure form. Moody's Rating Symbols and Definitions can be found at: https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_79004.

For ratings issued on a program, series, category/class of debt or security this announcement provides certain regulatory disclosures in relation to each rating of a subsequently issued bond or note of the same series, category/class of debt, security or pursuant to a program for which the ratings are derived exclusively from existing ratings in accordance with Moody's rating practices. For ratings issued on a support provider, this announcement provides certain regulatory disclosures in relation to the credit rating action on the support provider and in relation to each particular credit rating action for securities that derive their credit ratings from the support provider's credit rating. For provisional ratings, this announcement provides certain regulatory disclosures in relation to the provisional rating assigned, and in relation to a definitive rating that may be assigned subsequent to the final issuance of the debt, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive rating in a manner that would have affected the rating. For further information please see the ratings tab on the issuer/entity page for the respective issuer on www.moodys.com.

For any affected securities or rated entities receiving direct credit support from the primary entity(ies) of this credit rating action, and whose ratings may change as a result of this credit rating action, the associated regulatory disclosures will be those of the guarantor entity. Exceptions to this approach exist for the following disclosures, if applicable to jurisdiction: Ancillary Services, Disclosure to rated entity, Disclosure from rated entity.

The rating has been disclosed to the rated entity or its designated agent(s) and issued with no amendment resulting from that disclosure.

This rating is solicited. Please refer to Moody's Policy for Designating and Assigning Unsolicited Credit Ratings available on its website www.moodys.com.

Regulatory disclosures contained in this press release apply to the credit rating and, if applicable, the related rating outlook or rating review.

Moody's general principles for assessing environmental, social and governance (ESG) risks in our credit analysis can be found at https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_1133569 .

The Global Scale Credit Rating on this Credit Rating Announcement was issued by one of Moody's affiliates outside the EU and is endorsed by Moody's Deutschland GmbH, An der Welle 5, Frankfurt am Main 60322, Germany, in accordance with Art.4 paragraph 3 of the Regulation (EC) No 1060/2009 on Credit Rating Agencies. Further information on the EU endorsement status and on the Moody's office that issued the credit rating is available on www.moodys.com.

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Research Update:

UEP Penonome II S.A. Proposed $275 Million Senior Secured Notes Assigned Preliminary 'BB' Rating; Outlook Stable

November 30, 2020

Rating Action Overview

- Panama-based power generation company UEP Penonome II S.A. (UEP II, the project, or the issuer) is planning to issue up to $275 million in senior secured amortizing notes due 2038.
- On Nov. 30, 2020, S&P Global Ratings assigned its preliminary 'BB' issue-level rating to the notes.
- The preliminary rating incorporates our view of a relatively stable and predictable cash flow generation underpinned by the project's contracted nature until 2033. While in the last five years of the transaction, contracts will mature and the project will be exposed to market exposure, it will be mitigated by stronger credit metrics.
- The stable outlook reflects our expectation that UEP II will generate the projected revenues, driven by our expectation of the P90 wind resource in the next 12–24 months, and that the debt service coverage ratio (DSCR) will remain at the lower end of the 1.20x-1.25x range, with at least a six-month debt service reserve account (DSRA).

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Project Description And Key Credit Factors

The transaction is composed of a combined portfolio of 215 megawatts (MW) of wind assets (UEP II) and 40 MW of solar parks, Tecnisol I, S.A., Tecnisol II, S.A., Tecnisol III, S.A., and Tecnisol IV, S.A. (collectively 'Tecnisol', or the guarantors). Overall, UEP II's revenues will represent almost 85% of total revenues during the life of the transaction, while Tecnisol will make up the remaining 15%. UEP II is 82.86% owned by InterEnergy Renewables (InterEnergy or the sponsor; not rated) and 17.14% by minority investors. Tecnisol is fully owned by InterEnergy. The latter has an established footprint in the region with 1,200 MW of installed capacity in the renewables sector. UEP II and Tecnisol account for 21% of InterEnergy's total installed capacity.

UEP II is situated along the southern shores of Panama to benefit from Caribbean winds. It has 86 turbines (wind turbine generators [WTGs]) sourced from Goldwind International Holdings (HK) Ltd.

(Goldwind; not rated), which also provides a maintenance and service agreement on the WTGs under a five-year agreement, with an extension for three years. This agreement establishes an annual fee, which adjusts by Panama's consumer price index (CPI). Under this contract, Goldwind guarantees for the project an average availability level of 96% from May to November and 97% from December to April, to account for seasonality of resource. The contract also requires the turbine's provider to pay liquidated damages if availability falls below the guaranteed level, adjusted to compensate for the shortfall of corresponding revenues. These assets have been operating since 2015.

UEP II revenues in the first 10 years of the transaction (2020-2030) will mainly come from power purchase agreements (PPAs), with an average price of $105/MWh adjusted by Panamanian CPI. Off-takers will be the country's three electricity distribution companies: Empresa de Distribución Eléctrica Chiriqui S.A. (Edechi), Empresa de Distribución Eléctrica Metro-Oeste S.A (Edemet), and Elektra Noreste S.A. (ENSA); none is rated by S&P Global Ratings. We view the overall creditworthiness of the distribution companies at the level of the project. UEP II's PPAs' participation over total revenues will be 70% in the first 10 years, sequentially decreasing until 2034 when the project will be fully exposed to the spot market.

Tecnisol assets are located over flat land in western Panama with access to one of the highest solar resource-rich areas of the country. Tecnisol has Jinko Solar (not rated) photovoltaic panels and Jema Energy (not rated) inverters. The latter include an inverters guarantee period of 10 years that can be extended (with spare parts and replacement works). Moreover, there is an additional contract with Jema for annual preventive maintenance of inverters that is renewed every year. Tecnisol has a service agreement with the sponsor, InterEnergy, for the O&M of the plant during the life of the transaction. Construction for the solar assets ended in 2018.

Tecnisol's revenues will come from PPAs with large clients, composed of subsidiaries of international and local commercial and industrial off-takers. However, for the purposes of our analysis, we consider that Tecnisol will be fully exposed to the spot market during the life of the transaction given that we do not have access to the financial information of the counterparties to assess their credit quality.

Transaction structure

The notes will be ultimately guaranteed on a first priority basis by all existing and future tangible and intangible assets owned by the project, its accounts, and equity. In addition, the notes will be unconditionally and irrevocable guaranteed in a joint and several manner by Tecnisol.

UEP II will use the proceeds from the issuance to pre-pay existing debt at the issuer's level, grant an intercompany loan to Tecnisol that will cancel intercompany debt with InterEnergy, pay fees and expenses, and for other general corporate purposes.

The transaction has unique characteristics-- the project is comprising the issuer and the guarantors -- we rate the debt based on our "Principles Of Credit Ratings" methodology. Subsequently, we define the project considering the cash flows generated by the issuer and the guarantors as if they were a single issuer because we believe bondholders will bear a single likelihood of default risk. We base this conclusion on the following factors:

- There will be a single cash flow waterfall mechanism where all cash flows available for debt service (CFADS) will be consolidated;
- The two entities share corporate history and purpose. UEP II and Tecnisol are part of InterEnergy's strategy and common purpose of owning, developing, and operating renewable projects in Latin America;
- Both entities share the same management and corporate functions; and

- Although the project has a different board of directors, members are appointed by InterEnergy.

Risks

- The project will be exposed to market risk and, therefore, subject to some cash flow volatility given that a portion of its revenues will come from spot market sales. The exposure to the spot market--which we estimate will remain about 25% in the first nine years of the transaction and increase to almost 90%, on average, in the remaining nine years--makes the CFADS more volatile than in fully contracted deals, particularly in later years.
- As with all renewable projects, there is resource risk. Although the projections are backed by resource data collected over the last few years, it is possible that future wind and solar patterns and electricity production could deviate from historical figures. Nevertheless, because we consider the project's location and track record, we believe the wind and solar resources shouldn't materially vary from our base-case assumptions.

Strengths

- The project will operate in a strong regulatory framework, illustrated by Panama's robust and consistent regulatory market, which provides transparency and stability to the overall energy industry.
- Will benefit from a widely used turbine technology with customary warranties provided by a top-tier player. Goldwind has a long track record of turbine experience, and provides the turbines and their O&M. The operator guarantees 96%-97% availability (according to the season), which makes the wind farm operations predictable.
- Has a certain level of technological and geographical diversification. The existence of the 40 MW solar assets adds a certain diversification of technologies that are not correlated. It also increases revenue diversification because the solar revenues don't come from the same contracts as the wind assets.

Rating Action Rationale

To determine the operational risk of the project, and given that the existing PPAs will mature before the debt is fully amortized, S&P Global Ratings determined two operational phases. Phase 1 starts in 2020 and ends in 2033, and the second commences when most of the PPAs mature in 2034 and runs until the debt is fully repaid in 2038.

There are some common factors within the two operational phases, including:

- The relatively low operational risk because of the low-complexity tasks that the wind and solar parks will have to perform, when compared to the risk for other power plants such as the thermal-based combined cycles or more complex assets, such as nuclear energy plants.
- A moderate exposure to resource risk due to expected wind and solar profile volatility. In our view, there is not a sufficient operational track record to incorporate lower volatility from resource risk. Nevertheless, considering the stable wind and solar patterns at the project's location (close to the Pacific Ocean with Caribbean winds and with good radiation), we don't expect resource risk to be a major issue.

- Our assessment of a satisfactory competitive position, considering the stable and transparent regulatory regime in Panama, the project's dispatch priority due to its low-cost position, and lack of exposure to fuel supply.
- The resiliency of the project under a downside-case scenario that includes stresses to the resource risk, operational performance, and market spot prices. Even in this context, we do not expect the minimum DSCR to fall below 0.8x and we believe the reserves in place should be enough to cover the shortfall.

In our view, the main relevant difference between the phases is the market risk exposure. During operational Phase 1, we expect an average of 25% of the project's revenues will come from the electricity spot market, limiting cash flow volatility, while in Phase 2 we anticipate an increase to more than 90% on average. Therefore, we assessed market risk as very low in Phase 1 and as high in Phase 2, as we believe the cash flows available for debt service might vary around 10% and 50%, respectively, in case of about 25% lower spot market prices.

Under Phase 1, which drives our operational assessment, we expect a minimum and average annual DSCR close to 1.23x and 1.34x, respectively, which, combined with our view of the operational risk of the project, results in a preliminary stand-alone credit profile (SACP) of 'b'. We view the project as resilient under the downside-case scenario because of its six-month debt DSRA and its very low resource and cash flow volatility. As a result, we lift the SACP by two notches.

In addition, when we compare this transaction to a single asset, we consider that UEP II's transaction has greater diversification given the project's combination of wind and solar assets. Moreover, although we don't include Tecnisol's contracted nature in the analysis due to the inability to determine the creditworthiness of such counterparties, the entity's existence should provide predictability and stability to cash flow generation until maturity. Consequently, we provide a positive comparative rating analysis (CRA) to the transaction with one additional notch to the SACP, reaching to 'bb'.

Outlook

The stable outlook reflects our expectation that UEP II will generate the projected revenues, driven by our expectation of the P90 wind resource in the next 12–24 months, and that the DSCR will remain at the lower end of the 1.20x-1.25x range, with at least a six-month DSRA.

Downside scenario

We could lower the rating if the project's net energy produced is lower than we expect, or if the transaction registers expenses above our expectations, leading to a minimum DSCR below 1.1x. We could also lower the rating on UEP II if we observe a sustained deterioration of the off-takers' credit quality that could hurt UEP II's cash flow generation.

Upside scenario

We could raise the rating if UEP II performs better than we expect, both operationally and financially, increasing the forecast minimum DSCR to 1.35x or above. We envision such a scenario if we observe lower O&M expenses, which would ease pressure on the DSCRs or if there is a substantial and sustained improvement in spot prices that could improve the project's cash flow generation. In addition, we could raise the rating if we observe continued better wind availability.

For an upgrade, all of these scenarios would need to occur in conjunction with an improvement of our view of the credit quality of Panama's electricity distribution companies, which are the project's off-takers.

Base Case

Assumptions

Macroeconomic variables

- In our projections, we consider macroeconomic variables relevant for this project, particularly inflation in Panama that affects the price of PPAs and most of the operating costs. We expect Panama's CPI to be negative 0.8% in 2020, 0.5% in 2021, and 1.5% afterward, according to our latest published article "Panama Long-Term Sovereign Ratings Lowered To 'BBB' From 'BBB+' On Higher Interest Burden; Outlook Stable," published Nov. 24, 2020, on RatingsDirect.

Revenues

- Total installed capacity of 215 MW of wind farms and 40 MW of solar parks.
- Energy generation based on 97% availability from December to April and 96% availability May to November for wind, and 100% for solar assets.
- We incorporate a one-year P90 wind and solar resource for all years.
- An electricity spot price of $50-$55/MWh until 2026, gradually increasing to about $80-$85/MWh in the project's final phase. Our spot price expectations incorporate the electricity demand growth, which has historically been highly correlated to GDP growth; the natural gas and liquid fuel prices; and the upcoming capacity expansions, particularly in renewable energy.
- For the PPAs, we incorporate an average price awarded of $105/MWh linked to the Panamanian CPI.

Costs

- O&M fees in accordance with existing agreements, adjusted by U.S. inflation.

Key metrics

Under our base-case scenario, cash flow available for debt service leads to a minimum DSCR of about 1.23x in 2026 and an average of 1.30x-1.35x until 2033, in Phase 1 that drives the preliminary rating.

Downside Case

Assumptions

Macroeconomic variables

- Panamanian and U.S. CPI stressed by negative 0.50%.

Revenues

- No changes to total installed capacity or capacity payments.
- Generation levels consistent with a one-year P99 wind and solar resource and availability of 90%-91% for wind farms and 97% for solar parks.
- No changes in PPA prices.
- For the stressed spot prices, we anticipate a drop to about $50/MWh during the life of the transaction.

Operational expenses

- Operational expenses to increase by 12% from our base-case scenario.

Key metrics

Under our downside scenario, cash flow available for debt service leads to a minimum DSCR of about 0.80x and an average of 1.10x-1.15x, which is in line with a 'bbb' downside category, given that does not exhaust liquidity.

Construction phase	N/A	
Operations phase	Phase I (Dec. 2020 – Sept. 2033)	Phase II (Oct. 2033 – Sept. 2038)
Operations phase SACP	bb	bb
Operations phase business assessment (OPBA)	7 ('1' as the lowest risk and '12' as the highest risk)	11 ('1' as the lowest risk and '12' as the highest risk)
Minimum debt service coverage ratio (DSCR)	1.23x (2026)	2.01x (2036)
Average DSCR	1.34x	2.08x
Downside impact	+2 notches	+2 notches
Capital structure and average DSC impact on preliminary SACP	Neutral	Neutral
Liquidity	Neutral	Neutral
Comparative analysis assessment	Positive	Positive
Refinancing risk	N/A	N/A
Counterparty asset limitation	bb	N/A

Modifiers	
Parent linage analysis	De-linked
Structural protection	Neutral
Sovereign rating limitation	BBB/Stable
Senior secured issue rating	BB
Outlook	Stable

Operations counterparties

- Revenues. We deem the project's main off-takers, the three electricity distribution companies, as replaceable. The clean nature of the wind and solar assets and their zero marginal costs allow these assets to quickly find other off-takers in the event of an early termination of existing contracts with the electricity distribution companies that have similar contractual conditions. Considering the replaceability of the distribution companies, we blended the average of the distribution companies' credit quality that resulted in the same credit quality as the project. Therefore, we observe no constrains from a revenues' counterparty perspective.
- Operations. Due to the simplicity of the operations, we consider the O&M operators of the wind and solar assets to be replaceable. In addition, the project has an O&M reserve account equal to $1 million (more than month of fees) to face their eventual replacement.
- Financial. None of the following counterparties constrain the rating: Citibank N.A. (A+/Stable/A-1) is the intercreditor agent and indenture trustee; Global Bank Corp. (BBB-/Stable/A-3) could be the provider of the DSRA and O&M LoC; and Banco General S.A. (BBB/Stable/A-2) is the financial counterparty receiving electricity spot revenues before going to the cash waterfall accounts of the project.

Liquidity

We assess the project's liquidity as neutral because of a six-month DSRA until 2033, with a step-up to a 12-month DSRA in the last five years of the transaction and a $1 million O&M account (more than enough to cover one month of expenses). Both reserves will be funded with an LoC that will be potentially provided by Global Bank Corp. The cash lock-up mechanism, which ensures that the structure retains cash if the project-defined DSCR falls below 1.20x, also supports the project's liquidity. This trigger will be tested on a consolidated historical and projected 12-month basis.

Other modifiers

Positive CRA. When we compare this transaction with a single asset, we consider that UEP II's transaction has greater diversification given its combination of wind and solar assets. Moreover, although we don't include Tecnisol's contracted nature in the analysis due to the inability to determine the creditworthiness of such counterparties, its existence should provide predictability and stability to cash flow generation until maturity. Consequently, we provide a positive CRA to the transaction with one additional notch to the SACP, to reach 'bb'.

Related Criteria

- Criteria | Structured Finance | General: Counterparty Risk Framework: Methodology And Assumptions, March 8, 2019
- Criteria | Corporates | Project Finance: Project Finance Transaction Structure Methodology, Sept. 16, 2014
- Criteria | Corporates | Project Finance: Project Finance Operations Methodology, Sept. 16, 2014
- Criteria | Corporates | Project Finance: Project Finance Framework Methodology, Sept. 16, 2014
- Criteria | Corporates | Project Finance: Key Credit Factors For Power Project Financings, Sept. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Project Finance: Project Finance Construction Methodology, Nov. 15, 2013
- Criteria | Corporates | Project Finance: Project Finance Construction And Operations Counterparty Methodology, Dec. 20, 2011
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

New Rating	
UEP Penonome II, S.A	
Senior Secured	BB/Stable