

LA ROSITA II COMBINED CYCLE SUPPORT

PREPARED FOR GLOBAL INFRASTRUCTURE MANAGEMENT, LLC

August 2021

CONTENTS

LICENSE AGREEMENT 5

GLOSSARY 10

1 EXECUTIVE SUMMARY 12

1.1 KEY CONSIDERATIONS 12

1.2 MARKET PROJECTIONS 14

1.3 ASSET PROJECTIONS 17

2 THE MARKETS 18

2.1 OVERVIEW OF U.S. POWER MARKETS 18

2.2 CALIFORNIA MARKET AND REGULATORY STRUCTURE 18

2.3 FUEL PRICES 34

2.4 CLEAN ENERGY POLICY AND ECONOMICS 46

2.5 SUPPLY AND DEMAND 66

2.6 COST OF NEW ENTRY 67

2.7 TRANSMISSION 67

3 MARKET PROJECTIONS 69

3.1 CLEAN MARKET SPARK SPREADS 69

3.2 CLEAN MARKET HEAT RATES 70

3.3 CAPACITY COMPENSATION 70

3.4 FUEL ON THE MARGIN 71

3.5 DISPATCH MERIT ORDER CURVE 72

4 ASSET PROJECTIONS 73

4.1 CONTRIBUTION MARGINS 73

4.2 CAPACITY FACTORS 73

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Table of Figures

Figure 1-1: Location of the Asset 12
Figure 1-2: 2022 California Nameplate Capacity Mix 15
Figure 1-3: Clean Market Spark Spreads – California SP-15, ... 15
Figure 1-4: California Projected System and Local RA Capacity Compensation 16
Figure 1-5: Asset Contribution Margins 17
Figure 2-1: North American ISO Overview 18
Figure 2-2: Prominent Utilities in the California Market 19
Figure 2-3: Top Direct Access Providers by 2019 Sales 20
Figure 2-4: Current and Potential EIM Members 21
Figure 2-5: Current California LCAs 23
Figure 2-6: ELCC Values Determined by CPUC – 2019-21 27
Figure 2-7: CPUC Storage ELCC (Stand-Alone 4-Hour Battery) 28
Figure 2-8: RA Imports and Maximum Import Capability 29
Figure 2-9: CAISO RA vs. RAR Projection 31
Figure 2-10: California Community Choice Aggregators 33
Figure 2-11: Lower 48 Dry Gas Production (Bcf/d) vs. Henry Hub Natural Gas Prices ($/MMBtu) 35
Figure 2-12: Key U.S. Gas Producing Regions 35
Figure 2-13: US Natural Gas Production (2019 to present) 36
Figure 2-14: PA's Projection of US Natural Gas Production (Bcf/d) 37
Figure 2-15: US LNG Export Terminals 38
Figure 2-16: North American LNG Export Terminal Capacity 39
Figure 2-17: Historical and Projected Henry Hub Prices 40
Figure 2-18: CAISO Natural Gas Pipeline Network 41
Figure 2-19: SoCal System Map 42
Figure 2-20: SoCal and PG&E Basis 42
Figure 2-21: California Delivered Natural Gas Basis Projections 44
Figure 2-22: Changes to State Renewable (and Clean) Energy Targets Since 2018 Midterm Elections 46
Figure 2-23: PA View of Clean Energy Transformation Potential 47
Figure 2-24: US Nameplate Capacity Wind and Solar Additions 51
Figure 2-25: Offshore Wind Procurement Targets and Goals 54
Figure 2-26: Energy Storage Procurement Targets 55
Figure 2-27: Clean Energy Targets 57
Figure 2-28: California GHG Emission Allowance Prices 60
Figure 2-29: Historical and Projected Capital Costs by Clean Energy Technology – California 61
Figure 2-30: California Fuel Mix: Capacity and Energy 66
Figure 2-31: California Supply: Evolution of Natural Gas-Fired Generation 67
Figure 2-32: California 2019 Average On-Peak LMP 68
Figure 3-1: Clean Market Spark Spreads – California SP-15, ... 69
Figure 3-2: Clean Market Heat Rates – California SP-15, ... 70
Figure 3-3: California Projected System and Local RA Capacity Compensation 71
Figure 3-4: California Fuel on the Margin 72

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Figure 3-5: California 2022 Dispatch Curve 72
Figure 4-1: La Rosita II Contribution Margin Projections 73
Figure 4-2: La Rosita II Capacity Factors 74

Table of Tables

Table 1-1: Summary of the Asset 12
Table 2-1: Flexible Capacity Category Requirements 23
Table 2-2: RA Penalty Structure 24
Table 2-3: CAISO RA Enhancements Process – Implementation Plan 26
Table 2-4: CAISO Ancillary Services 30
Table 2-5: Major Permian Natural Gas Pipelines Under Development 40
Table 2-6: Drivers of the Clean Energy Transformation in the US Power Sector 48
Table 2-7: Remaining OTC Thermal Capacity Retirements 49
Table 2-8: Tax Credit by Type and Year 53
Table 2-9: California RPS Product Content Categories 58
Table 2-10: Average Annual Growth Rates 66
Table 2-11: Cost of New Entry – California (2021$) 67

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

LICENSE AGREEMENT

PA Consulting Group, Inc. ("PA") has prepared this independent Market Expert Report (the "Report") for the use of Global Infrastructure Management, LLC (the "Client"). PA and Client entered into a Terms of Business and Proposal dated _____, 2021 (“Agreement”).

PA understands that, for purposes of the refinancing related to the services, as described in the Agreement (the "Transaction"), the Client will enter into several financing agreements that will provide that New York law-governed notes (the "Notes") will be issued, offered and sold without being registered under the U.S. Securities Act of 1933, as amended (the "Securities Act"), (A) to qualified institutional buyers (QIBs) in compliance with the exemption from registration provided by Rule 144A under the Securities Act, (B) to non-U.S. Persons (as such term is defined in Regulation S under the Securities Act ("Regulation S")) in offshore transactions in reliance on Regulation S, and/or (C) to accredited investors within the meaning of Rule 501 of Regulation D under the Securities Act) in reliance on Section 4(a)(2) of the Securities Act in a private placement of Notes (the "Private Placement") directly to investors.

In connection with the preparation, distribution and use of any draft of a preliminary offering memorandum, final offering memorandum, preliminary private placement memorandum or final private placement memorandum (each an "Offering Document"), investor presentation or presentation to a rating agency related to issuance of the Notes, PA authorizes and consents to (a) the inclusion of the Report (or a draft of the Report only in case of non-final Offering Documents) prepared by PA pursuant to this Agreement and addressed to the Client, in its entirety, in such Offering Document, investor presentation or presentation to a rating agency; (b) the inclusion of one or more summaries and/or excerpts therefrom or a draft thereof in such Offering Document, investor presentation or presentation to a rating agency, which summaries and/or excerpts, as applicable, represent a fair and accurate summary of the Report or draft report, as applicable; provided that PA is first furnished with a copy of any such summary for its review and approval, which shall not be unreasonably withheld or delayed; (c) being named in such Offering Document, investor presentation or presentation to a rating agency as an independent market consultant for the Transaction; and (d) reliance on the Report by the issuer in relation to the Notes, any initial purchaser, any placement agent, their respective affiliates, and each investor that makes an investment in the Notes and any rating agency assigning a rating to the Notes, as if the Report had originally been addressed to such issuer, initial purchaser, placement agent, investor or rating agency; provided that the Report will state that as a condition to receiving the Report attached to the Offering Document, investor presentation or presentation to a rating agency that each recipient of such Offering Document, investor presentation or presentation to a rating agency will be deemed to acknowledge that it will be subject to the liability limitations and exclusions of damages in the Terms of Business. PA shall not be liable, in the aggregate, for any greater or different damages or amounts than stated therein.

For purposes of the previous paragraph, PA hereby agrees to deliver (A) a reliance letter, in the form provided as Annex A to this License Agreement, on and dated as of the date of each of the Offering Documents; and (B) a bring-down certificate, in the form provided as Annex A to Annex A to this License Agreement, dated as of the settlement date of the Notes. For the avoidance of doubt, each investor that makes an investment in the Notes shall be entitled to rely on the Report, as if the Report had been originally addressed to such investor, without need of receiving or being an addressee to any reliance letter described in this paragraph.

In addition, PA hereby consents to the disclosure of the Report by any Recipient (as defined in the reliance letters) thereof (a) as required by law or regulation, (b) as required to establish a due diligence defense in connection with any claim or controversy arising out of the Transaction, (c) with PA’s prior written consent or (d) to the employees, officers, directors or professional advisors of such Recipient who need to know and are informed of the Terms of Business and any applicable reliance letter.

ANNEX A

RELIANCE LETTER

[●], 2021

In connection with the proposed issuance of the senior secured notes (the "Securities") pursuant to Rule 144A and/or Regulation S under the United States Securities Act of 1933, as amended, (the "Offering") by Electricidad Firme de México Holdings, S.A. de C.V. an affiliate of [ ] (the "Client"), the report, (including any translation or abridgment thereof approved by Consultant, the "Report") by PA Consulting Group, Inc. (the "Consultant"), which is addressed to the Client, and any update thereof and the information therein, may be released to, and used by, [ ], [ ], [ ], and any other initial purchaser, underwriter or co-manager that becomes party to this reliance letter through a joinder (together, the "Initial Purchasers") and their affiliates, successors and assigns and (a) any actual or prospective purchaser of, or investor in, the Securities or any financing (or any portion thereof or interest therein by way of participation, syndication or otherwise), (b) any actual or prospective financing source for any such purchaser or investor, (c) any servicer for the financing or the Securities, (d) any trustee for the financing or the Securities, (e) any rating agency actually or prospectively rating the financing or the Securities, (f) any other underwriter, initial purchaser or placement agent for the financing or the Securities, (g) any institutional provider of any liquidity facility or credit support for the financing or the Securities, (h) the respective affiliates of each person or entity referenced in clauses (a)-(g) above, who have a need to review the Report for the purposes of the Offering, and (i) the respective officers, directors, employees, agents, advisors, counsel, successors and assignees of each person or entity referenced in clauses (a)-(h) above, who have a need to review the Report for the purposes of the Offering (such persons referenced in clauses (a)-(i) above, together with the Initial Purchasers, the "Recipients"). The Consultant further agrees upon the request of the Initial Purchasers to deliver a customary reliance certificate, in the form attached hereto as Annex A, on the date of pricing and on the date of closing of the Offering to this effect, each dated the date of delivery, provided that if Consultant reasonably believes that a fact material to the Report has changed, the parties shall renegotiate the Form of Reliance Certificate to provide for this change.

As a condition of and in consideration for receiving and having access to any portions of the Report, each Recipient agrees to the following terms and conditions, in addition to any assumptions, restrictions and/or limitations set forth in the Report, which are hereby incorporated in and made part of this Reliance Letter as if set forth in full herein and are referred to collectively as the Reliance Letter.

1. This Reliance Letter sets out the entire agreement between the Recipients and Consultant in relation to the Report. It replaces all prior agreements or understandings or warrants, if any, between the Recipients and Consultant in the regard and may not be modified or amended except in a writing executed by both Consultant and Recipients expressly stating such an intention. Any liabilities for, and any remedies in respect of, such agreements, representations or warranties are excluded. Each Recipient acknowledges that it has not entered into this Reliance Letter in reliance on any oral or written agreement, representation or warranty of any other person which is not repeated in this Reliance Letter. Each Recipient further acknowledges that this Reliance Letter does not create any third party beneficiary rights for the Recipient under any other contract to which Consultant is party, including, without limitation, Consultant's engagement agreement with its Client relating to this Report.

2. Recipients may have access to the Report and excerpts and/or summaries therefrom only under the terms, conditions, assumptions and limitations set forth in this Reliance Letter.

3. Recipients acknowledge that: (i) some information in the Report is necessarily based on predictions and estimates of future events and behavior; (ii) such predictions or estimates may differ from that which other experts in the industry might present; (iii) Consultant's analysis and findings are current as of the date of the Report and where applicable, incorporate underlying market data as of [___]; (iv) receipt of the Report does not obviate the need for potential investors to make further appropriate inquiries as to the accuracy of the information included therein, or to undertake an analysis on their own; and (v) the Report is not intended to be a complete and exhaustive analysis of the subject issues and therefore will not consider some factors that are important to a potential investor's decision making. Nothing in the Report should be taken as a promise or guarantee as to the occurrence of any future events. Each Recipient therefore acknowledges that Consultant offers no guarantee or assurance that any facts, observation, opinions, analysis, or other matters contained in the Report will be more reliable or accurate than the underlying data and information supplied by other and/or available in the public domain and, thus beyond its control, either at the time the Report is issued or at any other time.

4. The Report should not be construed as an invitation or inducement of any kind, to any person, to engage in the Offering or otherwise invest in any transaction with Client.

5. Consultant prepared the Report in consultation with, and on the basis of, the instructions received from and understandings with its Client only. Consultant has not been provided with any instructions from any other party in relation to the scope of the Report. Accordingly, the issues reviewed, investigated and covered by the Report and any emphasis

placed on them may not necessarily address any or all specific concerns and/or interests that Recipient or others may have. The Report does not necessarily take account of those matters which may be important to Recipient or others making credit and other decisions regarding the Offering. The Recipients and others should satisfy themselves as to the sufficiency of the overall level of due diligence in or otherwise in respect to the Report in relation to the transaction. Consultant does not warrant or represent that the Report is sufficient or appropriate for Recipient's purposes and all conditions, warranties, representations, terms and undertakings, express or implied, statutory or otherwise in respect to the Report for these purposes is hereby excluded.

6. In furtherance of the paragraph 5, the Report addresses only the issues which Consultant, in its absolute discretion, or as a result of instruction received from, or specific understandings with its client, considered significant from a business perspective and that Consultant may or might have considered material in the context of the proposed transaction. Consultant makes no assurances that any or all of these issues are the same as those which Recipient deems material.

7. Recipients agree that potential losses or damages resulting from Recipients' use of the Report would be impractical, unquantifiable and difficult, if not impossible to calculate. Consequently, and to the fullest extent permitted by law, in any event, each Recipient agrees that any damages due such Recipient, or to any other Recipient of Client, on a cumulative and aggregate basis, resulting from Consultant's actions in relation to the creation and dissemination of the Report will be limited, in the aggregate, to 150% of the amount of compensation (exclusive of the reimbursement of costs and expenses) received by Consultant from Client for the creation of the Report and, except in relation to damages arising from the Consultant's gross negligence, willful misconduct, fraud, fraudulent misrepresentation or deceit, each Recipient hereby waives any right to seek or collect damages in excess thereof under any other legal theory, including, without limitation, breach of contract, breach of express or implied warranties, strict liability and/or otherwise. As such, each Recipient hereby waives and releases Consultant from any and all damages to any third parties, including Client, in an amount that would exceed the amount of compensation actually received by Consultant under the Agreement. Recipients and Consultant each affirm and agree that this amount is not a penalty, but is rather a reasonable forecast of Recipients' damage(s).

9. By use of this Report, each Recipient acknowledges that Consultant agrees to allow Recipients to rely on certain limited usage of the Report solely in connection with the Offering and subject to the assumptions, disclaimers, limitations and restrictions set forth herein in this Reliance Letter.

10. The interpretation of this Reliance Letter, and the parties' rights and obligations established hereunder, are to be governed by and construed in accordance with the laws of the State of New York, without giving effect to the conflicts of law principals thereof other than Sections 5-1401 and 5-1402 of the General Obligations Law of the State of New York. The exclusive venue for any claim, cause of action, legal proceeding or challenge, or lawsuit relating to this Reliance Letter shall be the state and federal courts located within the City of New York, Borough of Manhattan. Each Recipient and Consultant irrevocably waives any objection which it may now or hereinafter claim of any action, or have to the laying of venue of any action, proceeding arising out of or related to this Reliance Letter, brought in the state and federal courts located in the City of New York, Borough of Manhattan and further irrevocably waives any claim that any such action, proceeding or suit brought in any court has been brought in an inconvenient forum.

11. The Recipients, will not, under any condition, further distribute this Report or any summaries or excerpts therefrom to other persons or entities. Notwithstanding the foregoing, Consultant agrees that the Report and any summary or excerpt thereof may be included in any Preliminary Offering Memorandum (including market sounding, roadshows and the like) and Final Offering Memorandum in connection with the Offering. A summary of the Report may also be included in any roadshow presentation prepared by the Company or the Initial Purchasers in connection with the Offering of the Company, provided Consultant is first furnished with a copy of the same for its review and approval, such approval shall not be unreasonably withheld or delayed and further provided that such summary contains a disclaimer that Consultant makes no warranty or guarantee as to the contents of the material(s) so presented; provided , that the Recipients may disclose this Report (i) to their affiliates, employees, directors and legal counsel on a "need-to-know" basis in connection with the transaction, (ii) where compelled by subpoena or other similar form of legal process (including litigation discovery demands); and (iii) to any regulatory or governmental agency (including without limitation, bank examiners) having or claiming to have jurisdiction over Recipients, upon such agency's request, provided that Recipient(s) promptly inform Consultant of any such request they have knowledge of if practicable and/or permitted to do so. In addition, Consultant hereby consents to the disclosure of the Report and this Reliance Letter by any Recipients required to establish a due diligence defense in connection with the Offering.

12. This Reliance Letter may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which, where executed and delivered, shall be deemed as an original, but all such counterparts together shall constitute but one and the same instrument; signature pages may be detached from multiple separate counterparts and attached to a single counterpart so that all signature pages are physically attached to the same document. Delivery of an executed signature of this Reliance Letter in portable document format (.pdf) or by facsimile transmission shall be as effective as delivery of a manually or "wet" signed counterpart hereof.

13. THE LIMITATIONS AND DISCLAIMERS SET FORTH ABOVE SHALL APPLY NOTWITHSTANDING ANY FAILURE OF ESSENTIAL PURPOSE OF ANY LIMITED REMEDY.

Annex A

FORM OF RELIANCE CERTIFICATE

[DATE]

This certificate is furnished by PA Consulting Group, Inc. (the "Consultant") in connection with the proposed issuance and sale by Electricidad Firme de México Holdings, S.A. de C.V. (the "Issuer") of U.S.$[___] in aggregate principal amount of [___]% Senior Secured Notes due [___] (the "Notes"), as more particularly described in the Preliminary Offering Memorandum, dated [___], of the Issuer, and the Final Offering Memorandum, dated [___], of the Issuer (collectively, the "Offering Memorandum").

We have provided a report entitled "[___]" dated [___], which is attached to the Offering Memorandum as Annex A thereto (the "Report").

We hereby confirm that (i) we have reviewed the sections of the Offering Memorandum entitled "Summary—Independent Energy Market Expert's Report" and (ii) the statements contained therein accurately reflect the sections of our Report described therein. We hereby consent to the (a) inclusion of our Report in its entirety and approve and consent to a summary of the Report in the Offering Memorandum, the (b) use of our trade name in connection with the specific textual references to the conclusions of the Report in the section of the Offering Memorandum entitled "Independent Energy Market Expert's Report" and (c) use of our trade name in connection with the specific textual references in the section of the Offering Memorandum entitled "Summary—Independent Energy Market Expert's Report" and "Independent Energy Market Expert." We understand that the Offering Memorandum will be delivered to various investors or prospective investors in the Notes.

We also confirm to you, as of the date hereof, that neither the Consultant nor any of its directors or officers (i) is an affiliate (as defined in Rule 144(a)(1) under the United States Securities Act of 1933, as amended) of the Issuer or any of its affiliates, (ii) has any substantial interest, direct or indirect, in the Issuer or any of its affiliates or (iii) is connected with the Issuer or any of their affiliates as an officer, employee, promoter, underwriter, trustee, partner, director or person performing similar functions.

In addition, as of the date hereof, nothing has come to Consultant's attention that would cause us to believe that any of the section of the Offering Memorandum entitled "Summary—Independent Energy Market Expert's Report" or the Report contains material statements that should be revised in light of changes in the energy market.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

GLOSSARY

AAEE - Additional Achievable Energy Efficiency
ACE - Affordable Clean Energy
Asset – refers to La Rosita II combined cycle plant
Bcf - Billion cubic feet
BPA - Bonneville Power Administration
CAA - Clean Air Act
CAISO - California Independent System Operator
CalCCA - California Community Choice Aggregation Advocate
CARB - California Air Resources Board
CBA - California Balancing Authority
CC - Combined cycle
CCA - Community Choice Aggregation
CCS - Carbon Capture and Sequestration
CEC - California Energy Commission
CHP - Combined Heat and Power
Client - refers to Global Infrastructure Management, LLC
CO_2 - Carbon dioxide
COD - Commercial Online Date
CONE - Cost of New Entry
CPM - Capacity Procurement Mechanism
CPP - Clean Power Plan
CPUC - California Public Utilities Commission
CRR - Congestion Revenue Rights
CSAPR - Cross-State Air Pollution Rule
CT - Combustion turbine
CWA - Clean Water Act
DA - Day Ahead
DAME - Day Ahead Market Enhancements
DOE - Department of Energy
EIA - Energy Information Administration
EIM - Energy Imbalance Market
ELCC - Effective Load Carrying Capability
EPA - Environmental Protection Agency
ERCOT - Electric Reliability Council of Texas
FERC - Federal Energy Regulatory Commission
GHG - Greenhouse gas
GIM - refers to Global Infrastructure Management
HH - Henry Hub
IFM - Integrated Forward market
IOU - Investor Owned Utility
IRP - Integrated Resource Plan
ISO - Independent system operator
ISO-NE - New England Independent System Operator
ITC - Investment Tax Credit
LADWP - Los Angeles Department of Water and Power
LCA - Local Capacity Area
LMP - Locational marginal pricing
LNG - Liquified Natural Gas
LOLE - Loss of Load Expectation
LR2 - refers to La Rosita II combined cycle plant
LSE - Load Serving Entity
MACRS - Modified Accelerated Cost Recovery System
MISO - Midcontinent Independent System Operator
NERC - North American Electric Reliability Corporation
NIMBY - Not In My Backyard
NOx - Nitrogen oxide
NQC - Net Qualifying Capacity
NYISO - New York Independent System Operator
OTC - Once Through Cooling
PA - PA Consulting Group, Inc.
PCC - Public Contract Code
PCIA - Power Charge Indifference Adjustment
PG&E - Pacific Gas and Electric
PJM - Pennsylvania - New Jersey - Maryland Interconnection, LLC
PPA - Power purchase agreement
PTC - Production Tax Credit
PURPA - Public Utility Regulatory Policies Act
PV - Photovoltaics
QF - Qualifying Facility
RA - Resource Adequacy
RAAIM - Resource Adequacy Availability Incentive Mechanism
RAR - Resource Adequacy Requirement
REC - Renewable Energy Credit
RGGI - Regional Greenhouse Gas Initiative
RPS - Renewable Portfolio Standard
RTO - Regional transmission organization
RUC - Residual Unit Commitment
SB - Senate Bill
SCE - Southern California Edison
SDG&E - San Diego Gas & Electric
SMUD - Sacramento Municipal Utility District
SO_2 - Sulfur dioxide
SOC - Standard Offer Contracts

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

SoCal - Southern California Gas Company

SPP - Southwest Power Pool

ST - Steam Turbine

SWB - State Water Resources Control Board

T&D - Transmission & Distribution

TETCO - Texas Eastern Transmission Company

WCI - Western Climate Initiative

WECC - Western Electricity Coordinating Council

WREGIS - Western Renewable Energy Generation Information System

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

1 EXECUTIVE SUMMARY

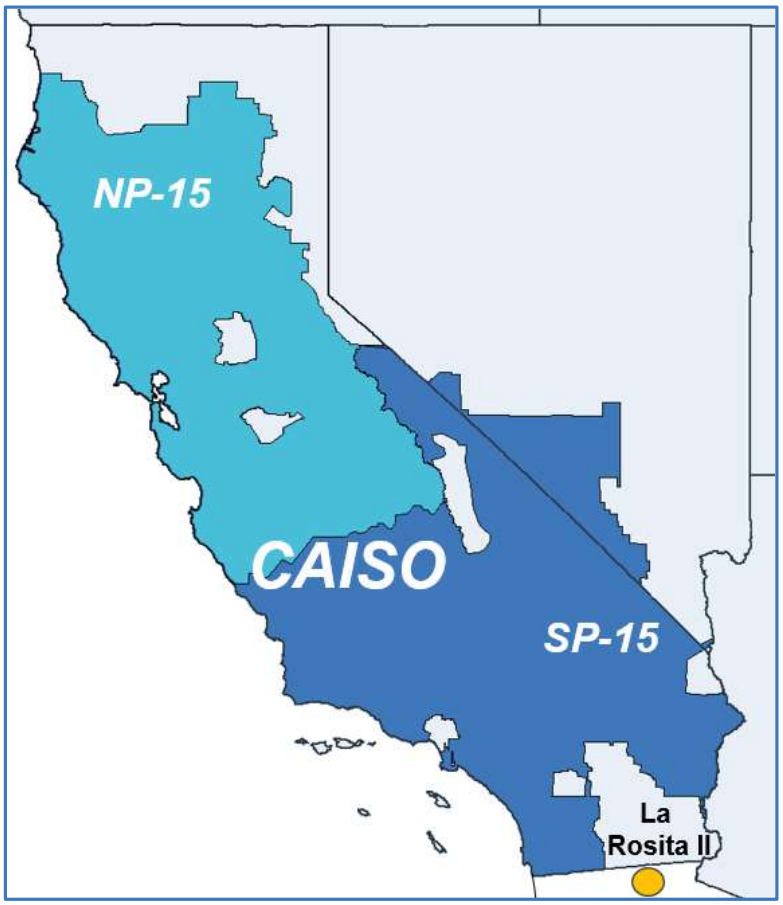
Global Infrastructure Management, LLC ("GIM" or the "Client") engaged PA Consulting Group, Inc. ("PA") to serve as the independent energy market advisor related to the potential acquisition of the 322 MW La Rosita II combined cycle power plant ("LR2" or the "Asset") located in Baja California, Mexico, and directly interconnecting to the SP-15 zone of the CAISO power market. Table 1-1 provides a summary of the Asset and Figure 1-1 shows the Asset's location in CAISO.

This Report summarizes PA's analysis, including an overview of the California power market, PA's underlying market assumptions, and modeling methodology. This Report also summarizes PA's energy market and capacity price forecasts as well as a forecast of LR2's operations and contribution margins for balance of year 2021 through 2040 (reported in nominal dollars assuming 2.2% inflation unless otherwise indicated).

Table 1-1: Summary of the Asset

Facility Name	Facility Type	Fuel	Turbine Technology	COD	Net Qualifying Capacity (MW)	Summer Heat Rate (Btu/kWh)	Zone
La Rosita II	CC	Natural gas	Siemens W501FD2	June 2003	322	7,709 (7,410)	SP-15

Figure 1-1: Location of the Asset



1.1 KEY CONSIDERATIONS

The following outlines the key considerations for LR2 and the broader California power market.

- California is one of the more regulated wholesale electricity regions in the United States. CAISO is the grid operator for the over 80% of the state's load and operates nodal day-ahead and real-time energy markets.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

- Power procurement in the state is largely handled by three large investor-owned utilities – Pacific Gas and Electric in Northern California, and Southern California Edison and San Diego Gas & Electric in Southern California.
- In recent years, these utilities have been losing customers to CCAs, which serve as new counterparties for merchant power generators to secure both short-term and long-term contracts.

- Despite recent upward pressure on natural gas prices, PA projects that delivered natural gas in California will gradually trend from a significant ($2/MMBtu) premium over Henry Hub in 2022 to only a slight premium of $0.02/MMBtu in SP-15 by the middle of next decade.
  - Delivered basis in SP-15 currently prices near a $3-4/MMBtu premium to Henry Hub. Recent volatility in the California natural gas market has been precipitated largely by infrastructure, storage, and import constraints, as well as ongoing maintenance issues. These events have occurred simultaneously with peak demand events related to prolonged warm or cool weather.
  - California's aggressive pursuit of its clean energy goals is expected to weaken demand in the coming years and ease pressure on prices. Additionally, ongoing reliability and maintenance issues are expected to abate and provide additional relief for prices.
  - LR2's natural gas supply is indexed to El Paso South Mainline (EPSML), which is supplied by natural gas sourced mostly in the Permian basin. EPSML faces far fewer constraints than natural gas priced at SoCal City Gates, and so is projected to price at a $1.36/MMBtu discount in 2022. This discount is projected to narrow to approximately $0.40/MMBtu by the mid-2020s but will continue to provide LR2 with a fuel price advantage over most other generators in SP-15.
- A series of major policy developments have shaped the outlook for electric generation in California, including:
  - In October 2015, Senate Bill 350 set an electric sector-specific target of reducing carbon emissions to 40% below 1990 levels by 2030.
  - In September 2016, Senate Bill 32 established an economy-wide greenhouse gas reduction target of 40% below 1990 levels by 2030, which was one of the most aggressive targets in North America. Assembly Bill 398 (signed July 2017) then granted legislative authority for the California Air Resources Board to continue implementing its cap-and-trade program for emissions credits through 2030, which will increase power pricing across the majority of hours.
  - In February 2018, the CPUC released its IRP process (pursuant to SB 350), establishing a two-year IRP cycle for all electricity providers with a primary objective of optimizing system-wide resources to meet GHG reduction targets.
  - In September 2018, SB 100 increased California's RPS from 50% to 60% by 2030 and directed state policymakers to plan for 100% renewable energy and zero-carbon retail electric sales by 2045.
  - In November 2019, the CPUC issued a decision requiring the incremental procurement of system-level RA capacity of 3.3 GW by LSEs serving load within the CAISO balancing authority area. In June 2021, the CPUC approved an increase to the region's target reserve margin to 20.7% with 11.5 GW of additional capacity procurement by 2026 to help ameliorate potential future reliability.
- As renewable generation output increases, driven by the policies described above, California is projected to continue relying on thermal generation for capacity, flexibility, and overnight energy production throughout the study period.
  - Wind and solar generation are intermittent, meaning they are not continuously available due to external factors that cannot be controlled such as the sun shining and the wind blowing.
  - Moreover, as California has increased the amount of intermittent renewable generation on the system, it has continued to reduce the ELCC of solar and wind generation; this means that each incremental megawatt of wind or solar has a declining ability to satisfy California's peak demand needs.
  - Natural gas-fired assets can help balance the output of intermittent renewables and provide firm, flexible, on-demand capacity to ensure continued reliability in California; California's most recent IRP process concluded that efficient natural gas generation will remain part of the power system over the long-term to help with balancing and reliability challenges.
- The declining capacity contribution of wind and solar power generation has already begun to put upward pressure on pricing in California's RA market.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

- In large part driven by the rapidly declining ELCC of renewables, as well as OTC-driven thermal retirements, CAISO projects a capacity shortfall of 4.1 GW in 2024 and up to 7.5 GW in 2026. In response, RA pricing has increased, and several OTC retirements have been delayed for reliability purposes. To help mitigate future reliability concerns, California has approved an 11.5 GW procurement of firm clean capacity by 2026.
- PA projects system RA capacity prices to remain elevated though the study period with RA prices rising as the net fixed costs of in-state thermal power generation (including cost of firm natural gas transportation) increase with declining market spark spreads.

- The current tight market conditions, exacerbated by unusually warm summer weather and lower than normal hydroelectric generating capacity, manifested in blackouts in August 2020, reinforcing the need for reliable capacity within the market. This has also pushed up RA pricing.
  - In response, California has implemented several reforms to improve resource adequacy, including additional capacity procurements and an increase in the target reserve margin from 15% to 17.5% for the three large IOUs during (at minimum) 2021 and 2022 and increasing to 20.7% thereafter. (The 20.7% target technically applies only through 2026, but PA anticipates California will maintain this reserve margin as it continues to accommodate intermittent generation.) Increases to the target reserve margin will further increase system RA requirements and puts upward pressure on RA pricing.
- As reliance on intermittent resources increases, California has commenced a process of updating all aspects of its RA program to adequately reflect resource availability and operational needs. Regulators also seek to clarify rules for import resources (which met approximately 10% of peak demand in 2020).
  - Rule changes for RA imports, including real-time market must-offer requirements and mandated firm transmission rights, will likely put further upward pressure on RA pricing. California has also tightened how it establishes qualifying capacity for other intermittent resources (e.g., hydroelectric capacity).
  - Additionally, states across the broader WECC are experiencing the closure of coal plants and the addition of more intermittent renewable energy, which have the potential to put upward pressure on RA pricing in California by tightening available supply deliverable into California.
  - This shift in the WECC capacity mix is driven by state RPS targets, tighter emissions regulations, decreasing capital costs for renewables, consistently low natural gas prices, utility planning decisions to decarbonize electric generation portfolios, and divestments of out-of-state coal-fired resources by California entities.
- A settlement framework proposed in late 2019 would have introduced a central buyer mechanism for RA procurement. The CPUC denied this for system and flexible RA; however, it introduced a “hybrid” central buyer mechanism for Local RA in the PG&E and SCE territories (but not SDG&E) beginning in 2023 that maintains each LSE’s ability to self-supply with preferred resources.

1.2 MARKET PROJECTIONS

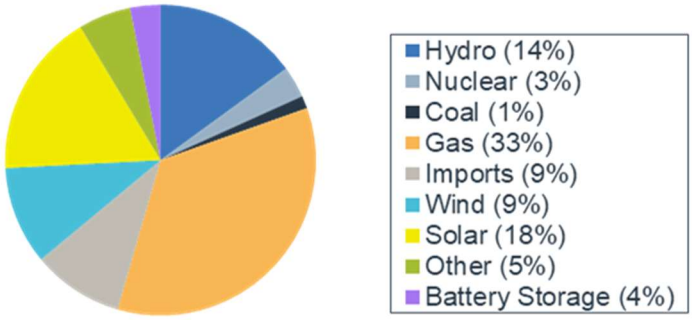
PA considers the California electricity region holistically, including CAISO as well as non-CAISO municipal territories due to the high number of transmission connections within California, as well as the degree of impact state policy has for both CAISO and non-CAISO markets. CAISO oversees the operation of the majority of the power grid, manages the day ahead and real-time LMP energy market, and conducts structured auctions to set the prices for ancillary services.

1.2.1 Supply

PA projects the California market to have approximately 69 GW of capacity to meet 57 GW of net demand in 2022, which results in a reserve margin of 21.2%. As illustrated in Figure 1-2, 33% of California’s 2022 nameplate capacity is projected to be comprised of natural gas-fired generators (with solar and wind capacity comprising 18% and 9%, respectively).

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Figure 1-2: 2022 California Nameplate Capacity Mix



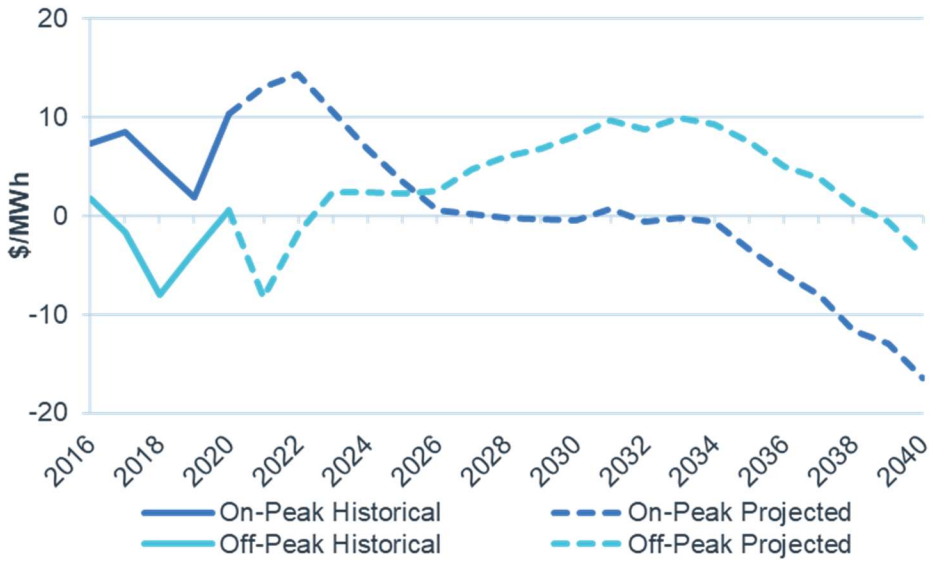
1.2.2 Clean Market Spark Spreads

Clean market spark spreads, along with resource adequacy revenues, are a primary indicator of a natural gas-fired power plant's earnings potential in a wholesale electricity region like California. Clean market spark spreads are driven by a number of factors including electricity demand, commodity prices, near-term weather, capacity additions and retirements, and environmental regulations (including CO_2 emissions allowance prices).

In California, upward pressures on spark spreads primarily include rising natural gas prices (which in turn drive even higher power prices, as natural gas-fired generators set the price of power in most hours in California), rising CO_2 emissions allowance prices (wherein the boost to power prices is greater than the increase in variable operating costs for a representative 7,000 Btu/kWh combined cycle in most years), and large generator retirements (wherein a tightened dispatch stack leads less-efficient gas-fired generators to be on the margin and setting prices more frequently). Downward pressures on spark spreads primarily include new renewable energy (wherein near-zero marginal cost capacity is added to the dispatch stack and drives more-efficient generators to be on the margin more often, thereby lowering power prices without affecting natural gas prices) and energy storage builds (which can support midday prices when they're charging but have a greater depressing impact on-peak hour prices when discharging).

As shown in Figure 1-3, near-term on-peak spark spreads are uplifted in the forwards markets, reflecting expectations of COVID-19 recovery and tight summer conditions driven by hotter than normal weather and drought conditions, which lowers available hydroelectric capacity. PA projects SP-15 on-peak clean market spark spreads to decline from current levels in the early 2020s with normalizing weather and hydrological conditions, falling natural gas prices and the continued entry of solar and battery storage additions. This trend is moderated by significant retirements beginning in the mid-2020s, temporarily stabilizing on-peak spark spreads around $0/MWh. Ultimately, the continued entry of renewables and storage cause spark spreads to continue declining in the long term.

Figure 1-3: Clean Market Spark Spreads – California SP-15[1,2]



[1] Clean market spark spreads normalize for assumed price of CO2. Clean spark spread subtracts the variable CO2 cost of a 7,000 Btu/kWh combined cycle.
[2] 2021 uses a blend of historical spot prices (Jan-Jun) and forwards (Jul-Dec).

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Historically, off-peak clean market spark spreads have priced below on-peak spreads, as on-peak power prices have typically been set predominantly by more expensive peaking generators. However, PA projects off-peak clean market spark spreads to increase from current levels, surpassing on-peak spark spreads by 2026. This trend is driven by the continued penetration of solar resources, which contribute to very low power prices in the mid-day hours (intersecting with CAISO's definition for "on-peak hours"). As solar and storage penetration drive down daytime spark spreads, lower renewable production overnight plus thermal retirements (e.g., Diablo Canyon nuclear in 2025 and 2026) act to support higher overnight spark spreads. In the longer term, growth in off-peak clean market spark spreads is moderated and eventually reversed as large amounts of renewable and energy storage capacity slow the growth of off-peak power prices.

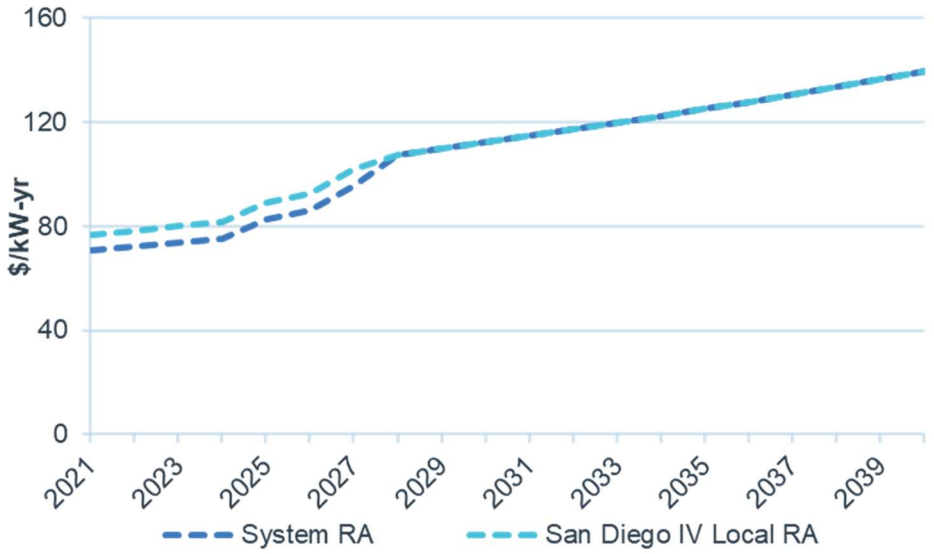
1.2.3 Capacity Compensation

Capacity compensation represents the amount of revenue, net of energy and ancillary services revenue, that the marginal unit required for reliability would need in order to ensure the recovery of fixed and non-sunk investment costs. In California, capacity compensation is expected to be realized primarily through the RA mechanism (see Section 2.2.2).

System RA pricing has risen substantially in the past few years due to tightening reserve margins, which reflects the declining ELCC of solar as well as some thermal capacity retirements. In response, some planned retirements have been delayed in order to maintain reliability. PA projects RA capacity prices to gradually increase in the 2020s as thermal retirements and load growth outpace the capacity contribution of replacement renewable and energy storage capacity additions. The full California electricity region is projected to be short supply in 2028, driven by over 10 GW of thermal retirements (largely units affected by OTC regulations) as well as further declines in the ELCC of wind and solar.

PA projects that new capacity (primarily renewable and energy storage) in the California market will continue entering the market via long-term bilateral agreements, thus maintaining the current bifurcated market structure between new and existing resources for capacity recovery. This means that the amount of legacy capacity that will be competing for RA contracts will prevent long-term System RA pricing from rising materially above the net fixed costs of existing thermal power generation. Specifically, PA anticipates that this existing unit will be a natural gas-fired generator located in California, since existing out-of-state power generation will be needed to satisfy reserve margins in the Desert Southwest and elsewhere (and the CPUC is instituting reforms to RA imports – see Section 2.2.5). Therefore, System RA pricing is projected to reflect the fixed cost of existing in-state natural gas-fired combined cycle generators (inclusive of firm natural gas transportation costs), rather than reaching thermal new build costs. See Figure 1-4.

Figure 1-4: California Projected System and Local RA Capacity Compensation[3]



Additionally, PA developed a Local RA premium for San Diego–Imperial Valley LCR by analyzing available supply, transmission constraints, and demand within the LCA as well as observed transactions for Local RA. Based on this analysis, PA forecasts San Diego-IV to be at a modest premium (approximately $0.50/kW-mo, or $6/kW-yr) to system RA in the near-term driven by relatively tight conditions within the LCA. Specifically, San Diego–IV is projected to have 4.6 GW of load in 2022, 4.4 GW of qualifying capacity and a 4.0 GW LCR (which needs to be satisfied by in-area capacity). Over the next several years, the LCR is projected by CAISO to decline to 3.6 GW in 2025 and to 3.4 GW in

[3] Incremental capacity compensation may be realized in the energy markets, bilateral transactions or through other mechanisms in the long term.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

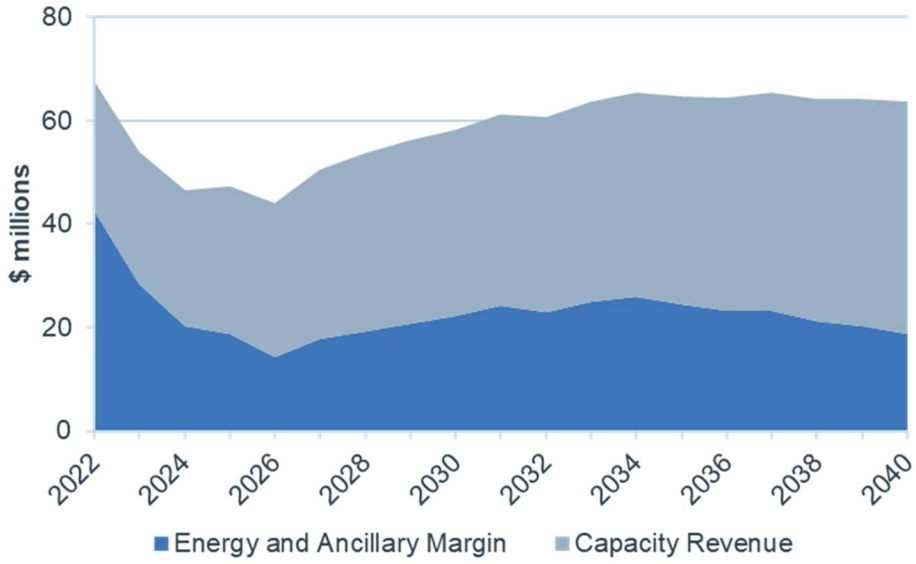
2026 due to transmission upgrades and capacity additions, which together reduces the LCR. By 2028, PA projects this premium over system RA to decline to zero.

1.3 ASSET PROJECTIONS

PA projects LR2's contribution margins (excluding major maintenance) to decrease from $68 million in 2022 (first full year of projections) to $44 million in 2026 as near-term supply and weather-driven market conditions normalize and as new supply enters the California market. Thereafter, contribution margins increase gradually and flatten over the remainder of the study period to $58 million in 2030 and to $64 million in 2040. Energy and ancillary margins are projected to follow the trajectory of spark spreads: declining in the early 2020s (from $43 million in 2022 to $14 million in 2026) due to the easing of tight near-term market conditions and declining natural gas prices, and then rising gradually thereafter.

By the mid-2030s, LR2's energy and ancillary margins flatten out due to continued renewable additions and rising CO_2 pricing. Capacity revenues make up the remainder of total margins, steadily rising from $25 million in 2022 to nearly $45 million in 2040. Capacity revenues make up a growing share of contribution margins, averaging 37% in 2022 and over 50% annually starting in 2024. Over the study period, capacity revenues make up 61% of total margins.

Figure 1-5: Asset Contribution Margins



Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

2 THE MARKETS

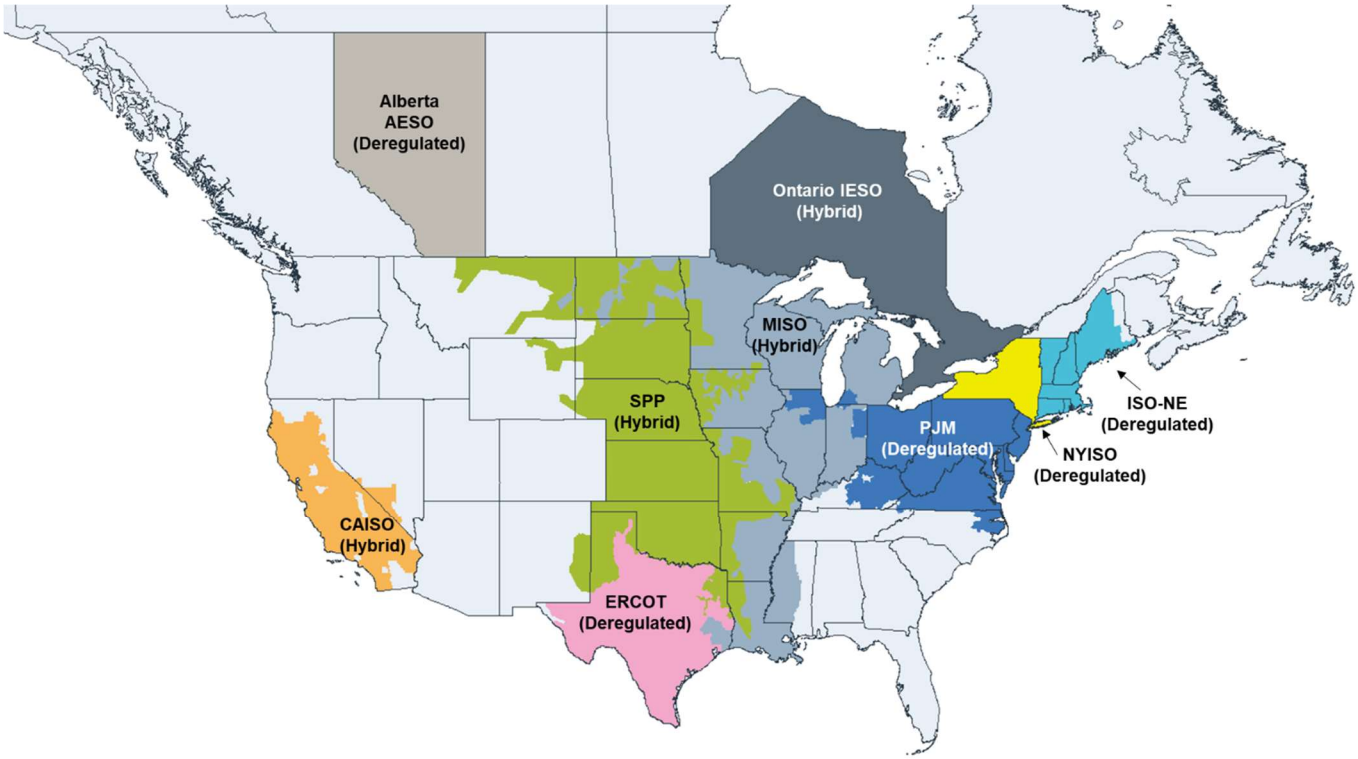
This section provides an overview of the US power markets in general, and the California electricity region specifically. Section 2.1 provides a broad overview of the historical and current state of the overall U.S. power market industry, while Section provides a detailed discussion of the market structure in California. Section 2.3 and beyond provide an overview of the market assumptions PA has used in its analysis to develop the market price projections in Section 3.

2.1 OVERVIEW OF U.S. POWER MARKETS

Electric deregulation can be characterized by the presence of centralized and liquid wholesale markets for energy (and sometimes capacity), the unbundling of generation supply from regulated utilities, open transmission access, and retail electric choice for consumers. The pace of deregulation has progressed quite differently across the United States. ISO-NE, NYISO, PJM, and ERCOT are generally the most deregulated regions and feature ISO markets with nodal pricing, generation unbundling, and retail electric choice. Conversely, the Southeast and much of the West remain dominated by vertically integrated utilities that handle all transmission planning, resource planning, and scheduling. In the Midwest and in California, “hybrid” ISOs including MISO, SPP and CAISO operate nodal markets for wholesale energy, but vertically integrated utilities still conduct integrated resource planning processes and serve most customer load.

In deregulated and hybrid markets, ISOs provide independent oversight over each region’s transmission system. ISOs help ensure open access to transmission, operate competitive wholesale markets for various electricity products, standardize resource adequacy requirements, and centralize and coordinate transmission planning. See Figure 2-1 for an overview of the geographies served by each ISO in the US. Non-regulated power generating assets located in markets that are not under ISO oversight generally rely on bilateral transactions, formal futures, and spot exchanges for the sale of electricity products.

Figure 2-1: North American ISO Overview[4]



2.2 CALIFORNIA MARKET AND REGULATORY STRUCTURE

One of four primary subregions of WECC, the California market consists of the majority of California and a small part of Nevada. CAISO oversees operation of most of the power grid and manages the day ahead and real-time LMP energy

[4] Source: PA Consulting Group and ABB’s Velocity Suite.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

and ancillary services markets.[5] While the events of the 2001 energy crisis led California to halt its restructuring efforts, CAISO's wholesale electricity market operation is more advanced than other parts of the Western United States.

The California market features three prominent IOUs—PG&E, SCE, and SDG&E—as well as LADWP, the largest municipal utility in the United States. The IOUs are projected to continue relying on a mix of off-take power contracts and owned power generation to meet electric demand needs and using the day-ahead and real-time markets as backstop sources of power. In addition to mandated short-term RA procurement, the CPUC also holds an IRP proceeding every two years to review ten-year capacity procurement plans for all LSEs operating within the IOUs' service territories or whose customers utilize the IOUs' T&D services.[6] California's IOUs have also invested in self-build electric generation capacity across resource types, but this capacity represents only a fraction of newly built capacity.

Figure 2-2: Prominent Utilities in the California Market[7]

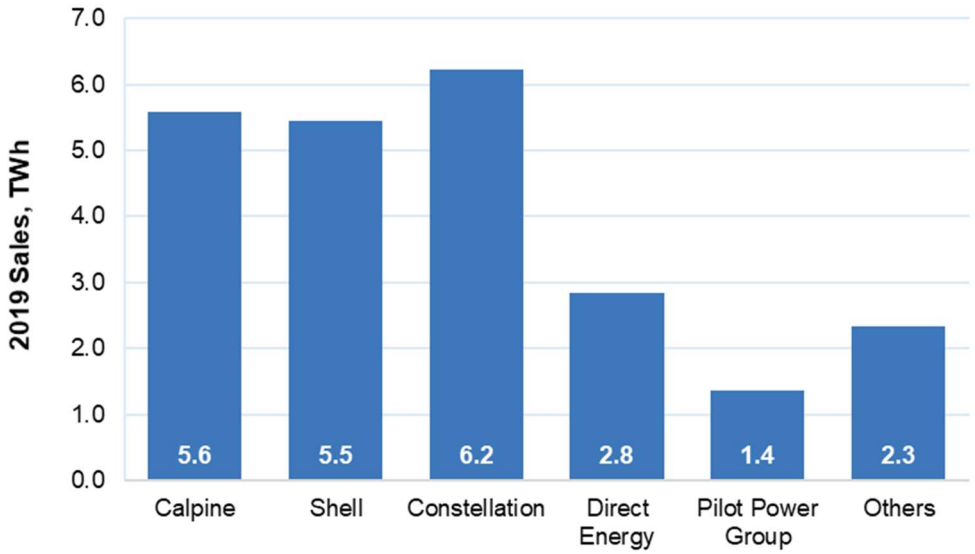


Outside of traditional LSE service, load in California can be served either by CCAs or by "Direct Access" providers (i.e., power marketers serving non-residential load). Direct Access participation, which is limited to non-residential customers in IOU territory, currently totals roughly 16% of IOU load. Under SB 237 (passed in December 2018), the statutory cap has been expanded to 28.8 TWh (approximately 18% of total IOU load), with new enrolees having started as early as January 2021.[8] SB 237 also directed the CPUC to submit to the legislature a report on whether to further expand Direct Access. The September 2020 report ultimately recommended that Direct Access expansion should be conditional on retail suppliers complying with IRP, RPS, and RA requirements, and that it should grow gradually (by 10% of eligible customer load per year, subject to CPUC approval). In May 2021, the CPUC ultimately issued a proposed decision that Direct Access should not be expanded, citing concerns with reliability and meeting RPS goals (in addition to potential loss of load for CCAs). The top five Direct Access providers by volumetric sales are shown in Figure 2-3 below – these top providers account for over 90% of total Direct Access sales.

[5] Ancillary services markets include Regulation, Spinning Reserves, and Non-Spinning Reserves in day-ahead and real-time markets.
[6] The IRP process replaced the LTPP process in February 2018 as part of CPUC Decision 18-02-018; whereas the LTPP process applied only to IOUs, IRPs consider the unique circumstances of each LSE.
[7] Source: PA Consulting Group and ABB's Energy Velocity Suite.
[8] Direct Access restrictions and TWh limits do not apply to CCA customers.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Figure 2-3: Top Direct Access Providers by 2019 Sales[9]



CCA participation is increasing and currently makes up approximately 20% of California load. Load switching from IOUs to CCAs is discussed more fully in Section 2.2.5.

2.2.1 Energy Market

In 2009, CAISO implemented nodal pricing for both real-time and day-ahead markets, thereby enhancing market efficiency. Pricing based on 3,000 nodes was intended to provide for more localized signals to would-be investors in new electric generation and transmission capacity.

Day-ahead market

CAISO uses the day-ahead market to determine market-clearing energy prices and unit commitments, and to ensure adequate energy is scheduled to meet projected hourly demand on the following day. First, CAISO runs a market power mitigation test, resetting failing bids to predetermined limits. Second, the IFM procures the power generation needed to meet CAISO-forecasted demand and co-optimizes energy with ancillary services. Third, the RUC process is run in order to ensure sufficient capacity is available to bridge the gap between day-ahead forecasted demand and supply scheduled in the IFM. The day-ahead market opens seven days prior to the operating day and closes at 10:00 AM one day in advance of the operating day. Publication of the results at 1:00 PM triggers the opening of the real-time market processes.

Real-time market

The real-time market facilitates procurement of power to meet demand not covered by day ahead schedules. Motivated in part by FERC Order 764, which required intra-hour transmission scheduling, CAISO implemented a 15-minute power generation scheduling and settlement process and a five-minute dispatch (i.e. balancing) process in May 2014. As a result, all settlement in the real-time market now occurs every fifteen minutes, improving price transparency and price formation. The real-time market opens at 1:00 PM one day in advance of the operating day, closing 75 minutes before the start of the trading hour. Results are then published 45 minutes ahead of the start of the trading hour.

Energy Imbalance Market

Currently implemented through CAISO's existing real-time market, the EIM is an energy-only balancing market that runs every five minutes to deploy sufficient power generation to meet load at the lowest cost. The EIM, which began operations in November 2014, allows balancing authorities outside of CAISO to voluntarily participate in CAISO's real-time market. The EIM features a fifteen-minute market solution and five-minute dispatch instructions. In addition to CAISO, there are currently 14 EIM members, as shown in Figure 2-4.

Several additional entrants are expected to join by 2023, including Avista, TEP, Tacoma Power, BPA, Avangrid, and El Paso Electric. By increasing both the amount and geographical spread of resources and load participating in its energy market (though not forming a regional RTO), CAISO hopes to accomplish three main goals: (1) create a more efficient and reliable market by improving operational awareness and responsiveness, (2) improve renewable integration by capturing the benefits of geographical diversity in both load and power generation, and (3) achieve cost savings by

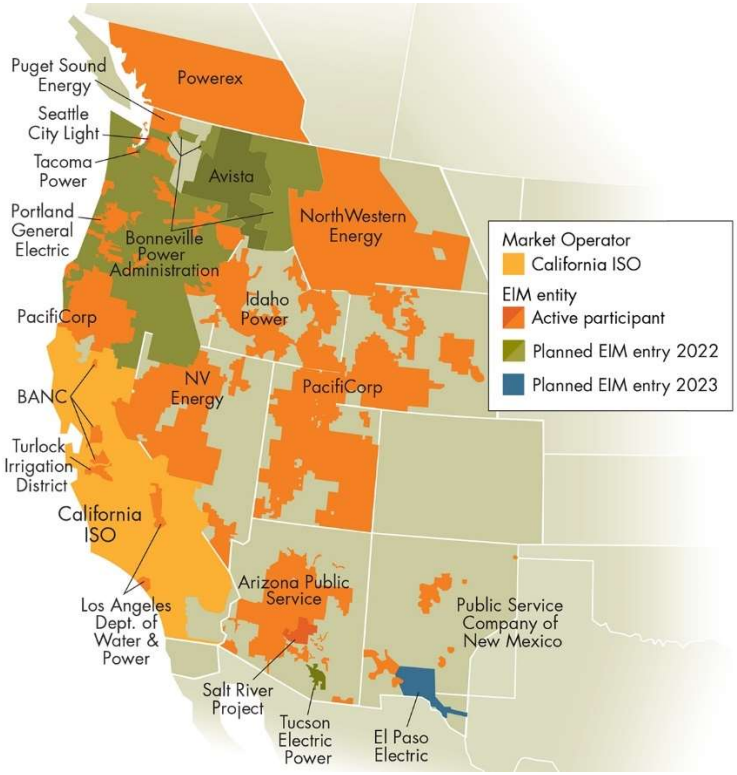
[9] Source: Form EIA-861.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

dispatching least cost resources from a larger, more fuel-diverse pool of generators. There is also potential for ancillary benefits, such as lower contingency reserve and flexible ramp resource requirements.

CAISO is considering several initiatives to expand the operational function of the EIM, and California has considered legislation to regionalize CAISO – see Section 2.2.5 for more detail.

Figure 2-4: Current and Potential EIM Members[10]



2.2.2 Resource Adequacy

Within California, the primary mode for ensuring sufficient capacity to maintain reliability is the RA program. RA is jointly administered by the CPUC and CAISO and applies to CPUC-jurisdictional LSEs, which include the three major California IOUs (PG&E, SCE, and SDG&E), CCAs, and Direct Access providers. CPUC-jurisdictional LSEs serve the majority of load within the broader California market. Via the RA program, CPUC-jurisdictional LSEs are required to contract with generating facilities or self-build to secure adequate capacity to meet system requirements on a year-ahead and month-ahead basis.[11]

Resource adequacy emerged as a response to the market failures of the early 2000s California energy crisis, and the CPUC first established a resource adequacy framework in a January 2004 order.[12] The current RA framework consists of three distinct components: System RA (effective 2006), Local RA (effective 2007), and Flexible RA (effective 2015). As of 2019, Local RA is now partially procured on a three-year forward basis, whereas System and Flexible RA are procured on a one-year forward basis. In June 2020, the CPUC also approved a central buyer mechanism, but only for Local RA and only in PG&E and SCE territory (see Section 2.2.5).

Unlike centrally cleared capacity auction processes, RA in California is transacted on a bilateral basis. As such, there is limited price discovery in the market, although structural shifts such as the proliferation of CCAs have increased transaction frequency which has helped improve market visibility. There is a mechanism to ensure availability called the Resource Adequacy Availability Incentive Mechanism that charges resources $3.79/kW-mo for availability shortfalls below 94.5% of its must-offer obligation during certain assessment hours.[13] For a resource to qualify for RA, its contract

[10] Source: Western EIM.
[11] In addition to the CPUC-mandated RA program, non-CPUC jurisdictional electric utilities have also instituted similar capacity reserve margin programs.
[12] Source: CPUC docket D.04-01-050.
[13] Hours vary by RA type. For generic RA capacity, it is weekdays HE 17-21, while for Category 1 Flexible RA, hours are daily HE 6-22.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

needs to carry a must-offer obligation, which requires it to submit self-schedules or bids into the CAISO market and make itself available for dispatch.

Other non-CPUC-jurisdictional LSEs in California (e.g., LADWP, SMUD) are part of separate balancing authorities and are subject to NERC reliability requirements. While these LSEs do not undertake CPUC-mandated RA procurements, they have instituted similar capacity reserve margin programs and typically secure firm capacity through a mix of self-owned electric generation and bilateral agreements.

System Resource Adequacy

System RA requirements are designed to ensure LSEs meet expected peak loads (plus a 15% reserve margin) in the entire CAISO balancing area. CPUC-jurisdictional LSEs (which include the three major IOUs as well as CCAs and Direct Access providers) are currently required to contract with generating facilities or self-build to secure adequate capacity to meet system requirements on year-ahead and month-ahead bases. In their annual filings (due October of each year), LSEs must demonstrate that they have procured 90% of their System RA requirements for the five summer months of that upcoming compliance year (May through September); in their monthly filings, LSEs must show 100% procurement for the upcoming month.

CPUC-jurisdictional LSEs typically hold open solicitations for both existing and planned[14] capacity resources one to five years ahead of the year in which capacity is required.[15] These LSEs contract for RA capacity outside of the market-wide solicitations (as well as relying on self-owned capacity). Solicitations are reviewed by an independent evaluator who reports to the CPUC. Long-term RA contracts for new-build resources are common. However, while LSEs can contract with existing resources for five years or longer, doing so requires that the utility apply to the CPUC for approval, and such contracts have historically been rare; this is because LSEs and the CPUC are wary of locking in capacity given uncertainty around future capacity needs in California's evolving market and policy environment.[16]

Local Resource Adequacy

Under Local RA, LSEs under CPUC jurisdiction are required to procure a minimum amount of capacity for transmission-constrained load pockets known as LCAs (which are determined by CAISO). A map of the current LCAs considered by CAISO is shown in Figure 2-5. LR2 is located in the San Diego – Imperial Valley LCA.

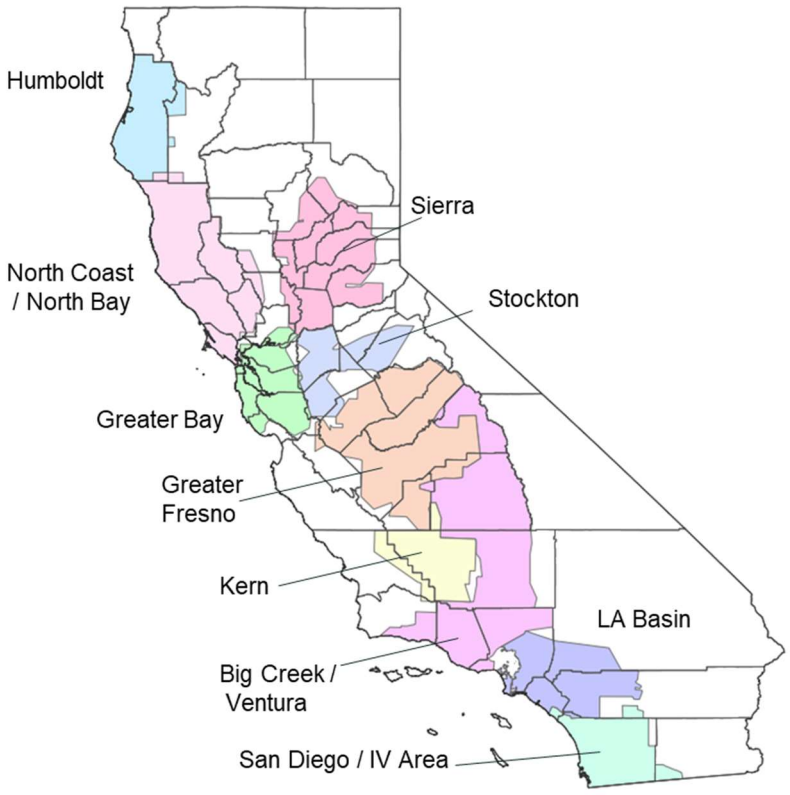
As additional capacity cannot be reliably transmitted from regions where capacity builds may be more economic into these constrained zones, Local RA contracts are generally of higher value than those for System RA. For example, reported RA contract prices from 2018-2022 showed Local RA weighted average contract prices as approximately 16% higher than those for System RA.[17]

Under a February 2019 order by the CPUC, California IOUs must utilize multi-year (i.e., minimum three-year) contracts to secure the majority of their Local RA requirements. Beginning with the 2020 compliance year, IOUs must secure 100% of Year 1 and Year 2 Local RA requirements, and at least 50% of Year 3 Local RA requirements, under multi-year contracts. Driven in part by a tightening RA market, many IOUs and CCAs have also been increasingly procuring more system RA on a multi-year basis.

[14] Planned capacity resources must be able to provide capacity in the year for which they are contracted. For example, if a capacity resource contracts to provide capacity for 2021, then it must be operational by 2021.
[15] For example, an electric utility may hold a 2021 auction for RA capacity in 2024.
[16] Source: CPUC 2013; Review of Current Issues with Long Term Resource Adequacy.
[17] Source: CPUC, 2018 Resource Adequacy Report, August 2019.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Figure 2-5: Current California LCAs[18]



Flexible Resource Adequacy

The RA program's final component, Flexible RA, attempts to ensure that LSEs can meet the largest continuous three-hour ramp need in every month. Utilities must verify their flexible capacity procurement on a monthly and annual basis. Additionally, there are must-offer obligations for certain resources within each flexible capacity category (base, peak and super-peak ramping flexibility) and a backstop procurement mechanism that will be used in the event of a system-wide deficiency. Each of the flexible capacity categories has specific operating requirements that are summarized below in Table 2-1.

Table 2-1: Flexible Capacity Category Requirements[19]

Flexible Resource Category	Energy Requirement	Minimum Allowable Starts	Availability
Category 1 (Base)	At least 6 hours per dispatch	2 per day	7 days per week
Category 2 (Peak)	At least 3 hours per dispatch	1 per day	7 days per week
Category 3 (Super-Peak)	At least 3 hours per dispatch	5 per month	Weekdays

Thus far, Flexible RA showings have been adequate to meet needs. However, the product has generally attracted inflexible units rather than the highly flexible capacity desired. For example, over 40% of total procured Flexible RA in March 2016 had a ramp rate of 10 MW/minute or less, and 25-33% of Flexible RA showings represented OTC resources, which are typically older, slower-ramping steam turbines.

Such issues have motivated CAISO to pursue multi-year efforts to update rules around eligibility for Flexible RA. For example, as part of its Resource Adequacy Enhancements process, CAISO is proposing to replace its existing Flexible RA products in favor of a new set that will value the speed at which resources can ramp up and down; such changes to Flexible RA eligibility would likely reduce the amount of inflexible capacity procured in favor of resources that can respond

[18] Source: PA Consulting and CEC.
[19] Source: CAISO Regional Resource Adequacy Issue Paper, released December 9, 2015.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

quickly in real-time markets (e.g., battery energy storage systems).[20] More detail regarding ongoing RA reforms can be found in this section (2.2.2) as well as Section 2.2.5.

Resource Adequacy Penalties

CAISO and the CPUC each have mechanisms in place to deter RA operational and procurement shortfalls.

Resource Adequacy Availability Incentive Mechanism

CAISO uses RAAIM to incentivize resources with RA contracts to meet their Must Offer Obligations during Availability Assessment Hours. CAISO defines Availability Assessment Hours prior to each RA Compliance Year. For Local and System RA, Availability Assessment Hours are set as five consecutive hours (varying by month) that are chosen with the intent of aligning with periods of high demand; for Flexible RA, Availability Assessment Hours are contingent on the Flexible Resource Category. CAISO then determines the rate at which resources with RA contracts met their Must Offer Obligations during Availability Assessment Hours by comparing the MWs of RA capacity bid into the relevant markets on a given day with the MWs of RA capacity for which the resource had a Must Offer Obligation via its RA contract(s).

Each month, CAISO assesses Non-Availability Charges to generators that meet less than 94.5% of their Must Offer Obligations during Availability Assessment Hours and redistributes proceeds through Availability Incentive Payments to generators that meet more than 98.5% of their obligations in these hours through its settlement process. The Non-Availability Charge is calculated as 60% of the CPM soft offer cap price (currently set at $6.31/kW-mo) – that is, a rate of $3.79/kW-mo – multiplied by the difference between 94.5% and the resource's actual availability percentage for the given month; the Availability Incentive Payment for a resource is then distributed proportionately based on the total MW of well-performing (i.e., greater than 98.5%) resources and the revenues collected from Non-Availability Charges.

Certain classes of resources are exempt from RAAIM, including small resources (less than 1 MW) and those with Legacy RMR Contracts (i.e., RMR contracts entered into before September 1, 2018). Separately, hours under certain types of outages are excluded from the RAAIM calculations, such as outages caused by forces outside the control of the resource owner (e.g., gas supply issues) as well as maintenance outages scheduled sufficiently far in advance.[21] For outages that do not qualify for an exemption, the resource owner must arrange a substitute resource to fill its role in order to avoid RAAIM charges.

In sum, non-performance risk for RA resources is relatively low in California, due to protections against availability shortfalls for certain outages (e.g., gas supply issues), the ability to seek a substitution resource, and relatively low penalty rates.

Resource Adequacy procurement shortfall mechanisms

The CPUC's current penalty structure features two tiers of penalties for LSEs under both System RA and Local/Flexible RA – see Table 2-2. In addition to CPM costs (discussed below), these penalties help inform the prices at which LSEs may be willing to enter into RA contracts to avoid deficiencies.

Table 2-2: RA Penalty Structure

Length of Deficiency	System RA	Local & Flexible RA
Cured within 5 business days	1st deficiency in year: $5,000/incident (≤ 10 MW), 10,000/incident (> 10 MW) 2nd deficiency in year: $10,000/incident (≤ 10 MW), $20,000/incident (> 10 MW)	
Cured after 5 business days	$6.66/kW-mo.	$3.33/kW-mo.

LSEs that are unable to procure sufficient capacity to meet obligations may obtain a waiver from the CPUC. However, even with a waiver, non-compliant LSEs remain responsible for any backstop procurement costs accrued by CAISO. For backstop procurement, CAISO employs the CPM, a process under which CAISO designates certain resources as CPM Capacity and imposes various availability requirements. CAISO allocates the cost for compensating CPM capacity across LSEs based on LSE-specific deficiency levels.

As part of the CPM, CAISO issues competitive solicitations for existing resources that do not have RA contracts. Resources can voluntarily bid into this solicitation; if a resource is selected, the resource is required to accept a contract

[20] Source: CAISO Resource Adequacy Enhancements Revised Straw Proposal, released July 1, 2019. CAISO has since released its Final Phase 1 Proposal (on March 23, 2021), indicating that flexible resource adequacy reform will be delayed to Autumn 2022 for RA year 2023. See Table 2-3.

[21] The advance notice required for scheduled maintenance outages is contingent on the expected availability of all other resources to serve load during the relevant period of time; as fewer resources are available, more lead time is required to be granted an exception.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

(typically for a month or a year in length) at the offered price. To mitigate market power abuse under tight reserve margin conditions, the CPM includes a soft offer cap, whereby any offer above the administratively set cap must be reviewed and have its fixed costs verified to receive compensation at its bid price. The soft offer cap lessens risk exposure for LSEs that may otherwise face very high costs for undersupply.

The soft offer cap has been priced at the going-forward fixed costs (plus a 20% adder) of a hypothetical mid-cost 550 MW natural gas-fired combined cycle with duct firing capability since 2016. In early 2019, CAISO began an initiative to review the soft offer cap and determine whether it should adopt changes. In early 2020, CAISO released its final proposal, which concluded that the soft offer cap did not need to change from its current level ($6.31/kW-mo). The proposal also noted that the reference technology for the soft offer cap may need to change in the future as CAISO's generating portfolio trends toward clean energy resources, but that such a change is not yet necessary, as the CPM is meant to procure existing rather than new resources as needed for reliability.

Resource Adequacy Reforms

California has continued to explore improvements to its RA mechanism, both through refinements to its existing program as well as potential larger-scale changes to how capacity may be procured. Through its reform processes, a chief concern of the CPUC and CAISO is ensuring the deliverability of RA resources. Efforts to limit potential deleterious effects of imported RA include sustained reductions in MIC, as well as the recent CPUC order to impose delivery obligations on imports (see Section 2.2.5 for more detail). In addition, as discussed below, state entities are pursuing reforms to capacity credits for renewable energy resources and evaluating a potential shift to centralized RA procurement.

CAISO Reliability Services Initiative

In 2013, CAISO and the CPUC issued a Joint Reliability Plan, which launched a multi-pronged effort to improve California's reliability framework for electricity procurement. The proceeding that emerged from development of the Joint Reliability Plan included consideration of market-based backstop procurement mechanisms, long-term interagency coordination on reliability issues, and multi-year resource adequacy forward procurement requirements. The process also launched CAISO's Reliability Services Initiative, which CAISO used to a develop a series of improvements to the RA program over two phases; these improvements included capping LSEs' Local RA requirements at their System RA, as well as allowing capacity located in an LCA that is procured for use as system capacity to have a system substitute, rather than requiring the substitute be sourced from the same LCA. All tariff changes resulting from the Reliability Services Initiative were implemented by CAISO by May 2018.

CAISO RA Enhancements process

CAISO has since begun working through a comprehensive stakeholder process to further update all aspects of the RA program. The CAISO RA Enhancements process formally initiated in October 2018 with an issue paper; in March 2021, CAISO released its Final Proposal. This process is meant to address the discrepancies between the RA program's design in 2006 (when natural gas, nuclear, and hydro dominated the state's power generation) and challenges with a grid that features an ever-growing reliance on intermittent resources as the state pursues its clean energy targets. In particular, the final proposal notes that current RA rules do not adequately reflect resource availability, flexible capacity rules do not match operational needs, rules for import resources lack clarity, the existing planned outage provisions and process need revisions, and CAISO has not properly accounted for a growing reliance on intermittent resources for RA purposes.

CAISO's stakeholder engagement plan for the RA Enhancements process includes releasing both a draft final and final proposal for Phase 2A in 2021. However, much uncertainty remains about the final details of the plan; thus, PA does not incorporate any proposed changes to the process as part of its Base Case. Current topics under consideration, and their proposed roll-out dates, are presented in Table 2-3.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Table 2-3: CAISO RA Enhancements Process – Implementation Plan[22]

Phase	Proposed Tariff Changes	Target Implementation Date
1	• Planned outage process enhancements (phase 1) • Operationalizing storage • Backstop capacity procurement – CPM for local energy sufficiency	2021 for RA year 2022
2A	• Unforced capacity evaluations • Determining system RA requirements • Must offer obligations and bid insertion modifications • Backstop capacity procurement – CPM modifications, availability penalty structure for RMR resources • Planned outage process enhancements (phase 2) • Flexible resource adequacy	2022 for RA year 2023
2B	• RA import requirements – aligned with timeline for upcoming Maximum Import Capability (MIC) enhancements initiative	2022 for RA year 2023

Centralized Procurement

In January 2018, the CPUC began a proceeding in Docket R.17-09-020 to evaluate various RA improvements, including evaluating the merits of centralized capacity procurement. Under a centralized procurement mechanism, a central buyer (e.g., CAISO, the large utilities, or a special purpose entity) would procure capacity on behalf of smaller LSEs. In June 2018, it found that centralized procurement is most appropriate for multi-year Local RA, but that it has drawbacks for system or flexible RA.

In February 2019, after extensive review and stakeholder debate over various reforms, the CPUC formally adopted a set of changes to the RA program. These changes included a multi-year Local RA procurement beginning in 2020, whereby Local RA is procured for three-year forward periods. The CPUC at the time postponed adoption of the central procurement mechanism, under which large utilities (or CAISO) would procure Local RA on behalf of smaller LSEs.

In response, some stakeholders developed a settlement framework that would allow (but not require) LSEs to procure resources to meet all or part of their local, system, and flexible RA requirements; however, it would also establish a Resource Adequacy-Central Procurement Entity (RA-CPE) – the settlement stayed mum on what that entity would be – that would procure the "residual" capacity needed to meet each LSE's three-year RA obligations. Such a framework would allow LSEs (including CCAs) to continue making their own resource decisions while allowing for an independent party to cover the difference where necessary, reducing the need for CAISO's backstop mechanism.

On June 11, 2020, the CPUC voted to approve a rulemaking that denies this settlement agreement but approves a separate centralized procurement framework; the approved framework applies only for Local RA in PG&E and SCE territories and operates under a "hybrid" model that still allows LSEs to self-supply.[23] Given their procurement expertise, PG&E and SCE are designated as the central buyers. Centralized procurement for multi-year local RA is set to begin with the 2023 compliance year. The framework does not apply to SDG&E's Local RA requirement, as in most months, its local RA resources exceed the system requirement. It also does not apply to system RA or flexible RA.

PA expects the new mechanism will improve market visibility and price transparency for Local RA, possibly reducing the variance of RA pricing relative to the extant bilateral market. Given that local RA makes up a minority of the total system need in both PG&E and SCE territories, the magnitude of overall change is expected to be small, particularly relative to if such a framework were applied to system RA.

Effective Load Carrying Capability

In June 2017, the CPUC adopted the ELCC approach to determine the NQC of intermittent renewable resources for 2018. The NQC of wind, solar PV, and solar thermal resources that count toward LSE RA requirements are now determined based on their ELCC, as modeled by the CPUC. The ELCC reflects the capacity value of different resources

[22] Source: CAISO Resource Adequacy Enhancements – Phase 1 Final Proposal, posted March 23, 2021.
[23] Source: CPUC. Decision on Central Procurement of the Resource Adequacy Program. Rulemaking 17-09-020. March 26, 2020. (This proposed decision was later approved by the CPUC on June 11, 2020.)

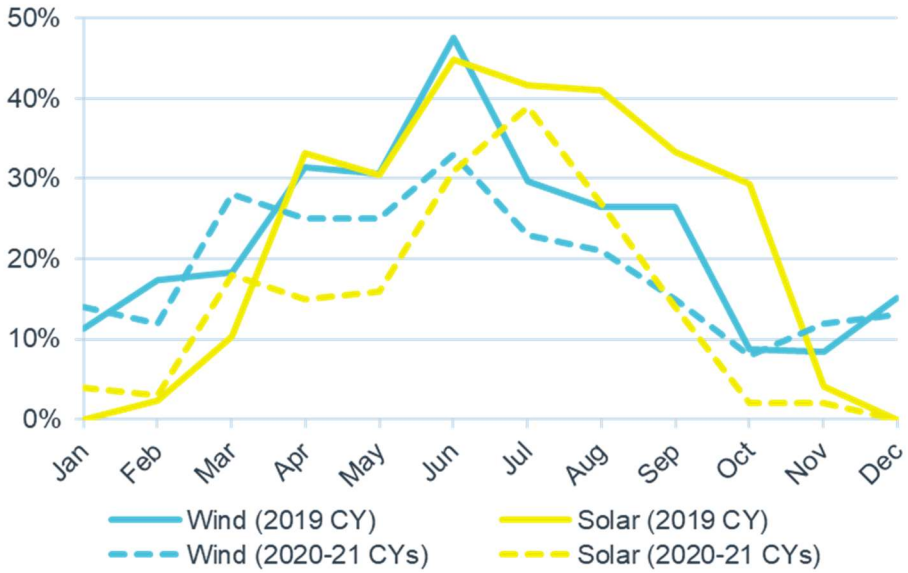
Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

relative to “perfect capacity,” which represents a hypothetical fully-dispatchable resource.[24] ELCC values are determined for each month based on CAISO-wide supply and demand conditions.

The ELCC approach was effective as of January 2018. Under ELCC, the average summer capacity contribution for solar decreased from approximately 78% to 40%, and the average summer wind contribution increased from 19% to 33%. This effectively resulted in the California market seeing approximately 3 GW less solar and nearly 1 GW more wind capacity in 2018 relative to 2017 (on a de-rated basis, ignoring 2018 new builds).

In June 2019, the CPUC finalized a decision adopting new ELCC values for wind and solar resources for the 2020 compliance year. [25] As illustrated in Figure 2-6, the revised monthly ELCC values are significantly lower than previously adopted ELCC values during much of the shoulder and summer months. Furthermore, the ELCC values determined by the CPUC are the system average ELCC values for each resource type. The ELCC of each marginal solar resource that is added to the system is significantly lower than the system average, since each marginal solar resource’s contribution to reliably serving demand is less than the prior solar resource addition. Finally, solar and wind ELCC values for the 2021 CY are the same as for the 2020 CY.

Figure 2-6: ELCC Values Determined by CPUC – 2019-21[26]

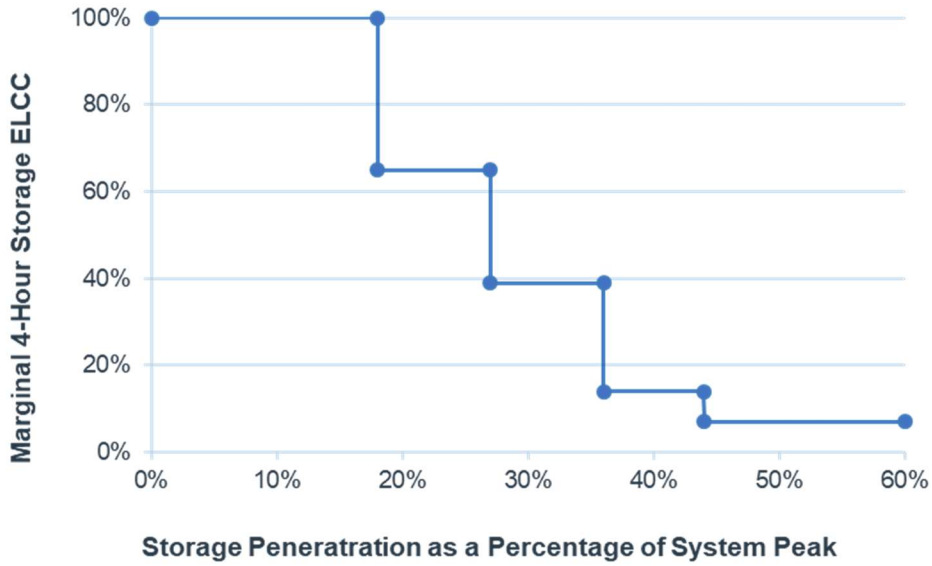


Starting with the 2019 Integrated Energy Policy Report, the CPUC has begun using a declining ELCC curve for battery storage resources for resource planning purposes. Battery storage resources are time-limited and do not provide the equivalent capacity compared to dispatchable thermal resources. At higher battery storage penetrations, storage flattens the net peak hour, which means that the instantaneous peak hour (used for system planning) can now occur in far more hours. This requires longer duration batteries and/or higher stored energy volumes to maintain the same level of reliability. Additionally, at higher battery penetration levels, there is the challenge of having enough energy to charge the batteries in order to support peak demand. The ELCC curve adopted by the CPUC is for battery storage resources with a four-hour duration – see Figure 2-7. The contribution to the planning reserve margin is a function of the penetration of battery storage as a percentage of system peak demand. PA relies on the CPUC’s battery ELCC curve for modeling capacity expansion in the California market. [27]

[24] For example, if removing 100 MW of solar resource from the grid and replacing it with 50 MW of perfect capacity does not change the LOLE, the ELCC of the solar resources would be 50%.
[25] Source: CPUC. Decision Adopting Local Capacity Obligations for 2020-2022, Adopting Flexible Capacity Obligations for 2020, and Refining the Resource Adequacy Program. Rulemaking 17-09-020. Decision 19-06-026. June 27, 2019.
[26] Source: CAISO. Final Net Qualifying Capacity Report for Compliance Year 2021.
[27] California has also introduced ELCC for paired resources. For 4-hour batteries paired with solar, the ELCC is projected to remain above 90% for the duration of the 2020s. See: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5868-E.pdf

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Figure 2-7: CPUC Storage ELCC (Stand-Alone 4-Hour Battery)



Resource Adequacy import considerations

Due in part to the likely increasing reliance on RA imports to ensure reliability, the CPUC investigated potential changes to how RA imports are treated. In September 2018, CAISO's market monitor issued a report on RA imports raising the concern that LSEs are relying on imported RA capacity that is not actually deliverable when needed. Specifically, the market monitor noted that while RA imports are technically required to bid into the day-ahead market, these imports are permitted to bid at any price up to $1,000/MWh regardless of actual dispatch cost. Furthermore, these RA imports are not required to bid into the real-time market. This treatment allows imports to qualify for RA but routinely bid in the day-ahead market at prices ensuring that they do not clear, potentially limiting their availability during periods of tight system conditions.

After considering requested stakeholder input on potential changes to rules regarding RA import treatment, the CPUC ruled to affirm the existing requirements governing imports to meet RA requirements in October 2019.[28] However, CAISO and CalCCA subsequently filed applications for rehearing (with CalCCA additionally filing a motion to stay the decision), claiming the order adopted changes beyond affirming existing precedent and created uncertainty in California's markets. In December 2019, the CPUC granted the motion to stay its earlier order until it makes a final determination on the applications for rehearing; [29] the CPUC then granted a limited rehearing in March 2020.

On June 25, 2020, the CPUC approved a decision that sets new requirements for RA imports beginning in the 2021 RA compliance year.[30,31] Specifically, the decision creates two categories for RA imports: resource-specific imports and non-resource specific imports. The former is associated with specific resources identified through CAISO; these imports can qualify for RA if they are pseudo-tied or dynamically scheduled into CAISO's day-ahead and real-time markets. The latter are not associated with specific resources and must meet a range of other requirements; these include entering a contract for energy with no economic curtailment provisions, delivering the energy to the LSE for which RA is being credited, and self-scheduling (or bidding at or below $0/MWh) into CAISO's day-ahead and real-time markets as well as during availability assessment hours. These stricter requirements are likely to reduce the amount of imports that qualify for RA, particularly where speculative supply no longer seeks RA contracts; this in turn is expected to put upward pressure on RA value beginning in 2021.

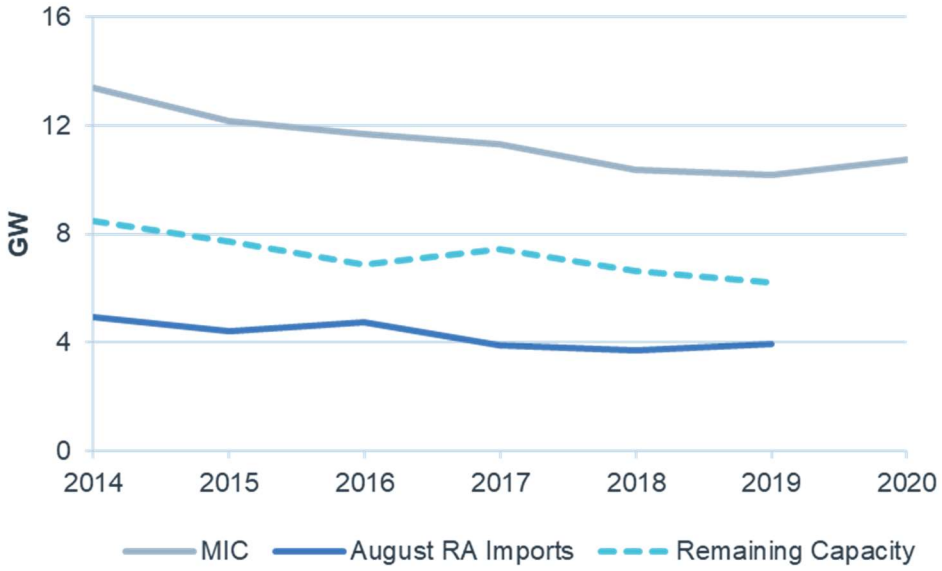
Separately, capacity in neighboring regions also face tightening markets that may limit the amount of capacity available to California. However, while RA imports have generally declined in recent years, the CAISO-determined MIC (i.e., the maximum amount of RA-qualifying capacity that can be imported from outside CAISO) has declined at a more rapid pace. Due to the faster relative decline in MIC, the remaining available RA import capacity (i.e., the difference between MIC and the amount of contracted RA imports) has declined, from approximately 8.5 GW in 2014 to approximately 6.2 GW in 2019. However, to the extent that California relies more heavily on RA imports to ensure reliability in the face of

[28] Source: CPUC. R.17-09-020. Decision Affirming Resource Adequacy Import Rules. October 17, 2019.
[29] Source: CPUC. R.17-09-020. Order Granting Stay of Decision (D.) 19-10-021. December 23, 2019.
[30] Source: CPUC. R.17-09-020. Decision Adopting Resource Adequacy Import Requirements. June 25, 2020.
[31] The decision also completes the limited rehearing granted in March 2020 and ends the stay put in place in December 2019.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

declining renewable ELCC and thermal capacity retirements, or the MIC continues to decline further in the future, there may be a limit to the extent that California can rely on imports for RA, placing increased value on local firm capacity.

Figure 2-8: RA Imports and Maximum Import Capability[32]



Net Qualifying Capacity methodology for hydropower

Hydropower resources are dependent on rainfall and snowmelt as well as environmental and regulatory limitations, with these conditions affecting the reliability of such assets and generally lying outside of the control of the asset operators. As filings must be submitted in October of each year for year-ahead RA requirements, hydropower resources often have to determine their available capacity well before they will have more accurate estimates of snowpack and rainfall (i.e., in late spring). With tightening reserve margins in California, these dynamics have driven concern among stakeholders that hydropower resources will not be able to contribute when needed (particularly in dry years) and have led to a process through which the NQC methodology for hydropower is being reconsidered.

In March 2020, SCE and CAISO released a draft joint report recommending a change in methodology in the accounting of hydropower for RA purposes, pursuant to a CPUC directive.[33] The proposal (which also received the support of PG&E) would allow hydropower resources to elect an optional new NQC methodology. Resources that choose to elect the new methodology would receive a lower NQC that accounts for water availability by considering the previous 10 years of same-month bid-in availability (i.e., examining historical offered capacity in Availability Assessment Hours); in turn, these resources would be exempt from RAAIM charges in cases where outages are due to water availability shortfalls (noting that mechanical outages would continue to face such charges). Resources that opt to apply the current NQC methodology would continue to be subject to RAAIM for any outage. The CPUC ruled in favor of the proposal in June 2020 and was implemented for the 2021 RA compliance year. As a result of the change, total NQC for hydro declined by 1.1 GW in 2021, which further tightens the supply-demand balance in California.

2.2.3 Ancillary Services

To meet reliability standards, CAISO procures regulation up, regulation down, spinning reserve, and non-spinning reserve ancillary services in day-ahead and hour-ahead markets, co-optimized with the clearing of energy bids. These ancillary services may also be self-provided by generators. See Table 2-4 below for a description of the deployment and procurement of these ancillary services. Note that spinning reserve is capacity provided by generating resources that are already online, while non-spinning reserve is capacity from resources that are not yet online. In addition, CAISO procures voltage support via cost-based contracts.

[32] Source: CPUC and CAISO.
[33] Source: CPUC. Southern California Edison Company (U 338-E) and California Independent System Operator Corporation's Joint Report for the Track 2 Hydro Counting Working Group. Rulemaking 19-11-009. March 11, 2020.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Table 2-4: CAISO Ancillary Services[34]

Ancillary Service	Deployment	Typical Resource Types Providing Service	Approximate Procurement
Regulation:			
Regulation Up	Instantaneous response must reach maximum offered regulation within 10 minutes, following a signal that updates every 4 seconds	A large portion of regulation capacity is currently procured from CCs but can be provided by any unit with Automatic Generation Control, including coal, steam turbines, and storage resources.	300-480 MW
Regulation Down	Instantaneous response must reach maximum offered regulation within 10 minutes, following a signal that updates every 4 seconds		360-550 MW
Operating Reserves:[35]			~1,700 MW
Spinning Reserves	Initiate real power response within 1 minute, reach maximum offered reserve within 10 minutes	These are often provided by conventional power generation such as CC and coal units but can also be provided by DSM resources that are able to reduce load.	At least 50% of Operating Reserves
Non-Spinning Reserve	Initiate response as soon as possible, reach instructed capacity within 10 minutes	These can be provided by resources with quick-start capabilities such as gas turbines, as well as interruptible load.	Remainder of Operating Reserves

Flexible ramping product

Recognizing the increasing need to manage demands on the system caused by intermittent resources and load forecasting uncertainty, CAISO is pursuing price signal reforms to further incentivize resource flexibility. In 2016, CAISO implemented its Flexible Ramping Product as a replacement for its administrative flexible ramping constraint. The Flexible Ramping Product improves price signals to resources that can ramp up quickly to serve load through real-time dispatch. The purpose is to insure against insufficient ramp capability in real time that would have previously resulted in extreme prices.

The Flexible Ramping Product is a five-minute product procured in the real-time and fifteen-minute markets. Like regulation reserves, CAISO separately procures up and down flexible ramp. However, unlike other ancillary products, prices are determined by opportunity costs of providing energy rather than generator bids. Since the product is intended to help manage unexpected ramp needs, rather than overall ramp needs that it can anticipate in advance, CAISO has to date procured only a couple hundred MW per hour in the five-minute market, far less than their need for overall flexible capacity. As part of its DAME initiative, CAISO is also considering a flexible ramping product for the day-ahead market (see Section 2.2.5 for more detail).

2.2.4 Congestion Management

CAISO has a market for CRRs, financial instruments that enable market participants to manage variability in congestion costs in the day-ahead market. Congestion costs collected by CAISO are paid out to holders of CRRs. CRRs are made available (and most are distributed) through allocations as well as monthly and annual auctions but can also be transacted bilaterally through the Secondary Registration System.

[34] Source: CAISO.
[35] CAISO's real-time EIM is energy-only and does not directly impact the ancillary services market in CAISO. However, the amount of Contingency Reserves (required to be held to respond to major system outages), and by extension Spinning and Supplemental Reserves, required to be procured may be impacted by net transfers into or out of CAISO in the EIM.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

The objective of CRR allocation is to provide the quantity of CRR coupons necessary to offset fully the annual congestion charges that customers will be assessed. In addition, CAISO allocates CRRs to companies that invest in building new transmission facilities and are not compensated for such investment through a customer surcharge.

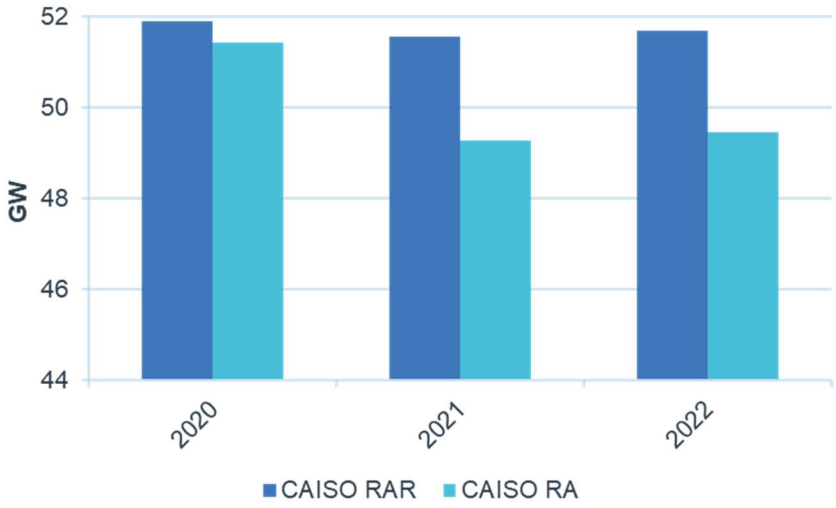
2.2.5 Recent Market Developments

California's energy markets are undergoing a significant transition with several key developments including resource adequacy concerns (amplified by the August 2020 blackouts), PG&E's bankruptcy, load migration, and the potential expansion of the EIM/CAISO.

August 2020 Blackouts and Resource Adequacy Concerns

In light of major changes to the supply outlook in California, including imminent OTC-driven thermal retirements and declining ELCC for intermittent renewables, several key market participants in California (including the CPUC and CAISO) have raised concerns about near- and moderate-term resource adequacy for reliability. In August 2019, CAISO filed comments in a CPUC IRP proceeding on reliability concerns – these comments projected an RA shortfall compared to the RAR (i.e., peak demand plus a 15% target reserve margin) of over 2 GW in 2021 and 2022.[36] See Figure 2-9 for a summary of CAISO's outlook on available RA capacity compared to RAR.

Figure 2-9: CAISO RA vs. RAR Projection[37]



On November 7, 2019, the CPUC issued a decision recommending that the State Water Resources Control Board extend the compliance deadline for OTC units that were set to retire by December 31, 2019. The units recommended for extensions include Alamitos Units 3 and 5 (1,200 MW) for up to three years, Huntington Beach Unit 2 (200 MW) for up to three years, Redondo Beach Units 5, 6, and 8 (850 MW) for up to two years, and Ormond Beach Units 1 and 2 (1,500 MW) for up to one year – see Section 2.4.1 for more detail on the results of these OTC recommendations. The decision also required incremental procurement (beyond the baseline resources assumed for the year 2022 and in addition to the OTC retirement extensions) of system level RA capacity of 3.3 GW by all LSEs serving load within the CAISO balancing authority area. At least 50%, 75%, and 100% of these additional resources would be required to come online by August 1, 2021, August 1, 2022, and August 1, 2023, respectively.

Resource adequacy concerns were further stressed by blackouts that occurred during an extreme heat wave in August 2020. Reserve margins were critically tight on August 14-15 due to extremely hot weather, which drove record-high electricity demand across the state and the broader Western U.S. On several afternoon hours, CAISO was unable to maintain its operating reserve requirement without load shedding. The load shedding occurred after the gross peak hour in part because declining solar output exacerbated real-time conditions. In response, the CPUC has made (or is set to make) several changes:

- Greater planning focus on the net peak demand hour (i.e. net of solar power generation) instead of the gross peak demand hour. This is because the net peak demand hour sees most operating uncertainty because solar ramps offline quickly and load served by BTMPV instead begins pulling from the grid;

[36] In comments submitted in the same proceeding, SCE projected a likely shortfall of at least 5.5 GW in 2021 and subsequent years.
[37] Source: CAISO. Note that PA's analysis shows that sufficient uncontracted RA import capacity exists to mitigate the near-term RA shortfall projected by CAISO.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

- Potentially increasing the planning reserve margin to account for greater operating reserve requirements and more uncertain peak demand outcomes;[38]
- Emergency procurement of approximately 1 GW of capacity, most of which is from existing in-state capacity (including capacity sales on emergency output at these plants); and
- Various reforms or capital expenditures to support greater adoption of demand-side management during critical hours.

On balance, these changes are likely to tighten the RA market by increasing the system's need for existing capacity (particularly flexible capacity or capacity in local RA areas) and puts upward pressure on the RA pricing available to this capacity. A tighter RA market also increases the need for RA imports, as it is unlikely for sufficient new local CAISO system capacity to be developed in time to alleviate the projected RA shortfall.

PG&E wildfire liabilities and bankruptcy proceedings

In January 2019, PG&E, the largest IOU in California, filed for Chapter 11 bankruptcy in response to tens of billions of dollars in potential liability stemming from wildfires tied to malfunction of PG&E-owned and operated equipment. PG&E's electric and natural gas service will not be interrupted as a result of bankruptcy proceedings. However, the proceedings have near- and long-term implications for California's contracting environment and the likelihood of the state staying on track to meet its renewable energy targets. A new state law also threatens to convert PG&E into a state-run entity should it fail to adequately emerge from bankruptcy.

2019 preventative actions

In July 2019, California Governor Gavin Newsom signed AB 1054 into law, creating a wildfire insurance fund (collectively up to $21 billion) for utilities facing wildfire liabilities and risks. The fund is set to be raised through two mechanisms: (1) up to $10.5 billion raised via an existing $2.50/month charge on customers' bills; and (2) up to $10.5 billion raised via proportional contributions from the three major IOUs on an opt-in basis. Statute further dictates that PG&E can only participate in the fund if the utility settles its 2017 and 2018 wildfire liabilities and successfully emerges from bankruptcy by June 30, 2020; however, as discussed below, PG&E's settlements and the approval of its reorganization plan collectively allow PG&E to participate.

In an effort to help reduce future risk, PG&E began implementing widespread proactive wildfire prevention power shutoffs during the 2019 wildfire season. For example, from October 9-12, 2019, PG&E proactively shut off power to approximately 800,000 customers for at least 48 hours. PG&E survived the 2019 wildfire season without any new wildfire liabilities, and according to PG&E's CEO, proactive shutoffs may continue to be leveraged over the next decade. Frustrated with the proactive power shutoffs and wildfires caused by utility equipment, a large coalition of mayors and county leaders (including for the cities of San Francisco, Sacramento, and San Jose) have called upon the CPUC to restructure PG&E into a consumer-owned utility; however, PG&E has reiterated its intent to maintain private control of the utility.

Managing load migration

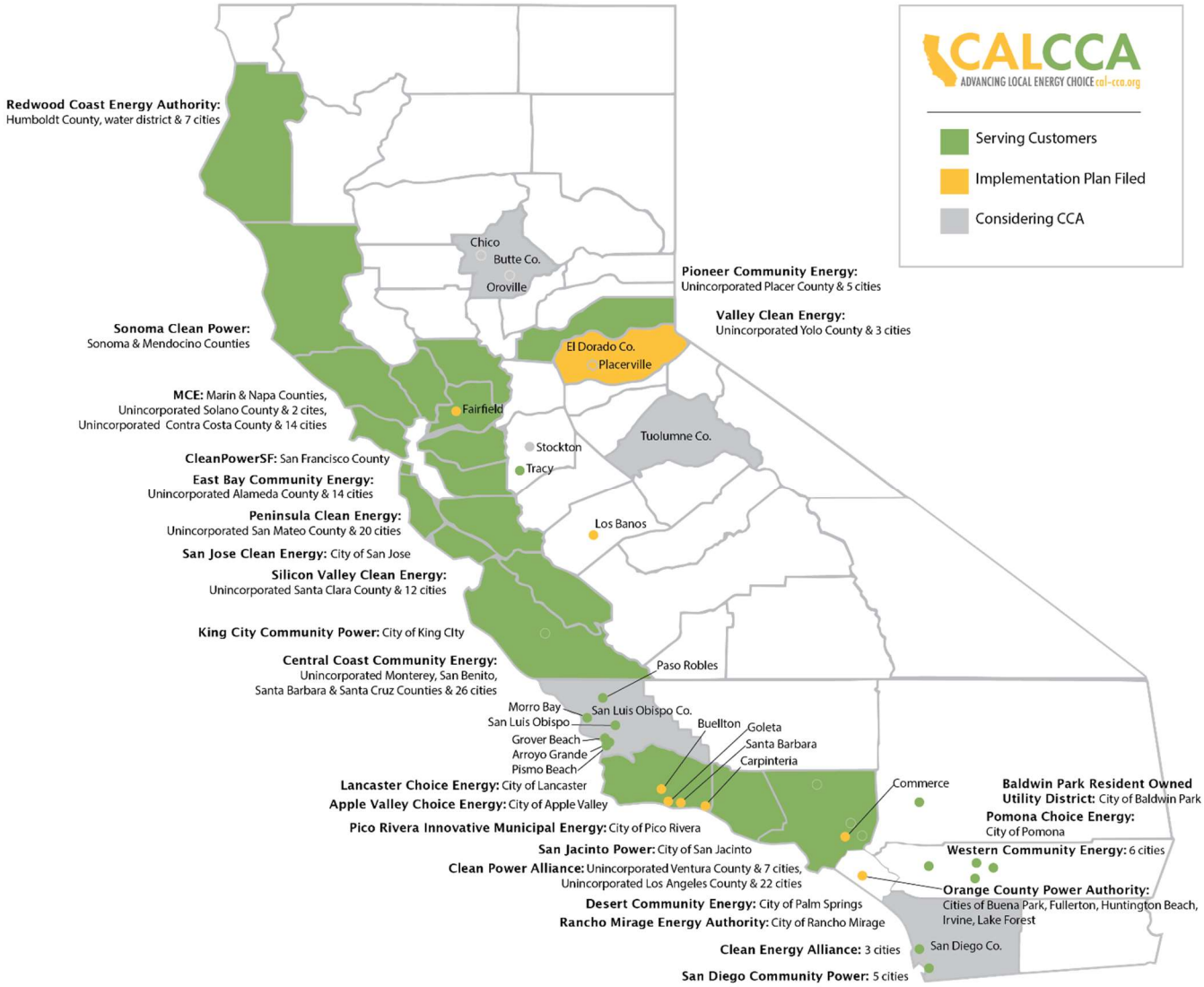
California IOUs continue to lose customers to CCAs, rooftop solar, and existing retail energy access programs (with many non-residential customers served by Direct Access providers). California is poised to see increased switching activity over the next few years through CCAs alone; according to CalCCA, CCAs serve over 4 million customer accounts as of December 2020 – roughly double the total in 2017. The state currently has 23 CCAs with several new CCAs anticipated by the end of 2021. In its 2017 white paper, the CPUC staff estimates that 85% of retail load could be served by CCAs, Direct Access, or customer-sited electric generation by the mid-2020s.[39] Like all LSEs, CCAs must demonstrate RA compliance, which they can satisfy via short- or long-term contracts.

PA has observed CCAs actively pursuing multi-year RA contracts. The California Community Choice Association announced that CCAs in the state have signed long term contracts with new renewable energy facilities totalling more than 6,000 MW.[40] In addition, PA has observed CCAs entering into RA contracts with thermal resources to satisfy RA requirements. Beginning in 2021, SB 350 mandates that at least 65% of LSE procurements (including CCAs) toward RPS targets must be satisfied via long term contracts of at least 10 years. See Figure 2-10 for more detail on operational and planned CCAs in California.

[38] On March 26, 2021, the CPUC approved an increase in the PRM from 15% to 17.5% for 2021 and 2022 for the three large IOUs in the state.
[39] CPUC Staff White Paper, "Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework." 2017
[40] CalCCA website

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Figure 2-10: California Community Choice Aggregators[41]



IOUs sign multi-year power contracts with the objective of serving their anticipated load; however, the trend of customers departing to competitive electric providers is causing the IOUs to have excess supply. To prevent shifting a greater share of contract costs to the IOU's fully bundled customers, the CPUC developed the PCIA, which is levied on customers who switch away from their IOUs. The PCIA is intended to compensate IOUs for the difference between their contracts and the market rates they receive for power that had initially been procured to serve the since-departed load.

In October 2018, in response to IOU concerns about accelerating switching levels, the CPUC approved a proposed set of changes to the PCIA in order to better capture all costs associated with their power purchases. Some of the changes include factoring legacy utility-owned power generation into the PCIA calculation, as well as establishing a price collar that limits upward or downward changes to the PCIA to 25% in either direction from the prior year. This is expected to allow IOUs greater cost recovery and establish a higher level of year-to-year predictability, and it generally favors IOU interests over CCA interests.

The CPUC also adopted a resolution in February 2018 changing the implementation plan filing deadlines for new or expanding CCAs in order to align with the CPUC's RA program. Prior to this resolution, IOUs would have to fulfil obligations for CCAs that submitted their load forecasts too late in the year, resulting in cost shifting to IOU customers for the following year. CCAs now must meet implementation plan deadlines of January 1 of the year before they plan to start serving new customers.

[41] Source: CalCCA.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Day-ahead market enhancements

CAISO is currently working to improve its day-ahead market through the DAME initiative, with the primary goals of improving flexibility and reducing uncertainty associated with the day-ahead market. Most recently, in June 2020, a revised straw proposal was released, proposing two new sets of market products. The first set (Reliability Capacity Up and Reliability Capacity Down) would replace existing residual unit commitment awards in order to co-optimize and schedule resources to satisfy both bid-in demand and the net load forecast; the products would be limited to resources with 60-minute ramp capability (with variable energy resources excluded from the Reliability Capacity Up product). The second set (Imbalance Reserves Up and Imbalance Reserves Down) would aim to schedule sufficient real-time dispatch capability via the day-ahead market in order to meet net load imbalances (driven by higher penetrations of intermittent renewables on the system) that manifest between the day-ahead and 15-minute markets; the products would be limited to resources that can be dispatched in the 15-minute market. The DAME initiative would also extend the day-ahead market (and its enhancements) to EIM participants.

CAISO expects that DAME will allow for more efficient resource use and greater integration of renewables across California and the EIM. However, the DAME initiative is still in the early stages of development, with the final proposal originally expected in late Q1 2021 (which has since been delayed allowing CAISO to address more near-term RA concerns) and implementation estimated to take place in Fall 2022.

2.3 FUEL PRICES

Fuel prices affect the projected dispatch cost of thermal power generating assets as well as the resource planning decisions of retail electric providers. Natural gas is the fuel of primary importance in California and will play a significant role in power price formation over the course of the study period.

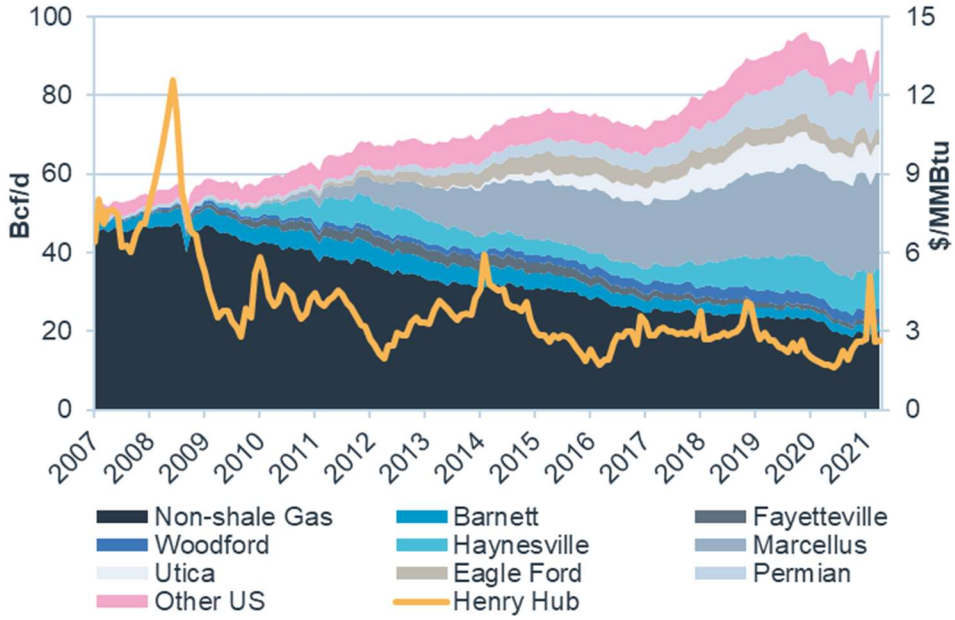
2.3.1 Natural Gas Supply

US gas production comes from essentially two supply pools – dry gas and associated gas. Dry gas is that which is produced in fields such as the Marcellus where what comes out of the ground is primarily methane and other light hydrocarbons. Associated gas, on the other hand, is gas that is produced in association with oil production, and gas might not be the primary target of drilling. As a result, associated gas production follows crude oil market dynamics more closely than North American natural gas dynamics. The Permian is an example of an associated gas play where drillers in the region are primarily after crude oil but produce natural gas as a by-product of drilling activity.

As a result of the shale revolution, US natural gas production has grown from 55 Bcf/d in 2008 to over 96 Bcf/d in October 2019. The resiliency of US shale dry gas production is illustrated below in Figure 2-11, with a map of North American shale gas basins shown in Figure 2-12. Availability of shale gas production has led to a decline of Henry Hub gas price from peak levels in 2008 to a current price below $3/MMBtu, yet shale production has still grown from 2008 to present; increased efficiencies and continued demand growth has continued to spur additional production despite falling prices. Through June 2021, the top five natural gas producing shale basins were the Marcellus (24.2 Bcf/d), Permian (12.5 Bcf/d), Haynesville (10.6 Bcf/d), Utica (7.2 Bcf/d), and Eagle Ford (3.8 Bcf/d).

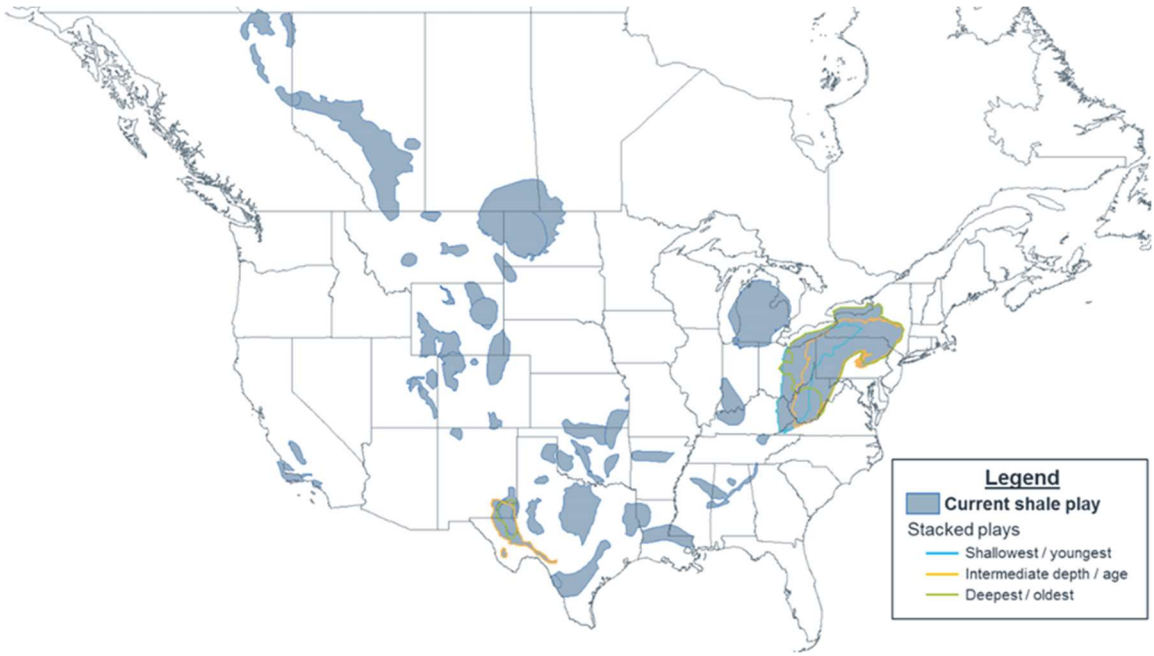
Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Figure 2-11: Lower 48 Dry Gas Production (Bcf/d) vs. Henry Hub Natural Gas Prices ($/MMBtu)[42]



Dry gas production in the Marcellus and Utica was just over 3 Bcf/d in 2010 and currently sits near 31.4 Bcf/d, representing just over 34% of current daily US production. The Permian has also recently emerged as a key player with over 200% growth in gas production since 2010 as a result of an uptick in global crude oil prices and improvements in completions technology. Production growth in the Permian led to severe constraints in the basin, similar to those seen in the Northeast in 2017 and 2018. Lack of adequate gas gathering and takeaway infrastructure drove spot prices at Waha in West Texas into negative territory at times during 2019, with producers unable to move gas and relying heavily on flaring to dispose of excess supply. Recently, however, two pipeline projects came online to help alleviate Permian takeaway constraints and another 3.9 Bcf/d of capacity is due online by the end of 2022.

Figure 2-12: Key U.S. Gas Producing Regions[43]



Well-level breakeven costs (the price at which producers can earn a reasonable rate of return from drilling and completing a well) have declined in recent years and producers have increased efficiencies via targeted drilling techniques. At the same time, advances in technology have improved well economics and made production more profitable even at low

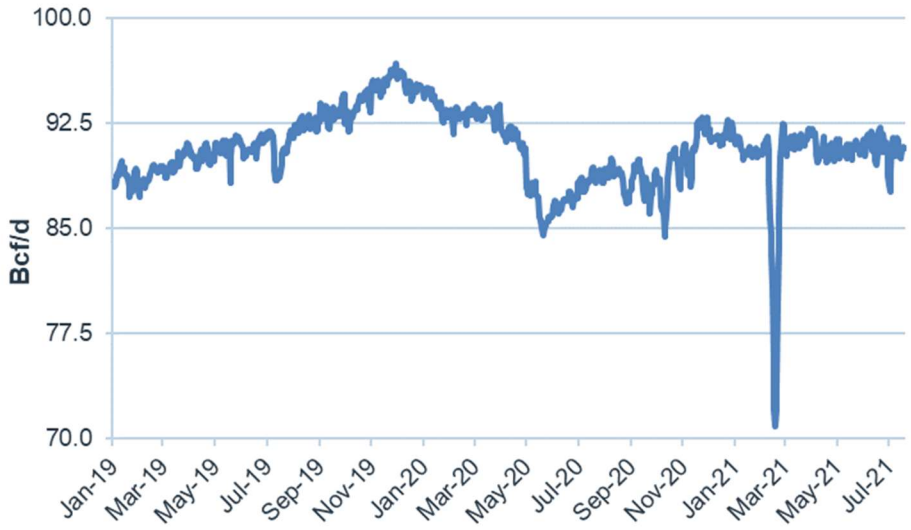
[42] Source: EIA and NYMEX ClearPort, using EIA data available as of July 2021.
[43] Source: ABB's *Energy Velocity Suite*.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

commodity prices. For cross-basin comparisons, breakevens in the Marcellus trend around $2/MMBtu and slightly higher in the nearby Utica, whereas the Permian has a zero-dollar gas breakeven as long as crude oil prices remain in the $40/bbl range or above. Breakevens in the Haynesville shale, formerly one of the more expensive plays to drill, have come down from $4/MMBtu in 2015 to near $2.50/MMBtu. In the Niobrara basin in the Rockies, an oil-rich play like the Permian, oil prices in the $45-50/bbl range support zero-dollar gas breakevens.

Recent domestic and global events significantly impacted US natural gas production volumes through the first three quarters of 2020. Production fell from a record 96.2 Bcf/d in November 2019 down to 82.9 Bcf/d in October 2020 because of low oil prices (partly due to lower Covid-related demand and partly due to OPEC+ price wars) which had a significant impact on oil and associated gas production, before recovering somewhat in the final quarter of the year. See Figure 2-13. More recently, production was severely impacted by cold weather that affected Texas and much of the central United States in February 2021. This event, which froze pipelines and gathering systems, however, was an outlier when viewed in relation to the general downturn that has been observed recently in production.

Figure 2-13: US Natural Gas Production (2019 to present) [44]



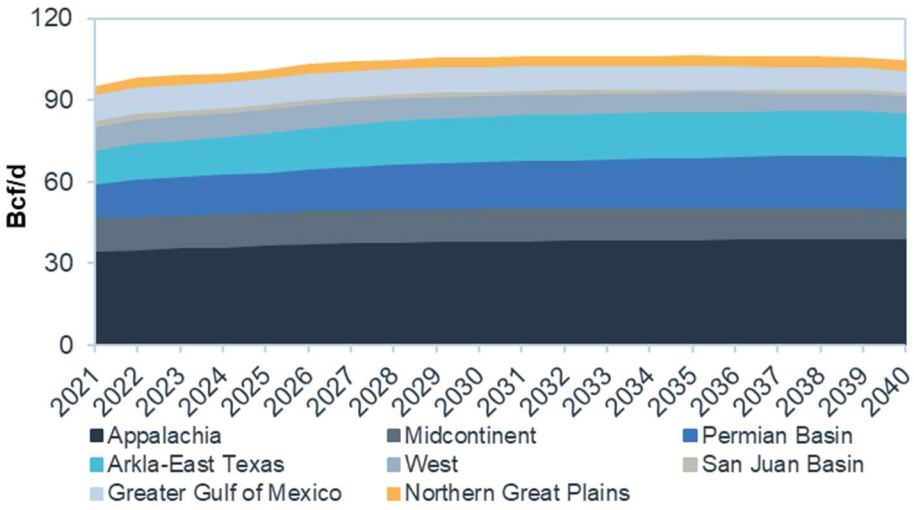
Despite the recent downturn in production and recovery in commodity prices, PA expects that persistent oversupply will outpace demand growth and temper production gains in the medium-term, with potential upside in the latter part of the forecast period should additional LNG demand materialize and provide price support. PA projects that US production will reach 100 Bcf/d by 2025 and 105 Bcf/d by 2030, representing increases of 8.5% and 13.9%, respectively, over 2019 production levels.

The magnitude and timing of forward-looking growth is dependent on several factors including degree of commodity price stability as well as when the well production efficiency limit (or point of diminishing return) is reached. Of the US shale plays, the Appalachian (the combined Marcellus and Utica) is by far the largest, expected to account for 38% of natural gas production in 2030. With outlooks for crude oil pricing stabilizing, the Permian is anticipated to continue to produce high volumes of associated gas. Dry natural gas production averaged 11.5 Bcf/d in 2020, with a peak of 11.9 Bcf/d in March 2020. PA projects Permian production to grow to 14.8 Bcf/d by 2025. These shale plays are likely to add substantial production volumes to the US supply stack, leading to downward pressure on Henry Hub despite increasing domestic demand. See Figure 2-14.

[44] Source: S&P Global Platts Gas Daily Market Fundamentals Data.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Figure 2-14: PA's Projection of US Natural Gas Production (Bcf/d)



2.3.2 Natural Gas Demand

Electric power makes up approximately 35% of total US consumption not including exports, with industrial uses making up 27%. Residential (15%), commercial (11%), and LNG feedgas (12%) end uses make up most of the remainder. In addition, cross-border pipelines into Mexico are providing a growing sink for US supply, particularly as downstream constraints in Mexico begin to clear.

Power sector demand

Power sector demand for natural gas is expected to continue to grow as more coal capacity and in some locations nuclear capacity retires, and new natural gas-fired power plants enter the market or existing assets are more heavily utilized. Power sector demand is expected to grow by 2.6 Bcf/d to 32.7 Bcf/d by 2028 and add another 1.8 Bcf/d by 2040. Some areas of the country, such as California, are projected to see declines in gas demand for electric generation over the forecast period while other areas such as Texas are projected to see increases. Thus, the general upward trajectory in gas demand for electric generation is not uniform across the US, but rather varies by state and the clean energy goals and policies of the states.

Power sector demand can also serve as an important sink for natural gas during times of low prices. Relatively cheaper natural gas encourages fuel switching on the margin for power generation, which can increase demand and provide price support and help bring stability to the market. This phenomenon, however, is at risk in some power markets as coal exits the market, decreasing coal-to-gas switching capability.

Industrial demand

Industrial demand for natural gas is primarily driven by its use as a feedstock and in improving process efficiency. Natural gas is a key component in the production of petrochemicals, fertilizer, hydrogen, and other compounds, with additional demand coming from the manufacturing and mining sectors. Industrial demand for natural gas in the US has risen 30% from 17 Bcf/d in 2009 to over 23 Bcf/d in 2019, driven in-part by the promise of low-cost gas supply.

PA projects small amounts of incremental growth in this sector, predominantly driven by rising petrochemical demand and increased economic output. In particular, three new methanol facilities are expected to come online by the end of 2021 and are slated to add 3.3 million tonnes/year of capacity (0.4 Bcf/d), bringing total US methanol capacity to 9.4 million tonnes/year. In addition, over 5 million tonnes/year of ammonia capacity have come online since 2016; significant growth is expected to continue across the country over the next few years, with most activity occurring in the Midwest and the Gulf Coast. PA projects that industrial demand will reach 23.5 Bcf/d by 2024 and slowly grow to over 25 Bcf/d by the latter half of next decade, representing a 10% increase from current levels.

Demand from Mexico

Mexico is a fast-growing source of demand for US natural gas supply. Pipeline capacity across the US-Mexico border now exceeds 10 Bcf/d, providing a substantial sink for Gulf and Permian production. PA projects that pipeline exports will increase from year-to-date levels of 5.8 Bcf/d to 8 Bcf/d by 2030. Exports to Mexico will be largely driven by projected increases in local demand and LNG export demand from the newly sanctioned Costa Azul terminal on Mexico's west coast (450 Bcf/d in feedgas requirement). The growth in demand for US supply will primarily be dictated by the pace of

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

(1) natural gas pipeline buildout, particularly downstream of existing cross-border pipelines and (2) rising power burn in Mexico due to fuel switching from fuel oil.

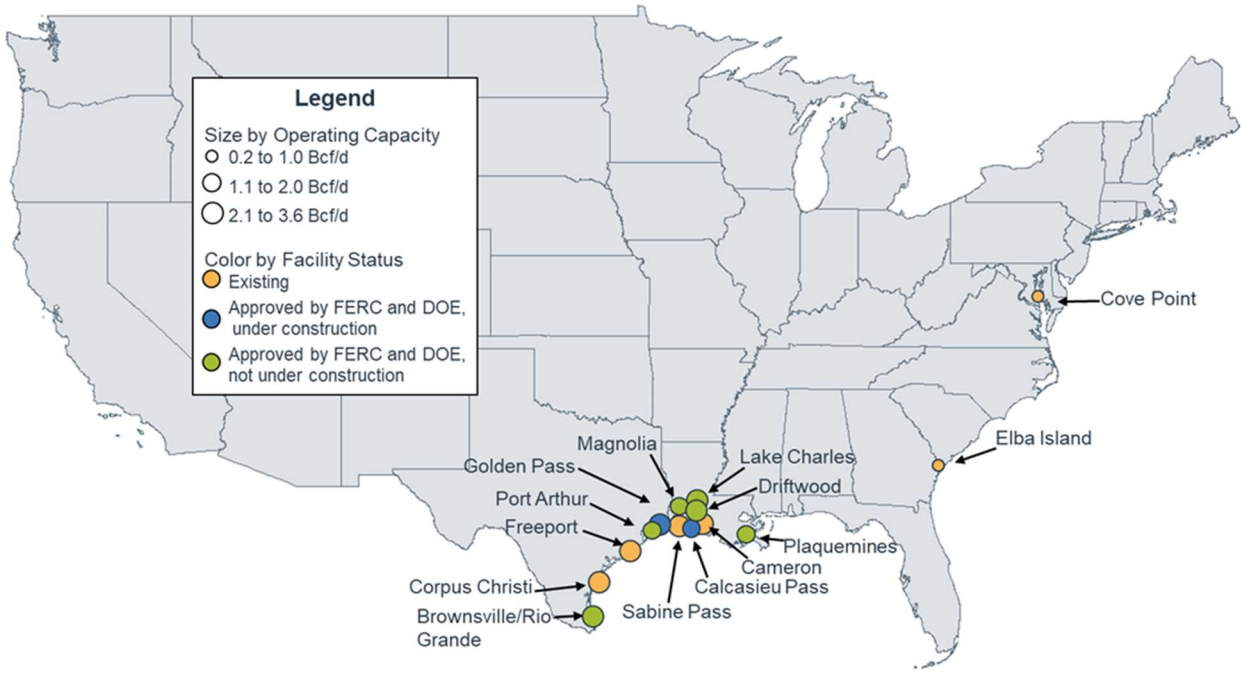
In recent years, energy reforms liberalizing the electric power, natural gas, and oil markets in Mexico have accelerated this trend. The Electric Industry Law (LIE) passed in 2013 introduced nodal electricity markets and spurred private investment into new combined cycle generating facilities as well as pipelines. Cross-border natural gas flows have increased from an average of 1.7 Bcf/d in 2012 to 5.4 Bcf/d in 2020. The current administration of Andrés Manuel López Obrador (AMLO), to support state champions PEMEX and CFE, is seeking to undo some of these energy reforms. For example, he has proposed dispatching the CFE generating fleet ahead of lower-cost and less-emitting alternatives, such as privately-owned combined cycles or renewables. However, native natural gas production in Mexico is only approximately 2 Bcf/d and has declined in recent years. It is insufficient to supply the 4 Bcf/d used for power generation as well as 5 Bcf/d of industrial demand in the country. PA anticipates that AMLO's proposed reforms, if ultimately successful, will not meaningfully impact cross-border natural gas flows into the country.

International LNG demand

Historically, LNG terminals were constructed to receive gas in the US with the early adaptation of natural gas-fired power plants. However, growth of domestic production to the point of exceeding domestic demand sparked US producers to look overseas for new sources of demand. Japan, China, India, and Europe were the largest markets, seeking import diversification from Russia. Once developers received authorization to start exporting LNG from the US in 2012, over 16 Bcf/d of capacity entered the approval pipeline.

Current US LNG feedgas capacity stands at just under 12 Bcf/d across six terminals currently in operation. As of July 2021, Cheniere's Sabine Pass, Freeport, Corpus Christi, Cameron LNG, and Dominion's Cove Point are commercially operational. Elba Island has also begun commercial operations for all 10 of its small-scale modular units. Cheniere recently reported that they expect Sabine Pass Train 6 to begin exporting cargoes by the end of 2021. Calcasieu Pass in Louisiana and Golden Pass in Texas are projected to start operations in 2022 and 2024, respectively. See Figure 2-15.

Figure 2-15: US LNG Export Terminals



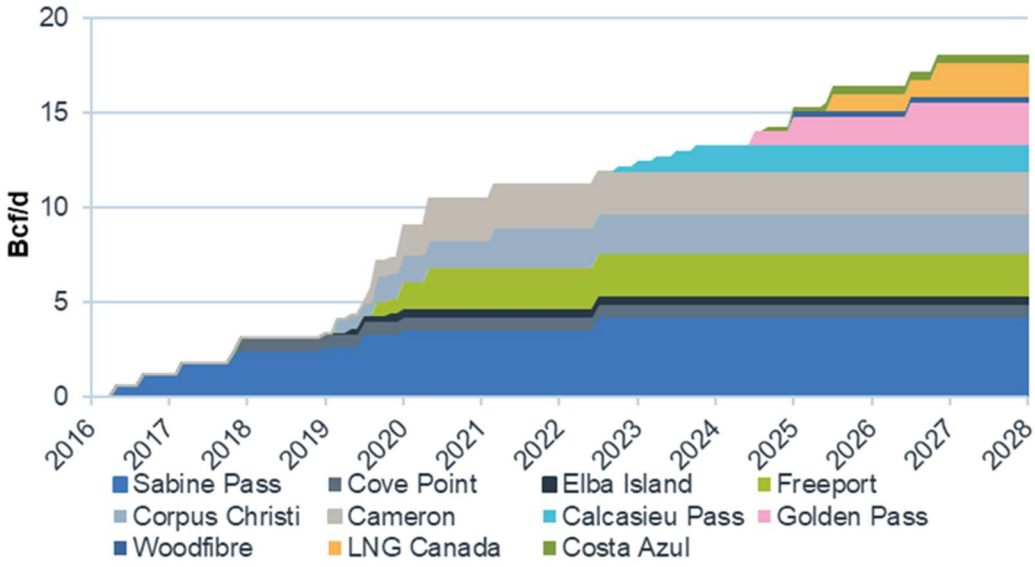
LNG feedgas demand fell from 8 Bcf/d in January 2020 to as low as 3.1 Bcf/d in July as global demand languished through the summer. Demand has since re-emerged, however, and held strong at 11 Bcf/d year to date, reaching a record of just under 12 Bcf/d on multiple occasions. The recent feedgas volumes reflect all export terminals running near or at full capacity. Record feedgas demand has been driven in large part by strengthening prices in Asia and Europe.

By 2028, just under 15 Bcf/d of export capacity is projected to be online in the US, with an additional 2 Bcf/d coming online in Canada in the form of LNG Canada in British Columbia, and 450 MMcf/d of capacity coming online in Mexico from Costa Azul, as shown in Figure 2-16. LNG export projects that have not yet taken a final investment decision (as of June 2021) are not included in PA's assumptions. An example of such a project is Driftwood LNG. Tellurian, the developer

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

of the Driftwood terminal, recently signed a long-term supply deals with Vitol and Gunvor, each for 3 mtpa of LNG, its first such agreements in three years, raising the prospects for a potential positive FID. However, it was recently announced that Tellurian and Petronet's negotiation window for Petronet to invest $2.5 billion in the terminal had lapsed and was no longer under consideration.

Figure 2-16: North American LNG Export Terminal Capacity[45]



The summer of 2020 demonstrated the price elasticity of US LNG export contracts as offtakers declined cargoes during a weak global price and demand environment. Most current US LNG export contracts are take-or-pay and, with enough notice, cargoes can be rescheduled for later dates with minimal financial penalties incurred. Declined volumes during the summer can be pushed to later in the year when demand is typically stronger, as demonstrated recently with a resurgence in feedgas demand as exports reached record levels.

As US export capacity and LNG feedgas demand increase, PA projects that this will support domestic prices at Henry Hub and along the Gulf Coast. However, as new LNG facilities come online, they are doing so with more flexible contract structures relative to those currently in place, which could lead to greater elasticity for US LNG demand. This could contribute to increased price volatility due to fluctuations in LNG terminal utilization, but the overall portion of LNG demand that is price-sensitive will still be minimal in comparison to total US demand, which mitigates the associated impacts to pricing.

2.3.3 Natural Gas Infrastructure

The US has a vast network of natural gas pipelines with over 3 million miles of mainline. Several large new pipelines have recently come online, particularly in Texas, although many planned pipelines are beginning to face significant delays or are being cancelled due to high costs and lengthy lawsuits. Pipeline projects intended to run from the Marcellus east across West Virginia and Virginia are facing stiff opposition. For example, Atlantic Coast was cancelled in July 2020 due to mounting delays and costly litigation, despite having previously received a favorable ruling from the Supreme Court; nearly $8 billion was spent by Dominion and Duke Energy on the project before its cancellation. Mountain Valley Pipeline and PennEast have both been delayed significantly, although PA anticipates they will enter service in 2022, with the final phase on PennEast online in 2024.

Further south in Texas, increased drilling activity in the Permian has incentivized a large push for new natural gas transportation infrastructure. Producers have already met pipeline takeaway capacity in the basin, and production is forecast to grow by roughly 7 Bcf/d over the next five years (PA projects only slight long-term impacts to Permian production related to COVID-19). Currently, there are over 13 Bcf/d of long-haul pipelines proposed to enter service over the next three years, and given Texas's friendly stance towards the oil and gas industry, PA projects that three of these projects will move forward.[46] These projects will allow production growth to continue and will moderate Henry Hub pricing in the longer-term. Additionally, these projects should compress basis in the Permian back to the variable cost of transport and leave the basin unconstrained through 2024. These projects are shown in Table 2-5.

[45] Source: ABB's Velocity Suite.
[46] The Gulf Coast Express pipeline, with approximately 1.9 Bcf/d capacity, entered service in August 2019.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

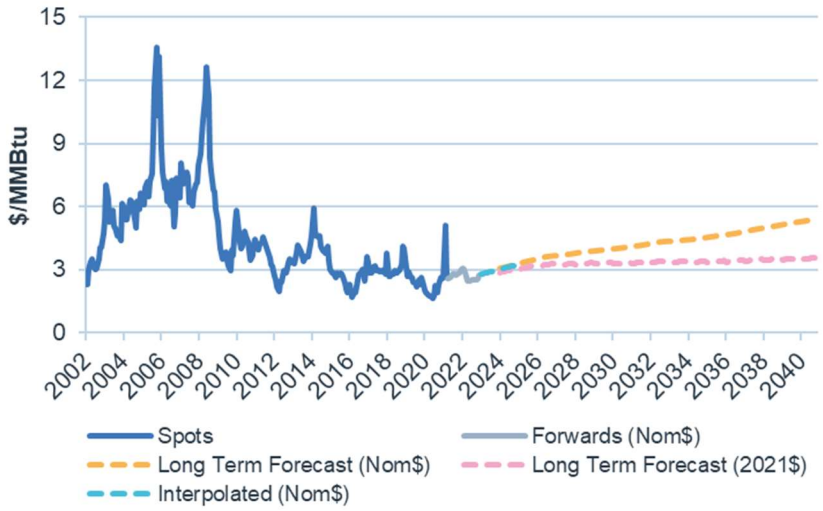
Table 2-5: Major Permian Natural Gas Pipelines Under Development

Pipeline	Capacity	Status	Projected In-Service Date
Permian Highway Pipeline	2.0 Bcf/d	In-service	Q1 2021
Whistler	2.0 Bcf/d	Under Construction	Q3 2021
Pecos Trail	1.9 Bcf/d	Proposed	Q4 2022

2.3.4 Henry Hub Price Projections

As shown in Figure 2-17, PA projects Henry Hub prices to rise over the study period. PA's Henry Hub natural gas price forecast incorporates Henry Hub futures through 2022 and a long-term forecast beginning 2025. For the years 2023 and 2024, PA's forecast interpolates between the 2022 forwards price and the 2025 forecast price. By 2025, PA projects Henry Hub to reach $3.39/MMBtu (in nominal terms).

Figure 2-17: Historical and Projected Henry Hub Prices[47]



This slight increase in Henry Hub is driven primarily by higher demand from the present through the early 2020s, as LNG and Mexican exports ramp up and power sector consumption grows due to coal retirements and new natural gas-fired generators entering the market. In the long term, PA projects Henry Hub prices to continue to rise, reaching $5.35/MMBtu in 2040, which represents a 3.1% compound annual growth rate from 2025 through 2040.

2.3.5 Delivered Natural Gas

Natural gas is a key fuel in California, particularly because the state has almost entirely phased out coal and oil. Natural gas-fired generators set the price of power in nearly all hours over the study period. California has traditionally been home to some of the most expensive gas in the nation, but spot and forwards prices have weakened recently as storage and maintenance-driven deliverability issues have abated.

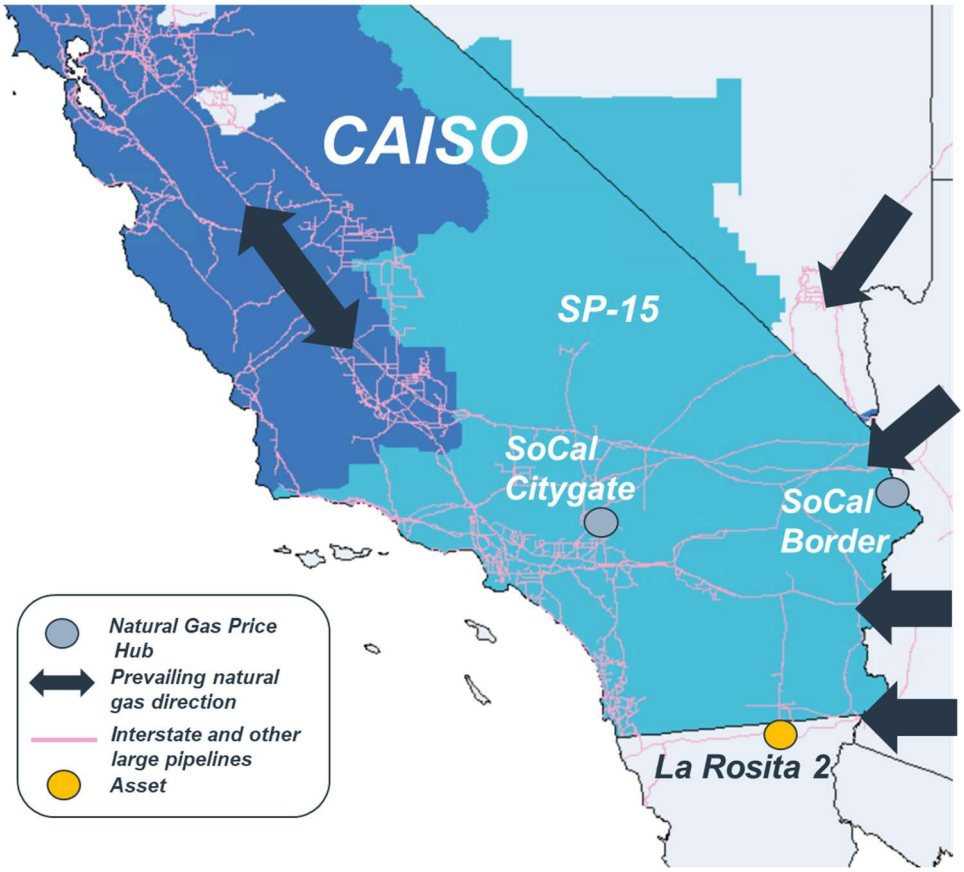
Supply

California is a net importer of natural gas from Alberta, the Rockies, and the Permian, as California itself produces only nominal amounts of gas while accounting for over 8% of US consumption.[48] California relies on underground storage facilities when demand exceeds import capacity, and the tightness of this balance coupled with oft-constrained import corridors has historically led to price blowouts.

[47] Source: PA Consulting Group, with copyrighted material excerpted from NYMEX ClearPort, Bloomberg, and S&P Global Platts. Using forwards as of June 30, 2021.
[48] Source: EIA.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Figure 2-18: CAISO Natural Gas Pipeline Network[49]



CAISO is supplied with natural gas via four major interstate pipelines: EPNG, Transwestern, Kern River, and GTN. EPNG, Transwestern, and Kern River all deliver gas into California near the AZ-CA-NV border with supply being sourced from the Permian and the Rockies. GTN delivers gas imported from Canada into northern California. While Kern River and EPNG extend some distance into California, the majority of gas delivered within the state is transported on the PG&E and SoCal Gas systems. The PG&E system spans much of California and receives gas at the northern border from the Malin hub and at the southern border at the SoCal Border hub. PG&E supplies much of California's central valley and the San Francisco Bay area. SoCal Gas draws supply from Transwestern and EPNG near the Topock/Needles receipt zone (as well as from PG&E and Kern River in the Wheeler Ridge Zone north of Los Angeles), supplying much of Southern California and the Los Angeles metropolitan area.

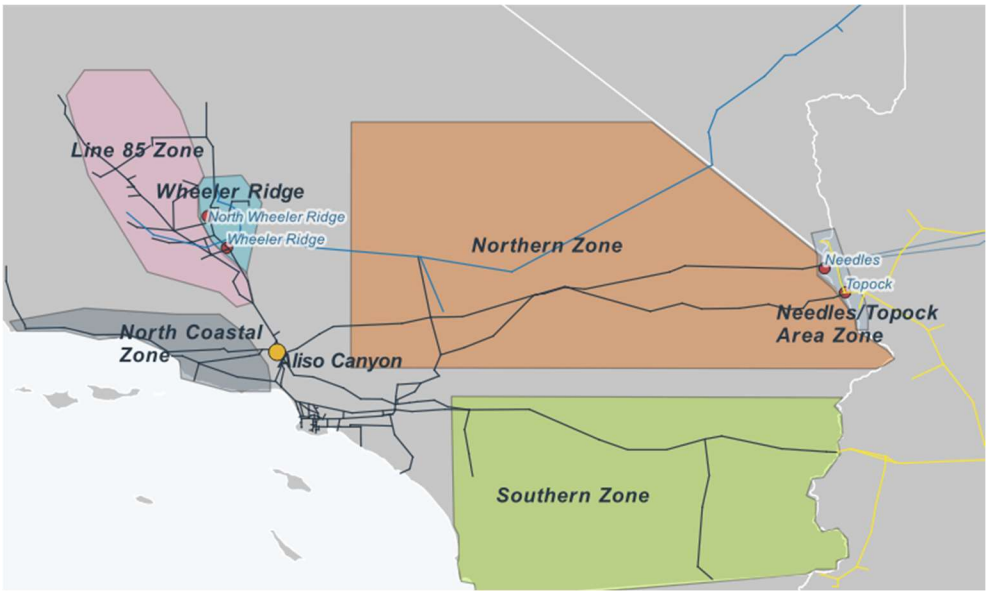
California is also home to 14 natural gas storage fields that provide buffers to supply disruptions or spikes in demand. The largest of these storage fields, SoCal's 86 Bcf Aliso Canyon field, was shut down in 2015 due to a leak. Remediation work has been ongoing, and the field recently received permission from regulators to operate with more flexibility. PA does not anticipate issues at Aliso Canyon to have long term implications for gas prices in California, but the situation has illustrated the precarious and volatile nature of the California gas market, particularly when reliability events have occurred simultaneously in 2018 and 2019.

In addition to ongoing remediation work at Aliso Canyon, SoCalGas has been conducting maintenance in its Northern Zone since 2017, as well as the Wheeler Ridge Zone, though this has since completed. See Figure 2-19. In the Northern Zone, SoCal primarily receives gas at the California border from Transwestern at the Needles interconnect as well as from EPNG and Transwestern at the Topock interconnects. SoCal also has interconnects with PG&E and Kern River in the Wheeler Ridge Zone. Receipt capacity at the Topock and Needles interconnect has been reduced at various times during the maintenance and is currently operating at just 450 MMcf/d on a design capacity of nearly 1.3 Bcf/d.

[49] Source: PA Consulting Group, with copyrighted material excerpted from ABB's Velocity Suite.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

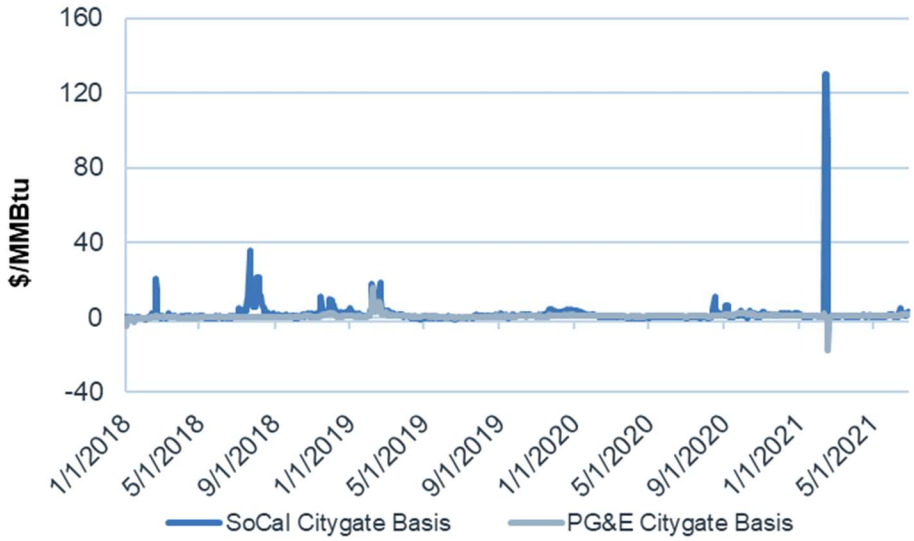
Figure 2-19: SoCal System Map[50]



Price volatility

At various times during the maintenance, receipt capacity has been limited in the Northern and Wheeler Ridge Zones, leading to significant basis volatility in Southern California. In Figure 2-20, volatility is seen at SoCal Citygate in February and then August to September of 2018 – times of the year when volatility is usually low due to a lack of significant demand on the system. However, limited receipt capacity on the SoCal system during these times affected the system's ability to meet demand, resulting in pipeline imbalances and price volatility. With Aliso Canyon also experiencing reliability issues during this time, including a two-week curtailment in February, there was limited ability to withdraw gas to meet curtailed supply, further exacerbating pressure on prices. In addition to storage being unable to compensate for lost supply, the issues in August and September came at a time when gas was typically being injected into storage in preparation for cooler winter weather. Thus, storage levels for 2018 trended well below the five-year average, baking in an even greater risk for volatility in the subsequent winter of 2018/19.

Figure 2-20: SoCal and PG&E Basis[51]



This risk for increased volatility came to fruition when basis at SoCal Citygate spiked again in November and December of 2018. SoCal placed restrictions on receipts in the Wheeler Ridge Zone in addition to the Northern Zone. At Wheeler

[50] Source: SoCal Gas.
[51] Source: PA Consulting Group, with copyrighted material excerpted from NYMEX ClearPort, ABB's Velocity Suite, Bloomberg, and S&P Global Platts.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Ridge, receipt capacity fell from 796 MMcf/d to 728 MMcf/d, while receipt capacity at Topock/Needles was restricted to 276 MMcf/d out of a possible 1,374 MMcf/d. Storage levels were low heading into the winter due to limited receipt capacity and flexibility at Aliso Canyon, leading to a significant price response when demand taxed the SoCal system.

SoCal's system issues and price impacts in 2018 and early 2019 were largely confined to Southern California with limited impact to prices on the PG&E system in Northern California at PG&E Gate outside San Francisco. However, in February 2019, when Westcoast Energy announced restrictions on exports from Canada to the US via the Westcoast Pipeline, the ability for PG&E supply issues to impact prices on the SoCal system became evident.

A key source of PG&E supply comes from the Malin hub, with Malin heavily reliant on Canadian imports. Reduced Canadian imports had a ripple effect reducing available supply on the West Coast and down through California. With Canadian flows to the Northwest curtailed, purchasers were forced to bid up prices to secure scarce supply. The restrictions on Westcoast came at a time when storage inventories were low and demand in Vancouver surged, driving cash prices at Sumas to over $200/MMBtu and pressuring much of the Northwest.

With prices across the Northwest and at Malin climbing, PG&E drew supply from its interconnects in Southern California, a region already constrained by storage and supply issues. This caused an immediate and significant price response on the SoCal system in February 2019 as buyers in Southern California had to compete for natural gas with an undersupplied PG&E system.

In February of 2021, a break down in the polar vortex led to abnormally cold temperatures enveloping much of the U.S. and causing systematic failure of power generation, oil and gas production, storage, and transportation infrastructure across significant portions of Texas and the Midcontinent region. Roughly 20 Bcf/d of production was curtailed or shut-in during this event. Spot prices across most of the country reached recent highs or set records during this time period. Due to SoCal Citygate's majority reliance on Permian imports, spot prices reacted sharply to incentivize pipeline flows into the region – on February 12th, the spot price at SoCal Citygate reached $144/MMBtu. While being an outlier event, this price reactivity illustrates the volatility of California's gas market and how the confluence of storage inflexibility, import constraints and lack of supply diversity can lead to price blow-outs.

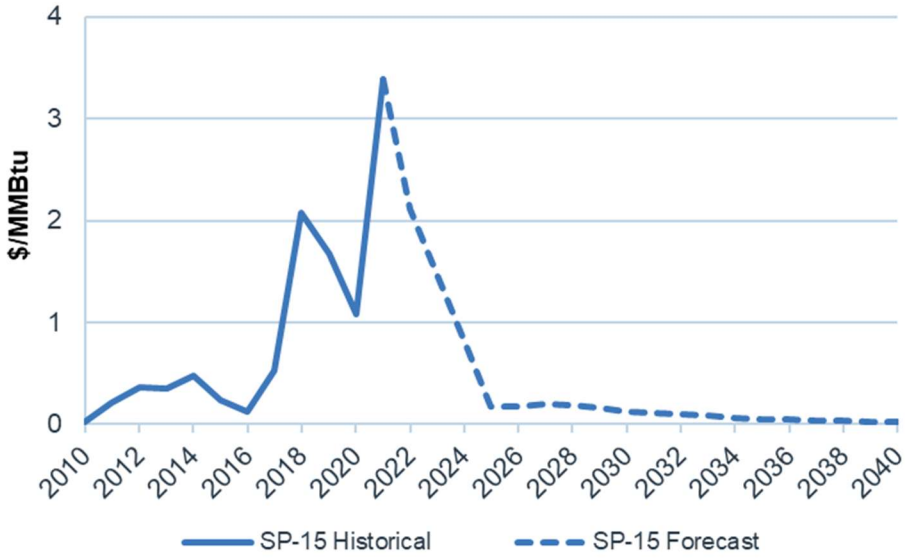
However, the volatility seen over the last few years in the California gas market is projected to lessen as access to and flexibility at Aliso Canyon has increased, and capacity has been increasing at the site of maintenance events at key import and flow points on the SoCal System The completion of repairs on SoCal's Line 235-2 Line has allowed import capacity at Topock and Needles to increase by 270 MMcf/d and has also ushered back into service the adjacent Line 4000, which carries Northern Zone gas towards the Los Angeles metropolitan area.

Delivered natural gas

California has traditionally been home to some of the most expensive gas in the nation, particularly in recent years due to the events discussed above. LR2's supply is indexed to El Paso South Mainline (EPSML), whereas the asset sells power into CAISO's SP-15 transmission zone, where most natural gas generators are indexed to SoCal Citygate or SoCal Border. Prices for El Paso South Mainline and SoCal Citygate typically trade near each other with El Paso South Mainline normally at a discount which provides the asset with a fuel price advantage compared to other generators in SP-15. Delivered basis for SP-15 gas is indexed to SoCal Citygate (subject to a tax and fuel loss adder). See Figure 2-21 below. Despite the recent volatility in California, PA projects that SP-15 basis will gradually trends towards parity with Henry Hub. Outright cash prices, however, are projected to rise over the study period.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Figure 2-21: California Delivered Natural Gas Basis Projections



Influenced by upstream supply issues, import constraints and price competition with Northern California, SP-15 basis is expected to remain elevated in the near term, as it has since 2017. Basis is expected to remain in the $2-4/MMBtu range through 2022 before weakening. Despite the overall downward trajectory of PA's forecast, recent weather-driven volatility, hot summer temperature, and a below average hydro power outlook for the west are lending to this near-term price strength. By 2025, however, SP-15 basis is predicted to reach $0.17/MMBtu, nearly in-line with pre-2017 levels, before falling gradually in the 2030s to near parity with Henry Hub.

The decrease in projected SP-15 basis (and natural gas basis in general in California) is the result of policy measures designed to wean the state off fossil fuels for power generation. State lawmakers and regulators are pushing for more renewable penetration on the grid, as well as for increased electrification of new homes and buildings in the state. Some local governments, such as Berkeley, have already taken the step to ban natural gas connections in some categories of new construction. Following the move, more than 50 cities and counties across California are considering similar measures. The result is a declining demand profile for the state, with industrial and residential/commercial demand projected to stagnate.

A key risk to prices, which has been evident lately, is sustained cold or warm weather leading to significant draws on storage volumes. During peak days in recent summers and winters, California power prices have been impacted by very high natural gas prices at SoCal Citygate. Receipt capacity on the SoCal system cannot meet peak demand without drawing on storage, as there is not enough import capacity into the state given the physical constraints at the California border. Under normal conditions, storage withdrawals can make up for the shortfall in supply but sustained abnormal weather can impact the flexibility of storage fields in California. Storage fields operate subject to a daily maximum withdrawal amount, and with each successive draw on a storage field, this daily maximum amount decreases, leaving less gas available for withdrawal the following day. Sustained cold weather has the potential to tax storage withdrawal capabilities such that curtailments are required, which creates significant price volatility and provides upside risk to prices in the event of extreme weather.

Trend away from natural gas

As California shifts away from natural gas and customer counts decline, transporters of natural gas will have a smaller base of customers over which to spread operations and maintenance costs, and such costs will not decrease commensurately with customer counts. Natural gas commodity prices at key import hubs into California, such as Malin and SoCal Citygate, are expected to trend in-line with PA's forecast, but actual delivered natural gas within the state will likely be subject to more expensive transportation adders, raising the delivered price of fuel within the state.

As the marginal fuel for California in a significant number of hours, an increase in natural gas prices will lead to an increase in power prices. When higher transportation costs materialize and are passed on to power generators within California, this will have the effect of raising power prices across the state.

In terms of gas demand for power generation, PA projects California will retire approximately 1 GW of combined cycle natural gas-fired generators by 2030, and nearly 4.5 GW of steam generators, providing further downside to natural gas demand in the state by the end of the study period. Gas demand for power generation typically averages 1.5 to 1.7 Bcf/d and is projected to fall to 700 MMcf/d by 2025 to just 129 MMcf/d by the end of the study period. Despite following an

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

overall downward trajectory through 2040 and beyond, demand is expected to increase marginally from 2024-2027 as CAISO loses 2 GW of coal-fired capacity (including the out-of-state Intermountain units) and 2.2 GW of nuclear power generation. In the near term, existing natural gas-fired power plants and infrastructure will be called upon to make up for the retired capacity. After 2030, when the last OTC-driven thermal retirements are set to occur, sustained solar and battery storage additions will displace natural gas demand in California. From this point through the end of the study period, gas demand is projected to decline precipitously.

PUC rulemaking to ensure safe and reliable gas systems

In response to the anticipated decline in natural gas demand, significant volatility in the California natural gas market over the past several years, and safety concerns arising from the 2010 San Bruno explosion and the 2015 Aliso Canyon leak, the CPUC issued a rulemaking on January 16, 2020 aimed at improving natural gas safety and reliability. Specifically, the rulemaking seeks to address three key areas: (i) develop and adopt updated reliability standards that reflect current and prospective operational challenges to gas system operators; (ii) determine the regulatory changes necessary to improve the coordination between gas utilities and gas-fired generators; and (iii) implement a long term planning strategy to manage the state's transition away from natural gas-fuelled technologies to meet California's decarbonization goals.[52] Among the respondents, the CPUC has named numerous gas utilities and storage providers, including PG&E and SoCal Gas.

The CPUC will approach this is three phases, which track the above listed areas. Phase I will address reliability, and this has typically focused on historical temperatures during winter months. However, according to projections, average winter temperatures are projected to warm over the coming years, which will require new analyses and scenario planning to meet peak demand. Additionally, SoCal's most recent assessment as of January 2020 indicated that the system would be unable to meet demand under the current reliability standards.

The commission will also revisit the need for slack capacity, which is capacity that is held in excess of peak throughput along the backbone and storage systems of SoCal and PG&E, among others, as well as the impact of the Costa Azul LNG export terminal in Baja California, Mexico, which undertook a positive FID at the end of 2020. The supply line for Costa Azul could divert up to 495 MMcf/d off the El Paso South Mainline to the proposed North Baja XPress expansion project for delivery into Mexico.

Phase II will focus on market structure and regulations. The issues discussed in the previous section that affected operations on the SoCal system posed significant reliability issues to CAISO and LADWP balancing areas. Most gas-fired generators in California rely on interruptible transportation rather than firm transportation, which exposes them to increased market volatility. Additionally, when SoCal is forced to curtail gas supply during times of peak demand, gas-fired power generators are the first to be curtailed, which leads to price blowouts in wholesale electricity markets and local gas markets. The CPUC will seek to address this by identifying opportunities for enhancing reliability of supply and mitigate the risk it poses to gas-fired generators and electricity markets.

The key objective of Phase III will be long term natural gas policy and planning. Specifically, the CPUC plans to address the impact that anticipated reductions in gas demand will have on the transmission systems within California, and how costs are recovered by operators of these systems. Reduced demand across the state, driven by climate and energy policy, as well as municipalities looking to ban gas hook-ups in new residential and commercial construction, could affect operational flows along the state's transmission systems as pressures are reduced and segments of pipeline no longer serve any demand. This will also lead to a risk of stranded assets for utilities, with segments of pipeline unutilized prior to full recovery of costs. As such, the CPUC will examine the extent to which reduced gas demand at various points across the state's systems will require regulatory changes and shortening the useful life of gas assets to ensure the proper allocation of transmission costs and mitigate stranded asset risk.

Environmental groups have lauded the move as a prescient step in getting ahead of reliability issues that could surface in an era of declining gas demand. The pool of gas customers in California will shrink over the coming years, leading to higher costs for those still using gas, putting low-income and other vulnerable customers at risk. Additionally, the move is seen by some as a clear acknowledgement that California will be pursuing electrification as a primary means to the meet the state's climate goals. However, interest groups representing gas users have pushed back against the possibility of electrification, calling it an ideological, rather than a pragmatic goal. These groups point out the fact that while the CPUC is looking to address the anticipated increase in gas costs that will result from a dwindling customer base, the proposed regulatory policy does not sufficiently consider the magnitude of costs that will fall on the remaining customers. Others point out the difficulty in meeting climate goals and incorporating renewables without gas-fired power generation as a backstop.

[52] Source: California Public Utilities Commission, Agenda ID #18075: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M324/K792/324792510.PDF

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

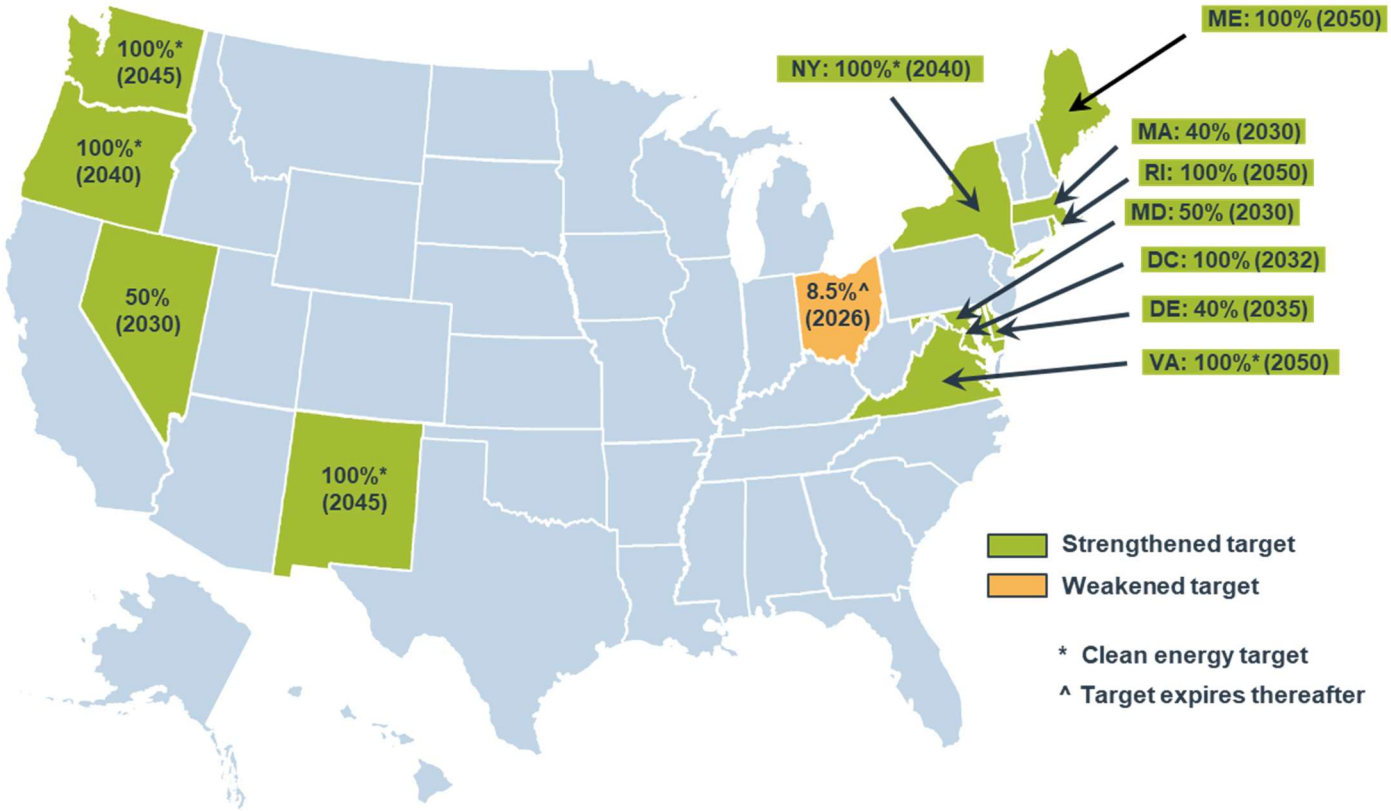
The impact that the CPUC's rulemaking will have on wholesale power and natural gas markets remains to be seen at this time. However, it should be noted that the CPUC is not mandating any reduction in the use of natural gas or introducing any new regulations about the use or procurement of natural gas with this rulemaking. California's natural gas market will continue to be influenced by state and municipal level policy that looks to reduce greenhouse gas emissions. This rulemaking is an effort to get ahead of any adverse impacts that this transition could have on remaining gas users and utilities facing a risk of stranded assets. In light of this, impacts of this effort could include greater protections for operators of gas transmission systems, and the potential for cost recovery of natural gas assets to be borne by broader rate base than which actually remains, or accelerated recovery which would lead to greater short-term costs to ratepayers.

2.4 CLEAN ENERGY POLICY AND ECONOMICS

The US power sector was dominated by coal-fired and nuclear power plants through the end of the 20th century, with natural gas-fired capacity having a more limited role in power generation supply. However, as discussed in Sections 2.1 and 2.3, the liberalization of regulated power markets in several regions of the country led to a surge in natural gas-fired capacity development, and the shale gas boom a decade later drove a substantial decline in natural gas prices as well as a second wave of gas-fired generator builds. Separately, federal policies providing financial support to renewables (e.g., PURPA, ITC, PTC) and state RPS programs collectively lowered costs for and raised investor confidence in renewable energy assets, while tightened emissions control regulations narrowed the scope of coal-fired generators that could remain profitable. These factors, combined with rising public concern over climate change, marked the beginning of a paradigm shift in the US fuel mix from coal to natural gas and clean energy resources.

However, following the failure of federal legislative initiatives to implement a carbon cap-and-trade system and federal RPS during the Obama era, and given the Trump administration's aggressive deregulatory agenda, the push toward deep decarbonization has shifted to the states, where several progressive states such as California and New York had already been trailblazing with ever more aggressive policies. Subsequently, the November 2018 midterm elections re-established Democratic control of several statehouses and governorships. As a result, newly-emboldened legislators in states around the US began enacting a range of policies targeting renewable energy and GHG emissions cuts – see Figure 2-22.

Figure 2-22: Changes to State Renewable (and Clean) Energy Targets Since 2018 Midterm Elections



Although the new Biden administration has signalled its intentions to pursue aggressive regulatory action on climate change, large legislative changes in support of clean energy (e.g., federal carbon pricing, a federal clean energy standard) face significant headwinds to adoption in the US Senate. However, backed by rising public support for climate

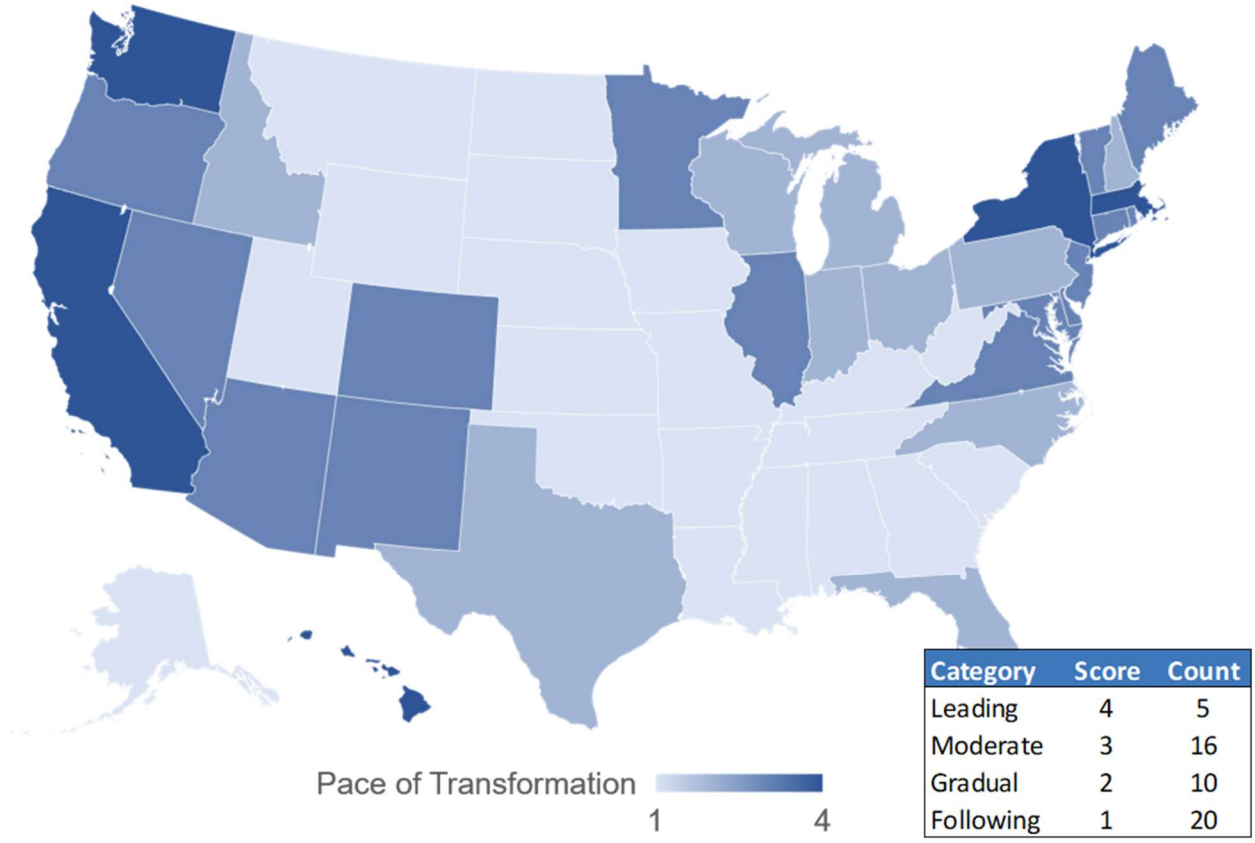
Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

action in certain regions and falling capital costs for renewable energy technologies, state-led efforts could still lead to transformational outcomes in select US power markets, even if significant future federal support does not materialize.

Clean energy transformation potential

While PA assumes that certain federal policies and regulations will play a sustained role in clean energy development throughout the US (e.g., tax credit extensions), PA expects clean energy leadership to generally continue at the state level. PA's natural gas, power, and clean energy market views start with a policy-led view of states' clean energy transformation potential over the next few decades (as shown in Figure 2-23). Different paces toward decarbonization between states create different opportunities for clean energy investors; consequentially, a low or high score for a state translates into different investment paths rather than indicating a ranking of the quality of investment opportunities. Having a fundamentally derived view of the economic viability of investment opportunities in specific markets is foundational to PA's approach.

Figure 2-23: PA View of Clean Energy Transformation Potential[53]



Category	Score	Count
Leading	4	5
Moderate	3	16
Gradual	2	10
Following	1	20

Clean energy transformation implications

Over the next decade, the combination of state policy, shifting economics, and public demand are poised to drive significant changes in the US power sector. Certain regions will have to integrate large amounts of intermittent renewable energy, with offshore wind (primarily in the Northeast and Mid-Atlantic) and solar penetration (particularly in California) potentially having outsized impacts on power market dynamics and load patterns (e.g., negative pricing in overnight hours, the "duck curve" in California). DER may also impact load growth where state policies enable such technologies. Such changes foreshadow the growth of the energy storage industry as well as new utility rate structures. Concurrently, new and replacement transmission and distribution infrastructure will be required to deliver larger amounts of distant renewables to load centers.

[53] States with higher rankings are expected to have the greatest potential for large-scale, economy-wide clean energy transformation, while those with lower rankings are likely to have a slower pace of transformation. PA's scores encapsulate and are informed by many factors, including current and potential policies (e.g., clean energy targets, economy-wide decarbonization initiatives), economics and resource potential, utility IRPs and stated goals, demographics, public sentiment, legislative history, customer and commodity sales growth, and the likelihood of a state meeting (or backtracking on) its targets. Current and future policies and public sentiment within states can vary significantly, and as a result, there can be a long path to decarbonization even in "leading" states.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

In the longer term, 100% clean energy targets will change the risk structures around different generator classes, and ISO/RTOs may need to rethink price formation in their markets. Meanwhile, the electrification of other economic sectors could also re-establish robust load growth, providing room for substantial new investment. As states progress toward these goals, they will need to continue balancing reliability, safety, and affordability, and managing these realities will affect how states achieve their ambitions and whether they can do so on schedule.

In regions with high renewable penetration, the most efficient and flexible thermal generators will have a role to play in grid reliability for years to come. However, older and less flexible thermal generators are already being stressed economically by renewable entry, expanding carbon pricing programs, and sustained low natural gas prices. Furthermore, states in the Northeast are making it very challenging to develop new natural gas transportation and generation infrastructure. Due to economic pressures, several nuclear generators are already dependent on state subsidies, which may keep these resources in regional power mixes indefinitely. Separately, while renewables make up an increasing percentage of nameplate capacity in each market and generally stand to benefit from an evolving policy landscape, individual renewable assets face a spectrum of risks contingent on the power market in which they participate, their location on the grid, and where they are financially settled. Thus, understanding the drivers behind and implications of a shift toward a clean energy economy are critical to making informed power market investment decisions.

Clean energy transformation drivers

As previewed in Table 2-6, five key interrelated forces are responsible for driving the ongoing clean energy transition in the US power sector: (1) emissions control regulations; (2) direct financial assistance; (3) market mechanisms; (4) market economics; and (5) public demand. These forces are described in the sections below, followed by a discussion of longer-term, economy-wide considerations (e.g., policies affecting the transportation and buildings sectors), with implications for regional load growth. Where applicable, additional detail is provided throughout the following sections on California policies.

Table 2-6: Drivers of the Clean Energy Transformation in the US Power Sector

Emissions Control Regulations (Section 2.4.1)	Direct Financial Assistance (Section 2.4.2)	Market Mechanisms (Section 2.4.3)	Market Economics (Section 2.4.4)	Public Demand (Section 2.4.5)
CSAPR	Federal support for small clean energy projects	Environmental attribute markets (RPS)	Natural gas prices	Executive orders and municipal policy
Federal GHG regulations	Federal tax incentives for clean energy	Carbon cap-and-trade programs (California cap-and-trade)	Capital costs	Regulated utility commitments
State-level mandates (OTC) (Divestitures) (IRPs)	Baseload generation subsidies	Carbon taxation efforts	Renewable energy generation risks	Corporate demand for renewables
	Competitive clean energy procurements (Storage procurement targets) (Backstop procurement)	ISO/RTO market rules	Energy storage economics	Opposition to local development

2.4.1 Emissions control regulations

Arguably the initial force behind the clean energy transition, regulations designed to limit pollutant emissions from power plants largely emerged in the early 1970s, following an historic shift in public sentiment toward environmental issues in the 1960s. However, the original, landmark statutes that first granted the newly formed EPA much of its power (e.g., the CAA and CWA) still form the basis of current federal environmental regulations targeting air and water pollution, with

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

such rules evolving and generally becoming more stringent through the end of the Obama administration. These regulations directly or indirectly affect all power generating resources, albeit disproportionately affecting coal-fired resources given the range and quantity of pollutants they emit.

EPA emissions regulations are in various stages of legal review. On January 19, 2021, the DC Circuit Court vacated the Trump Administration's proposed replacement to the Obama-era Clean Power Plan, which makes it likelier that GHG emissions rules will revert to the Obama-era standards more quickly under the incoming Biden Administration.[54] Meanwhile, new legislation to limit GHG emissions (including CO_2) has stalled at the Congressional level. Pending any dramatic repeal (or future implementation) of major federal environmental rules, the dust has generally settled across US power markets from such regulations, with thermal generators that cannot economically comply with existing regulations (e.g., by installing scrubbing technology) having exited the market or announced their planned retirement dates. Thus, while these regulations continue to play an important role in protecting air and water, other forces share greater responsibility in furthering the growth of clean energy.

State mandates

In some cases, states have their own policies that dictate the installation of emissions control technologies or otherwise directly mandate which types of generators may continue operating in the state (and when others must retire). These policies are detailed below for the California market.

California | Once-Through Cooling and SWB Resolution No. 2010-0020 regulations

The OTC and California SWB Resolution No. 2010-0020 regulations place pressure on steam gas generators by gradually requiring the phase-out of OTC systems at most generators. In practice, this requirement either forces these generators to install costly system upgrades or retire. However, in late 2019, the CPUC recommended delayed retirements for some of these units in order to address a projected near-term capacity shortfall in CAISO. In September 2020, the State Water Resources Control Board approved a policy amendment to the OTC regulations, thereby delaying the retirement of a series of units by 1-3 years – see Table 2-7.

Table 2-7: Remaining OTC Thermal Capacity Retirements

Facility	Type	Capacity (MW)	Previous Expected Retirement Year	Current Expected Retirement Year
Alamitos 3-5	ST Gas/Oil	1,152	2021	2024
Huntington Beach 2	ST Gas/Oil	226	2021	2024
Ormond Beach 1-2	ST Gas/Oil	1,516	2021	2024
Redondo Beach 5, 6, 8	ST Gas/Oil	840	2021	2022
Diablo Canyon 1	Nuclear	1,122	2025	2025
Scattergood 1-2	ST Gas/Oil	305	2025	2025
Diablo Canyon 2	Nuclear	1,118	2025	2026
Haynes 1-2	ST Gas/Oil	444	2030	2030
Haynes 8	CC	575	2030	2030
Harbor CC 10	CC	231	2030	2030

California | Long term financial commitments and coal divestitures

California's SB 1368, passed in 2006, limits long-term investments in electricity imports that do not meet certain GHG emissions requirements. In practice, the law is projected to drive a total of 3,250 MW of coal divestitures within two decades of its enactment, with the affected coal plants ceasing to directly dispatch into California's electricity market.

[54] Although the ruling occurred after PA's analysis, we already project 38 GW of coal-fired retirements in PJM as a result of tightening emissions criteria, worsening coal plant economics, and accelerated ESG demand from utility shareholders and others to retire these facilities.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Three coal-fired power plants have already been affected or will be impacted by this legislation moving forward. First, LADWP divested its 469 MW share of the Navajo power plant in July 2016, and the facility retired its last two units (Navajo 1 and Navajo 2) in November 2019. Next, several California utilities divested their shares (totaling 381 MW) of the San Juan Generating Station in 2017; no California utilities currently own shares of the facility, which is projected to retire its final two units in 2022. Finally, PA does not assume any divestment from Intermountain (1,800 MW) ahead of its currently assumed retirement date of 2025; instead, parties involved in Intermountain are planning to repower the unit as an 840 MW natural gas-fired CC to come online in 2025, which PA assumes will be successful. Collectively, these divestments, retirements, and repowerings will contribute to tightening reserve margins and will likely increase both capacity and energy pricing in California (and evening energy pricing in particular).

California | System-wide resource optimization

California has also passed policies that regulate state-wide emissions outside the fence line (i.e., targeting the system as a whole as opposed to specific power plants). In particular, SB 350 serves in part as a command-and-control policy that provides the CPUC with authority to achieve California's electric sector-specific GHG reduction target (discussed further in Section 2.4.3), directing the CPUC to adopt a process for each LSE to file IRPs that will ensure progress toward achieving the target. In February 2018, the CPUC released its IRP process, establishing a two-year IRP cycle for all electricity providers (including IOUs, CCAs, and municipal utilities). The process is meant to periodically update GHG reduction targets, estimate the optimal mix of system-wide resources to meet the targets, and determine which actions each electricity provider should take to ensure compliance.

2.4.2 Direct financial assistance

In contrast to emissions control regulations (which broadly increase costs for fossil fuel-fired generators), policies that provide direct financial assistance encourage the development of renewable and other clean energy technologies, particularly when these technologies are not otherwise cost-competitive with traditional power generation sources.

In summary:

- PURPA historically supported the entry of small CHP and renewable energy projects, but recent changes are likely to slow renewables development – particularly in regulated states that lack strong clean energy targets.
- Federal tax incentives have been one of the most important factors in utility-scale wind and solar development over the last decade. Recent ITC and PTC extensions will play a continued role in supporting wind and solar entry.
- Baseload power generation subsidies keep select nuclear and coal-fired resources in the market, suppressing energy and capacity prices, all else equal.
- Competitive clean energy procurements (e.g., for offshore wind, transmission, and energy storage) allow for sufficient investor confidence (via state-backed contracts) to bring a range of new resources online, suppressing energy and capacity prices, all else equal.

Federal support for small clean energy projects

Direct federal financial assistance for clean energy resources essentially began in 1978 with the passage of PURPA, which was implemented partly in response to the OPEC oil embargoes and accompanying price spikes. To encourage fuel diversity and energy efficiency, PURPA established a new class of power generation facilities that would receive special regulatory treatment, known as QFs. These facilities would fall under two categories: (1) power generation facilities of 80 MW or less[55] whose primary energy source is renewable; and (2) qualifying cogeneration facilities. Under PURPA rules, QF facilities are guaranteed the ability to sell energy or capacity to a utility at the utility's "avoided" cost or at a negotiated rate. In principle, the avoided cost represents the cost a utility would incur if it chose to either provide the energy and/or capacity itself (i.e., by building new capacity) or purchase electricity from non-QFs. Implementation of PURPA's requirements is a shared responsibility; FERC sets the regulatory framework, while state PUCs establish avoided cost rates and set PURPA contract terms.

In practice, avoided cost rates and contract terms are highly contentious, being key to both the economics of a given QF and the profitability of utilities. Avoided cost rate structures (e.g., fixed-price, non-firm contracts) and terms (1-20 years) vary by state, and several states have made substantial changes to QF rates and contract structures that likely reduce the economic attractiveness of QF contracts to developers. Such changes reflect a broader trend of states and utilities seeking to update avoided cost methodologies to reflect the avoided cost of a similar renewable resource procured via open solicitation (rather than a more expensive thermal resource) and to shorten contract lengths.

Most recently, FERC issued a final rule in July 2020 that represents the first comprehensive review of PURPA, designed to allow state regulators to adjust PURPA implementation in response to wholesale power market developments as well

[55] In 2005, PURPA rules were modified to remove utilities' obligation to purchase the output of QFs larger than 20 MW that have access to competitive ISO/RTO markets.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

as streamline FERC policies and practices. The rule grants states more flexibility in using variable energy rates to determine avoided costs (while keeping capacity rates fixed), allows rates to be based on market factors (e.g., LMPs, gas prices, heat rates), reduces the size of QFs considered to have a non-discriminatory access to wholesale power markets to 5 MW from 20 MW (for small power facilities only), and expands the area wherein multiple small facilities may be considered as a single facility for the purposes of seeking QF status. The ruling is expected to chill the pace of renewables development in regulated states that lack strong clean energy targets, although it should have less of an impact elsewhere.

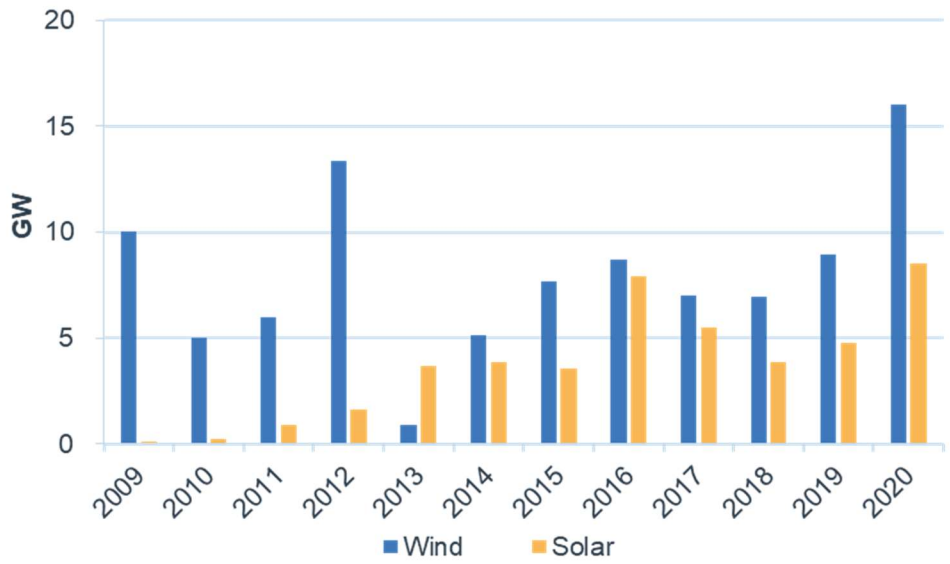
Federal tax incentives for clean energy

While PURPA helped clean energy resources break into US markets, the rapid growth of such resources in the US has been largely due to three federal tax incentives – the PTC for wind generators, the ITC for solar generators, and MACRS for multiple types of renewable power generation.[56] Each incentive effectively reduces the levelized cost of the qualifying technologies and improves cost competitiveness.

Tax credits

The PTC is an inflation-adjusted per-kWh tax credit for energy generated and sold from qualified resources that is awarded for the first 10 years of a facility's operation; originally enacted as part of the Energy Policy Act of 1992, it has been the principal driving factor in the growth of utility-scale onshore wind development. The ITC is a federal income tax credit originally enacted as part of the Energy Policy Act of 2005, serving as a primary driver of new solar development. Both tax credits have been renewed several times over the years, often at the last minute or shortly after they expired; the lack of business certainty has therefore occasionally led to years with massive buildouts (e.g., in 2012 for wind prior to the PTC expiring) and other years where the industries have been paralyzed (e.g., in 2013 for wind when Congress was slow to act on an extension) – see Figure 2-24.

Figure 2-24: US Nameplate Capacity Wind and Solar Additions



Commercial battery systems that charge more than 75% of their energy from renewable sources are also eligible for the ITC (in proportion to the percentage of energy derived from renewable power generation).[57] Further, in March 2018, the IRS issued a Private Letter Ruling that extended the ITC to residential batteries charged completely by on-site solar.[58] However, the tax credit does not currently apply to standalone storage.

Congress has passed multiple extensions of the PTC and ITC in recent years. In December 2015, Congress passed a multi-year extension of the PTC and ITC on the condition of both incentives phasing out over time. For solar generators, the ITC was reduced (from its historical value of 30%) to 26% in 2020 and was originally set to further decline in subsequent years. For wind generators, the PTC was set to phase down to 80%, 60%, and 40% of its full value for projects starting construction in 2017, 2018, and 2019, respectively, expiring altogether thereafter. The PTC was then

[56] While the ITC and PTC primarily drove growth in solar and wind capacity, they also apply to a range of other clean energy resources.
[57] Source: NREL *Federal Tax Incentives for Energy Storage Systems, NREL/FS-7A40-70384, January 2018*. According to 26 CFR § 1.48-9 (d)(6), "auxiliary equipment" counts as "solar energy property… only if its use of energy from sources other than solar energy does not exceed 25 percent of its total energy input in an annual measuring period."
[58] Source: IRS Document 201809003, released 3/2/2018.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

extended as part of the December 2019 spending package for one year to 60% of its full value for projects starting construction in 2020.

Most recently, the Consolidated Appropriations Act of 2021 – signed into law in December 2020 to fund the government through September 2021 and provide relief for the COVID-19 pandemic – included a suite of tax credit extensions that were left out of various prior stimulus bills. The bill extended the PTC for onshore wind at 60% of its full value for an additional year (i.e., at a value of ~$14/MWh for projects beginning construction in 2021), extended the ITC at its 2020 value of 26% for an additional two years (i.e., for projects beginning construction in 2021 and 2022) while pushing the phase-out schedule accordingly, and expanded offshore wind eligibility for the full 30% ITC for projects beginning construction from 2016-2025.[59]

A project is set to receive the value of its chosen tax credit for the year in which it begins construction (based on either the IRS-prescribed "Physical Work Test" or "Five Percent Safe Harbor"). The project must also demonstrate continuous progress towards completion (to meet the "Continuity Requirement") – often difficult to prove and leading to higher risk – or enter service by the end of its fourth year (e.g., by end-of-2023 for projects that started construction in 2019) (to meet the "Continuity Safe Harbor" provision).[60] While the ITC is a lump sum that often requires tax equity investors to capture the full value, projects qualifying for the PTC will receive the credits for 10 years from the date in which they are placed in service.

Given the challenges brought about by COVID-19 (including supply chain issues and stay-at-home orders), the Treasury Department and IRS jointly issued an extension of Continuity Safe Harbor provisions that could protect at-risk projects whose economic viability depends on receiving tax credits. Specifically, the notice extended Continuity Safe Harbor for projects that began construction in either calendar year 2016 or 2017 by one year; it also provided a Five Percent Safe Harbor extension (deemed the 3½ Month Safe Harbor rule) that allowed services or property paid for on or after September 16, 2019 and received by October 15, 2020 to count toward the provision, effectively helping projects starting construction in 2019 and 2020 to maintain eligibility for their respective tax credits.[61]

Separately, the IRS released new guidance on December 31, 2020, extending the Continuity Safe Harbor provisions for the ITC and PTC for "Federal Land Projects" and "Offshore Projects" from 4 to 10 years.[62] Federal Land Projects include renewable energy projects for which more than 50% will be placed in service on federally owned land and will require the construction of a new high-voltage transmission line to interconnect with the existing grid; Offshore Projects include renewable energy projects placed in service in any inland navigable waters or US coastal waters. Both types of projects require the development of transmission lines (implicit in the building of offshore wind projects) which require much more stringent permitting requirements and environmental reviews and generally face long construction timelines and occasional delays. Thus, the extension is meant to give investors more confidence in these types of projects, improving their chances to success and lowering their costs of equity.

In Congress, some legislators have pushed for even more sweeping extensions of the PTC and ITC to further enable economic recovery and infrastructure investment, and there has been increasing bipartisan support for tax credit extensions as part of broader legislative packages (as was observed in the most recent stimulus package). While there is potential for these tax credits to be extended again, expanded to include resources such as standalone energy storage, and/or replaced in lieu of direct payments, PA's assumptions reflect the most recent tax credit extensions enacted under the Consolidated Appropriations Act of 2021 – see Table 2-8.

[59] While the PTC is almost always preferable to onshore wind facilities, offshore wind facilities generally benefit more from electing to receive the ITC, as they are more capital intensive.
[60] Source: IRS notice 2016-31.
[61] Source: IRS notice 2020-41.
[62] Source: IRS notice 2021-05.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Table 2-8: Tax Credit by Type and Year[63]

Year	Solar ITC	Wind PTC	Offshore Wind ITC
2016	30%	~$24/MWh	30%
2017	30%	~$18/MWh	30%
2018	30%	~$14/MWh	30%
2019	30%	~$10/MWh	30%
2020	26%	~$14/MWh	30%
2021	26%	~$14/MWh	30%
2022	26%	-	30%
2023	22%	-	30%
2024	10%[64]	-	30%
2025	10%	-	30%
2026+	10%	-	-

Accelerated depreciation

MACRS is a federal depreciation schedule that allows owners to accelerate the depreciation schedule for certain types of property (including clean energy and energy storage assets), thus increasing the tax deduction benefit early in a project's life. MACRS establishes different "class lives" for different types of property. Solar and wind technologies, as well as geothermal electric assets, CHP assets, and qualified fuel cells, classify as five-year property, while other types of renewable energy (such as biomass, marine, hydrokinetic assets) classify as seven-year property.[65] A shorter cost recovery period has higher value to the property owner, as higher tax deductions earlier in a project's life contribute to higher NPV after discounting. However, if an owner claims the ITC, they must also reduce the project's depreciation benefit by 50% of the value realized by claiming the ITC.[66] Standalone storage systems classify as seven-year property, but systems that are paired with and charged by at least 75% on-site solar energy classify as five-year property.[67]

Bonus depreciation was introduced in 2008 with the goal of spurring capital investment across various sectors. Bonus depreciation increases the depreciation deduction benefit by a certain percentage, depending on when an asset was placed in service. Several bills have subsequently extended the original bonus depreciation provision;[68] currently, bonus depreciation is governed under the Tax Cuts and Jobs Act of 2017. Eligible renewable assets acquired and placed in service after September 27, 2017 and before January 1, 2023 are eligible for 100% bonus depreciation.

Baseload generation subsidies

In recent years, nuclear and coal-fired generators have struggled to compete with sustained cheap natural gas-fired power generation brought about by the shale gas boom and, to a lesser extent, the rise in renewable energy. While federal efforts to support these generators (based on fuel security arguments) have largely failed to gain traction, states across several markets in the Midwest and Northeast have successfully passed legislation to support certain struggling (mostly nuclear) generators; these programs generally take the form of setting very narrow rules for generator eligibility

[63] Years are based on when the projects begin construction, pursuant to IRS rules (except for residential solar, which is based on the placed-in-service date). Thereafter, projects typically have two years to achieve COD.
[64] Beginning in 2024 and holding thereafter, the 10% ITC only applies to commercial and utility-scale systems; the ITC expires completely for residential systems beginning in 2024.
[65] MACRS five-year assets are described in 26 USC § 168(e)(3)(B), which refers to 26 USC § 48(a)(3)(A) of the ITC.
[66] For example, if an owner claims the full ITC benefit of 30% of capital cost, they may only deduct 85% of the asset's value under MACRS.
[67] Standalone energy storage is classified under 26 USC § 168(e)(3)(C)(v)(I). Paired systems qualify as "solar energy property" under the same code referenced in the ITC/PTC section. As with solar assets, claiming the ITC reduces the project's depreciation benefit.
[68] Acts that extended or modified bonus depreciation include: the American Recovery and Reinvestment Act of 2009, the Small Business Jobs Act of 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, the American Taxpayer Relief Act of 2012, and the Tax Increase Prevention Act of 2014.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

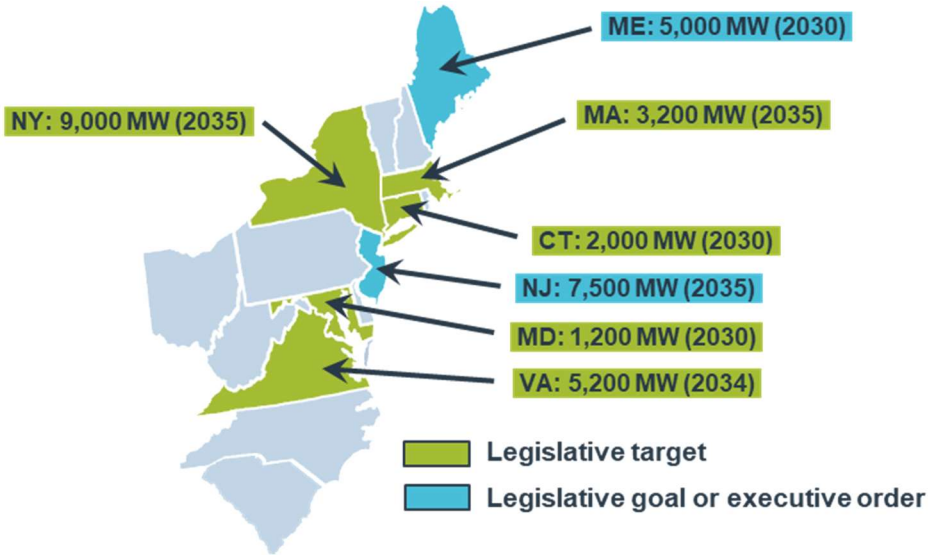
and then distributing payments (often tied to the social cost of carbon or the "missing money" required to make assets whole) to qualifying generators. States have successfully passed and defended these policies by highlighting that the zero-emission attributes of nuclear generators have been uncompensated by existing markets as well as by stressing the jobs and economic benefits that large baseload facilities provide to their affected districts. No major programs of this nature are currently present in WECC.

Competitive clean energy procurements

Several states are undertaking competitive procurements for new large-scale clean energy and energy storage resources to make active progress toward their policy targets. Presently, these efforts are concentrated primarily in the Northeast and largely support new offshore wind, transmission line, and battery developments. While still facing local NIMBY opposition, offshore wind and transmission line projects provide much more energy for their respective footprints compared to onshore wind and solar, allowing for large step-changes toward states' targets. Separately, energy storage resources allow states to integrate higher levels of renewables and at times avoid new transmission infrastructure deployments. However, offshore wind is highly capital-intensive and still largely untested in the US, transmission lines are high risk due primarily to the number of permits required, and battery storage is still nascent worldwide with unclear market participation rules; thus, investors are unlikely to pursue such projects absent explicit state support and the securing of long-term contracts. In the West, competitive procurements are currently limited to energy storage and onshore renewables, with no material activity around procuring transmission or offshore wind; in particular, the West Coast's deep shelf necessitates more-expensive floating offshore wind turbines, pushing the economic viability of this industry further into the future.

Competitive procurements for offshore wind typically support legislatively-mandated targets – see Figure 14. States with such targets are motivated to act quickly by a range of factors, including taking advantage of expiring tax credits and a desire to create industrial hubs for installing and maintaining offshore wind assets. However, the pace with which offshore wind assets actually achieve operation may be informed by the 800 MW Vineyard Wind's success or failure as the first large offshore wind facility in the US. Vineyard Wind's permit application was delayed by BOEM in part to address fishing industry concerns; however, due in part to strong support from several Northeast states for growing the offshore wind industry, the extension of the offshore wind ITC and Continuity Safe Harbor provision, and the Biden administration's support for the offshore wind industry, PA assumes Vineyard Wind will ultimately be successful, as will several other offshore wind projects.

Figure 2-25: Offshore Wind Procurement Targets and Goals[69]



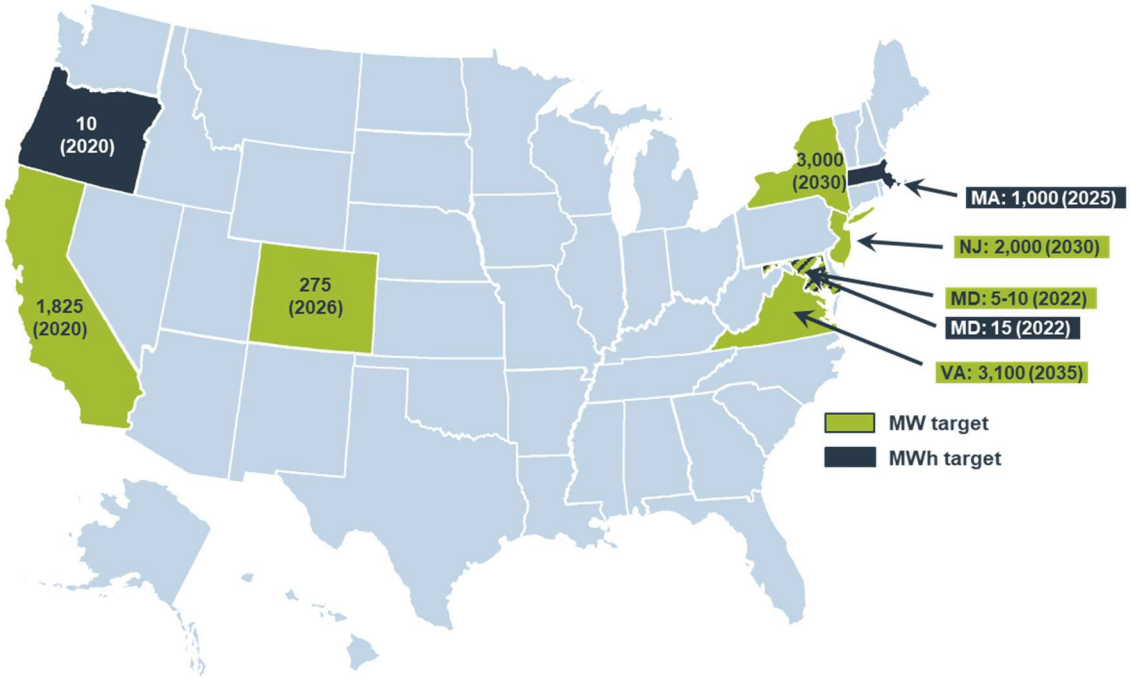
A number of coastal states (including in the West) are beginning to supplement their climate policies with energy storage procurement targets, as shown in Figure 2-26. These targets include various specifications for different types or uses of storage (e.g., FOTM vs. BTM). Competitive procurements play a dominant role in meeting targets, but they may also rely on other financial incentives that lower upfront investment costs. Once legislators and developers become more comfortable with storage and its business case – and as the grid absorbs increasing amounts of intermittent renewable

[69] Maine's goal was set through legislation. New Jersey's goals were set via a combination of legislation and executive orders. Rhode Island does not have a formal offshore wind-specific goal or target but has procured 430 MW to date via Block Island and Revolution Wind.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

power generation – additional states may set their own energy storage targets, likely to be driven in part by utility procurements.

Figure 2-26: Energy Storage Procurement Targets[70]



California's energy storage procurement target

Two Assembly Bills underlie California's total electric storage procurement target of 1,825 MW. AB 2514 was approved in 2010 and drove the CPUC to set a total procurement target of 1,325 MW, split unequally among SCE, PG&E, and SDG&E. AB 2868 added 500 MW of distribution-connected storage to the target, split equally among the three major IOUs. PG&E and SCE received the highest initial procurement targets; each was charged with a goal of procuring 310 MW of transmission-connected storage, 185 MW of distribution-connected storage, and 85 MW of customer-connected storage by 2020. By comparison, SDG&E's initial targets were 80 MW, 55 MW, and 30 MW of transmission-, distribution-, and customer-connected storage, respectively. The IOUs could meet their targets through owning or contracting with new energy storage installations. While the 1,825 MW target had to be procured by end-of-2020, the deadline for installation is 2024. By the end of 2020, the IOUs had collectively exceeded the AB 2514 targets and satisfied nearly all of the domain-specific requirements (with transmission-connected storage targets more easily met than the others).

In addition to these targets, CPUC Decision Requiring Electric System Reliability Procurement for 2021-2023 (made in November 2019) required incremental procurement of system level resource adequacy capacity of 3,300 MW, by all load serving entities within CAISO in aggregate. While this procurement occurred on an all-sources basis, energy storage constituted a majority of the procured resources. For example, PG&E exceeded its responsibility of 717 MW of capacity by procuring more than 800 MW of energy storage, around half of which will come online by August 2021.

In late June 2021, the CPUC approved new procurement requirements for mid-term reliability. The order calls for 11.5 GW of NQC (up from an originally proposed 7.5 GW) to come online by 2026, of which at least 1 GW each must come from long-duration storage and firm zero-emission resources (such as geothermal) based on a 20.7% target reserve margin. Unlike some of the original proposals, the final order did not include any consideration for fossil fuel procurement, though such procurement is not ruled out of future CPUC decisions. PA's analysis incorporates this most recent CPUC decision; all else equal it results in increased procurement of renewables and storage consistent with California's ambitious decarbonization goals.

California backstop renewable procurement

Attempted legislation in the California Assembly would have enabled the state government to act as a backstop authority to procure resources to meet the state's clean energy targets. California faces several headwinds in its clean energy deployment efforts, including the growth of CCAs as well as IOUs' wavering credit ratings resulting from varying wildfire liabilities. Concerned about the consequences of such headwinds, lawmakers introduced AB 56 in December 2018.

[70] As of March 2021. The Colorado energy storage procurement target is part of Xcel Energy's Colorado Energy Plan preferred portfolio. The plan was codified and signed by Governor Jared Polis in 2019.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

AB 56 would have enabled the CPUC to authorize the California Alternative Energy and Transportation Financing Authority – if deemed reasonable – to undertake backstop procurement of electricity to meet California's climate, clean energy, and reliability goals.[71] These centralized procurements would have reduced the procurement obligations of LSEs, with the stipulation that LSEs could be required to remit payments to cover the costs of the transferred obligations. After passing the House in May 2019, the bill went before the Senate Energy, Utilities and Communications Committee, which subsequently voted it down in July. However, should a bill similar to AB 56 be passed in the future, it would increase the probability that California meets its clean energy targets on schedule.[72]

2.4.3 Market mechanisms

Many states have spurred growth of clean energy resources via competitive market mechanisms. Unlike asset- or technology-specific subsidization, market mechanisms rely on setting targets and rules for participation within new financial systems, betting on the private sector to compete towards an economically efficient solution. ISO/RTO market rules are also shifting in an effort to uphold an even playing field while accommodating states' preferences for certain resources.

Environmental attribute markets

At the state level, RPS policies have been a major driver of renewable development across the US for much of the 21st century. Designed in part to promote resource diversity and reduce GHG emissions, RPS programs require that certain classes of "renewable" energy sources serve an increasing share of state electricity sales, with requirements typically placed on retail sellers of electricity. While state RPS requirements and eligible technologies vary considerably, RPS programs have generally excluded nuclear and large hydropower.

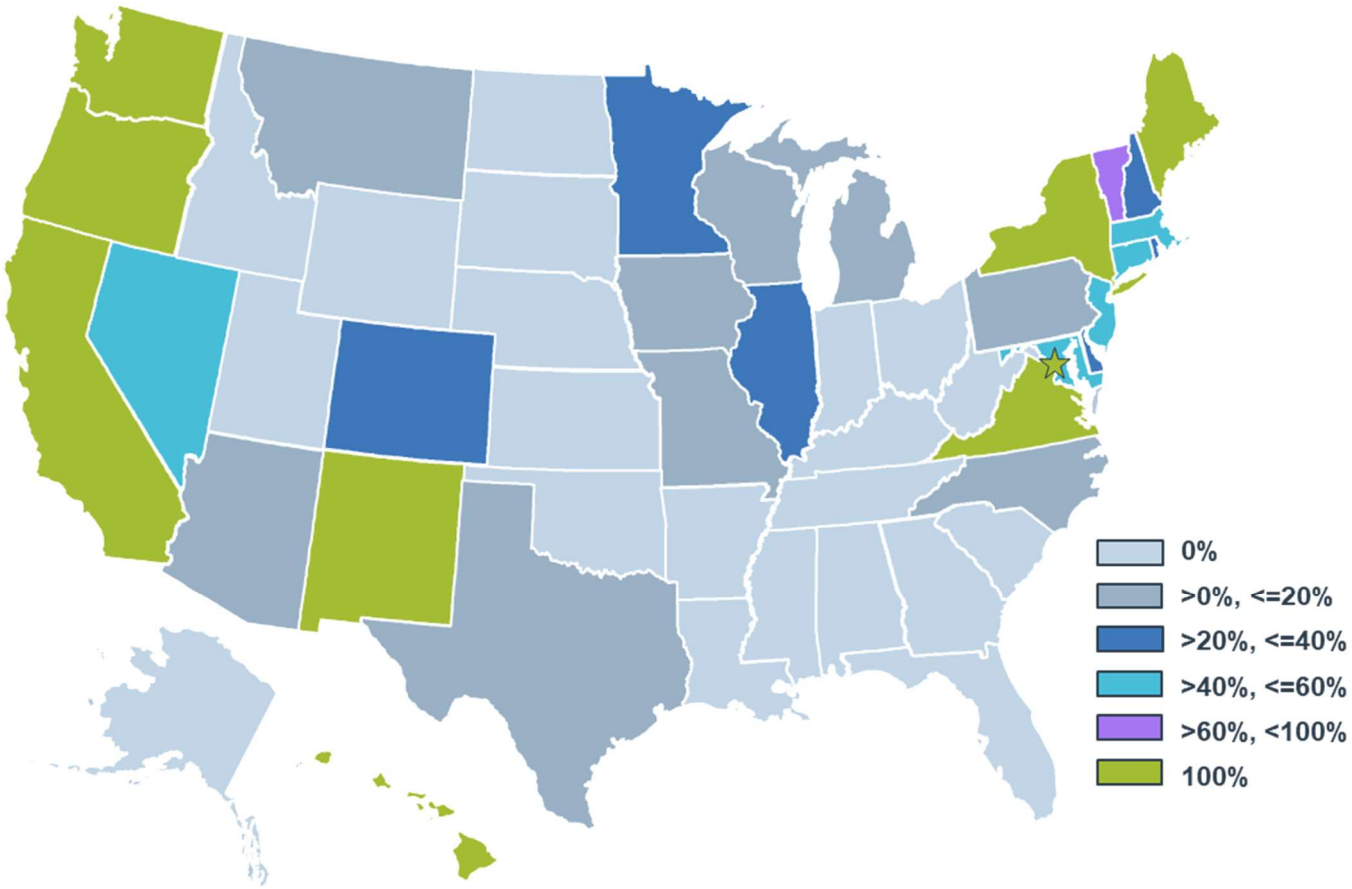
RPS programs function as market mechanisms by setting state-wide targets for renewable energy and establishing rules for trading RECs. Eligible generators earn RECs for each MWh of energy they produce, and RECs can then be sold to the entities responsible for meeting states' targets. Many programs allow certified REC trading across states, often within a given market (e.g., PJM) or under a set of conditions (e.g., requiring the electricity to be physically delivered into the state). States often allow entities to bank RECs for a number of years into the future (typically 3-5) and set ACPs as effective price ceilings for entities that fail to retire the requisite number of RECs by the end of the compliance period.

States have recently begun to enact separate and more stringent clean energy or zero-carbon electricity targets that function similarly to RPS programs but make eligible a wider range of resources, often including nuclear and large hydropower. Most of these policies were enacted in 2019 and 2020 following a change in party control of several state governments from the 2018 midterm elections. Hawaii, California, DC, New Mexico, Washington, Maine, New York, Virginia, and Oregon each have 100% zero-carbon electricity targets. Due to the ambitious nature of the targets, there is much uncertainty to states' abilities to achieve them on schedule. See Figure 2-27 for a comparison of clean energy targets across US states.

[71] Notably, this policy differs from the current backstop procurement measures put in place by CAISO, which correspond only to RA needs – see Section 2.2.2.

[72] In parallel, the CPUC recently approved a rulemaking that will instate a centralized procurement process for RA purposes in specific cases (rather than to achieve state clean energy goals) – see Section 2.2.2.

Figure 2-27: Clean Energy Targets[73]



Complementary to clean energy targets, some states are considering CPS programs to drive the increased use of clean energy in peak demand hours. CPS programs are designed to more quickly curb GHG emissions (by reducing reliance on inefficient, often oil-fired peaking plants), shift clean energy output to coincide with peak demand, and generally help transition a market to one relying solely on clean energy resources. Massachusetts is currently the only state with a CPS.

California's clean energy standards

On September 10, 2018, Governor Brown signed SB 100, increasing the state's RPS from its previous target of 50% by 2030 to 60% by December 31, 2030, with interim targets for IOUs of 33% by December 31, 2020 and 50% by December 31, 2026.[74] The state-wide mandate is jointly administered by the CPUC and the CEC and applies to all retail sellers of electricity, with certain modifications for small utilities.

In addition to strengthening the state's RPS, SB 100 also directs state policy to plan for 100% eligible renewable energy and/or zero-carbon retail electric sales by December 31, 2045. The legislation specifies certain requirements and standards that must be followed in achieving this goal, including that the pursuit of this target cannot increase emissions elsewhere in WECC. However, it leaves much of the implementation (including any interim targets) to various state agencies, and the contours of implementation and administration of the target will likely depend on additional legislation being passed, as well as additional regulations embodying this legislation. In light of the 2045 zero-carbon retail electric sales target, PA projects continued additions of solar, wind, and energy storage capacity beyond the 2030 RPS target date.

However, there are concerns regarding the feasibility of implementation. In a 2019 analysis of decarbonization pathways, Energy and Environmental Economics, Inc. concluded that completely replacing natural gas-fired capacity with wind, solar, and storage would be "extremely costly and impractical," and that natural gas-fired capacity was an economic source of the firm capacity necessary to preserve reliable electricity in California.[75] Similarly, in a January 2020 report,

[73] Map excludes Ohio's RPS (8.5% renewable energy by 2026), which expires beginning in 2027.
[74] Retail sellers of electricity (including CCAs) and publicly owned electric utilities each have interim targets of 33% by December 31, 2020, 44% by December 31, 2024, and 52% by December 31, 2027.
[75] Source: Energy and Environmental Economics, Inc.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

the California Legislative Analyst's Office released a report "Assessing California's Climate Policies - Electricity Generation" that outlines several issues the legislature should consider in meeting the state's renewable energy goals.[76]

Under current rules, California utilities meet their RPS obligations by acquiring and retiring RECs, which must be registered in the WREGIS and may be banked for up to three years. California's RPS compliance can be satisfied by RECs falling into any of three PCCs. The PCC under which a REC falls depends on whether the REC's associated renewable energy is (1) injected into or verifiably scheduled to a CBA along with the REC (also known as a "bundled" REC, and described in this Report as a "Tier 1" REC); (2) substituted by energy generated by other renewable resources (also known as a "firmed and shaped" REC); or (3) not verifiably delivered along with the REC (also known as an "unbundled" REC). See Table 2-9.

SB 100 provides for the assessment of penalties for non-compliance related to renewable energy targets unless a waiver from the CPUC is granted; currently, the penalty is set at $50/REC. However, the CPUC establishes cost limitations for each utility to prevent disproportionate rate impacts. California has met the 33% by 2020 interim target.

In general, California's renewable initiatives are projected to substantially increase renewable energy generation and reduce the dispatch of natural gas-fired generators, particularly during daytime hours when solar will increasingly contribute to the mix. Increased renewable penetration will also increase the demand for flexible and efficient power generation in the California region to address substantial projected ramping needs during late afternoon and early evening hours. California will likely also continue its debate on whether to expand CAISO throughout the West, as access to a larger market could prevent significant daytime curtailment of solar capacity, potentially driving lower system compliance costs – see Section 2.2.5.

Table 2-9: California RPS Product Content Categories[77]

Category	Description	Allowable Proportion[78]
PCC1	Includes the RECs and associated energy from an eligible renewable resource[79] having either: • A first point of interconnection with a CBA or with a distribution or transmission grid serving end users in a CBA; • An hourly or sub-hourly import schedule into a CBA without substituting electricity from another source (however, the use of real-time ancillary services is permitted); or • An agreement to dynamically transfer electricity to a CBA. If any of the above three requirements are met, the product qualifies for PCC1. These are typically known as "bundled" RECs.	Greater than or equal to 75%
PCC2	Includes the RECs and associated energy from an eligible renewable resource where: • The associated energy is substituted with energy firmed and shaped by a third party before being delivered into a CBA. The substitute renewable generation must be scheduled into the CBA within the same calendar year as the initial RPS-eligible generation; and • The substituted energy is "incremental" energy; that is, it cannot have been in the retail seller's portfolio prior to the transaction.	Less than or equal to 25%

[76] https://lao.ca.gov/reports/2020/4131/climate-policies-electricity-010320.pdf
[77] Source: California Energy Commission enforcement procedures for the renewable portfolio standard and Pub. Util. Code § 399.16.
[78] These proportions have changed over the years to favor greater procurement of Tier 1 RECs, but there are no announced changes to the current proportions.
[79] An "eligible renewable energy resource" meets the definition of a "renewable electrical generation facility" set forth by Section 25741 of the Public Resources Code. Pub. Util. Code § 399.12(e).

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

PCC3	Includes RECs from an eligible renewable energy resource which do not meet the criteria of PCC1 or PCC2. These RECs are referred to as "Tradable" RECs because they can be transferred to a California LSE wholly separate from the underlying physical energy.	Less than or equal to 10%

Carbon cap-and-trade programs

RPS programs treat coal, natural gas, and nuclear-fired generators equally, limiting their market share but otherwise prescribing no requirements for them. Given that generators emit differing quantities of GHG, some states moved in the late 2000s to price externalities under multi-state agreements, particularly given a lack of Congressional success in passing a federal program. States have to-date led with carbon cap-and-trade programs over carbon taxes, with two such regional programs currently in operation: RGGI in the Northeast and California's construct (currently linked with Quebec).[80] Both programs allow covered entities to buy allowances in periodic auctions and trade them amongst each other; allowance prices are then cleared as functions of auction supply and covered entity demand. The total allowances offered in auctions decline each year, with price floors (below which allowances are withheld), price ceilings (above which additional allowances are made available), carbon offset options, and allowance banking all providing some flexibility.

California's cap-and-trade program

California's general approach to regulating economy-wide and electric sector-specific GHG emissions was established in the California Global Warming Solutions Act of 2006, also known as AB 32. First, the law formally codified the concept of mandatory GHG reduction targets in the state. Second, the law authorized the use of both mandatory controls and market-based solutions to achieve GHG emission reductions. Third, the law directed CARB to develop periodically updated Scoping Plans to meet mandated GHG reduction targets.

California's GHG reduction targets have grown more aggressive over time and have also evolved to focus more heavily on reductions in the electric sector. AB 32 established an economy-wide target of achieving 1990 levels of emissions by 2020. SB 350 (signed into law in October 2015) set an electric sector-specific target of reducing emissions to 40% below 1990 levels by 2030. SB 32 (signed into law in September 2016) subsequently updated the economy-wide target to 40% below 1990 levels by 2030. Reflecting guidance from CARB's most recent Scoping Plan on how to most efficiently achieve the economy-wide target, the CPUC is planning to achieve an approximate 61% reduction in GHG emissions from the power sector by 2030.

To meet these targets, California is relying on a mix of mandatory controls (as discussed in Section 2.4.1) and market-based solutions, as authorized under AB 32. On the market side, CARB proposed (through its initial Scoping Plan in 2008) and ultimately implemented a cap-and-trade program. CARB formally developed the cap-and-trade program in December 2010, with auctions beginning in late 2012. Under the program, covered entities must obtain an allowance for every metric ton of CO_2e they emit, with the total supply of allowances capped and set to decline roughly 3% per year. CARB defines covered entities for different sectors (e.g., glass production, electric generation) according to threshold emissions levels, typically a minimum of 25,000 metric tons of CO_2e per year. To allocate and facilitate exchange of the allowances, CARB runs current and advance auctions every quarter (for a total of 8 auctions per year). At the conclusion of every three-year compliance period, each covered entity is required to submit to CARB compliance instruments (allowances plus a fixed number of offset credits) equivalent to that entity's total GHG emissions during the compliance period.

More recent legislation has updated the cap-and-trade program. AB 398 (signed into law in July 2017) authorized CARB to extend the cap-and-trade program through 2030, directed CARB to establish an allowance price ceiling, limited the amount of offset credits (obtained through approved carbon offset projects) and out-of-state credits that can be used to meet compliance, offered assistance to industry, and altered how program revenues must be allocated. In April 2019, CARB finalized rules to implement the amendments of AB 398.

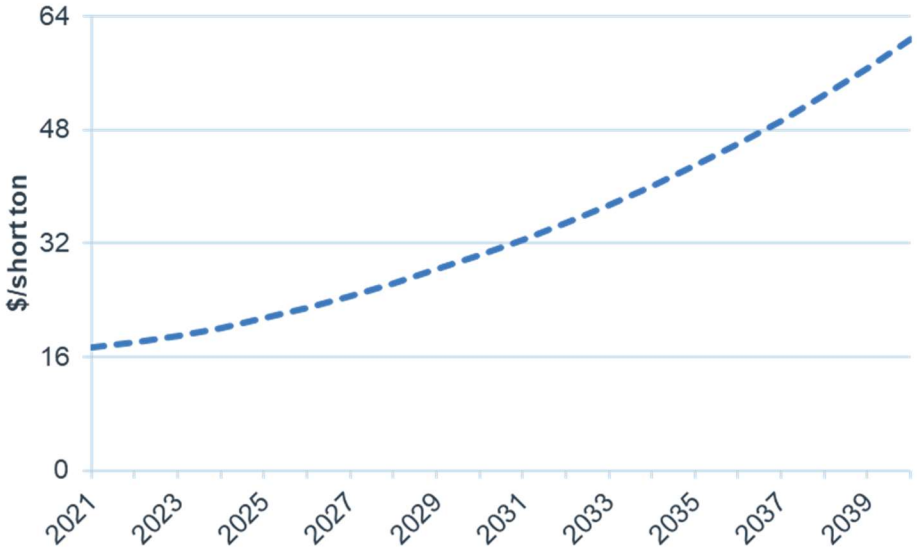
A mix of forces have kept actual emissions below the programmatic cap and suppressed allowance prices. Other mandate-style state policies designed to encourage clean energy investments and curb emissions, such as the state's RPS and CARB's Zero-Emission Vehicle program, have helped reduce carbon emissions relative to the initial expectations of program designers. This contributed to allowance oversupply, which in turn has depressed settlement prices to near the program floor price (which began at $10/allowance in 2013 and increases annually by 5% plus the rate of inflation). In a 2017 analysis, the LAO estimated between 100 and 300 million allowances of cumulative oversupply through 2020, which they projected would depress prices in the early 2020s.

[80] Most recently, Oregon also attempted to pass its own carbon cap-and-trade program in the 2019 legislative session; however, the authorizing bill fell just shy of the votes needed to make it to the governor's desk, who supports such a program.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Driven by continued and potential additional mandate-style policy interventions, PA projects that the trend of using command-and-control complementary measures will largely continue, resulting in settlement prices that will not significantly rise above floor prices through the study period. To the extent that these measures are insufficient to achieve required emissions reductions, allowance prices may increase above the floor-price levels projected by PA, resulting in an increase to projected power prices. PA's GHG allowance price projections are shown in Figure 2-28.

Figure 2-28: California GHG Emission Allowance Prices



CARB designed its cap-and-trade market to be able to link with other jurisdictions' markets within the WCI,[81] and in January 2014, California's market was linked with Quebec's market.[82] In October 2019, the US Department of Justice filed a civil complaint against the state of California alleging that it unlawfully entered a cap-and-trade agreement with the Province of Quebec. The Department of Justice claims that the power to enter into such international agreements lies exclusively with the Federal Government and that the Constitution prohibits states from making treaties or compacts with foreign powers. In March 2020, the US District Court of the Eastern District of California struck down two of the four arguments presented by the Department of Justice – namely, the two referenced by the plaintiff in seeking a summary judgment. The other two counts were subsequently struck down in July 2020, effectively reaffirming Quebec's participation in the WCI. Nova Scotia has since become a WCI participating member, with its first auction in 2020, though its program is not currently linked to California's and Quebec's.

Carbon taxation efforts

Whereas carbon cap-and-trade programs set targets for emission reductions and let markets arrive at prices for tradable allowances (within a pre-determined price band), carbon taxes set the price of emissions for covered entities outright and leave the level of emission reductions achieved to fall where it may. However, carbon taxes have been shown to-date to be politically unpalatable in the US, with even progressive states like Washington failing several times over to pass such a levy.

ISO/RTO market rules

While the market mechanisms discussed above establish new rules and allow participants to compete, these programs (as well as direct financial assistance policies) clearly and intentionally favor certain types of resources. As ISO/RTOs are charged with maintaining fair and just power markets, some ISO/RTOs have struggled to accommodate these effectively subsidized resources into their markets in a manner that preserves competition. For example, a nuclear generator receiving subsidies has historically been permitted to submit a lower bid into PJM's capacity market than it would have been able to do so absent the extra revenue; this had the effect of pushing out marginal thermal generators, even in states that have not passed RPS or other decarbonization policies. As a result, ISO/RTOs in the East have pursued measures to mitigate price-suppressive outcomes (i.e., PJM's expanded MOPR proposal, ISO-NE's substitution auction, and NYISO's buyer-side mitigation rules). However, in California, assets and LSEs contract bilaterally to meet

[81] The WCI is a consortium of US states and Canadian provinces working to design a regional GHG emissions reduction program. At its peak in 2008, the WCI consisted of seven states and four provinces, although it currently only has two linked, participating members (California and Quebec).
[82] The program also temporarily included Ontario starting in January 2018, but the Ford administration removed the province from participation in July 2018.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

RA requirements, and the state actively pushes IOUs and CCAs to meet decarbonization targets; thus, the developments in the East are unlikely to extend to CAISO.

2.4.4 Market economics

The policies described in the previous three sections laid the framework for and continue to accelerate the clean energy transition; however, market economics alone have recently become their own driving force. While the economic case for wind and solar technologies has vastly improved, renewables and storage both face new challenges under this paradigm shift, including risks of cannibalizing their own markets, as discussed in greater detail below.

Natural gas prices

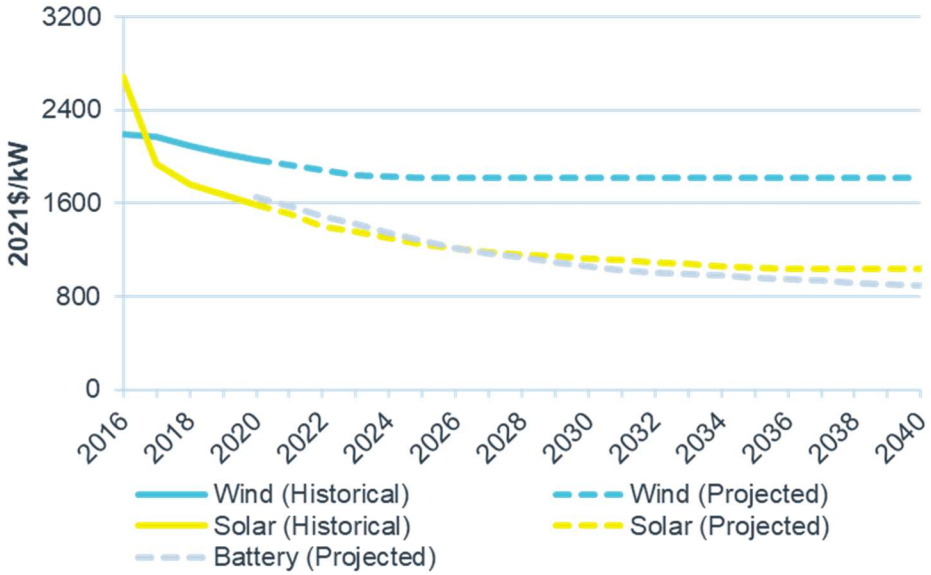
Perhaps the most significant driving force of evolving capacity mixes in power markets across the US has been and continues to be the decade-long access to low natural gas prices, with no sharp rise expected in the indefinite future. The innovative technologies of horizontal drilling and hydraulic fracturing led to the shale gas boom that began in the late 2000s and has resulted in natural gas-fired assets putting sustained pressure on other thermal generators with higher fixed costs, such as coal- and nuclear-fired generators. See Section 2.3 for more detail on historical and projected natural gas prices, as well as their underlying drivers.

Capital costs

As shown in Figure 2-29, there has been a significant decline in the capital costs associated with building new renewable capacity in recent years – particularly for solar. Increased demand for renewable technology has led to supplier competition, which in turn has driven dramatic technological improvements and supply chain efficiency. The trend has been accelerated by federal tax incentives, rising emissions pricing, and increased state renewable targets. For solar, the three main factors contributing to declining costs were improved technological efficiency, supply and distribution sectors scaling up to meet demand, and construction timelines shortening. Wind costs similarly declined but at less rapid rates than solar, as wind is a more mature technology with a more established supply chain. On the other hand, traditional thermal build capital costs have generally remained flat in recent years. Wind (and solar) technologies are already cost-competitive in some regions of the country on a levelized cost basis, which accounts for other factors such as federal tax incentives.

While too few battery storage projects have been completed in the US to inform historical trends, PA projects battery costs will decline rapidly in the near future as manufacturers scale up lithium ion module production facilities (to meet both electric vehicle and grid support demand) and developers gain experience with the technology (through building more standalone systems and capitalizing on opportunities to pair battery storage with renewable systems). PA also projects solar capital costs to continue their decline over the next decade, with wind capital costs falling slightly through the early 2020s before stagnating (due to industry maturity). PA does not project capital costs to materially change for natural gas-fired electric generation technologies.

Figure 2-29: Historical and Projected Capital Costs by Clean Energy Technology – California[83]



[83] "Battery" approximates a utility-scale 4-hour standalone lithium ion battery system. Values do not include tax credits such as the ITC. Source of historical data: NREL ATB Reports.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Renewable energy generation risks

Despite efficiency improvements and cost declines, renewable generators face a range of risks unique or particularly important to their technology class; further, some types of risks are being amplified for the entire pool of assets as their penetration in power markets rises. These risks include the following:

- As renewable generators are increasingly contracted or hedged at a liquid trading hub, rather than their locational pricing node, **nodal price basis** create a potential risk to some renewable assets. Particularly in regions with substantial and concentrated penetration of renewable power generation (e.g., certain pockets in southern California), nodal basis risk may be quite significant.
- Beyond just being subject to nodal basis price differentials, geographically dispersed intermittent resources may be constrained in their ability to deliver power over their localized transmission systems. This can result in market oversupply and occasional generation **curtailment,** particularly in regions with highly concentrated pockets of renewable power generation or in areas where transmission infrastructure is significantly lagging renewable buildout.
- Intermittent resources may also generate during hours of less-favorable pricing – particularly wind generators that demonstrate higher output during the overnight hours (e.g., Texas) as well as solar generators in oversupplied markets (e.g., California) – creating **shaped basis** risk. Intermittent renewables generate according to their relevant weather patterns; they therefore tend to have average generation shapes that may not align with the highest-price hours. This can reduce the revenues they receive relative to the all-hours energy prices received by baseload generators and the most lucrative energy prices captured by flexible natural gas-fired generators.
- Finally, there can be a meaningful inverse correlation between energy prices and renewables output, particularly when renewable output deviates from its normalized shape (e.g., high wind events). In regions with high penetration levels, when renewable output is very low, energy prices tend to spike, and when renewable output is high, energy prices are often suppressed; this dynamic can result in a larger shape basis than if just examining a renewable generator's median (normalized) output versus energy prices. PA has found that this **covariance** risk can be meaningful but is market dependent.

While these risks can be managed if properly understood, they complicate the ability of developers to economically build and operate incremental renewable assets in certain power markets. PA accounts for each of these risks as part of its analysis of renewable assets – see Appendix B for more detail. Notably, the risks outlined above apply almost exclusively to intermittent renewable power generation (e.g., wind and solar), whereas firm renewable resources are largely insulated from these downsides and complement the intermittency of wind and solar.

Energy storage economics

Energy storage technologies are still in the early adoption phase, but several factors are coalescing that point to significant growth on the horizon. While often relying on government support, capital costs are falling, and certain well-placed projects are now able to achieve profitability. Energy storage projects have a symbiotic relationship with renewable energy assets and, when co-located, the former can ameliorate risks faced by the latter and share certain capital cost elements, earning additional revenues and higher returns for the combined entity. Separately, standalone energy storage assets are beginning to find value performing several niche roles (e.g., ancillary services, T&D upgrade deferral) and are poised to take on much larger roles, including smoothing intraday net load curves (i.e., by shifting excess solar output from afternoon hours to evening hours and capturing the price differential) and replacing oil and gas-fired peaking assets in states with deep decarbonization goals. ISO/RTOs are also in the process of adjusting their rules to allow such assets to participate more fully in their markets, pursuant to FERC directives (e.g., Order 841).

Revenue streams

Energy storage can earn revenue across the electric value chain, loosely categorized into power generation, T&D, and DER services. Owners of energy storage assets can realize value from these revenue streams through merchant operations or via a tolling agreement, with the latter essentially capturing energy and capacity value through a single contract in exchange for the owner giving the offtaker (typically a utility) effective control over a standalone battery storage asset's operations.

Generation services encompass each of the following:

- **Bulk energy time shifting** involves charging an energy storage system during lower-priced hours (typically at times with abundant renewables on the system) and discharging during higher-priced hours. In regions like California where high levels of solar power generation oversaturate the market during the afternoon, bulk energy storage technologies can capture excess solar energy and release it to the grid in the evening, capturing revenue from the price differential.
- **Renewables shaping** uses higher-energy storage technologies to shape energy profiles over minutes to hours.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

- Finally, **ancillary services** such as frequency regulation and spinning reserves favor technologies that offer fast ramp rates and quick response times; energy storage can capture additional revenue in certain markets by offering non-spinning reserve, voltage support, and black start services.

Utilities are now procuring energy storage systems as "non-wires alternatives" to expensive T&D upgrades where cost-effective, taking advantage of storage's modularity, quick build time, and relative lack of local opposition. Transmission benefits include CapEx deferral and congestion relief. For example, storage systems can charge when a transmission line is congested and discharge when it has available capacity, reducing congestion costs on the line (where applicable, reducing renewable energy curtailment) and deferring capacity-related line or substation upgrades. Distribution services include voltage support, microgrid formation, and distribution CapEx deferral.

Customer-sited BTM services include demand charge management (particularly for larger C&I customers),[84], TOU rate optimization, and DER integration. These are best served by technologies with smaller footprints, faster ramp rates, higher roundtrip efficiencies, and capacities sized specific to customer load profiles.

Presently, energy storage technologies are too expensive in most cases to be profitable through any single revenue stream defined above. However, profitability is possible in select instances where revenues can be "stacked" from multiple sources, and where market prices are conducive to merchant operation. Revenue stacking is largely contingent on a given market's rules for storage participation, which are undergoing changes across the US per directives in FERC Order 841 (as discussed in more detail below). In general, markets that require storage capacity to be reserved exclusively for certain products in order to participate in their markets limit the potential for revenue stacking.

FERC Orders

Despite the above service offerings, energy storage technologies have struggled to gain traction in ISO/RTO markets. This is largely because ISO/RTO tariffs have excluded or otherwise failed to clearly specify storage participation rules. However, a series of FERC orders over the last decade have sought to gradually break down discriminatory barriers and clear any remaining confusion among market players.

Most recently, FERC issued Order 841 in February 2018. At that time (and currently), rules governing storage operation in wholesale markets were often murky or non-existent. Order 841 seeks to standardize certain aspects of storage participation in wholesale markets across the country by: (1) ensuring that storage resources are eligible to provide energy, capacity, and ancillary services; (2) ensuring that storage can be dispatched and set market clearing prices; (3) accounting for the specific physical and operational characteristics of storage resources; and (4) establishing a minimum size requirement of 100 kW or lower. In late 2019, FERC found that the ISOs' filings each individually met most of the requirements of Order 841, though none of them were completely compliant. The ISOs (including CAISO) have been in the process of revising their filings per FERC guidance, with certain accepted changes having an effective date of December 3, 2019; however, CAISO was largely in compliance with the requirements before FERC Order 841 was issued, and therefore not much is expected to materially change.

2.4.5 Public demand

Rising public demand for clean energy, decarbonization, and environmental protection represents the final driving force behind the clean energy transition. Some of this demand is satisfied through individual actions, such as installing rooftop solar or home battery systems, buying electric vehicles, and making lifestyle changes. However, in many regions of the country, the public at large is becoming more vocal about their demands and looking to both private corporations and government to make more impactful and systemic changes. Climate change and environmental issues are rising in importance at the polls (thereby affecting voting behavior), influencing consumer purchasing decisions, and inspiring public protests or demonstrations. The consequences of this paradigm shift are described in more detail below.

Executive orders and municipal policy

As discussed above, legislatively mandated support for clean energy at the state and federal level continues to drive growth for such assets in power markets across the US. Such policies pass a high bar of support, typically establish material incentives or penalties to affect change, and are difficult to repeal by future administrations; therefore, they are generally represented as part of PA's market assumptions. However, a large class of other public policy decisions are also influencing power markets (noting they may not always be directly incorporated into PA's assumptions).

At the state level, many governors around the country are issuing climate-related executive orders to begin planning and taking steps toward reducing GHG emissions. For example, New York Democratic Governor Andrew Cuomo relied on executive orders in his first two terms to set the state's clean energy targets (while Republicans controlled the Senate) prior to signing legislation in his third term. Governors in some states with Republican-held legislatures have issued executive orders to cut GHG emissions (e.g., Pennsylvania) or call for increased use of clean energy (e.g., Wisconsin),

[84] Rate classes for large C&I customers feature a per-kW charge based on the largest hourly usage in a particular month. Storage applications are therefore most valuable for customers with very spiky load profiles.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

allowing these states to take smaller-scale steps toward decarbonization (e.g., by setting EE standards for government buildings). However, the power and reach of executive orders are limited, and future governors can quickly undo past orders. These caveats make sustained progress toward future-oriented goals challenging via executive orders alone.

At the local level, city council decisions can set firm directives for a municipality, with mayoral executive orders facing the same risks and rewards (on a smaller scale) as gubernatorial and presidential orders. For example, New York City's Local Law 97 (2019) set aggressive targets for reducing building emissions, and Los Angeles' Green New Deal (2019) set high standards for renewable energy and electric vehicles. Smaller cities around the US are making similarly strong commitments, each of which have little impact individually but drive larger change when considered in the aggregate.

Regulated utility commitments

Regulated utilities across the US are also making public commitments to decarbonize, with goals typically materializing through updated IRPs (which serve more as planning documents than firm requirements). For example, several major utilities (including Xcel Energy, Consumers Energy, Southern Company, and Idaho Power) have announced plans with varying degrees of detail to achieve and work toward carbon neutrality by mid-century. While plans issued by regulated utilities must be approved by a state's PUC (weighing cost, affordability, and reliability), they represent potentially seismic shifts in regional power market dynamics, directly impacting decisions around when to retire, build, or enter PPAs with various assets. PA situationally incorporates utility IRPs and announced commitments into its assumptions, based on its review and expert judgment around the likelihood of such plans being followed or achieved.

Corporate demand for renewables

Corporate demand for renewable energy has also grown rapidly in recent years, driven by a desire to build brand, reduce energy costs via favorable PPAs (particularly as renewable capital costs have fallen), and hedge against market volatility. Nationwide, corporate PPAs with new renewable energy projects surpassed 6 GW in 2018 alone – and over 16 GW over the past five years – including large procurements from Google, Amazon, Facebook, AT&T, Apple, Walmart, ExxonMobil, and Microsoft.[85] Such arrangements are often responsible for PA assuming a development project will enter service in a particular year (i.e., representing a "firm build"). As demand for "additional" projects has been accelerating, state RPS targets may represent lower bounds to renewable energy growth in certain areas.

Opposition to local development

While public demand for clean energy is rising, civic opposition to new energy infrastructure projects is likewise building. In particular, residents of towns with proposed renewable energy developments are turning out to push for such projects to be built outside of their communities, reflecting strong NIMBY sentiments that can serve as headwinds to clean energy growth. NIMBY sentiments have long plagued the wind power industry in particular, given the size and range of the turbines and increasing proximity to more densely populated areas. Presently, such fights are played out most intensely in the Northeast; for example, concerns about the fishing industry and oceanfront views are derailing permitting processes for offshore wind projects, and apprehensions about damage to old-growth forests, wetlands, and the recreation/tourism industries are driving resistance to proposed new transmission lines (having successfully terminated Northern Pass). The pace with (and extent to) which regions achieve their clean energy goals may hinge on the outcomes of permitting and court decisions, as a string of rejections could drive up future projects' risks and, in turn, financing costs.

2.4.6 Future outlook

The convergence of emissions control regulations, direct financial assistance, market mechanisms, market economics, and public demand have induced a rapid shift away from traditional coal- and nuclear-fired resources in favor of new natural gas and clean energy generation. Each of these forces are generally expected to continue, accelerating the growth of renewables and storage to varying degrees in power markets across the US. However, a new suite of economy-wide, state-level decarbonization efforts are poised to add to this momentum for clean energy and provide longer-term risks and opportunities to the power sector at large via impacts on load growth. These initiatives are summarized below.

Greenhouse gas reduction targets

A highly partisan issue in the US, GHG reduction efforts have gained attention on the national scale in conjunction with rising warnings from the scientific community about the risks of global climate change. The US signed two major international GHG reduction agreements in the 21st century: the 2009 Copenhagen Accord, in which the US committed to reducing GHG emissions 17% below 2005 levels by 2020, and the 2015 Paris Climate Accord, in which the US committed to 26-28% reductions below 2005 levels by 2025. In 2019, the US had achieved emissions reductions of approximately 12% below 2005 levels.[86] However, in 2020 the US surpassed its Copenhagen target of by achieving a 21.5% reduction level. This achievement is attributed to COVID-19 pandemic, that resulted in a 10.3% drop -- the largest

[85] Excludes on-site electric generation and deals signed with existing assets. Source: Rocky Mountain Institute.
[86] Rhodium Group 2020, *Preliminary US Emissions Estimates for 2019*.

single drop in annual emissions in the US during the post-World War II era. [87]. In June 2017, the Trump administration announced that the US would leave the Paris agreement and halt federal actions to reduce GHG emissions (although the US could not formally exit the Accord until November 2020). On his first day in office, President Biden signed an executive order for the US to rejoin the Paris Climate Accord (effective in 30 days thereafter), reversing the Trump administration's previous efforts. At a climate summit held at the White House in April 2021, President Biden announced his intentions for the United States to reduce its emissions 50-52% by 2030 (vs 2005 levels), laying the groundwork for a new Paris commitment at COP26 in November 2021.

During the 2017-2020 timeframe, GHG reduction policy has generally shifted to the states, seven of which (plus DC) had begun with the power sector via implementing 100% zero-carbon electricity targets. However, some policies have moved further to set economy-wide GHG emission reduction targets; for example, New York's CLCPA establishes targets to reduce emissions 40% below 1990 levels by 2030 and 85% below 1990 levels by 2050. California has similarly set a target of reducing economy-wide emissions 40% below 1990 levels by 2030. The Northeast took a regional stance to tackle emissions, through creating the Transportation Climate Initiative, a joint effort amongst 12 northeast and mid-Atlantic states and the District of Columbia aimed at curbing emissions from the transportation sector. In December of 2020, the governors of Massachusetts, Connecticut, Rhode Island and DC (as members of TCI) announced they are launching a multi-state program to lower emissions and invest $300 million per year into cleaner transportation and public health[88].

Most of the decline in GHG emissions in the US power sector over the past decade was driven by a reduction in coal-fired power generation, with this capacity primarily outcompeted by new natural gas-fired generators and renewable energy. As states pursue more comprehensive clean and renewable energy policies, GHG emissions from the power sector will continue to fall. However, GHG emissions in the transportation, industrial, and building sectors have remained relatively flat or have even increased in the past decade (excluding 2020, an anomaly year).

Electrification of transport

Vehicle electrification represents both a pathway to reduced GHG emissions as well as a potential opportunity for utilities and LSEs to increase their customer bases. Amidst an environment of ever-increasing EE standards and flat or declining electric load forecasts, EVs are one of the biggest potential drivers of future load growth. More stringent vehicle fuel efficiency and EV procurement policies, combined with cost declines in lithium ion battery manufacturing and increased consumer demand, have driven a significant increase in EV production and sales in recent years.

Ten states (CA, CT, MD, MA, ME, NJ, NY, OR, RI, and VT) have together joined the Multi-State ZEV Task Force that published an Action Plan to deploy at least 3.3 million EVs by 2025. Although this policy is non-binding, the action indicates that certain states (many of which overlap with the group of states pursuing 100% zero-carbon electricity targets) are strongly considering policies to incentivize EV deployment. In particular, California has set a strong target of deploying 5 million EVs by 2030.

Public forecasts range from relatively conservative views of EV sales accounting for nearly 20% of total annual passenger-duty vehicle sales in the US by 2050 (EIA) to more bullish scenarios of such sales reaching 50% by 2030 (IEA); the latter could ultimately add approximately 160 TWh of electricity consumption per year in the US by 2030.[89]

All else equal, increased load from vehicle electrification will put upward pressure on power prices; further, as Level 3 EV chargers have very high power draws (on the order of 80 or more kW), widespread uncoordinated EV charging (i.e., in the absence of effective time-of-use rate structures) could create immense volatility in power prices and place a heavy demand on the power grid.

Electrification of buildings

Buildings also contribute substantially to US GHG emissions, and given buildings' very long lifespans, states face a steep challenge in retrofitting or replacing their existing stock in a timely manner. Buildings primarily use natural gas and fuel oil for heating, as well as electricity for lighting, consumer products, refrigeration, and cooling. Electrification of fossil fuel-fired heating processes and continued EE improvements together have the potential to drive significant GHG emissions reductions in the buildings sector, although these actions have countervailing impacts on load growth.

A recently growing trend, various cities across the country have begun moving to ban natural gas hook-ups in new construction. Berkeley, California became the first US city to ban natural gas hook-ups in new construction in July 2019, with several additional cities and counties in California passing similar laws thereafter. Separately, many cities and counties are beginning to encourage residents to replace aging gas appliances (e.g., furnaces, water heaters) with

[87] Rhodium Group 2021, Preliminary US Emissions Estimates for 2020. https://rhg.com/research/preliminary-us-emissions-2020/
[88] Source: TCI 2020, *Massachusetts, Connecticut, Rhode Island, D.C. are First to Launch Groundbreaking Program to Cut Transportation Pollution, Invest in Communities. https://www.transportationandclimate.org*
[89] EIA *International Energy Outlook 2019*; IEA *Global EV Outlook 2019.*

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

electrically powered alternatives. Such proposals are being advanced in areas where outright bans have not yet been viable.

All else equal, banning new natural gas hook-ups and switching to electric appliances will increase electric load and put upward pressure on power prices. However, improving EE standards and more aggressive EE initiatives have the potential to decrease electric load and mitigate some of this upward price pressure, with the potential to drive declining load from the buildings sector until more significant building electrification policies take hold.

2.5 SUPPLY AND DEMAND

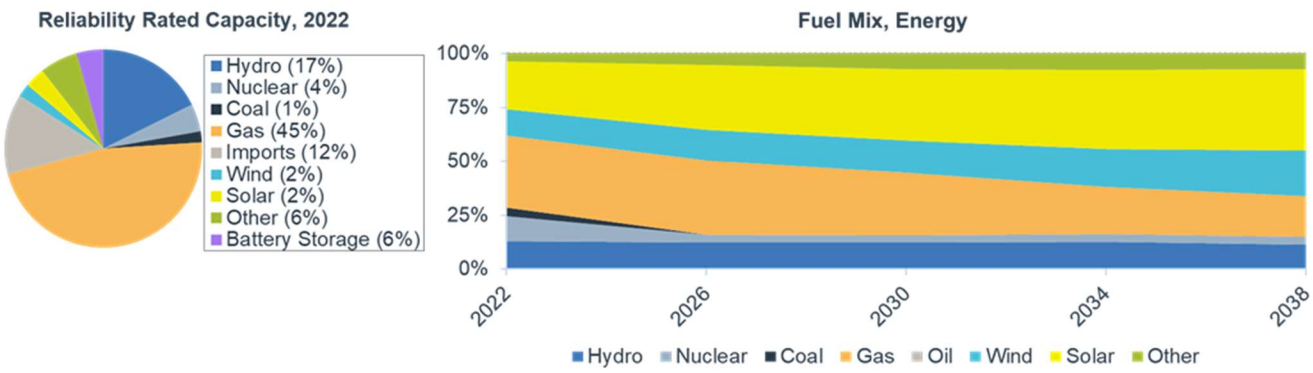
The supply and demand balance in a power market is one of the most critical factors in determining power generating asset value. In addition to capacity retirements, peak demand growth is a key factor in determining when a market will need new capacity to maintain its target reserve margin. The peak demand and energy growth rate assumptions for the California market are summarized in Table 2-10.

Table 2-10: Average Annual Growth Rates[90,91]

Period	Peak Demand	Energy
2021-2028	0.5%	0.4%
2021-2040	0.5%	0.4%

PA projects the California market to have approximately 69 GW of reliability-rated capacity to meet 57 GW of net peak demand in 2022, resulting in an installed reserve margin of 21.2%. As shown in Figure 2-30, California's reliability rated capacity mix for 2022 is 45% natural gas, 17% hydro, 12% imports, 6% battery storage, and less than 5% each of nuclear, solar, and wind, with much of the remainder coming from "other" sources such as biomass and cogeneration. California is projected to need new capacity in 2028 to meet its target reserve margin of 20.7%. This need is driven by 10.3 GW of capacity retirements – including 1.8 GW of coal from Intermountain, 2.2 GW from the Diablo Canyon nuclear station, and more than 6 GW of mostly OTC-driven natural gas – between 2021 and 2028, as well as the declining peak credit for solar capacity discussed in Section 2.2.5.

Figure 2-30: California Fuel Mix: Capacity and Energy

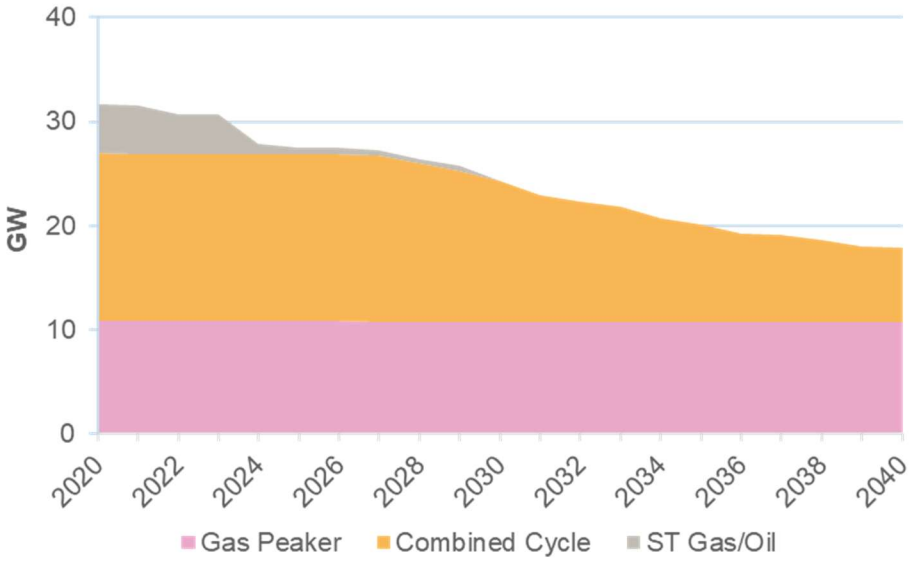


As California transitions towards a decarbonized economy, absent advances in fully dispatchable decarbonized energy resources, PA's analysis indicates natural gas fired generation will continue to be an important portion of California's capacity mix in order to maintain reliability. In particular, while the economics and capacity factors of some resources will likely decline, PA expect the majority of natural gas-fired peaking units and the majority of combined cycles (including LR2) will remain in the market through at least 2040 for reliability purpose. See Figure 2-31. The need for flexible and dispatchable generation resources is reinforced by CAISO, the CEC, and the CPUC's January 2021 final Root Cause analysis of the 2020 summer blackout, as well as NERC's most recent Long-Term Resource Assessment.

[90] Peak demand and load growth numbers through 2031 are from the 2020 CEC Mid-Demand, Mid AAEE forecast. Load growth for 2032-2040 is based on a 5 year CAGR.
[91] Values are net of the impacts of DGPV, EE, EV loads, pumping loads, and TOU rates.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Figure 2-31: California Supply: Evolution of Natural Gas-Fired Generation



2.6 COST OF NEW ENTRY

The cost of new entry is generally considered as the cost to build new power generation, incorporating financial assumptions such as debt/equity ratio, interest rate on debt, return on equity, etc., in addition to construction costs. It is also referred to as a capital cost. A power market's capital costs help define the premium a market places on capacity, and the overall compensation levels achievable in the market. See Table 2-11 for PA's CONE assumptions.

Table 2-11: Cost of New Entry – California (2021$)

Assumptions	Wind	Solar	Battery[92]
Capacity (MW)	100	100	100
Installed Capacity Cost[93] ($/kW)	1,830	1,496	1,524
Interest Rate on Debt (Nominal)	5.5%	5.5%	5.5%
Return on Equity (Nominal)	10.0%	10.0%	10.0%
Debt/Equity Ratio	65/35	65/35	65/35
Financing Life (yrs)	20	25	15
Property Tax	1.1%	1.1%	1.1%
Corporate Tax Rate	21.0%	21.0%	21.0%
Full Load Heat Rate (Btu/kWh)	N/A	N/A	N/A
Fixed O&M ($/kW-yr)	37.75	15.10	32.94
Variable O&M ($/MWh)	N/A	N/A	N/A

2.7 TRANSMISSION

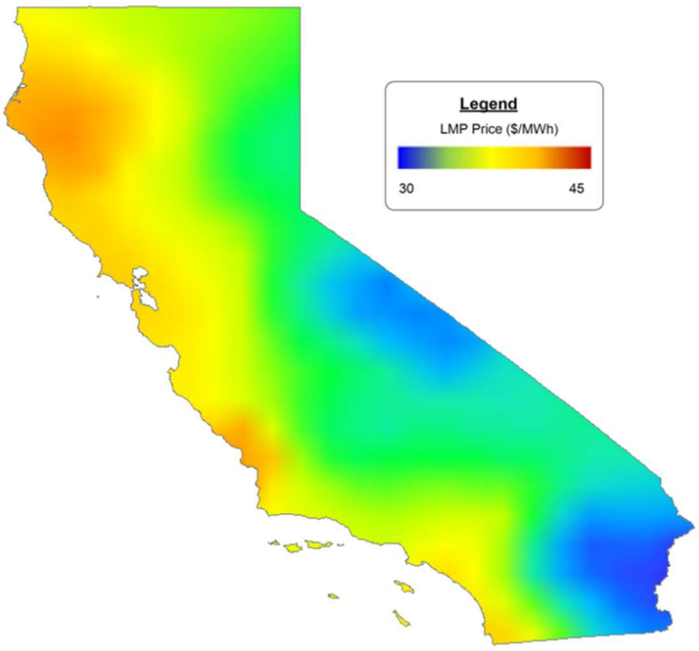
The California transmission system is comprised of a 500 kV backbone running north to south along the California and supported primarily by 230 kV lines traversing the state to supply the lower voltage level distribution system; however,

[92] Financial assumptions are for a four-hour battery.
[93] Includes interest during construction.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

pockets of congestion exist, particularly out of high-renewables areas such as the Mojave desert and in the vicinity of large coastal load centers. This is shown in the representative LMP heat map in Figure 2-32.

Figure 2-32: California 2019 Average On-Peak LMP[94]



CAISO's transmission planning process consists of a comprehensive analysis of the transmission system and is updated to reflect latest generator and demand forecasts. The most recent transmission plan (for the 2019-2020 planning process) identified 9 transmission projects totaling nearly $142 million that are designed to maintain reliability, meet renewable energy requirements, and provide economic relief throughout the state. However, no economic-driven transmission projects are recommended for approval in this planning cycle.

In the presence of evolving state renewable mandates, power generation mixes, and demand forecasts, the transmission planning process reassesses the reliability and economic benefits of previously approved transmission projects and upgrades. Numerous smaller upgrade projects designed to reduce congestion and improve deliverability are being accomplished each year. Most of these projects involve reconductoring existing lines, adding or replacing transformers, revising substation arrangements to minimize the impact of a contingency, and adding Special Protection Schemes to trip power generation for a contingency condition.

2.7.1 Transmission Impacts to the Asset

PA evaluated the interconnection location and regional transmission situation for LR2. The Asset interconnects to CAISO's 230 kV transmission system via the Imperial Valley substation. Historically, the Asset's LMPs have experienced a discount to the SP-15 Hub, primarily driven by daytime congestion; however, due to changes in generation and transmission patterns, it often realizes a slight premium to the Hub in overnight hours. Basis discounts due to congestion are driven by renewable generation overloads on nearby transmission lines that carry the region's solar energy from the east to California's southern load centers. This congestion discount is often greater during the fall and winter months, and also greater during on-peak hours.

CAISO has proposed a Remedial Action Scheme to mitigate thermal overloads on the transmission lines impacting the Asset's daytime relationship, with a proposed in-service date in 2022 and subsequent transmission upgrades scheduled in 2026. With the continued penetration of solar generation in eastern California, LR2 is projected to realize an average discount to the Hub during on-peak hours; however, due to lower east-to-west flows in the overnight hours, it is projected to realize a slight premium to the Hub in off-peak hours, on average. PA projects that the Asset will continue to observe a discount in the winter and fall months of approximately 5% in the on-peak hours to the SP-15 Hub throughout the study period.

[94] Source: PA Consulting Group and copyrighted material excerpted from Ventyx's *Velocity Suite* Energy Map.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

3 MARKET PROJECTIONS

This section provides an overview of PA's projections for the California power market based on the assumptions described in Section 2. Specifically, this section provides PA's projections of clean market spark spreads, clean market heat rates, and resource adequacy from 2021 to 2040, as well as fuel on the margin and dispatch curve figures.

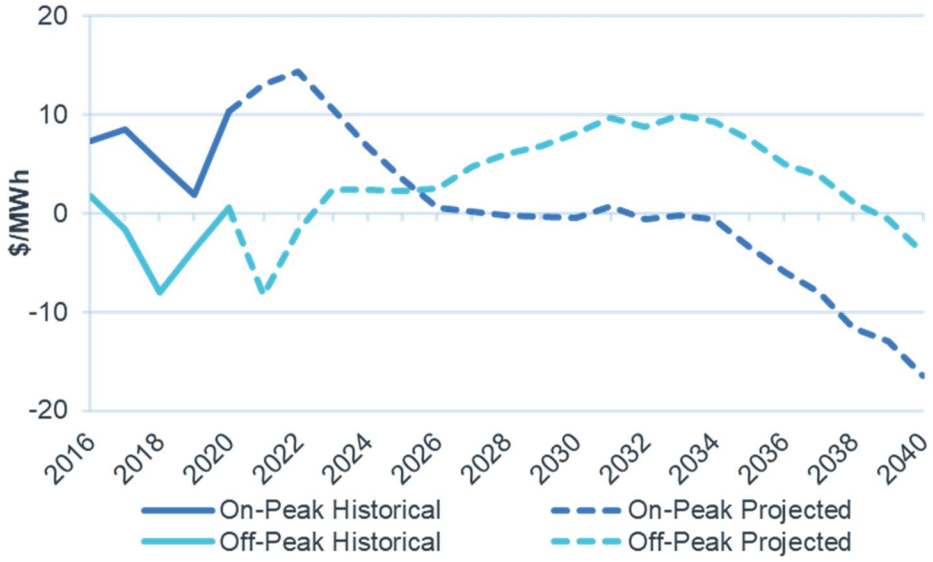
3.1 CLEAN MARKET SPARK SPREADS

Clean market spark spreads, along with resource adequacy revenues, are a primary indicator of a natural gas-fired power plant's earnings potential in a wholesale electricity region like California. Clean market spark spreads are driven by a number of factors including electricity demand, commodity prices, near-term weather, capacity additions and retirements, and environmental regulations (including CO_2 emissions allowance prices).

In California, upward pressures on spark spreads primarily include rising natural gas prices (which in turn drive even higher power prices, as natural gas-fired generators set the price of power in most hours in California), rising CO_2 emissions allowance prices (wherein the boost to power prices is greater than the increase in variable operating costs for a representative 7,000 Btu/kWh combined cycle in most years), and large generator retirements (wherein a tightened dispatch stack leads less-efficient gas-fired generators to be on the margin and setting prices more frequently). Downward pressures on spark spreads primarily include new renewable energy (wherein near-zero marginal cost capacity is added to the dispatch stack and drives more-efficient generators to be on the margin more often, thereby lowering power prices without affecting natural gas prices) and energy storage builds (which can support midday prices when they're charging but have a greater depressing impact on-peak hour prices when discharging).

As shown in Figure 3-1, near-term on-peak spark spreads are uplifted in the forwards markets, reflecting expectations of COVID-19 recovery and tight summer conditions driven by hotter than normal weather and drought conditions, which lowers available hydroelectric capacity. PA projects SP-15 on-peak clean market spark spreads to decline from current levels in the early 2020s with normalizing weather and hydrological conditions, falling natural gas prices and the continued entry of solar and battery storage additions. This trend is moderated by significant retirements beginning in the mid-2020s, temporarily stabilizing on-peak spark spreads around $0/MWh. Ultimately, the continued entry of renewables and storage cause spark spreads to continue declining in the long term.

Figure 3-1: Clean Market Spark Spreads – California SP-15[95,96]



Historically, off-peak clean market spark spreads have priced below on-peak spreads, as on-peak power prices have typically been set predominantly by more expensive peaking generators. However, PA projects off-peak clean market spark spreads to increase from current levels, surpassing on-peak spark spreads by 2026. This trend is driven by the continued penetration of solar resources, which contribute to very low power prices in the mid-day hours (intersecting with CAISO's definition for "on-peak hours"). As solar and storage penetration drive down daytime spark spreads, lower

[95] Clean market spark spreads normalize for assumed price of CO2. Clean spark spread subtracts the variable CO2 cost of a 7,000 Btu/kWh combined cycle.
[96] 2021 uses a blend of historical spot prices (Jan-Jun) and forwards (Jul-Dec).

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

renewable production overnight plus thermal retirements (e.g., Diablo Canyon nuclear in 2025 and 2026) act to support higher overnight spark spreads. In the longer term, growth in off-peak clean market spark spreads is moderated and eventually reversed as large amounts of renewable and energy storage capacity slow the growth of off-peak power prices.

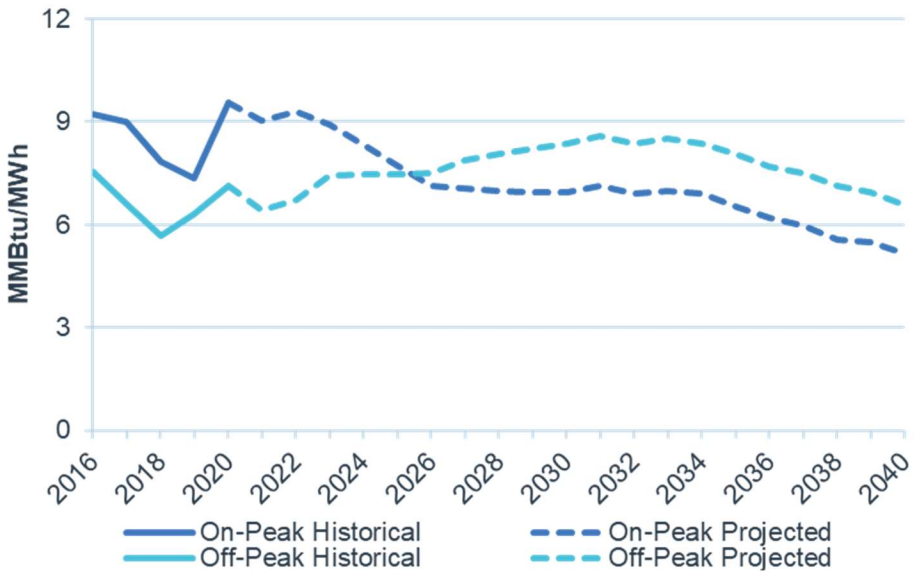
3.2 CLEAN MARKET HEAT RATES

Clean market heat rates measure the efficiency of the power plant setting the energy price in a given market. In general, market heat rates are inversely correlated with natural gas prices; that is, as natural gas prices increase, market heat rates tend to decrease, all else equal. This relationship is strongest in markets where natural gas is the marginal fuel in most hours, as is the case in California.

As illustrated in Figure 3-2, PA projects on-peak clean market heat rates for SP-15 to be uplifted in the near-term, as power forwards reflect an expectation of tight market conditions. PA projects on-peak clean market heat rates to generally decline in the mid-2020s over the study period as thermal power generation retirements are replaced by more efficient renewable and energy storage capacity additions and as weather conditions normalize. This trend is moderated in the middle of the study period, since California is projected to need new capacity to meet reliability in 2028, as large baseload thermal generator retirements (e.g., Diablo Canyon 1-2 in 2025-26) put upward pressure on power prices and heat rates. At this point, significant higher-cost capacity entry (including Intermountain and long-duration storage) temporarily increases market heat rates. However, in the long term, sustained entry of renewables and storage (and capital cost declines for both) drives on-peak clean market heat rates back down.

Similar to spark spreads, PA projects off-peak clean market heat rates to rise through most of the study period, surpassing on-peak heat rates by 2026. The retirement of base load generation (such as Diablo Canyon nuclear in 2025 and 2026) act to support higher overnight heat rates as less efficient generators must be dispatched to meet load. In the longer term, growth in off-peak clean market heat rates is moderated and eventually reversed as large amounts of renewable and energy storage capacity bring down market heat rates further.

Figure 3-2: Clean Market Heat Rates – California SP-15[97,98]



3.3 CAPACITY COMPENSATION

Capacity compensation represents the amount of revenue, net of energy and ancillary services revenue, that the marginal unit required for reliability would need in order to ensure the recovery of fixed and non-sunk investment costs. In California, capacity compensation is expected to be realized primarily through the RA mechanism (see Section 2.2.2).

System RA pricing has risen substantially in the past few years due to tightening reserve margins, which reflects the declining ELCC of solar as well as some thermal capacity retirements. In response, some planned retirements have been delayed in order to maintain reliability. PA projects RA capacity prices to gradually increase in the 2020s as thermal retirements and load growth outpace the capacity contribution of replacement renewable and energy storage capacity

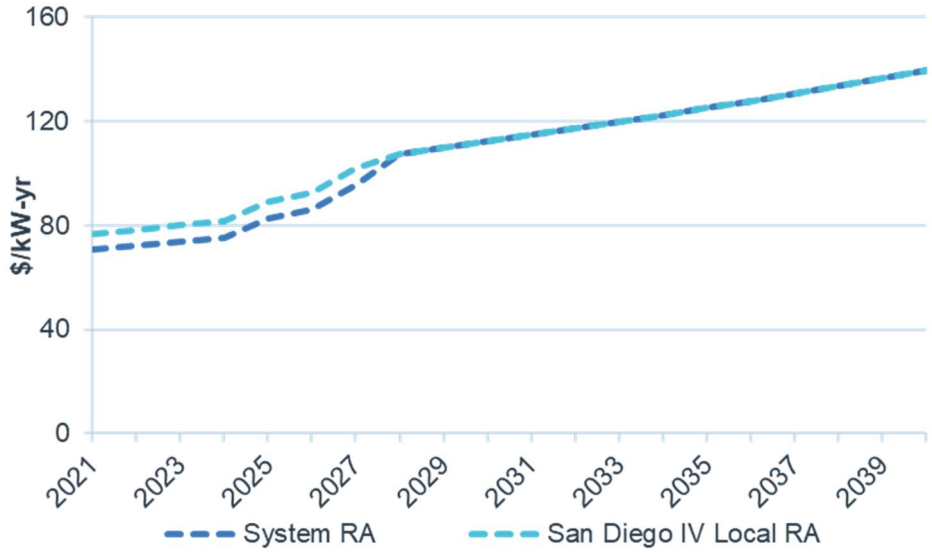
[97] Clean market heat rates normalize for assumed price of CO_2 and subtracts the variable CO_2 cost of a 7,000 Btu/kWh combined cycle.
[98] 2021 uses a blend of historical spot prices (Jan-Jun) and forwards (Jul-Dec).

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

additions. The full California electricity region is projected to be short supply in 2028, driven by over 10 GW of thermal retirements (largely units affected by OTC regulations) as well as further declines in the ELCC of wind and solar.

PA projects that new capacity (primarily renewable and energy storage) in the California market will continue entering the market via long-term bilateral agreements, thus maintaining the current bifurcated market structure between new and existing resources for capacity recovery. This means that the amount of legacy capacity that will be competing for RA contracts will prevent long-term System RA pricing from rising materially above the net fixed costs of existing thermal power generation. Specifically, PA anticipates that this existing unit will be a natural gas-fired generator located in California, since existing out-of-state power generation will be needed to satisfy reserve margins in the Desert Southwest and elsewhere (and the CPUC is instituting reforms to RA imports – see Section 2.2.5). Therefore, System RA pricing is projected to reflect the fixed cost of existing in-state natural gas-fired combined cycle generators (inclusive of firm natural gas transportation costs), rather than reaching thermal new build costs. See Figure 3-3.

Figure 3-3: California Projected System and Local RA Capacity Compensation[99]



Additionally, PA developed a Local RA premium for San Diego–Imperial Valley LCR by analyzing available supply, transmission constraints, and demand within the LCA as well as observed transactions for Local RA. Based on this analysis, PA forecasts San Diego-IV to be at a modest premium (approximately $0.50/kW-mo, or $6/kW-yr) to system RA in the near-term driven by relatively tight conditions within the LCA. Specifically, San Diego–IV is projected to have 4.6 GW of load in 2022, 4.4 GW of qualifying capacity and a 4.0 GW LCR (which needs to be satisfied by in-area capacity). Over the next several years, the LCR is projected by CAISO to decline to 3.6 GW in 2025 and to 3.4 GW in 2026 due to transmission upgrades and capacity additions, which together reduces the LCR. By 2028, PA projects this premium over system RA to decline to zero.

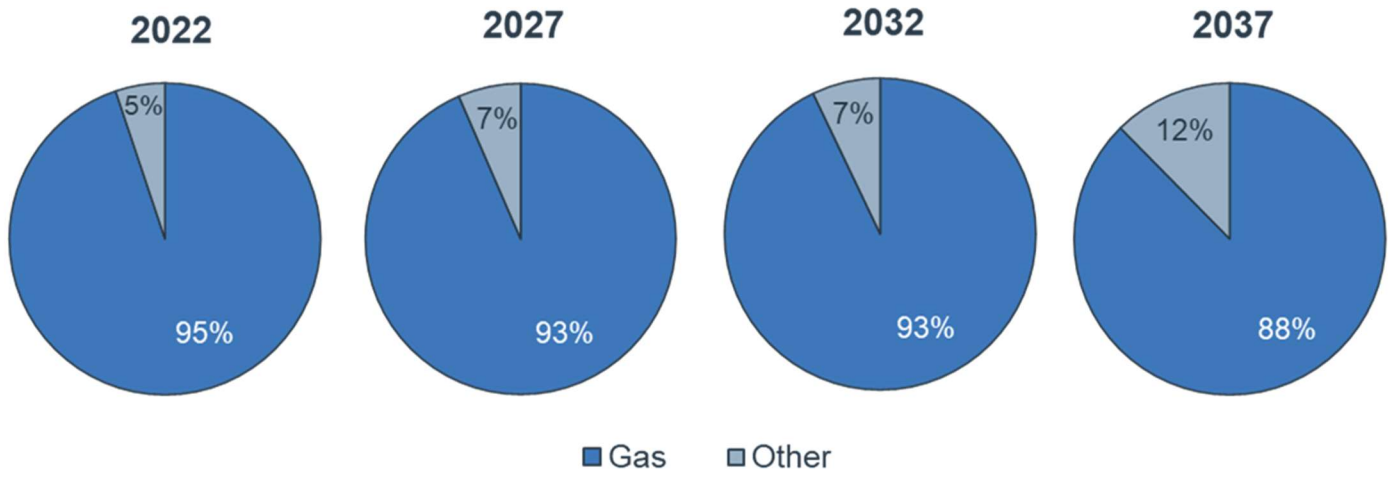
3.4 FUEL ON THE MARGIN

Natural gas-fired generators are projected to determine the price of energy in California in the vast majority of hours throughout the study period, with other resource types (mainly renewables) setting the price in the remainder. In the 2030s, significant growth in renewables and energy storage displaces natural gas for power generation, driving the percentage of hours in which the latter sets the price of power down to 88% by 2037 (and increasing the grid's reliance on renewable power generation). See Figure 3-4.

[99] Incremental capacity compensation may be realized in the energy markets, bilateral transactions or in other ways long term.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

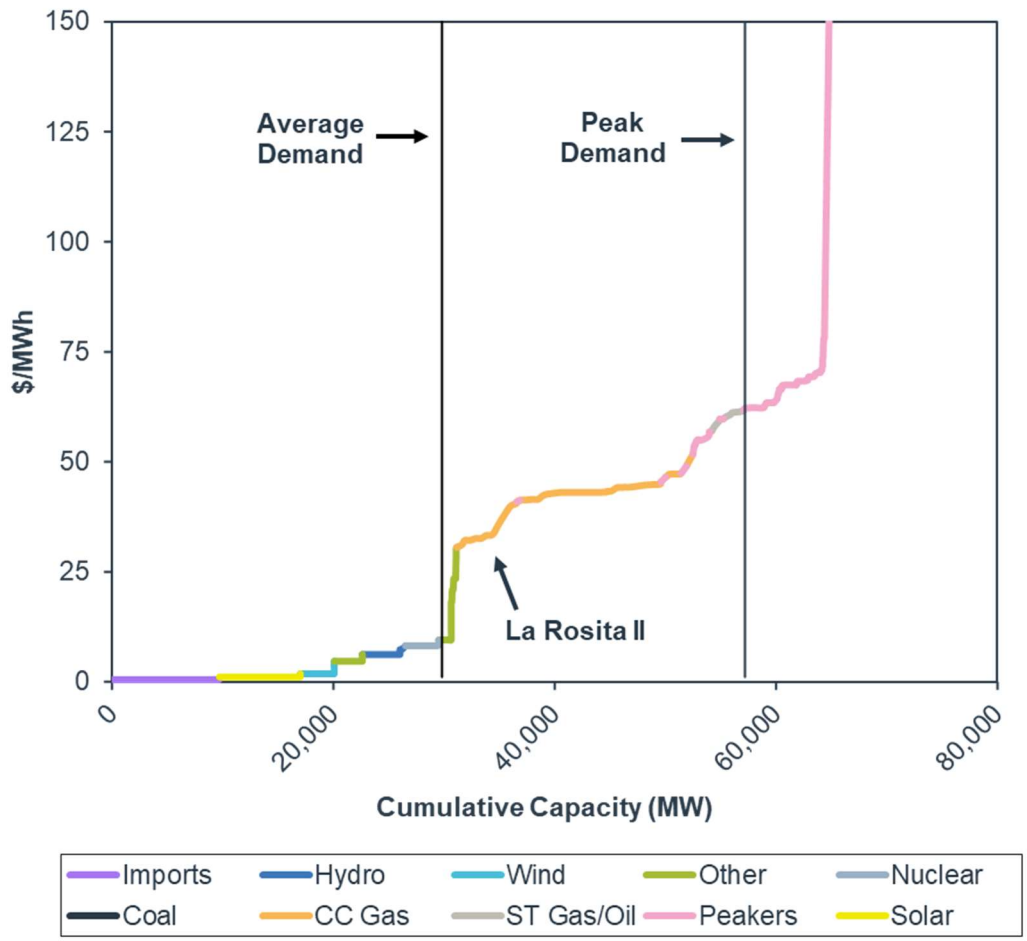
Figure 3-4: California Fuel on the Margin



3.5 DISPATCH MERIT ORDER CURVE

A dispatch merit order curve (or dispatch curve) illustrates power generating assets in order of their individual variable cost of operation, also referred to as the "dispatch cost," from a high-level snapshot perspective. The dispatch curve in Figure 3-5 shows the annual average, short-run marginal dispatch cost of power generating assets located in California. LR2, as a reasonably efficient combined cycle generator with a summer baseload heat rate of 7,410 Btu/kWh, falls directly within the area of other mid-merit generators.

Figure 3-5: California 2022 Dispatch Curve[100]



[100] Other includes storage, geothermal, biomass, municipal solid waste, and landfill gas.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

4 ASSET PROJECTIONS

This section provides an overview of PA's projections of LR2's operations and contribution margins from 2021 through 2040. PA forecasted LR2's operations and contribution margins using its standard modeling approach (see Appendix B for a detailed description), incorporating market power and commodity prices from PA's fundamental energy market model and operating dispatch characteristics provided by the Client.

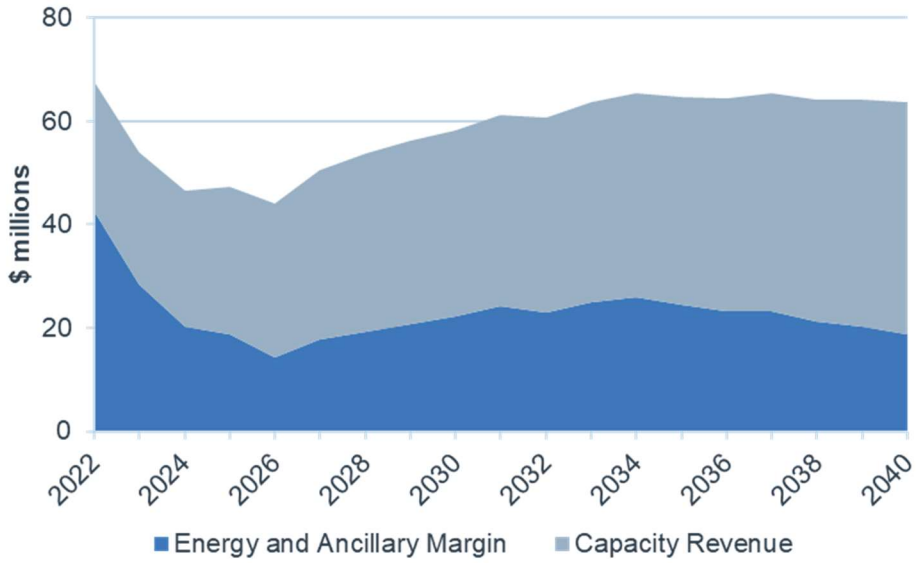
The market assumptions underlying PA's fundamental energy market model are outlined in Section 2. The clean market spark spreads, heat rates, and capacity price projections are described in Section 3, and the operating dispatch characteristics for the Asset are shown in Appendix A-6. All values are expressed in nominal terms using a 2.2% inflation assumption.

4.1 CONTRIBUTION MARGINS

PA projects LR2's contribution margins (excluding major maintenance) to decrease from $68 million in 2022 (first full year of projections) to $44 million in 2026 as near-term supply and weather-driven strong market conditions normalize and as new supply enters the California market. Thereafter, contribution margins increase gradually and flatten over the remainder of the study period (to $58 million in 2030 and to $64 million in 2040. Energy and ancillary margins are projected to follow the trajectory of spark spreads: declining in the early 2020s (from $43 million in 2022 to $14 million in 2026) due to the easing of tight near-term market conditions and declining natural gas prices, and then rising gradually thereafter.

By the mid-2030s, LR2's energy and ancillary margins flatten out due to continued renewable additions and rising CO_2 pricing. Capacity revenues make up the remainder of total margins, steadily rising from $25 million in 2022 to nearly $45 million in 2040. Capacity revenues make up a growing share of contribution margins, averaging 37% in 2022 and over 50% annually starting in 2024. Over the study period, capacity revenues make up 61% of total margins.

Figure 4-1: La Rosita II Contribution Margin Projections[101]



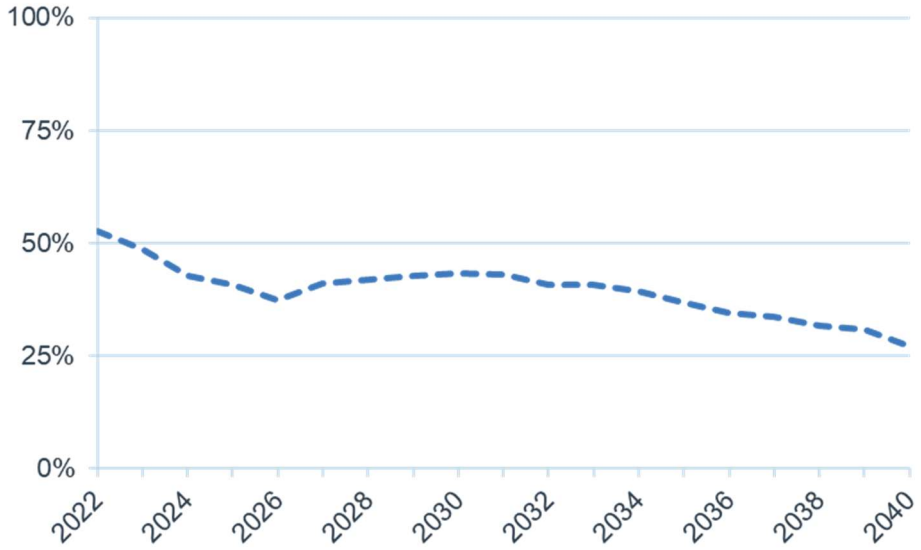
4.2 CAPACITY FACTORS

Figure 4-2 shows LR2's projected capacity factors. In the near-term, capacity factors are projected to soften, as current market conditions ease with new entry and as weather conditions normalize. Thereafter, LR2's capacity factors improve over the 2020s as large baseload generator retirements (e.g., Diablo Canyon 1-2 in 2025-26) put upward pressure on heat rates (particularly off-peak). By the 2030s, sustained renewable and storage capacity entry drives market heat rates back down and causes LR2 to be dispatched in fewer hours. LR2's capacity factors are projected to average 40% over the study period.

[101] Balance of year 2021 projections are excluded from this figure.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Figure 4-2: La Rosita II Capacity Factors[102]



[102] Balance of year 2021 projections are excluded from this figure.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

APPENDIX

A	PROJECTION AND ASSUMPTION DETAIL	76
A.1	MARKET PROJECTIONS	76
A.2	COMMODITY AND EMISSION PRICE PROJECTIONS	77
A.3	SUPPLY AND DEMAND PROJECTIONS	79
A.4	FIRM CAPACITY ADDITIONS AND RETIREMENTS	80
A.5	TRANSMISSION	81
A.6	OPERATING DISPATCH CHARACTERISTICS	82
A.7	CONTRIBUTION MARGIN PROJECTIONS	83
B	MODELING METHODOLOGY	84

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

A PROJECTION AND ASSUMPTION DETAIL

This appendix provides an overview of PA's market assumptions and projections for the California power market. All values, unless otherwise noted, are in nominal dollars, based on an inflation rate of 2.2%.

A.1 MARKET PROJECTIONS

Table A-1(a): Market Price Projections – CA SP-15[103,104]

Year	System RA Price ($/kW-yr)	San Diego - Imperial Valley Local RA ($/kW-yr)	All-Hours Market Power Price ($/MWh)	On-Peak Market Power Price ($/MWh)	Off-Peak Market Power Price ($/MWh)	Delivered Natural Gas Price ($/MMBtu)	On-Peak Clean Market Spark Spread ($/MWh)	On-Peak Clean Market Heat Rate (Btu/kWh)	Off-Peak Clean Market Heat Rate (Btu/kWh)
2021	70.52	76.52	72.42	89.32	50.40	6.99	33.79	11,259	6,353
2022	72.07	78.20	51.33	58.23	42.11	5.26	14.34	9,287	6,715
2023	73.65	79.92	45.60	49.12	40.95	4.42	10.58	8,923	7,439
2024	75.28	81.68	40.92	42.81	38.36	3.99	6.80	8,322	7,457
2025	82.59	89.00	36.61	37.11	35.93	3.57	3.46	7,721	7,475
2026	86.11	92.51	37.20	36.39	38.29	3.78	0.61	7,120	7,493
2027	95.40	101.80	39.51	37.59	42.09	3.91	0.21	7,038	7,881
2028	107.40	107.40	41.27	38.61	44.79	4.02	-0.20	6,964	8,079
2029	109.76	109.76	42.87	39.79	47.01	4.10	-0.36	6,938	8,196
2030	112.17	112.17	44.62	40.96	49.51	4.16	-0.44	6,926	8,371
2031	114.64	114.64	47.64	43.78	52.79	4.27	0.73	7,119	8,583
2032	117.16	117.16	48.42	44.44	53.74	4.41	-0.54	6,917	8,364
2033	119.74	119.74	50.46	46.11	56.29	4.46	-0.23	6,965	8,502
2034	122.38	122.38	51.61	47.36	57.27	4.53	-0.59	6,914	8,361
2035	125.07	125.07	51.12	46.45	57.36	4.63	-3.41	6,521	8,053
2036	127.82	127.82	50.82	46.15	57.06	4.77	-5.88	6,208	7,677
2037	130.63	130.63	51.52	46.43	58.32	4.93	-8.07	5,963	7,491
2038	133.50	133.50	50.85	45.39	58.16	5.08	-11.63	5,572	7,140
2039	136.44	136.44	51.90	46.58	59.02	5.23	-13.01	5,472	6,933
2040	139.44	139.44	51.14	45.76	58.28	5.37	-16.51	5,144	6,550

[103] <<< Incorporates forwards as of 6-28-21. 2021 is a partial year (August-December).

[104] California SP-15 Gas Hub: SoCal Citygate. Clean market spark spreads and market heat rates normalize for assumed price of CO2. Clean spark spreads and heat rates subtract the variable CO_2 cost of a 7,000 Btu/kWh combined cycle.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

A.2 COMMODITY AND EMISSION PRICE PROJECTIONS

Table A-2(a): Natural Gas Price Commodity Projections[105,106]

Year	Henry Hub ($/MMBtu)	CA SP-15 Delivered ($/MMBtu)
2021	3.61	6.99
2022	3.16	5.26
2023	2.95	4.42
2024	3.16	3.99
2025	3.39	3.57
2026	3.60	3.78
2027	3.71	3.91
2028	3.83	4.02
2029	3.93	4.10
2030	4.03	4.16
2031	4.15	4.27
2032	4.30	4.41
2033	4.37	4.46
2034	4.46	4.53
2035	4.59	4.63
2036	4.71	4.77
2037	4.89	4.93
2038	5.05	5.08
2039	5.20	5.23
2040	5.35	5.37

[105] <<< Incorporates forwards as of 6-28-21. 2021 is a partial year (August-December).
[106] California SP-15 Gas Hub: SoCal Citygate.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Table A-2(b): Emission Allowance Price Projections[107]

Year	AB 32 CO2 ($/short ton)	AB 32 CO2 ($/metric ton)
2021	16.07	17.71
2022	17.22	18.99
2023	18.46	20.35
2024	19.79	21.82
2025	21.22	23.39
2026	22.75	25.07
2027	24.38	26.88
2028	26.14	28.81
2029	28.02	30.89
2030	30.04	33.11
2031	32.20	35.49
2032	34.52	38.05
2033	37.00	40.79
2034	39.67	43.73
2035	42.52	46.88
2036	45.59	50.25
2037	48.87	53.87
2038	52.39	57.75
2039	56.16	61.90
2040	60.20	66.36

[107] PA's base case assumes California's state-specific greenhouse gas cap-and-trade program (AB 32), under which power imported into the AB 32 controlled region (e.g., California) will have the CO2 associated with this imported generation costed, effectively creating an incremental wheeling charge for out-of-state power accessing the California market.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

A.3 SUPPLY AND DEMAND PROJECTIONS

Table A-3(a): California Supply and Demand Projections: 2021 – 2030[108]

MW	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2020 Supply	67,044									
Combined Cycle	-	-	-	-	840	-	-	-	-	-
Combustion Turbine	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-
Hydro	3	-	-	-	-	-	-	-	-	-
Solar	260	(340)	11	35	15	(175)	(139)	(132)	(121)	(115)
Wind	120	104	42	101	69	28	34	(1)	48	23
Other Renewables	55	137	200	135	205	1,005	205	205	205	405
Energy Storage	1,762	1,470	1,750	5,735	1,219	1,197	197	1,197	690	1,444
Imports/Exports	-	-	-	-	-	(1,000)	(1,000)	(1,000)	-	-
Demand Side Resources	-	-	-	-	-	-	-	-	-	-
Retirements - Coal	-	(203)	-	-	(1,542)	-	-	-	-	-
Retirements - Non Coal	(273)	(839)	-	(2,835)	(1,480)	(1,118)	(307)	(1,735)	(575)	(1,377)
Total Supply	68,970	69,299	71,302	74,474	73,800	73,737	72,728	71,263	71,511	71,890
Gross Peak Demand[a]	58,419	58,887	59,655	60,635	61,215	61,931	62,468	62,994	63,529	64,238
Peak Shift Impact[b]	1,364	1,703	2,108	2,443	2,803	3,202	3,568	3,997	4,298	4,678
Net Peak Demand	57,055	57,185	57,547	58,191	58,412	58,728	58,900	58,997	59,231	59,561
Gross Load Growth		0.8%	1.3%	1.6%	1.0%	1.2%	0.9%	0.8%	0.8%	1.1%
Net Load Growth		0.2%	0.6%	1.1%	0.4%	0.5%	0.3%	0.2%	0.4%	0.6%
Reserve Margin	20.9%	21.2%	23.9%	28.0%	26.3%	25.6%	23.5%	20.8%	20.7%	20.7%

Table A-3(b): California Supply and Demand Projections: 2031 – 2040[109]

MW	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Combined Cycle	-	-	-	-	-	-	-	-	-	-
Combustion Turbine	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-	-	-	-
Solar	(102)	(98)	(93)	(85)	(79)	(72)	(66)	(65)	(57)	11
Wind	57	42	67	131	135	170	117	121	143	144
Other Renewables	205	205	205	200	200	200	200	200	200	200
Energy Storage	1,645	836	792	1,151	(194)	597	309	(264)	753	234
Imports/Exports	-	-	-	-	1,000	-	-	1,000	-	-
Demand Side Resources	-	-	-	-	-	-	-	-	-	-
Retirements - Coal	-	-	-	-	-	-	-	-	-	-
Retirements - Non Coal	(1,390)	(590)	(597)	(1,039)	(659)	(511)	(154)	(570)	(590)	(106)
Total Supply	72,305	72,701	73,075	73,433	73,836	74,219	74,625	75,047	75,495	75,978
Gross Peak Demand[a]	64,937	65,665	66,395	67,166	67,985	68,854	69,780	70,768	71,825	72,956
Peak Shift Impact[b]	5,044	5,441	5,870	6,333	6,834	7,376	7,962	8,596	9,282	10,024
Net Peak Demand	59,892	60,224	60,525	60,834	61,151	61,478	61,818	62,172	62,543	62,932
Gross Load Growth	1.1%	1.1%	1.1%	1.2%	1.2%	1.3%	1.3%	1.4%	1.5%	1.6%
Net Load Growth	0.6%	0.6%	0.5%	0.5%	0.5%	0.5%	0.6%	0.6%	0.6%	0.6%
Reserve Margin	20.7%	20.7%	20.7%	20.7%	20.7%	20.7%	20.7%	20.7%	20.7%	20.7%

[108] [a] Peak demand and load growth numbers through 2031 are from the 2020 CEC Mid-Demand, Mid AAEE forecast. Load growth for 2032-2040 is based on a 5-year CAGR; [b] The peak shift impact captures the impact of DGPV, EE, EV loads, pumping loads, and TOU rates on peak demand.
[109] *Ibid*.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

A.4 FIRM CAPACITY ADDITIONS AND RETIREMENTS

Table A-4(a): Firm Thermal and Hydro Additions – California[110]

Project Name	Zone	Estimated COD (Year)	Fuel Type	Capacity (MW)	Unit Type
White Rock - South Fork Powerhouse & Boating Flow Release Facility	N. California	2021	Water	3	HY
Intermountain Power Project CC	S. California	2025	Natural Gas	840	CC

Table A-4(b): Firm Renewable Additions (over 100 MW) – California[111]

Project Name	Zone	Estimated COD (Year)	Fuel Type	Capacity (MW)	Storage Capacity (MW)
Gateway Energy Storage Project 2-3	S. California	2021	Energy Storage	188	
Moss Landing Energy Storage Facility 1	N. California	2021	Energy Storage	300	
Saticoy Battery Storage Project (Ventura Energy Storage)	S. California	2021	Energy Storage	100	
Tesla Moss Landing Battery Energy Storage Project (Elkhorn)	N. California	2021	Energy Storage	182	
Blythe Solar II ES	S. California	2021	Energy Storage	115	
Blythe Solar III ES	S. California	2021	Energy Storage	115	
McCoy ES	S. California	2021	Energy Storage	230	
Alamitos Energy Center (AES Alamitos Energy Battery Storage Array) 1	S. California	2021	Energy Storage	100	
American Kings Solar Project	N. California	2021	Solar	123	
Golden Fields Solar III Project (Rosamond)	S. California	2021	Solar	192	
Maverick Solar 4 Project	S. California	2021	Solar	100	
Mustang Two Solar Park	N. California	2021	Solar	150	
Palen Solar Project (Maverick Solar Project) (Almasol)	S. California	2021	Solar	125	
Crescent City Harbor Solar	N. California	2021	Solar	350	
Westlands Almond	S. California	2021	Solar	250	
Vega SES	S. California	2021	Solar + Storage	100	100
White Hills (Arizona Wind Farm)	S. California	2021	Wind	350	
Luna Battery Storage Project	S. California	2022	Energy Storage	100	
Moss Landing Energy Storage Facility 2	N. California	2022	Energy Storage	100	
Alamitos Energy Center (AES Alamitos Energy Battery Storage Array) 2	S. California	2022	Energy Storage	100	
Aquamarine Westside Solar Project	S. California	2022	Solar	250	
Arlington (Riverside County Solar) Phase 1	S. California	2022	Solar	100	
Athos Solar Project 1	S. California	2022	Solar	250	
Palen Solar Project (Maverick Solar Project) (Almasol)	S. California	2022	Solar	232	
Chaparall	S. California	2022	Solar	125	
Tumbleweed	S. California	2022	Solar	125	
Westlands Aquamarine	S. California	2022	Solar	250	
Drew Solar Project	S. California	2022	Solar	100	
Athos Solar Project 2	S. California	2022	Solar	200	
Desert Quartzite Solar Project	S. California	2022	Solar	450	
Sandrini Solar Park Phase 1	S. California	2022	Solar	100	
The Slate Solar Project	N. California	2022	Solar + Storage	300	140
High Desert Solar & Battery Storage Project	S. California	2022	Solar + Storage	100	50
Big Beau Solar+Storage Project	S. California	2022	Solar + Storage	128	60
Rabbitbrush Solar Plus Storage Project	N. California	2022	Solar + Storage	100	20
Alamitos Energy Center (AES Alamitos Energy Battery Storage Array) 3	S. California	2023	Energy Storage	100	
Arlington (Riverside County Solar) Phase 2	S. California	2023	Solar	133	
Sandrini Solar Park Phase 2	S. California	2023	Solar	200	
Sonrisa Solar Park	S. California	2023	Solar + Storage	200	40
Edwards Air Force Base Solar Project (Edwards Solar II)	S. California	2023	Solar	100	
Raceway Solar 1	S. California	2023	Solar	125	
Sanborn Solar Project	S. California	2023	Solar + Storage	300	50
Eland Solar & Storage Center 1 & 2	S. California	2023	Solar + Storage	400	300
Aratina Solar Center	N. California	2024	Solar + Storage	200	50
Rexford 1 Solar & Storage Center	S. California	2024	Solar + Storage	300	180
Small Biomass Projects	CAISO	2020 -2025	Biomass	85	
Small Energy Storage Projects	CAISO	2020 -2025	Energy Storage	668	
Small Solar Projects	CAISO	2020 -2025	Solar	1,218	
Small Fuel Cell Solar Projects	CAISO	2020 -2025	Fuel Cell	0	
Small Solar + Storage Projects	CAISO	2020 -2025	Solar + Storage	247	153
Small Geothermal Projects	CAISO	2020 -2025	Geothermal	46	
Small Wind Projects	CAISO	2020 -2025	Wind	380	10

[110] If a power generating asset is not on-line by August 1st of a given year, it does not count towards market reliability until the following year.
[111] *Ibid*.

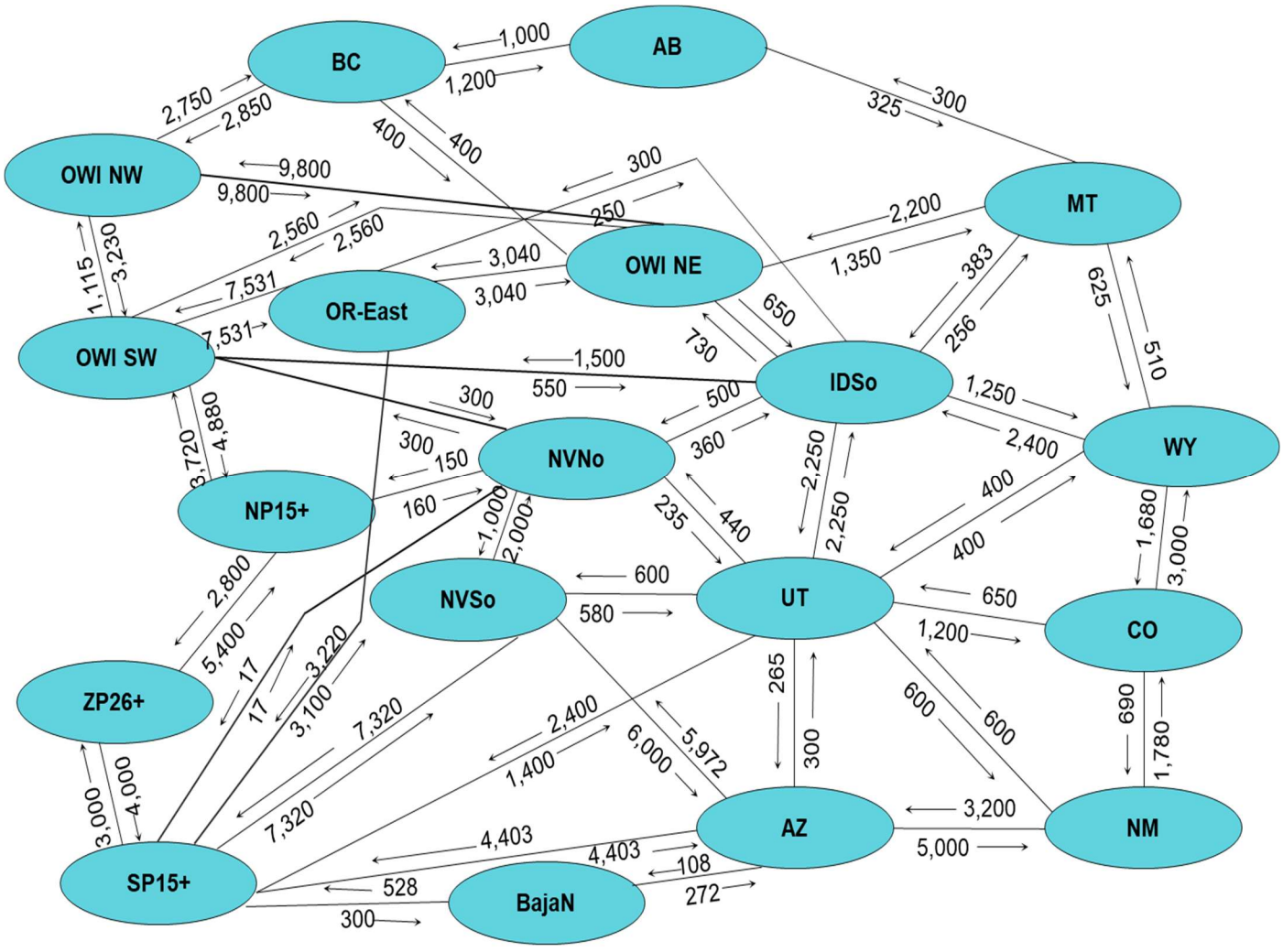
Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Table A-4(c): Firm Retirements – California[112]

Plant Name	Zone	Retirement Year	Type	Capacity (MW)
Biola University	S. California	2021	Peaker	1
Coca Cola American Canyon Plant	N. California	2021	Other	1
Tajiguas Landfill	S. California	2021	Other	3
Grayson CC	S. California	2021	Gas CC	118
Cow Creek HY 1-2	N. California	2021	Hydro	2
Grayson ST 3	S. California	2021	Other	18
Grayson ST 4-5	S. California	2021	ST Gas/Oil	80
Kilarc	N. California	2022	Hydro	2
Redondo Beach ST 5-6,8	S. California	2022	ST Gas/Oil	840
Oakland	N. California	2023	ST Gas/Oil	165
Alamitos ST 3-5	S. California	2024	ST Gas/Oil	1,152
Huntington Beach ST 2	S. California	2024	ST Gas/Oil	226
Ormond Beach ST 1-2	S. California	2024	ST Gas/Oil	1,516
Intermountain ST 1-2	S. California	2025	Coal	1,800
Diablo Canyon PWR 1	N. California	2025	Nuclear	1,122
Scattergood ST 1-2	S. California	2025	ST Gas/Oil	305
Diablo Canyon PWR 2	N. California	2026	Nuclear	1,118
Haynes CC 8-10	S. California	2029	Gas CC	575
Harbor CC 5, 10A, 10B	S. California	2030	Gas CC	231
Haynes ST 1-2	S. California	2030	ST Gas/Oil	444

A.5 TRANSMISSION

Table A-5: 2021 Transfer Capability – WECC (MW)



[112] "Retirement Year" corresponds to the year a power generating asset retirement affects the reserve margin referenced in Tables A-3(a) and A-3(b). If a plant does not retire by August 1st of a given year, it does not impact that table until the following year.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

A.6 OPERATING DISPATCH CHARACTERISTICS

Table A-6(a): La Rosita II Operating Dispatch Characteristics

Operation State	Winter Capacity (MW)	Summer Capacity (MW)	Winter Heat Rate (Btu/kWh)	Summer Heat Rate (Btu/kWh)	VOM Total (2021$/MWh)
1x1 Max + Duct	328	318	7,563	7,709	$3.13
1x1 Max	263	258	7,252	7,410	$3.13
1x1 Min	185	185	7,500	7,550	$3.13

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

A.7 CONTRIBUTION MARGIN PROJECTIONS

Table A-7(a): La Rosita II Contribution Margins (2021-2030)[113]

La Rosita 2	Units	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Operations:											
RA Capacity	MW	322	322	322	322	322	322	322	322	322	322
Operating Capacity[a]	MW	318	318	318	318	318	318	318	318	318	318
Production	GWh	830	1,500	1,387	1,220	1,164	1,063	1,171	1,197	1,221	1,236
Capacity Factor	%	58%	53%	49%	43%	41%	37%	41%	42%	43%	43%
Total Fuel Used (inc start fuel)	MMBtu'000	6,309	11,393	10,511	9,274	8,877	8,107	8,910	9,109	9,284	9,394
Total Turbine Starts	#	156	323	330	334	356	339	333	331	320	316
Total Turbine Run Hours	hrs	2,928	5,289	4,918	4,322	4,106	3,765	4,123	4,224	4,278	4,323
N-Factor	#	19	16	15	13	12	11	12	13	13	14
Market Revenue:											
Market Capacity	$'000	12,319	25,181	25,735	26,301	28,657	29,789	32,780	34,582	35,342	36,120
Market Energy	$'000	77,859	99,235	80,498	64,943	58,609	53,177	62,199	66,570	70,967	75,073
Incremental Regulation and Reserves	$'000	289	379	269	151	136	115	137	148	149	145
Total Revenue	**$'000**	**90,468**	**124,795**	**106,502**	**91,395**	**87,402**	**83,081**	**95,117**	**101,300**	**106,458**	**111,338**
Variable Expenses:											
Fuel Cost (inc start fuel)	$'000	31,725	44,742	40,242	33,416	28,328	27,447	31,190	32,797	34,255	35,623
Variable O&M (chemicals & water)	$'000	481	889	840	756	736	688	774	809	843	872
Emission Costs	$'000	5,930	11,479	11,353	10,738	11,018	10,788	12,709	13,929	15,218	16,506
Total Variable Expense	**$'000**	**38,135**	**57,111**	**52,434**	**44,909**	**40,083**	**38,922**	**44,673**	**47,535**	**50,316**	**53,001**
Contribution Margin (no Major Maintenance)	**$'000**	**52,332**	**67,684**	**54,068**	**46,485**	**47,319**	**44,159**	**50,444**	**53,765**	**56,142**	**58,337**
Major Maintenance Accrual:											
VOM-related MM	$'000	2,115	3,910	3,693	3,322	3,237	3,023	3,403	3,556	3,704	3,834
Fixed Start Costs	$'000	-	-	-	-	-	-	-	-	-	-
Total Major Maintenance Accrual	**$'000**	**2,115**	**3,910**	**3,693**	**3,322**	**3,237**	**3,023**	**3,403**	**3,556**	**3,704**	**3,834**
Contribution Margin (with Major Maintenance)	**$'000**	**50,217**	**63,774**	**50,375**	**43,163**	**44,082**	**41,136**	**47,041**	**50,209**	**52,438**	**54,503**

Table A-7(b): La Rosita II Contribution Margins (2031-2040)[114]

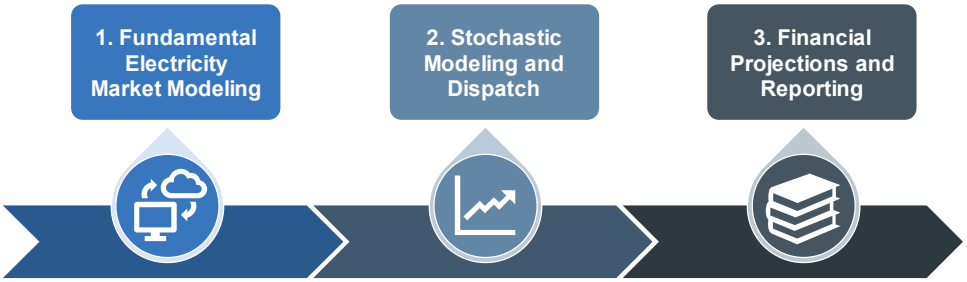
La Rosita 2	Units	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Operations:											
RA Capacity	MW	322	322	322	322	322	322	322	322	322	322
Operating Capacity[a]	MW	318	318	318	318	318	318	318	318	318	318
Production	GWh	1,229	1,168	1,161	1,122	1,048	984	958	905	878	779
Capacity Factor	%	43%	41%	41%	39%	37%	35%	34%	32%	31%	27%
Total Fuel Used (inc start fuel)	MMBtu'000	9,346	8,880	8,837	8,530	7,963	7,483	7,282	6,874	6,677	5,926
Total Turbine Starts	#	304	289	285	264	244	236	229	223	230	199
Total Turbine Run Hours	hrs	4,270	4,082	4,034	3,891	3,631	3,428	3,330	3,161	3,083	2,755
N-Factor	#	14	14	14	15	15	14	15	14	13	14
Market Revenue:											
Market Capacity	$'000	36,914	37,727	38,557	39,405	40,272	41,158	42,063	42,989	43,934	44,901
Market Energy	$'000	79,342	77,972	81,872	82,970	80,167	78,128	79,302	76,736	76,803	70,688
Incremental Regulation and Reserves	$'000	149	136	144	138	127	124	124	117	117	100
Total Revenue	**$'000**	**116,406**	**115,834**	**120,573**	**122,512**	**120,565**	**119,409**	**121,489**	**119,841**	**120,854**	**115,689**
Variable Expenses:											
Fuel Cost (inc start fuel)	$'000	36,688	36,350	36,930	36,548	35,291	34,237	34,497	33,768	33,863	30,483
Variable O&M (chemicals & water)	$'000	886	860	875	863	824	791	787	760	753	683
Emission Costs	$'000	17,605	17,931	19,130	19,795	19,809	19,956	20,819	21,067	21,936	20,870
Total Variable Expense	**$'000**	**55,178**	**55,142**	**56,935**	**57,206**	**55,924**	**54,984**	**56,103**	**55,596**	**56,553**	**52,036**
Contribution Margin (no Major Maintenance)	**$'000**	**61,228**	**60,693**	**63,638**	**65,306**	**64,641**	**64,425**	**65,386**	**64,246**	**64,301**	**63,653**
Major Maintenance Accrual:											
VOM-related MM	$'000	3,895	3,783	3,845	3,796	3,624	3,479	3,462	3,341	3,312	3,003
Fixed Start Costs	$'000	-	-	-	-	-	-	-	-	-	-
Total Major Maintenance Accrual	**$'000**	**3,895**	**3,783**	**3,845**	**3,796**	**3,624**	**3,479**	**3,462**	**3,341**	**3,312**	**3,003**
Contribution Margin (with Major Maintenance)	**$'000**	**57,333**	**56,910**	**59,793**	**61,510**	**61,017**	**60,946**	**61,924**	**60,905**	**60,989**	**60,650**

[113] 2021 reflects a partial year (August – December). [a] Annual numbers reflect summer capacity.
[114] *Ibid*.

Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

B MODELING METHODOLOGY

We have been active in the North American electricity sector for more than two decades, helping owners of regulated and unregulated power plants make smart decisions to safeguard their existing capital and deploy new capital. Our assignment teams are made up of engineers and economists who understand how power plants and electricity systems work and can shape that technical knowledge to meet our clients' needs and empower their strategic decision making. Our modeling approach is made up of three essential steps, as illustrated below.



Step 1: Fundamental Electricity Market Modeling

Our electricity market modeling leverages the AURORA^{xmp} software, in both nodal and zonal configurations, for the Eastern, Western and, Texas Interconnections to simulate hourly dispatch and energy price formation. The model is populated with our proprietary view of all key assumptions, developed by our subject matter experts, such as:

- capacities, operating profiles, and heat rates for existing thermal and renewable generation;
- natural gas and coal price projections;
- emission allowance price projections;
- new capacity additions and retirements of thermal and renewable generation;
- energy and peak demand growth;
- inter-zonal and inter-market transmission capability and flows; and
- new build costs for thermal and renewable generation.

The output of the AURORA^{xmp} is used in Step 2 (stochastic modeling) along with our proprietary models for renewable compensation (i.e. RECs), spot and forward capacity auctions (e.g. FCA, ICAP and RPM), and ancillary services.

Step 2: Stochastic Dispatch Modeling (for dispatchable power generation only)

Our proprietary stochastic model is used to simulate real-world volatility and associated energy price formation and dispatch. The model runs a set of Monte Carlo simulations, using a Mean-Reverting, Jump-Diffusion (MRJD) process with seasonal assumptions for (i) mean-reversion level, (ii) volatility, (iii) jump heights, and (iv) jump frequency. The model produces a range of price outcomes (typically from 100 to 1,000 simulations) and associated hourly dispatch.

The model has been used to analyze dispatchable thermal generation (e.g. combined cycles and combustion turbines) and hydro generation (e.g. pumped storage and pondage facilities) and captures the inherent volatility of day-ahead and real-time energy markets and extrinsic value of dispatchable generation operating within them.

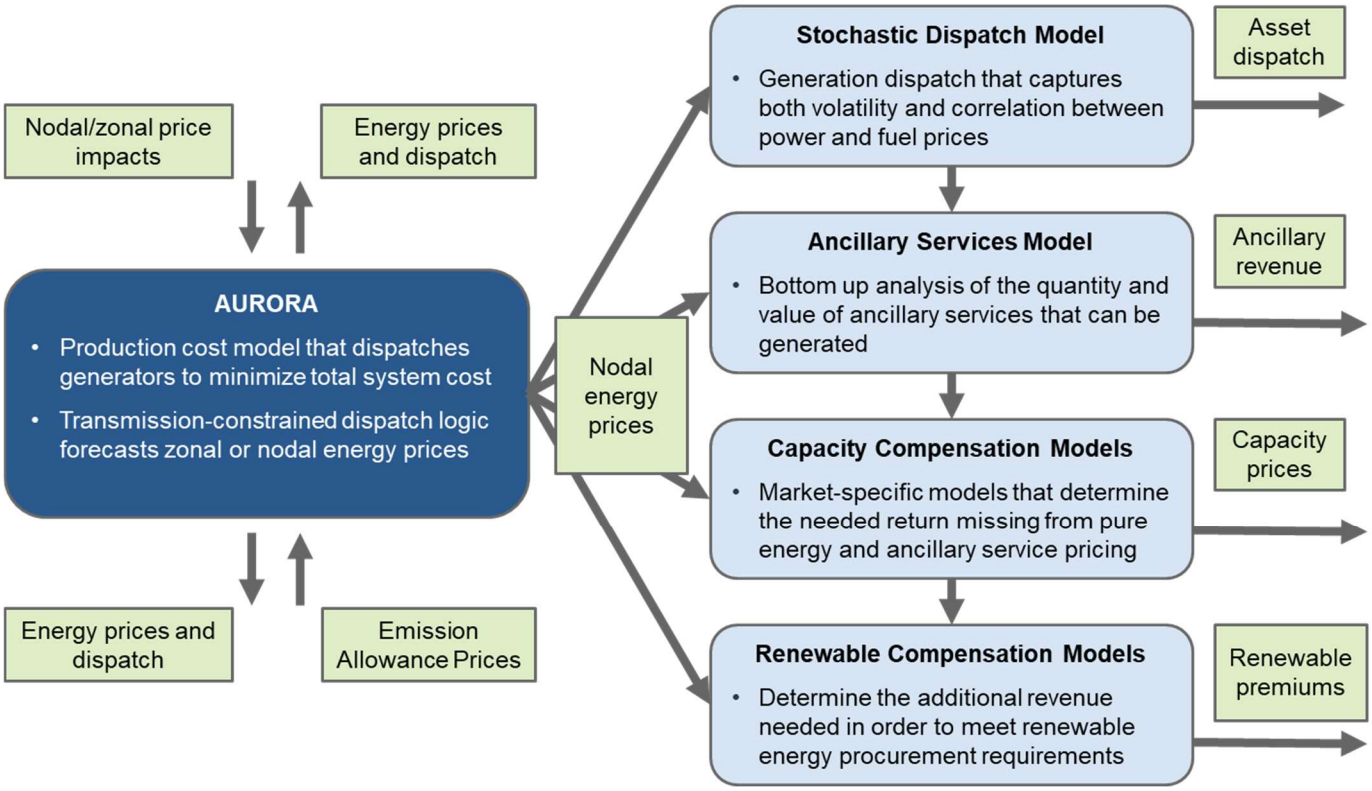
Confidential between PA and Global Infrastructure Management © PA Knowledge Limited

Step 3: Financial Projections and Reporting

Lastly, Step 3 brings together the results from Steps 1 and 2 to create a forecast of a power generator's operations, revenues and operating costs. These financial projections are typically delivered via a pro forma (in spreadsheet format) and accompanying summary report (in Word or PPT format).

Our financial projections and reporting have been used to support strategic initiatives related to (i) business strategy, (ii) civil litigation and (iii) buy, sell, and financing M&A.

The graphic below provides a detailed view of our modeling approach.



Confidential between PA and Global Infrastructure Management © PA Knowledge Limited



Denver Office
PA Consulting Group Inc.
Suite 3550
1700 Lincoln Street
Denver
CO 80203
USA
+1 720 566 9920

paconsulting.com

This report has been prepared by PA Consulting Group on the basis of information supplied by the client, third parties (if appropriate) and that which is available in the public domain. No representation or warranty is given as to the achievability or reasonableness of future projections or the assumptions underlying them, targets, valuations, opinions, prospects or returns, if any, which have not been independently verified. Except where otherwise indicated, the report speaks as at the date indicated within the report.

All rights reserved
© PA Knowledge Limited 2021

This report is confidential to the organisation named herein and may not be reproduced, stored in a retrieval system, or transmitted in any form or by any means, electronic, mechanical or otherwise, without the prior written permission of PA Consulting Group. In the event that you receive this document in error, you should return it to PA Consulting Group, PA Consulting Group Inc., Suite 3550, 1700 Lincoln Street, Denver, CO 80203, USA. PA Consulting Group accepts no liability whatsoever should an unauthorised recipient of this report act on its contents.

About PA.

An innovation and transformation consultancy, we believe in the power of ingenuity to build a positive human future in a technology-driven world.

As strategies, technologies and innovation collide, we turn complexity into opportunity.

Our diverse teams of experts combine innovative thinking and breakthrough technologies to progress further, faster. Our clients adapt and transform, and together we achieve enduring results.

We are over 2,600 specialists in consumer, defence and security, energy and utilities, financial services, government, healthcare, life sciences, manufacturing, and transport, travel and logistics. And we operate globally from offices across the Americas, Europe, the Nordics and the Gulf.

PA. Bringing Ingenuity to Life.

ANNEX B
INDEPENDENT ENGINEER REPORT

The Independent Engineer Report – included as Annex B to this Offering Memorandum has been prepared by Sargent & Lundy.

CONFIDENTIAL

Lender's Report for Operating Combined-Cycle & Gas Compression Projects in Mexico

Prepared for

Global Infrastructure Management, LLC

Prepared by Sargent & Lundy

Report SL-016423

Revision 1

September 3, 2021

Project A14292.003

55 East Monroe Street
Chicago, IL 60603-5780 USA
312-269-2000
www.sargentlundy.com

Sargent & Lundy

LEGAL NOTICE

This deliverable was prepared by Sargent & Lundy, L.L.C. (S&L) expressly for the sole use of Global Infrastructure Management, LLC (Client) in accordance with the contract agreement between S&L and Client. This deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) S&L prepared this deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of Client; (2) information and data provided by others, including Client, may not have been independently verified by S&L; and (3) the information and data contained in this deliverable are time-sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this deliverable. Any use or reliance upon this deliverable by third parties shall be at their sole risk.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Sargent & Lundy is one of the oldest and most experienced full-service architect engineering firms in the world. Founded in 1891, the firm is a global leader in power and energy with expertise in grid modernization, renewable energy, energy storage, nuclear power, and fossil fuels. Sargent & Lundy delivers comprehensive project services—from consulting, design, and implementation to construction management, commissioning, and operations/maintenance—with an emphasis on quality and safety. The firm serves public and private sector clients in the power and energy, gas distribution, industrial, and government sectors.

55 East Monroe Street • Chicago, IL 60603-5780 USA • 312-269-2000

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

VERSION LOG

Version	Issue Date	Sections Modified
Revision 0	July 21, 2021	All Sections– Issued to Client for Review
Revision 1	September 3, 2021	All Sections– Issued Final

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

ISSUE SUMMARY AND APPROVAL PAGE

This is to certify that this document has been prepared, reviewed, and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ANSI/ISO/ASSQC Q9001 Quality Management Systems.

Contributors

Prepared by:

Name	Title	Section(s) Prepared	Signature	Date
Clifford Kozak	Principal Consultant	ES, 1, 2, 8, 9		September 3, 2021
Roxanne Richards	Senior Energy Consultant	3, 4, 5		September 3, 2021
Kevin Hopkins	Principal Consultant	6		September 3, 2021
Marco Cruz	Senior Energy Consultant	7		September 3, 2021

Reviewed by:

Name	Title	Section(s) Reviewed	Signature	Date
Clifford Kozak	Principal Consultant	3		September 3, 2021
Roxanne Richards	Senior Energy Consultant	ES (General, Chihuahua, Campeche), 1, 2		September 3, 2021
Kevin Hopkins	Principal Consultant	Executive Summary (Bajío, El Sauz, Altamira); Sections 7, 8, 9		September 3, 2021
Marco Cruz	Senior Energy Consultant	ES (SLP, LaRosita-1, LaRosita-2), 4, 5, 6		September 3, 2021

Approved by:

	September 3, 2021
Clifford J. Kozak Project Manager	Date

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

TABLE OF CONTENTS

EXECUTIVE SUMMARY ..... **I**
GENERAL I
CHIHUAHUA COMBINED-CYCLE PROJECT I
CAMPECHE COMBINED-CYCLE PROJECT V
LAROSITA - UNIT 1 COMBINED-CYCLE PROJECT IX
LAROSITA UNIT 2 COMBINED-CYCLE PROJECT XIV
BAJÍO COMBINED-CYCLE PROJECT XVIII
SAN LUIS DE LA PAZ (SLP) COMBINED-CYCLE PROJECT XXIII
ALTAMIRA COMPRESSION PROJECT XXVII
EL SAUZ COMPRESSION PROJECT XXX
1. INTRODUCTION **1**
1.1. S&L SCOPE OF WORK 1
2. CHIHUAHUA COMBINED-CYCLE POWER PROJECT **3**
2.1. PLANT DESCRIPTION 3
2.1.1. MAIN EQUIPMENT *3*
2.2. MAJOR PLANT INTERCONNECTIONS 4
2.3. SUMMARY OF O&M PRACTICES 5
2.3.1. PLANT STAFFING *5*
2.3.2. SAFETY RECORD *5*
2.3.3. LTSA & OTHER MAINTENANCE CONTRACTING *6*
2.3.4. S&L OVERALL ASSESSMENT OF PLANT CONDITION *7*
2.4. O&M AND CAPITAL COST BUDGET PROJECTIONS 8
2.4.1. O&M COSTS *8*
2.4.2. CAPITAL COSTS *9*
2.5. PLANT PERFORMANCE 11
2.6. ENVIRONMENTAL PERFORMANCE 12
2.7. MAJOR CONTRACTS 12
2.8. MAJOR RISKS 13
3. CAMPECHE COMBINED-CYCLE POWER PLANT **15**
3.1. PLANT DESCRIPTION 15
3.1.1. MAIN EQUIPMENT *15*
3.2. MAJOR PLANT INTERCONNECTIONS 16
3.3. SUMMARY OF O&M PRACTICES 16
3.3.1. PLANT STAFFING *17*

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

3.3.2. SAFETY RECORD *17*
3.3.3. LTSA & OTHER MAINTENANCE CONTRACTING *18*
3.3.4. S&L OVERALL ASSESSMENT OF PLANT CONDITION *19*
3.4. O&M AND CAPITAL COST BUDGET PROJECTIONS 20
3.4.1. O&M COSTS *20*
3.4.2. CAPITAL COSTS *22*
3.5. PLANT PERFORMANCE 23
3.6. ENVIRONMENTAL PERFORMANCE 24
3.7. MAJOR CONTRACTS 24
3.8. MAJOR RISKS 25
4. LA ROSITA UNIT 1 COMBINED-CYCLE PROJECT 27
4.1. PLANT DESCRIPTION 27
4.1.1. MAIN EQUIPMENT *27*
4.2. MAJOR PLANT INTERCONNECTIONS 28
4.3. SUMMARY OF O&M PRACTICES 29
4.3.1. PLANT STAFFING *29*
4.3.2. SAFETY RECORD *29*
4.3.3. LTSA & OTHER MAINTENANCE CONTRACTING *30*
4.3.4. S&L OVERALL ASSESSMENT OF PLANT CONDITION *32*
4.4. O&M AND CAPITAL COST BUDGET PROJECTIONS 33
4.4.1. O&M COSTS *33*
4.4.2. CAPITAL COSTS *34*
4.5. PLANT PERFORMANCE 36
4.6. ENVIRONMENTAL PERFORMANCE 36
4.7. MAJOR CONTRACTS 37
4.8. MAJOR RISKS 37
5. LA ROSITA UNIT 2 COMBINED-CYCLE PROJECT 40
5.1. PLANT DESCRIPTION 40
5.1.1. MAIN EQUIPMENT *40*
5.2. MAJOR PLANT INTERCONNECTIONS 41
5.3. SUMMARY OF O&M PRACTICES 41
5.3.1. PLANT STAFFING *42*
5.3.2. SAFETY RECORD *42*
5.3.3. LTSA & OTHER MAINTENANCE CONTRACTING *42*
5.3.4. S&L OVERALL ASSESSMENT OF PLANT CONDITION *44*
5.4. O&M AND CAPITAL COST BUDGET PROJECTIONS 45

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

5.4.1. O&M COSTS *45*
5.4.2. CAPITAL COSTS *47*
5.5. PLANT PERFORMANCE 47
5.6. ENVIRONMENTAL PERFORMANCE 48
5.7. MAJOR CONTRACTS 49
5.8. MAJOR RISKS 49
6. BAJÍO COMBINED-CYCLE PROJECT 51
6.1. PLANT DESCRIPTION 51
6.1.1. MAIN EQUIPMENT *51*
6.2. MAJOR PLANT INTERCONNECTIONS 52
6.3. SUMMARY OF O&M PRACTICES 53
6.3.1. PLANT STAFFING *53*
6.3.2. SAFETY RECORD *54*
6.3.3. LTSA & OTHER MAINTENANCE CONTRACTING *54*
6.3.4. S&L OVERALL ASSESSMENT OF PLANT CONDITION *55*
6.3.5. IMPACTS OF ADVANCED GAS PATH UPGRADES *57*
6.4. O&M AND CAPITAL COST BUDGET PROJECTIONS 58
6.4.1. O&M COSTS *58*
6.4.2. CAPITAL COSTS *60*
6.5. PLANT PERFORMANCE 63
6.6. ENVIRONMENTAL PERFORMANCE 64
6.7. MAJOR CONTRACTS 64
6.8. MAJOR RISKS 65
7. SAN LUIS DE LA PAZ COMBINED-CYCLE PROJECT 67
7.1. PLANT DESCRIPTION 67
7.1.1. MAIN EQUIPMENT *67*
7.2. MAJOR PLANT INTERCONNECTIONS 68
7.3. SUMMARY OF O&M PRACTICES 68
7.3.1. PLANT STAFFING *69*
7.3.2. SAFETY RECORD *69*
7.3.3. LTSA & OUTSIDE MAINTENANCE CONTRACTING *69*
7.3.4. S&L OVERALL ASSESSMENT OF PLANT CONDITION *70*
7.4. O&M AND CAPITAL COST BUDGET PROJECTIONS 71
7.4.1. O&M COSTS *71*
7.4.2. CAPITAL COSTS *73*
7.5. PLANT PERFORMANCE 75

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

7.6. ENVIRONMENTAL PERFORMANCE 76
7.7. MAJOR CONTRACTS 76
7.8. MAJOR RISKS 77
8. ALTAMIRA GAS COMPRESSION STATION 80
8.1. PLANT DESCRIPTION 80
8.1.1. MAIN EQUIPMENT 80
8.2. MAJOR PLANT INTERCONNECTIONS 81
8.3. SUMMARY OF O&M PRACTICES 81
8.3.1. PLANT STAFFING 81
8.3.2. SAFETY RECORD 82
8.3.3. MACHINE MANAGEMENT SERVICES AGREEMENT (MAJOR EQUIPMENT MAINTENANCE) 82
8.3.4. S&L OVERALL ASSESSMENT OF PLANT CONDITION 83
8.4. O&M AND CAPITAL COST BUDGET PROJECTIONS 84
8.4.1. O&M COSTS 84
8.4.2. CAPITAL COSTS 85
8.5. PLANT PERFORMANCE 86
8.6. ENVIRONMENTAL PERFORMANCE 87
8.7. MAJOR CONTRACTS 88
8.8. MAJOR RISKS 89
9. EL SAUZ GAS COMPRESSION PROJECT 91
9.1. PLANT DESCRIPTION 91
9.1.1. MAIN EQUIPMENT 91
9.2. MAJOR PLANT INTERCONNECTIONS 92
9.3. SUMMARY OF O&M PRACTICES 92
9.3.1. PLANT STAFFING 93
9.3.2. SAFETY RECORD 93
9.3.3. PREVENTATIVE & MAJOR MAINTENANCE 94
9.3.4. S&L OVERALL ASSESSMENT OF PLANT CONDITION 95
9.4. O&M AND CAPITAL COST BUDGET PROJECTIONS 96
9.4.1. O&M COSTS 96
9.4.2. CAPITAL COSTS 97
9.5. PLANT PERFORMANCE 98
9.6. ENVIRONMENTAL PERFORMANCE 99
9.7. MAJOR CONTRACTS 100
9.8. POTENTIAL RISKS 101
10. REFERENCES 103

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

TABLES

TABLE ES-1 — CHIHUAHUA PROJECTED O&M EXPENDITURES (2021–2023), $ X 1000 III
TABLE ES-2 — CHIHUAHUA PROJECTED CAPITAL EXPENDITURES ($ X 1000) III
TABLE ES-3 — CHIHUAHUA AVERAGE PERFORMANCE 2017–2020 IV
TABLE ES-4 — POTENTIAL RISKS - CHIHUAHUA V
TABLE ES-5 — CAMPECHE PROJECTED O&M EXPENDITURES (2021–2023) VII
TABLE ES-6 — CAMPECHE PROJECTED CAPITAL EXPENDITURES, $ X 1000 VII
TABLE ES-7 — CAMPECHE AVERAGE PERFORMANCE 2017–2020 VIII
TABLE ES-8 — POTENTIAL RISKS – CAMPECHE VIII
TABLE ES-9 — LAROSITA UNIT 1 PROJECTED O&M EXPENDITURES (2021–2023) XI
TABLE ES-10 — LAROSITA I PROJECTED CAPITAL EXPENDITURES XII
TABLE ES-11 — LAROSITA I AVERAGE PERFORMANCE 2017–2020 XII
TABLE ES-12 — POTENTIAL RISKS – LAROSITA UNIT 1 XIII
TABLE ES-13 — LAROSITA UNIT 2 PROJECTED O&M EXPENDITURES (2021–2023) XV
TABLE ES-14 — LAROSITA II PROJECTED CAPITAL EXPENDITURES XVI
TABLE ES-15 — LAROSITA II AVERAGE PERFORMANCE 2017–2020 XVII
TABLE ES-16 — POTENTIAL RISKS – LAROSITA UNIT 2 XVIII
TABLE ES-17 — BAJÍO – PROJECTED O&M EXPENDITURES (2021–2023) XX
TABLE ES-18 — BAJÍO PROJECTED CAPITAL EXPENDITURES XX
TABLE ES-19 — BAJÍO AVERAGE PERFORMANCE 2017–2020 XXI
TABLE ES-20 — BAJÍO – POTENTIAL RISKS XXII
TABLE ES-21 — SLP – PROJECTED O&M EXPENDITURES (2021–2023) XXIV
TABLE ES-22 — SLP PROJECTED CAPITAL EXPENDITURES (NOMINAL 2019 DOLLARS) XXV
TABLE ES-23 — SLP AVERAGE PERFORMANCE 2017–2020 XXV
TABLE ES-24 — SLP – POTENTIAL RISKS XXVI
TABLE ES-25 — ALTAMIRA PROJECTED O&M COSTS (2021–2023) (NOMINAL USDX1000) XXVIII
TABLE ES-26 — ALTAMIRA PROJECTED CAPITAL COSTS (INCLUDING LIFE EXTENSION) XXVIII
TABLE ES-27 — ALTAMIRA AVERAGE PERFORMANCE 2015–2020 XXIX
TABLE ES-28 — POTENTIAL RISKS ALTAMIRA XXX
TABLE ES-29 — EL SAUZ PROJECTED O&M COSTS (2021–2023) (NOMINAL USDX1000) XXXII
TABLE ES-30 — EL SAUZ PROJECTED CAPITAL COSTS (INCLUDING LIFE EXTENSION) XXXII
TABLE ES-31 — EL SAUZ AVERAGE PERFORMANCE 2015–2020 XXXIII
TABLE ES-32 — POTENTIAL RISKS EL SAUZ XXXIV
TABLE 2-1 — CHIHUAHUA PROJECTED OUTAGE SCHEDULE 6
TABLE 2-2 — CHIHUAHUA – PROJECTED O&M EXPENDITURES (2021–2023) 8

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

TABLE 2-3 — CHIHUAHUA PROJECTED CAPITAL EXPENDITURES 10
TABLE 2-4 — CHIHUAHUA ANNUAL AND AVERAGE PERFORMANCE 2017–2020 11
TABLE 2-5 — CHIHUAHUA MAJOR AGREEMENTS 12
TABLE 2-6 — POTENTIAL RISKS – CHIHUAHUA 13
TABLE 3-1 — CAMPECHE PROJECTED OUTAGE SCHEDULE 18
TABLE 3-2 — CAMPECHE – PROJECTED O&M EXPENDITURES (2021–2023) 20
TABLE 3-3 — CAMPECHE PROJECTED CAPITAL EXPENDITURES 22
TABLE 3-4 — CAMPECHE ANNUAL AND AVERAGE PERFORMANCE 2017–2020 23
TABLE 3-5 — CAMPECHE MAJOR AGREEMENTS 24
TABLE 3-6 — POTENTIAL RISKS – CAMPECHE 25
TABLE 4-1 — LAROSITA I PROJECTED OUTAGE SCHEDULE 30
TABLE 4-2 — LAROSITA I – PROJECTED O&M EXPENDITURES (2021–2023) 33
TABLE 4-3 — LAROSITA I PROJECTED CAPITAL EXPENDITURES 35
TABLE 4-4 — LAROSITA I ANNUAL AND AVERAGE PERFORMANCE 2017–2020 36
TABLE 4-5 — LAROSITA I MAJOR AGREEMENTS 37
TABLE 4-6 — POTENTIAL RISKS – LAROSITA I 38
TABLE 5-1 — LAROSITA II PROJECTED OUTAGE SCHEDULE 43
TABLE 5-2 — LAROSITA II – PROJECTED O&M EXPENDITURES (2021–2023) 46
TABLE 5-3 — LAROSITA II PROJECTED CAPITAL EXPENDITURES 47
TABLE 5-4 — LAROSITA II ANNUAL AND AVERAGE PERFORMANCE 2017–2020 48
TABLE 5-5 — LAROSITA II MAJOR AGREEMENTS 49
TABLE 5-6 — POTENTIAL RISKS – LAROSITA II 50
TABLE 6-1 — BAJÍO – HISTORICAL AND PROJECTED MAJOR OUTAGES 55
TABLE 6-2 — BAJÍO – PROJECTED O&M EXPENDITURES (2021–2023) 59
TABLE 6-3 — BAJÍO – PLANT LIFE EXTENSION CAPITAL EXPENDITURES 61
TABLE 6-4 — BAJÍO ANNUAL AND AVERAGE PERFORMANCE 2017–2020 63
TABLE 6-5 — BAJÍO MAJOR AGREEMENTS 65
TABLE 6-6 — BAJÍO – POTENTIAL RISKS 65
TABLE 7-1 — SLP PROJECTED OUTAGE SCHEDULE 70
TABLE 7-2 — SLP – PROJECTED O&M EXPENDITURES (2021–2023) 72
TABLE 7-3 — SLP PROJECT CAPITAL EXPENDITURES 73
TABLE 7-4 — SLP ANNUAL AND AVERAGE PERFORMANCE 2017–2020 75
TABLE 7-5 — SLP MAJOR AGREEMENTS 77
TABLE 7-6 — POTENTIAL RISKS – SLP 78
TABLE 8-1 — ALTAMIRA PROJECTED O&M COSTS (2021–2023) (NOMINAL USDX1000) 84
TABLE 8-2 — ALTAMIRA PROJECTED CAPITAL COSTS (INCLUDING LIFE EXTENSION) 85

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

TABLE 8-3 — ALTAMIRA ANNUAL AND AVERAGE PERFORMANCE 2015–2020 86
TABLE 8-4 — ALTAMIRA MAJOR AGREEMENTS 88
TABLE 8-5 — POTENTIAL RISKS AND IMPROVEMENTS 89
TABLE 9-1 — EL SAUZ SCHEDULED MAJOR MAINTENANCE INTERVALS 95
TABLE 9-2 — EL SAUZ PROJECTED O&M EXPENDITURES (2021–2023) 97
TABLE 9-3 — EL SAUZ PROJECTED CAPITAL COSTS (INCLUDING LIFE EXTENSION) 97
TABLE 9-4 — EL SAUZ ANNUAL AND AVERAGE PERFORMANCE 2015–2020 98
TABLE 9-5 — EL SAUZ COMPRESSION PROJECT MAJOR AGREEMENTS 100
TABLE 9-6 — EL SAUZ COMPRESSION STATION POTENTIAL RISKS 101

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

ACRONYMS AND ABBREVIATIONS

Acronym/Abbreviation	Definition/Clarification
ACC	Air-cooled condenser
BOP	Balance of Plant
Btu	British thermal units
CEMS	Continuous emissions monitoring system
CFE	Comisión Federal de Electricidad (Federal Electricity Commission of Mexico)
CO	Carbon monoxide
COD	Commercial Operation Date
CT(s)	Combustion turbine(s)
CTG(s)	Combustion turbine generator(s)
DCS	Distributed control system
DLN	Dry low-NO_X
EAF	Equivalent availability factor
EOH	Equivalent operating hours
EUOF	Equivalent unplanned outage factor
FSA	Fuel Supply Agreement
Gcal	Gigacalories
GE	General Electric Company
GIM	Global Infrastructure Management
GSU	Generator Step-Up
GT	Gas Turbine
HGPI(s)	Hot-gas-path inspection(s)
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG(s)	Heat recovery steam generator(s)
IP	Intermediate pressure
LHV	Lower heating value

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Acronym/Abbreviation	Definition/Clarification
LP	Low pressure
LTI(s)	Lost-time incident(s)
LTSA	Long-Term Service Agreement
MDQ	Maximum Daily Quantity
MI(s)	Major inspection(s)
NCF	Net capacity factor
NDE	Non-destructive examination
NO_X	Nitrogen oxide
O&M	Operations and maintenance
OEM(s)	Original equipment manufacturer(s)
POF	Planned outage factor
PPA	Power Purchase Agreement
HSSE	Health, Safety, Security and Environment
RCA	Root-cause analysis
rpm	Revolutions per minute
RWC(s)	Restricted workday case(s)
Saavi	Saavi Energía S. de R.L. de C.V.
Sargent & Lundy, S&L	Sargent & Lundy LLC
SEMARNAT	Secretario de Medio Ambiente y Recursos Naturales (Secretary of Environment and Natural Resources)
ST(s)	Steam turbine(s)
STG	Steam turbine generator

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

EXECUTIVE SUMMARY

GENERAL

Sargent & Lundy LLC (S&L) was engaged by Global Infrastructure Management, LLC (GIM) to conduct an asset review of the following existing projects in Mexico:

- Bajío Combined-Cycle Project
- Campeche Combined-Cycle Project
- Chihuahua Combined-Cycle Project
- LaRosita Units 1 and 2 Combined-Cycle Projects
- San Luis de la Paz (SLP) Combined-Cycle Project
- Altamira Compression Station
- El Sauz Compression Station

GIM is in the process of acquiring the above facilities from the current Owner, Saavi Energía ("Saavi"), and GIM is presently in contact with potential lenders to complete the transaction. To support GIM in this phase, S&L has prepared this Lender's Report. This Lender's Report consists of useful information to potential lenders excerpted from S&L's earlier May 2021 Independent Assessment project reports provided to GIM.

S&L's objective for this report is to provide a high level assessment of the condition of the plant, evaluate whether the facility has been operated and maintained in accordance with generally accepted industry practices, and identify any significant risks that would affect continued long-term, successful operation. Additionally, S&L reviewed the future capital and O&M costs projected by the current Owner, and opined on their reasonableness based on historical trends and industry benchmarks. A summary of our findings for each project follows below.

CHIHUAHUA COMBINED-CYCLE PROJECT

Chihuahua began commercial operation in 2003 and was originally commissioned as a 271 MW capacity combined-cycle unit. The current Owner is upgrading the gas turbines (GTs) to increase the unit's output to 283 MW. The plant configuration is 2x2x1: two GTs, two heat recovery steam generators (HRSGs), and one steam turbine (ST). Each HRSG is equipped with supplemental firing to increase the HRSG steam production to generate additional MW in the ST. Although S&L did not visit Chihuahua in 2021, we participated in a lengthy virtual site visit with plant personnel and management.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Operations & Maintenance Management

Chihuahua is currently staffed with 33 shift personnel operating and performing minor maintenance on the units, a staffing level typical for a plant of its size. S&L considers the O&M organization, staffing, and management to be appropriate for continued safe and reliable operation of the Chihuahua plant.

The safety programs at Chihuahua are equal to or better than programs at similar gas-fired, combined-cycle plants. All staff are engaged in safe practices and training activities. The plant has had no lost time incidents (LTI) in over 4000 days, which is the longest duration without an LTI for the Saavi Mexico combined-cycle fleet.

Chihuahua contracts its major maintenance work in an LTSA to a consortium of Power Services Group (PSG) and Liburdi Turbine Services, Inc. (Liburdi). A new agreement was signed in 2020 for a term through 2031. Major component inspection and overhaul work (including GTs, ST, and electric generators) are scheduled with PSG/Liburdi consistent with the original equipment manufacturers' (OEM) recommendations, which is prudent industry practice.

A key milestone in plant life extension is the replacement of the GT rotors, which is typically performed after 150,000 to 200,000 operating hours. While the Chihuahua rotors have not yet been replaced, the plant is aware of the need to replace them in the next 4 to 5 years, based on continued base load operation.

Assessment of Plant Conditions

S&L finds the Chihuahua plant in good condition for an 18-year old plant, based on our March 2021 virtual site visit, our review of plant records and reports, and discussions with the plant staff.

Our review of the plant's inspection and maintenance reports indicates the plant has been well maintained and is performing in accordance with industry expectations. If the plant continues its practices for O&M inspections, monitoring, and overhauls, including major required replacements (e.g., CT rotor replacement), S&L believes the plant can continue operating for an additional 20 or more years.

Operations & Maintenance Costs

The projected yearly O&M expenditures for 2021 through 2023 are summarized in Table ES-1. These values show a trend consistent with the actual expenditures from the plant records from 2017 to 2020.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table ES-1 — Chihuahua Projected O&M Expenditures (2021–2023), $ x 1000

Expenditure	2021	2022	2023	Average
Total O&M Expenditures	$4,327	$4,370	$15,884	$8,194
Total Fixed Costs	$3,073	$3,442	$3,503	$3,339
Plant MW Rating	–	–	–	271
Fixed Costs, US$/kW per Year	–	–	–	$12.3
Total Variable Costs	$1,254	$928	$12,381	$4,854
MWh/Year x 1,000 Projected	2,093	2,050	1,841	1,995
US$/MWh	–	–	–	$2.4

In S&L's experience, fixed costs for a combined-cycle plant typically range from US$10 to $15 per kilowatt (kW) per year. Chihuahua's projected fixed costs are within this range (12.3 US$/kW). Regarding variable costs, the typical range of variable costs for a combined-cycle unit is approximately US$2.50 to $3.00 per MW-hour (MWh). Per Table ES-1, Chihuahua's projected variable O&M costs are slightly lower than the typical range at 2.4 US$/MWh. Overall, the O&M cost levels and trends for Chihuahua are reasonable and compare well with expected ranges.

Capital Costs

The current yearly totals of projected capital cost expenses are provided in Table ES-2. The higher expenditures in 2023 reflect the Major Inspections on the GTs and ST planned for that year.

Table ES-2 — Chihuahua Projected Capital Expenditures ($ x 1000)

	2021	2022–2023	2024–2025	2026–2027	2028 and Beyond
Yearly Total	$839	$7,255	$1,470	$2,681	$16,373

Included in the above capital costs are additional allocations to the current Owner's budget, suggested by S&L, which GIM concurred with, including:

- Potential HRSG repairs that may be necessary in the future due to increased wear and potential corrosion over the long-term life of the plant
- Decommissioning cost at the project's end of life
- GT rotor replacement cost
- Potential future need for additional well water pump for raw water supply

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Performance

The Chihuahua plant has maintained stable performance trends, and relatively high-performance levels over the recent four years. Chihuahua's operational summary from 2017 through 2020 per Table ES-3.

Table ES-3 — Chihuahua Average Performance 2017–2020

	Equivalent Availability Factor	Equivalent Forced Outage Factor	Planned Outage Factor	Net Capacity Factor	Net Unit Heat Rate (Btu/kWh) HHV
Average	95.6%	0.8%	3.7%	90.1	7,708

S&L's key observations about the last four years of performance trending are as follows:

- The Equivalent Availability and Equivalent Forced Outage Factors have been better than expected for plants of this size, type and age. (Typical average Forced Outage Factor is about 2% and Equivalent Availability about 92%.)
- Net Unit Heat Rate, an indicator of plant efficiency, has been stable over the last four years and is within a reasonable range for this type, size and age plant.

With continuing diligent maintenance, the plant should be able to maintain its high performance level.

Environmental Performance

In the period of 2017 to 2020, there were no environmental exceedances reported for air, water, or noise emissions.

Major Contracts

At this time, there are no current problems with the counterparties or contracts. The plant changed their primary fuel supply agreement (FSA) in 2019 and also changed their long-term service agreement (LTSA) in 2020 to reduce costs and improve contract terms.

Potential Risks

Refer to Table ES-4 for potential risks at the Chihuahua plant.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table ES-4 — Potential Risks - Chihuahua

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Future HRSG Repairs/replacements	2.3.3, 2.4.2	1	Despite the fact that there are indications of HRSG wear due to flow accelerated corrosion, the plant has not budgeted any Capex funds for potential future HRSG repair/replacement work.
GT Rotor Replacement	2.3.3, 2.4.2	1	GT rotor replacement is not currently budgeted in the Owner's Capex projection, despite the fact that the total equivalent operating hours will reach typical end of life in 4-5 years
Water supply	2.2, 2.4.2	3	Raw water quality and quantity has dropped by a small amount, but still manageable today to support plant operations, which could potentially require another well in the future.
Decommissioning Costs	2.4.2	2	The plant indicated no decommissioning cost in their budget.

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

As noted under the Capital Cost section above, the above risk items pertain to potential additional capital costs not included in the Owner's current budget, which GIM has added to their capital cost project.

In summary, if the plant continues its practices for O&M inspections, monitoring, and overhauls, including scheduling major required replacements per OEM or specialty contractor recommendations (e.g., gas turbine rotor replacement), S&L believes the plant can continue operating for an additional 20 or more years.

CAMPECHE COMBINED-CYCLE PROJECT

The Campeche combined-cycle plant began commercial operation in 2003, and is rated for 252 MW firing natural gas and 192 MW firing diesel oil. The plant configuration is 1x1x1: one combustion turbine (CT), one heat recovery steam generator (HRSG), and one steam turbine (ST). The HRSG is equipped with supplemental firing to increase the HRSG steam production to generate additional MW in the ST. Although S&L did not visit Campeche in 2021, we participated in a lengthy virtual site visit with plant personnel and management.

Operations & Maintenance Management

Campeche is staffed with 33 personnel operating and performing minor maintenance on the units, a staffing level typical for a plant of its size. S&L considers the O&M organization, staffing, and management to be appropriate for safe and reliable operation.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

The plant's safety programs are equal to or better than programs at similar combined-cycle plants. All staff are engaged in safe practices and training activities, and follow the Saavi Fleet safety management and control programs. The plant had a Lost Time Injury (LTI) incident in July 2020. Subsequently, Campeche operated over 200 days without an LTI.

Campeche contracts its major maintenance work in an LTSA to Power Systems Manufacturing LLC (PSM). Major component inspection and overhaul work (including the CT, ST, and electric generators) are scheduled with PSM consistent with the original equipment manufacturers' (OEM) recommendations, which is prudent industry practice.

A key milestone in the plant's life is the replacement of the CT rotor, which is typically performed after 150,000 to 200,000 Equivalent Operating Hours (EOH). While the Campeche rotor has not yet been replaced, the plant is aware of the need to replace it in the next few years, depending on the number of hours per year the unit operates.

Assessment of Plant Conditions

S&L finds the Campeche plant generally in good condition for an 18-year old plant, based on our March 2021 virtual site visit, our review of plant records and reports, and discussions with the plant staff. However, due to the change from gas to oil firing in 2017 resulting from a long-term interruption in fuel gas supply, there were several problems that surfaced when firing oil. The plant management advised that the plant was originally design for emergency oil firing, that originally, the plant was not fully commissioned for oil firing. Hence, equipment such as the CT oil burners and supporting auxiliary systems required adjustments, repairs, or in some cases, replacement. With the latest maintenance work on the CT and auxiliaries, the plant reports successful operations for several months. A longer track record of problem-free operation is needed to ensure the problems with oil firing have been fully solved. While the current Owner indicated that the gas fired service could return in late 2021 or 2022, there is no firm schedule for the return of the fuel gas supply.

If the plant continues its practices for O&M inspections, monitoring, and scheduling major required overhauls and replacements per OEM recommendations, S&L believes the plant can return to consistent reliable operation in 2021 on oil.

Operations & Maintenance Costs

The projected yearly O&M expenditures for 2021 to 2023 are summarized in Table ES-5.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table ES-5 — Campeche Projected O&M Expenditures (2021–2023)

Expenditure	2021	2022	2023	Average
Total O&M Expenditures	5,442	7,754	5,756	6,317
Total Fixed Costs	3,834	3,948	3,871	3,884
Plant MW Rating	–	–	–	192
Fixed Costs, US$/kW per Year	–	–	–	$20.3
Total Variable Costs	1,608	3,806	1,885	2,433
MWh/Year x 1,000 Projected	234	253	321	269
US$/MWh	–	–	–	$9.0

Notes: Costs in thousands of US$, Nominal | Higher 2022 projected costs reflect costs for ST MI, and GT Rotor Assessment and HGPI

In Sargent & Lundy's experience, fixed costs for a combined-cycle plant typically range from US$10 to $15 per kilowatt (kW) per year. Campeche's projected fixed costs are above this range (20.3 $/kW).

Regarding variable costs, the typical range of variable costs for a combined-cycle unit is approximately US$2.50 to $3.00 USD per MW-hour (MWh). Campeche's projected 9.0 $/MWh for the 2021 through 2023 period is substantially higher than the expected range. This is a result of greater EOH per operating hour and the greater amount of maintenance required on the CT when firing oil compared to natural gas. In our opinion, even after considering the plant's report that oil firing problems have been resolved, the relatively high O&M costs will still persist until the unit is returned to natural gas firing.

Capital Costs

The current yearly totals of projected capital cost expenses are provided in Table ES-6. The higher expenditures in 2022 and 2025 reflect projects planned during the lengthy HGPI and Major Inspection outages planned for those years.

Table ES-6 — Campeche Projected Capital Expenditures, $ x 1000

	2021	2022	2023	2025
Yearly Total	$734	$2,401	$0	$4,214

In addition to the above costs in Table ES-6, S&L recommended adding the following future capital costs which were not in the Owner's original budget (which GIM has agreed to include in their budget):

- Potential HRSG repairs that may be necessary in the future due to increased wear and potential corrosion over the long-term life of the plant ($5 Million spread over 10 years)
- Decommissioning cost at the project's end of life ($3.8 Million at end of life)

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- CT rotor replacement cost ($7.5 Million)

Performance

The averages of the plants' performance key indicators from 2017 through 2020 are provided in Table ES-7. Campeche has had some challenges operating on diesel oil the last four years, as indicated by the plant's low availability and high unplanned outage factor. (Expected availability is 90 to 92%, and 2 to 3% forced outage for this type and age of plant.) However, the plant's performance trends have been improving through 2020, and, based on the oil-fired problems being fully resolved per our discussions with the plant, the positive trends should continue in 2021.

Table ES-7 — Campeche Average Performance 2017–2020

	Equivalent Availability Factor	Equivalent Unplanned Outage Factor	Planned Outage Factor	Net Capacity Factor	Net Unit Heat Rate (Btu/kWh)*
Average	88.95%	10.22%	0.83%	22.00%	7,969

*Heat Rate value is on an LHV basis | **Note:** HHV/LHV = 1.07 (approximately)

Environmental Performance

In the period of 2017 to 2020, there were no environmental exceedances reported for air, water, or noise emissions. Even with diesel the plant runs below the environmental permit limits.

Major Contracts

Campeche's key contracts include an LTSA for the major plant equipment and a PPA. Currently, Campeche does not have an FSA for natural gas. Aside from the resolution of the fuel gas supply situation, there are no other current problems with the counterparties or contracts.

Potential Risks

Refer to Table ES-8 for potential risks at the Campeche plant.

Table ES-8 — Potential Risks – Campeche

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Future HRSG Repairs/tube replacements	3.3.3, 3.4.2	1	Despite the fact that major repairs and tube replacements have not been identified, there is a potential for future HRSG repair/replacement work that should be budgeted for Campeche; propose an allocation of $5 Million expended in the next 10 years.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
CT Rotor Replacement	3.3.3, 3.4.2	1	The CT rotor has never been changed out and is in the range of end of life. (Budget cost: $7.5 Million)
Operation on oil	3.3.3, 3.4.2, 3.5	1	Decreased major maintenance intervals and higher O&M costs. Low reliability on oil. Also, it is noted that the timing of the resumption of fuel gas flow to the site is not certain, and oil operation will continue.
Decommissioning Costs	3.4.2	3	Plant indicated no decommissioning cost of $3.8 Million in their budget at the end of the project life.
Steam Turbine Electric Generator	3.3.3	3	A steam turbine generator inspection report was not provided for S&L to review thus we cannot provide a recommendation. Based on discussions with Campeche plant management, there are no critical issues.

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

As noted under the "Capital Cost" section above, the above risk items pertain to potential additional capital costs not included in the Owner's current budget, which GIM has added to their capital cost project.

To summarize, if the plant continues its practices for O&M inspections, monitoring, and overhauls, including scheduling major required replacements per OEM's recommendations (e.g., CT rotor replacement) with continuing mitigation of current problems and risks (especially, regarding oil firing issues), S&L believes the plant can return to consistent reliable operation in 2021, and can continue operating for an additional 20 or more years.

LAROSITA - UNIT 1 COMBINED-CYCLE PROJECT

LaRosita Unit 1 (LR1) began commercial operation in 2003 and was originally commissioned as a 780 MW capacity combined-cycle unit. The plant configuration is 3x3x1: three combustion turbines (CTs), three heat recovery steam generators (HRSGs), and one steam turbine (ST). Each HRSG is equipped with supplemental firing to increase the HRSG steam production to generate a small amount of additional MW in the ST. An increase of 8 MW is projected when upgrading plans are completed on one of the CTs in 2021. S&L visited the plant in March 2021.

Operations & Maintenance Management

LR I and LaRosita Unit 2 (LR II) current staffing consists of a total staff of 67: 48 union and 19 non-union employees. During our site visit, S&L met with La Rosita managers and plant personnel. Plant management did not identify any material disputes between the company and union. Based on our interviews at the site,

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

S&L considers the O&M organization, staffing, and management to be appropriate for continued safe and reliable operation of the LaRosita plant.

The safety programs at LaRosita are equal to or better than programs at similar gas-fired, combined-cycle plants. All staff are engaged in safe practices and training activities. LR I & II have not had a recordable safety incident since 2018. Through December 2020, La Rosita has gone 3,400 days without a Lost Time Injury (LTI) and registered a Total Recordable Case Frequency (TRCF) rate of zero for the year 2020.

LR 1 contracts its major maintenance work in a Long Term Service Agreement (LTSA) to Power Systems Manufacturing (PSM) to provide services for all of LaRosita's combustion and steam turbine generators. LTSA services transitioned from Original Equipment Manufacturer Siemens to PSM starting in 2015. Major component inspection and overhaul work with PSM is consistent with the original equipment manufacturers' (OEM) recommendations, which is prudent industry practice. To date, there have been no major issues with the PSM's performance.

All three CTs at LR I have undergone rotor replacements. This was accomplished over the period 2016 to 2019 during major inspection outages. Costs of the rotor refurbishments and replacement work were covered under the LTSA budget. An increase of 8 MW is projected when upgrading plans are completed on one of the CTs in 2021.

Assessment of Plant Conditions

Based on our March 2021 site visit, our review of approximately four years of plant records and lengthy conference calls with the plant staff, S&L finds LR I in overall good condition for an 18-year old plant. During our site visit, no obvious significant deterioration was observed, nor other indications of operating problems (e.g., high noise levels) were noted.

The plant has experienced higher than expected forced outage rates in the past two years. All three of the LR I HRSGs experienced recurrent unplanned outages caused by tube leaks in the high-pressure evaporators (HPEV) of each unit. Tube sampling has identified the root cause of the tube failures to be the accumulation of deposits inside the tubes that leads to the thinning and overheating of the material. The plant is implementing repairs as required through 2022 and pre-emptive changes to reduce HRSG wear (e.g., water chemistry changes), along with close monitoring of the HRSGs, and anticipates reducing the forced outage rate in the coming years.

S&L found that the plant equipment has been maintained in accordance with prudent industry practices and the plant's overall condition is conducive to continued safe and reliable operation. A key point is that the CT rotors have been recently replaced. Depending on the number of operating hours per year going

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

forward, the CT rotor life should be from 15 to 20 years. As the plant continues to follow good maintenance practices, the plant can be expected to continue to operate for an additional 20 years and beyond.

Operations & Maintenance Costs

The projected O&M expenditures for LR I for 2021 through 2023 are summarized in Table ES-9. The original values were provided on a plant basis (i.e., for both LR I and II). S&L reallocated costs on a percentage basis according to the MW rating of the units and annual outage plans. These values show a trend consistent with the actual expenditures from the plant records from 2017 to 2020.

Table ES-9 — LaRosita Unit 1 Projected O&M Expenditures (2021–2023)

	2021	2022	2023	Average
Total O&M Expenditures	21,514	18,970	21,595	20,693
Total Fixed Costs	4,884	4,857	4,857	4,866
Plant MW Rating	–	–	–	774
Fixed Costs, US$/kW per Year	–	–	–	6.3
Total Variable Costs	16,630	14,113	16,738	15,827
MWh/Year x 1,000 Projected	4,468	4,391	4,139	4,333
US$/MWh	–	–	–	3.7

Notes: Costs in thousands of US$ Nominal x 1000 | MWh/y projections were provided by Saavi Energia, week of March 15, 2021.

In Sargent & Lundy's experience, fixed costs for a combined-cycle plant typically range from $10 to $15 USD per kilowatt (kW) per year. LR I fixed costs are well below this range (6.3 $/kW-year projected going forward). The projected fixed costs are expected to trend downward in the future due the elimination of LTSA fixed fees that took effect in 2020 after migrating from Siemens to PSM.

Regarding variable costs, the typical range of variable costs for a combined-cycle unit is approximately $2.50 to $3.00 USD per MW-hour (MWh). LR I projected variable O&M costs going forward is slightly out of range at $3.7 per MWh. It is noted that while the variable O&M costs going forward are higher than S&L's benchmark range, the very low fixed costs ($6.3 per kW-year versus the low-end bench mark of $10/kW-y), basically offsets the higher variable costs, and the overall O&M costs are considered reasonable.

Capital Costs

The current yearly totals of projected capital cost expenses are provided in Table ES-10.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table ES-10 — LaRosita I Projected Capital Expenditures

	2021	2022	2023	2025	2027
Total	$9,649,968	$7,495,980	$2,880,072	$3,030,420	$10,173,480

Notes: Costs in Nominal US$ | Does not include miscellaneous annual allocation of approximately $248,000/year from 2023 to 2032

In addition to the above cost, S&L recommended adding the following future capital costs which were not in the Owner's original budget (which GIM has agreed to include in their budget):

- Potential HRSG repairs that may be necessary in the future due to increased wear and potential corrosion over the long-term life of the plant ($11.1 Million spread over 10 years).
- Decommissioning cost at the project's end of life ($11.7 Million at end of life).

Performance

LR I operational summary from 2017 through 2020 per Table ES-11.

Table ES-11 — LaRosita I Average Performance 2017–2020

	Equivalent Availability Factor (EAF)	Equivalent Unplanned Outage Factor (EUOF)	Planned Outage Factor (POF)	Net Heat Rate (Btu/kWh)*
Average	90.3%	4.2%	5.5%	6,541

*Heat Rate value is on an LHV basis. HHV Basis = LHV Basis x 1.11 (approximately)

S&L's key observations about the last four years of performance trending are as follows:

- The four-year average EAF for LR I is 90.3 %. Based on S&L's experience, approximately 92% EAF is expected for plants of this age.
- LR I forced outage value has been elevated in recent years: 4.8% in 2019 and 7.8% in 2020. S&L expects forced outage rates for combined-cycle units to be in the range of 2%. The main driver has been the HRSG issues on LR I; however, with the implementation of the long-term corrective and preventative actions, LR I intends to lower its forced outage rate to be within the 2% to 3% range by 2022.
- The four-year average heat rate for LR I is 6,541 BTU/kWh LHV (or 7,247 BTU/kWh-HHV). The annual heat rate has been consistent during the same period. The heat rates for LR I are within the range of the expected values.

Based on our analysis, LaRosita's staff is managing and correcting outstanding deficiencies to maintain a reasonable level of performance, aiming to improve the availability and outage rates in the coming two years.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Environmental Performance

There were no environmental exceedances reported in 2019 but two exceedances were reported in 2020 (one air and one water). The cause, severity and mitigation of the exceedances were not provided for S&L to review. During the site visit the O&M management indicated that the plant is now in compliance with all permit requirements and all permits are up to date.

Major Contracts

At this time, there are no current problems with the counterparties or contracts. Major project agreements for LR I include the LTSA with PSM for the CTs, ST, and electric generators; the Power Purchase Agreement (PPA) with CFE; and the Fuel Supply Agreement (FSA) with Exelon.

Potential Risks

Refer to Table ES-12 for potential risks at LR I. Note that we have included items with potential additional capital costs not included in the Owner's original budget (HRSG repair allocation and decommissioning cost).

Table ES-12 — Potential Risks – LaRosita Unit 1

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Future HRSG Repairs/tube replacements	3.3.3, 3.4.2	1	Despite the fact that major repairs and tube replacements have been identified for all three of LaRosita I HRSG's, there is a potential future HRSG repair/replacement work that should be budgeted for LaRosita I.
LR I HRSG 1A	3.3.3, 3.4.2	1	Long-Term corrective actions are not scheduled until 2022. If Short-Term corrective actions fail to slow the rate of tube failures, procure parts for repair/replacement work in 2021.
LR I Steam Turbine	3.3.3	2	According to the 2019 steam turbine inspection report, white deposits were found on the inner casing and rotors of the HP, IP and LP turbines. Based on the concerns with the carryover of deposits from the HRSG, non-destructive testing of the last stage of the steam turbine blades should be performed. During the site visit, no major issues were identified.
Decommissioning Costs	3.4.2	3	Plant indicated no decommissioning cost in their budget at the end of the project life.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Environmental	4.6	2	The December 2020 Monthly Report identified that two exceedances were reported in 2020, one air and one water. The cause, severity and mitigation of the exceedances were not provided for S&L to review.

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

In summary, if the plant continues its diligence in mitigating HRSG issues thereby reducing forced outages, and continues its practices for O&M inspections, monitoring, and overhauls, S&L believes LR I can continue operating for an additional 20 or more years.

LAROSITA UNIT 2 COMBINED-CYCLE PROJECT

LaRosita Unit 2 (LR II) began commercial operation in 2003 and was originally commissioned as a 320 MW capacity combined-cycle unit. The plant configuration is 1x1x1: one combustion turbine (CT), one heat recovery steam generator (HRSG), and one steam turbine (ST). The HRSG is equipped with supplemental firing to increase the HRSG steam production to generate additional MW in the ST. An increase of 8 MW is projected for a CT upgrade on LR II, when upgrading plans are completed in 2021. S&L visited the plant in March 2021.

Operations & Maintenance Management

LaRosita I (LR I) and LR II current staffing consists of a total staff of 67: 48 union and 19 non-union employees. During our site visit, S&L met with La Rosita managers and plant personnel. Plant management did not identify any material disputes between the company and union. Based on our interviews at the site, S&L considers the O&M organization, staffing, and management to be appropriate for continued safe and reliable operation of the LaRosita plant.

The safety programs at LaRosita are equal to or better than programs at similar gas-fired, combined-cycle plants. All staff are engaged in safe practices and training activities. LR I & II have not had a recordable safety incident since 2018. Through December 2020, La Rosita has gone 3,400 days without a Lost Time Injury (LTI) and registered a Total Recordable Case Frequency (TRCF) rate of zero for the year 2020.

LR II contracts its major maintenance work in a Long Term Service Agreement (LTSA) to Power Systems Manufacturing (PSM) to provide services for all of LaRosita's combustion and steam turbine generators. LTSA services transitioned from Original Equipment Manufacturer Siemens to PSM starting in 2015. Major component inspection and overhaul work with PSM is consistent with the original equipment manufacturers' (OEM) recommendations, which is prudent industry practice. To date, there have been no major issues with the PSM's performance.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

The CT at LR II has undergone a rotor replacement. This was accomplished in 2017 during a major inspection outage. Costs of the rotor refurbishment and replacement work were covered under the LTSA budget. As noted above, a CT upgrade in planned for 2021 which will increase the plant MW output by 8 MW.

Assessment of Plant Conditions

Based on our March 2021 site visit, our review of approximately four years of plant records and lengthy conference calls with the plant staff, S&L finds LR I in overall good condition for an 18-year old plant. During our site visit, no obvious significant deterioration was observed, nor other indications of operating problems (e.g., high noise levels) were noted.

The LR II HRSG has not experienced as many leaks and problems as LR I. This is attributable to the LR II HRSG being supplied by a different vendor, likely with a different design than LR I. Nevertheless, the plant is implementing a close monitoring and testing of the LR II HRSG along with revising the HRSG water chemistry to reduce potential future problems.

S&L found that the plant equipment has been maintained in accordance with prudent industry practices and the plant's overall condition is conducive to continued safe and reliable operation. A key point is that the CT rotor has been recently replaced. Depending on the number of operating hours per year going forward, the CT rotor life should be from 15 to 20 years.

As the plant continues to follow good maintenance practices, the plant can be expected to continue to operate for an additional 20 years and beyond.

Operations & Maintenance Costs

The projected O&M expenditures for LR II for 2021 through 2023 are summarized in Table ES-13. The original values were provided on a plant basis (i.e., for both LR I and II). S&L reallocated costs on a percentage basis according to the MW rating of the units and annual outage plans. These values show a trend consistent with the actual expenditures from the plant records from 2017 to 2020.

Table ES-13 — LaRosita Unit 2 Projected O&M Expenditures (2021–2023)

	2021	2022	2023	Average
Total O&M Expenditures	8,826	7,782	3,033	6,547
Total Fixed Costs	2,003	1,992	1,992	1,996
Plant MW Rating	–	–	–	318

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

	2021	2022	2023	Average
Fixed Costs, US$/kW per Year	–	–	–	6.3
Total Variable Costs	6,823	5,790	1,041	4,551
MWh/Year x 1,000 Projected	1,833	1,801	1,698	1,777
US$/MWh	–			2.6

Notes: Costs in thousands of US$ Nominal | MWh/y, projections were provided by Saavi Energia, week of March 15, 2021.

In Sargent & Lundy's experience, fixed costs for a combined-cycle plant typically range from $10 to $15 USD per kilowatt (kW) per year. LR II fixed costs are well below this range (6.3 $/kW projected going forward). The projected fixed costs are expected to trend downward in the future due to the elimination of LTSA fixed fees that took effect in 2020 after migrating from Siemens to PSM.

Regarding variable costs, the typical range of variable costs for a combined-cycle unit is approximately $2.50 to $3.00 USD per MW-hour (MWh). Per the above tables, LR II projected variable O&M costs going forward is within the range at $2.6 per MWh.

Capital Costs

The current yearly totals of projected capital cost expenses are provided in Table ES-14.

Table ES-14 — LaRosita II Projected Capital Expenditures

	2021	2022	2023	2025	2027
Total	**$3,983,692**	**$2,313,360**	**$0**	**$0**	**$995,520**

Notes: Costs in Nominal US$ | Does not include miscellaneous annual allocation of approximately $107,000/year from 2022 to 2032.

In addition to the above costs, S&L recommended adding the following future capital costs which were not in the Owner's original budget (which GIM has agreed to include in their budget):

- Potential HRSG repairs that may be necessary in the future due to increased wear and potential corrosion over the long-term life of the plant ($1.6 Million spread over 10 years)
- Decommissioning cost at the project's end of life ($4.8 Million at end of life)

Performance

LR II operational summary from 2017 through 2020 is shown in Table ES-15.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table ES-15 — LaRosita II Average Performance 2017–2020

	Equivalent Availability Factor (EAF)	Equivalent Unplanned Outage Factor (EUOF)	Planned Outage Factor (POF)	Net Heat Rate (Btu/kWh)*
Average	92.5%	3.0%	4.5%	7,568

* Heat Rate value is on an LHV basis. HHV Basis = LHV Basis x 1.11 (approximately)

S&L's key observations about the last four years of performance trending are as follows:

- The four-year average EAF for LR II is 92.5%. Based on S&L's experience, approximately 92% EAF is expected for plants of this age.
- Until 2020, LR II three-year (2017 to 2019) average forced outage rate was 2.3%. In 2020 the forced outage rate was 4.8% due to a feedwater pump coupling failure. A recurrence of this issue has been mitigated with the procurement of spare parts. (A forced outage rate of about 2% is expected for this type of plant.)
- The heat rate is higher for LR II due to the greater usage of supplemental HRSG duct firing of the Unit 2 HRSG to increase ST load. (The supplemental firing mode is less efficient than the unfired mode.)

Based on our analysis, LaRosita's staff is managing LR II O&M properly and correcting deficiencies to maintain a high level of performance.

Environmental Performance

There were no environmental exceedances reported in 2019 but two exceedances were reported in 2020 (one air and one water). The cause, severity and mitigation of the exceedances were not provided for S&L to review. During the site visit the O&M management indicated that the plant is now in compliance with all permit requirements and all permits are up to date.

Major Contracts

At this time, there are no current problems with the counterparties or contracts. Major project agreements for LR II include the LTSA with PSM for the CT, ST, and electric generators and the Fuel Supply Agreement (FSA) with EDF Energy. (LR II sells power on a merchant basis and has no PPA.)

Potential Risks

Refer to Table ES-16 for potential risks at LR II. Note that we have included items with potential additional capital costs not included in the Owner's original budget (i.e., HRSG repair allocation and decommissioning cost).

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table ES-16 — Potential Risks – LaRosita Unit 2

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Future HRSG Repairs/tube replacements	3.3.3, 3.4.2	1	There is a potential future HRSG repair/replacement work that should be budgeted for LaRosita II.
Decommissioning Costs	3.4.2	3	Plant indicated no decommissioning cost in their budget at the end of the project life.
Environmental	4.6	2	The December 2020 Monthly Report identified that two exceedances were reported in 2020, one air and one water. The cause, severity and mitigation of the exceedances were not provided for S&L to review.
LR II Bypass Stack	3.3.3	3	LaRosita should confirm the damper can operate, especially if GIM wants to operate the unit in Simple Cycle.

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

In summary, if the plant continues its practices for O&M inspections, monitoring, and overhauls, S&L believes that LR II can continue operating for an additional 20 or more years.

BAJÍO COMBINED-CYCLE PROJECT

Bajío is a 645 MW capacity, dual-fuel combined-cycle power plant that began commercial operation in 2002. The plant configuration is 3x3x1: three combustion turbine (CTs), three heat recovery steam generators (HRSGs), and one steam turbine (ST). The CTs have dual fuel capability with natural gas as a primary fuel and diesel (No. 2 oil) as a backup. The plant was originally built by the EPC contractor Bechtel. Although the plant was tested to achieve 670 MW firing natural gas following recent upgrading work, it is currently limited to 645 MW due to interconnection limitations. S&L visited the site in March 2021.

Operations & Maintenance Management

The management at Bajío also manages the adjacent SLP plant and the Bajío STP. The operating staffs at Bajío, Bajío STP, and SLP are hired through three separate contracts with unionized companies. The total staff is 73 people for the three facilities, including three contractors and three temporary operators needed for COVID-19 measures put in place since March 2020. S&L considers the O&M organization and staffing to be appropriate for continued safe and reliable operation of the Bajío combined-cycle plant and the associated sewage treatment plant.

Bajío's safety program utilizes training, posting danger and warning signage, work group meetings, site inspections, and other measures typical for combined-cycle power plant safety programs. Safety performance is tracked by a metric called Total Recordable Case Frequency (TRCF) which is the total

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

recordable lost time injury rate, per million hours worked. The 2020 cumulative Total Recordable Case Frequency (TCRF) was below the plant's 5-year cumulative rolling average of 0.406 recordables per 1 million hours which is a very good result. S&L finds the site's safety culture, operational procedures, and emergency plans to be acceptable.

Bajío contracts with Original Equipment Manufacturer (OEM) General Electric (GE) for major maintenance services for the CTs, ST and electric generators through a Long-Term Service Agreement (LTSA). Major maintenance of the HRSGs and other balance of plant (BOP) equipment is contracted to regional companies through competitive bid.

All three CTs have undergone rotor replacements. This was accomplished over the period 2015 to 2020 during major inspection outages. Costs of the rotor refurbishments and replacement work were covered under the LTSA budget.

Assessment of Plant Conditions

Based on our March 2021 site visit, our review approximately four years of plant records and lengthy conference calls with the plant staff, S&L finds the Bajío combined-cycle plant and the associated sewage treatment plant in good condition for a 19-year old facility. During our site visit, no obvious significant deterioration was observed, nor other indications of operating problems (e.g., high noise levels) were noted.

S&L found that the plant equipment has been maintained in accordance with prudent industry practices and the plant's overall condition is conducive to continued safe and reliable operation. A key point is that the main equipment's major maintenance is covered by an LTSA with OEM General Electric, which included the recent replacement of the CT rotors. Depending on the number of operating hours per year going forward, the CT rotor life should be from 15 to 20 years. As the plant continues to follow good maintenance practices, the plant can be expected to reach its full-service life of 35 years and beyond.

Operations & Maintenance Costs

The projected yearly O&M expenditures for 2021 through 2023 are summarized in Table ES-17. These values show a trend consistent with the actual expenditures from the plant records from 2017 to 2020. In general, the plant engages in an O&M approach with a corresponding budget that maintains the plant's high level of performance.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table ES-17 — Bajío – Projected O&M Expenditures (2021–2023)

	2021	2022	2023	Average
Total O&M Expenditures	$ 12,994	$ 15,210	$ 15,781	$ 14,662
Total Fixed Costs	$ 4,989	$ 4,925	$ 4,907	$ 4,940
Plant MW Rating	645	645	645	645
Fixed Costs, US$/kW per Year	$ 7.73	$ 7.64	$ 7.61	$ 7.66
Total Variable Costs	$ 8,005	$ 10,285	$10,874	$ 9,721
MWh/Year x 1,000 Projected	4,232	4,261	4,216	4,236
US$/MWh	$ 1.89	$ 2.41	$ 2.58	$ 2.29

Notes: | Costs in thousands of US$, Nominal x 1000 | MWh/Year Projected provided by Saavi, week of March 15, 2021 | A plant rating of 645 MW has been applied for all as the normalization factor for Total Fix Costs

In Sargent & Lundy's experience, fixed costs for a combined-cycle plant typically range from US$10 to $15 per kilowatt (kW) per year. Bajío's projected fixed costs are less than this range (7.66 $/kW per year projected through 2023). Bajío's low fixed O&M costs may be the result of shared management and services with the adjacent SLP plant. Another contributing factor to low fixed costs is that larger size plants such as Bajío generally trend lower for fixed costs, on a normalized $/kW per year basis. Regarding variable costs, the typical range of variable costs for a combined-cycle unit is approximately US$2.50 to $3.00 per MW-hour (MWh). Bajío's projected variable O&M costs going forward are also lower than the typical range at $2.29/MWh.

Overall, the O&M cost levels and trends for Bajío are reasonable and compare well with expected ranges for both fixed and variable costs.

Capital Costs

The current yearly projected capital cost expenses are provided in Table ES-18.

Table ES-18 — Bajío Projected Capital Expenditures

	2021	2022–2023	2024–2025	2026–2027	2028 and Beyond
Yearly Totals	$8,175	$5,072	$15,753	$3,000	$25,115

Notes: Costs in Nominal US$ (1000's) | Does not include miscellaneous annual allocation of approximately $710,000 year from 2023 onward | HRSG Life Extension work identified in Management Presentation. Scope of work description has not been provided

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

The major capex is forecasted for the 2024 outage which corresponds to the steam turbine generator's major inspection (MI). The capex for contingency parts for this STG MI is reasonable, based on S&L's experience with similar facilities. Included in the above capital costs are additional allocations to the current Owner's budget, suggested by S&L, which GIM concurred with, including:

- Potential HRSG repairs that may be necessary in the future due to increased wear and potential corrosion over the long-term life of the plant
- Decommissioning cost at the project's end of life

Performance

Bajío has maintained stable performance trends, and relatively high-performance levels over the recent four years. Bajío's average operational summary from 2017 through 2020 per Table ES-19.

Table ES-19 — Bajío Average Performance 2017–2020

	Equivalent Availability Factor (EAF)	Equivalent Forced Outage Factor (EFOF)	Planned Outage Factor (POF)	Net Capacity Factor	Net Unit Heat Rate (Btu/kWh) LHV
Average	93.9%	1.6%	3.7%	90.2%	6,240

Note: Regarding heat rate, HHV basis = LHV basis x 1.11 (approximately)

Bajío's average annual Equivalent Availability Factor (EAF) since 2017 is 93.9%. In 2020, Bajío conducted a planned major outage, contributing to a relatively low EAF of 90.0%. However, Bajío's 93.9% EAF average over the last four years is considered above average for this size and type of power plant. (Approximately 92% EAF is typical.) Bajío's 1.6% average forced outage rate is better than an expected 2% for this type of plant.

With continuing diligent maintenance, the plant should be able to maintain its high performance level.

Environmental Performance

In the period of 2017 to 2020, there were two air emissions exceedances reported. It is our understanding these were not chronic, recurring issues. There are no outstanding issues with water quality, wastewater emissions, or noise at the plant.

Major Contracts

At this time, there are no current problems with the counterparties or contracts. Major project agreements for Bajío include the LTSA with GE for the CTs, ST, and electric generators; the Power Purchase Agreement (PPAs) with CFE and industrial customers Goldcorp; and the primary Fuel Supply Agreement (FSA) with CFE.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Potential Risks

Refer to Table ES-20 for potential risks at the Bajío plant. Note that we have included items with potential additional capital costs not included in the Owner's original budget (HRSG repair allocation and decommissioning cost). Another key point would be whether or not the transmission limitation of about 645 MW can be resolved so that the plant can operate at its full capacity, about 670 MW. This is unresolved at this point.

Table ES-20 — Bajío – Potential Risks

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
HRSG Thermal Creep Tube Failures resulting from higher temperatures after AGP upgrades	6.3.4	1	Despite the fact that major repairs and tube replacements have been implemented to relieve stresses in the superheater and reheater sections of all three HRSGs, thermal studies and increased NDE will be required in an effort to prevent additional tube failures. This is also a recommendation from Tetra Engineering.
HRSG Flow Accelerated Corrosion	6.3.4	2	Tetra Engineering noted internal pitting and erosion in LP evaporator and economizer headers and has suggested a review of the station water chemistry. While FAC has not been an issue to date, a study should be performed to confirm.
AGP Impacts to BOP systems	6.3.5	3	A study was conducted by Kiewit to identify balance of plant systems that could be impacted by the AGP uprate. Open issues from that study include 1) the STG GSU and generator may need to be upgraded depending on which heat balance model is used; and 2) The findings also show that the plant is expected to be derated with gas turbines at part-load when ambient conditions begin to exceed 32°C due to increasing condenser back pressure.
CTG Main Transformer Ratings	6.3.5	3	The nameplate ratings for the CTG main transformers are lower than required for the uprated conditions. The GE study that was performed to re-certify the MVA ratings should be confirmed by the equipment OEM.
Decommissioning Costs	6.4.2	3	Owner indicated no decommissioning cost in their budget at the end of the project life. S&L suggests adding an estimated cost of $9.7 Million at the end of life for decommissioning.
Environmental	6.6	3	The monthly reports have identified two air emissions exceedances in 2020 and 2019. The cause, severity and mitigation of the exceedances were not provided for S&L to review. However, it is our understanding these were not chronic, recurring issues.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
HRSG Repair Allocation	6.4.2	3	Owner has allocated an insufficient budget to cover contingencies for performing major repair work on the HRSGs if this becomes necessary. S&L suggests adding an additional allocation of $15 Million, which would cover all three HRSGs.

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

In summary, the Bajío plant has been well-maintained and is in good condition. As the plant continues to follow good maintenance practices, the plant can be expected to reach a full-service life of 35 years and beyond at a high performance level.

SAN LUIS DE LA PAZ (SLP) COMBINED-CYCLE PROJECT

San Luis de la Paz (SLP) is a 235 MW capacity combined-cycle unit and began commercial operation in 2015. The plant configuration is 1x1x1: one combustion turbine (CT), one heat recovery steam generator (HRSG), and one steam turbine (ST). S&L visited the site in March 2021.

Operations & Maintenance Management

SLP's current staffing consists of 38 personnel (including temporary contractors). SLP's operations and maintenance staffing is typical for a plant of this size. S&L's assessment from interviews with the plant management are that they are very capable and knowledgeable of the SLP plant.

The safety programs at SLP are equal to or better than programs at similar gas-fired, combined-cycle plants. All staff are engaged in safe practices and training activities. There have been no lost-time incidents (LTI) since the commercial operation date (COD), and SLP has not had a total recordable case (TRC) in 1,640 days. Additionally, the plant's Total Recordable Case Frequency (TRCF) was zero for the year 2020.

SLP contracts with Original Equipment Manufacturer (OEM) General Electric (GE) for major maintenance services for the CT through an Operation Support & Maintenance Service Agreement, which is a type of Long-Term Service Agreement (LTSA). There is no major maintenance agreement in place for the ST, and costs for parts and labor are allocated in the plant's O&M budget. It is not uncommon for a plant to budget for major ST maintenance through the plant's O&M budget instead of having an LTSA.

The original CT rotor remains in operation and due to the relatively young age of the SLP plant, replacement of the rotor is far away into the late 2020s to early 2030s.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Assessment of Plant Conditions

From S&L's site visit, our review of approximately four years of plant records, and conference calls with the plant, no obvious significant deterioration was observed, nor other indications of operating problems (e.g., high noise levels) were noted. The plant has been well maintained and is performing in accordance with industry expectations.

S&L finds the SLP plant in good condition for a 6-year old plant. We found that the plant equipment has been maintained in accordance with prudent industry practices and the plant's overall condition is conducive to continued safe and reliable operation. If the plant continues its practices for O&M inspections, monitoring, and overhauls, including major required replacements (e.g., CT rotor replacement when required), S&L believes the plant can continue operating for 30 or more years.

Operations & Maintenance Costs

The projected yearly O&M expenditures for 2021 through 2023 are summarized in Table ES-21. These values show a trend consistent with the actual expenditures from the plant records from 2017 to 2020.

Table ES-21 — SLP – Projected O&M Expenditures (2021–2023)

	2021	2022	2023	Average
Total O&M Expenditures	5,395	5,089	9,630	6,704.7
Total Fixed Costs	2,694	2,639	2,648	2,660.3
Plant MW Rating	237	237	237	237
Fixed Costs, US$/kW per Year	11.37	11.14	11.17	$11.23
Total Variable Costs	2,701	2,450	6,982	4,044.3
MWh/Year x 1,000 Projected	1,693.76	1,815.57	1,724.09	1,744.47
US$/MWh	1.59	1.35	4.05	$2.33

Notes: Non-LTSA Major Maintenance costs are the Owner's costs during major maintenance work. Since 2023 has Major Inspections scheduled for the CT and ST, the Owner's costs will be higher than the other years. (The total cost of STG inspections and maintenance are covered by the Owner since STG is not included in the LTSA.) | Costs in thousands of US$, Nominal | MWh/year projections were provided by Saavi Energia.

In S&L's experience, fixed costs for a combined-cycle plant typically range from US$10 to $15 per kilowatt (kW) per year. SLP's projected fixed costs are within this range (11.23 $/kW). Regarding variable costs, the typical range of variable costs for a combined-cycle unit is approximately US$2.50 to $3.00 USD per MW-hour (MWh). SLP's projected variable O&M costs are slightly lower than the typical range at 2.33 $/MWh. S&L considers the O&M budget projection to be realistic and an indication of well-planned execution of long-term maintenance. The next substantial planned outage work is in 2023, when the CT will undergo the

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

first major inspection and the STG will also undergo a major inspection; Table ES-21 reflects higher 2023 costs related to those overhauls.

Capital Costs

The current yearly projected capital cost expenses are provided in Table ES-22.

Table ES-22 — SLP Projected Capital Expenditures (Nominal 2019 Dollars)

	2021	2022	2023	2024	2025	2026	2027–2032
Total	$360,000	$450,000	$250,000	–	–	$350,000	$7,800,000

SLP is a relatively new unit and no large Capex projects are foreseen in the near term.

Replacement of the GT rotor is still not foreseen in the near term. Included in the above capital costs are additional allocations to the current Owner's budget, suggested by S&L, and agreed to by GIM:

- Potential HRSG repairs that may be necessary in the future due to increased wear and potential corrosion over the long-term life of the plant
- Decommissioning cost at the project's end of life

Performance

SLP has maintained stable performance trends, and relatively high-performance levels over the recent four years. SLP's average operational summary from 2017 through 2020 per Table ES-23.

Table ES-23 — SLP Average Performance 2017–2020

	Equivalent Availability Factor (EAF)	Equivalent Unplanned Outage Factor (EUOF)	Planned Outage Factor (POF)	Net Unit Heat Rate (Btu/kWh) HHV Basis
Average	94.9%	1.7%	3.4%	6,748

S&L's key observations about the last four years of performance trending are as follows:

- Plant availability has been consistently high except for 2019 which was lower due to planned inspections. (S&L expects an availability of 92% for this type plant.)
- The EUOF average from 2017 to 2020 is 1.7%. For a plant of this size and type, we would expect an EUOF of about 2%, which SLP has been bettering, on average.

With continuing diligent maintenance, the plant should be able to maintain its high performance level.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Environmental Performance

In the period of 2017 to 2020, there were no environmental exceedances reported for air, water, or noise emissions.

Major Contracts

At this time, there are no current problems with the counterparties or contracts. Major project agreements for SLP include the LTSA with GE for the CT; the Power Purchase Agreement (PPA) with Goldcorp; and the primary Fuel Supply Agreement (FSA) with Pemex.

Potential Risks

Refer to Table ES-24 for potential risks at the SLP plant.

Table ES-24 — SLP – Potential Risks

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Future HRSG Repairs	7.3, 7.4.2	1	The SLP HRSG is still relatively new and the plant has not allocated any Capex funds for the foreseeable future. Potential future HRSG repair/replacement work should be budgeted.
Decommissioning costs	7.4.2	1	There are no decommissioning costs allocated in the budget for the end of the project useful life.
STG	–	2	Recommend replacement of the space heaters at the earliest opportunity. Maintain stator winding temperature 5 °C above the ambient temperature to avoid the entry of humidity. The plant reported this will be performed during the major inspection outage. Recommend installation of online Partial Discharge meter which will monitor continuous insulation condition status of the stator windings of the generators while in operation.
CTG and STG	–	2	Recommend installing a magnetic flux probe. Rotor flux monitoring involves measuring the magnetic flux in the generator airgap to determine if field winding degradation or turn to turn shorts have occurred in the rotor poles

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

The SLP plant is still relatively new, and Sargent & Lundy has not observed areas that require potential improvement. The plant has allocated costs for smaller items in its Capex budget, which S&L has reviewed and agrees with. As noted under the Capital Cost section above, the first two risk items in Table ES-24 pertain to potential additional capital costs not included in the Owner's current budget, which GIM has included them in their capital cost project.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

In summary, if the plant continues its practices for O&M inspections, monitoring, and overhauls, including scheduling major required equipment replacements per OEM or specialty contractor recommendations (e.g., gas turbine rotor replacement), S&L believes the plant can continue operating for an additional 30 or more years.

ALTAMIRA COMPRESSION PROJECT

The Altamira Compression Station (ACS) began commercial operation in December 2014, providing natural gas compression and transmission services. ACS is designed to operate in a 4x33% configuration including one redundant compression train. Each Solar Turbines' ("Solar") centrifugal natural gas compressor is driven by a Solar gas turbine with associated equipment on a skid. The station delivers compressed gas to the 48-inch Cactus-Reynosa main pipeline, and has a capacity of 1,388 million standard cubic feet per day (MMSCFD). Although S&L did not visit ACS in 2021, we participated in a lengthy virtual site visit with plant personnel and management.

Operations & Maintenance Management

ACS is staffed by a team of 25 workers. The station organization is lean, utilizing external support for major maintenance activities (e.g. major equipment inspections and maintenance). S&L finds the staffing level to be adequate for the operation and maintenance of the station.

Safety performance is tracked by a metric called Total Recordable Case Frequency (TRCF). The highest TRCF was 1.11 in May 2018 versus an industry benchmark of 1.5. In 2020, the TRCF was recorded as zero. There has not been a lost-time accident involving either station personnel or contractors working on the units since COD. Plant personnel receive regular safety training as part of Saavi Energia standards.

ACS contracts its major maintenance work to Solar in a Machine Management Services Agreement (MMSA), which is similar to a Long Term Service Agreement (LTSA). The MMSA covers the gas compressors and gas turbine drivers. Solar's scope includes performing a major overhaul on the gas turbine driver at 30,000-hour intervals (or longer based on Solar's assessment) or exchanging the driver for a new or refurbished turbine that will be used until the next major overhaul. S&L finds Solar's O&M practices for comply with generally accepted industry practices in the natural gas industry.

Assessment of Plant Conditions

S&L finds ACS in good condition based on our March 2021 virtual site visit, our review of plant records and reports, and discussions with the plant staff. The plant has been well maintained and is performing in accordance with industry expectations.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

In December 2020, Solar Turbines provided a 'Condition Assessment Report' for each of the four trains at ACS. Overall, this report verified the good working condition of the turbines and compressors, and recommended some relatively minor adjustments or maintenance on some of the auxiliary systems.

If the plant continues its practices for O&M inspections, monitoring, and overhauls, S&L believes the plant can continue operating to its 35-year design life and beyond.

Operations & Maintenance Costs

The projected yearly O&M expenditures for 2021 through 2023 are summarized in Table ES-25.

Table ES-25 — Altamira Projected O&M Costs (2021–2023) (Nominal USDx1000)

	2021	2022	2023	Average 2021–2023
Total O&M Expenditures	$ 2,322	$ 6,760	$ 4,612	$ 4,565
Total Fixed Costs	$1,934	$ 1,934	$ 1,940	$ 1,936
Plant MMSCFD Rating	–	–	–	1,388
Fixed Costs, US$/Rated MMSCFD per Year	–	–	–	$ 1,395
Total Variable Costs	$388	$ 4,826	$ 2,672	$ 2,629
Variable Costs, US$/MMSCFD per Year (Note)	–	–	–	$ 6.00

Note: $/MMSCFD based on Saavi's projection for average MMSCFD

The projected fixed O&M costs are consistent with the actual fixed O&M costs over the past several years. The variable costs are projected to increase significantly in 2022 and 2023 to coincide with costs related to the MMSA for a gas turbine driver major overhauls scheduled in 2022 and 2023. S&L reviewed the magnitude of the O&M costs and find them to be reasonable for the size, type, and age compression station.

Capital Costs

The capital costs projected by the Owner, including life extension costs, are indicated in Table ES-26.

Table ES-26 — Altamira Projected Capital Costs (Including Life Extension)

	2021	2022	2023	2024	2025	2026	2027/After
Total	$387,402	$627,961	$355,429	$1,318,438	$633,624	$633,624	$5,737,700

Notes: Costs in Nominal US$ | Does not include an approximately $100,000 annual allocation for miscellaneous projects from 2023 onward

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

During the period 2018-2020, approximately $1 million appeared in the life extension project budget to update station control systems. The original control system was recently upgraded, utilizing some of this budget. Additionally, future upgrades/replacement of the control system is projected for 2029 when the existing system is expected to be obsolete. This is a reasonable budget for this work, in our view.

Performance

ACS's operational summary from 2015 through 2020 is shown in Table ES-27.

Table ES-27 — Altamira Average Performance 2015–2020

	Total Hours of Operation (All Units)	Daily Average Volume of Compressed Gas (MMSCFD)	Primary Fuel Consumption (mmBtu)	Unit Consumption (Btu/scf)	Equivalent Availability Factor	Contractual Availability
Average	15,652	928	1,350,871	3.72	96%	100%

ACS operates based on demand dispatch. Currently, ACS can meet all required dispatch with one train in operation. The average daily volume of compressed gas has decreased each year from 2016 to 2020. The plant indicated that demand has decreased due to a new external compressor station coming on-line, new gas sources in the United States, and decreased industrial demand in 2020 coinciding with the COVID 19 pandemic. ACS's O&M procedures have shifted to consider the lower demand. Only one or two compressors typically operate and operation hours per train are managed to stagger the hours-based overhauls. Availability has been maintained at a high level, achieving 100% availability in 2020.

Our assessment indicates that Altamira has experienced a high average availability over the last four years after the start-up period following COD. If the plant continues its practices for O&M inspections, monitoring, and overhauls, S&L believes the plant can continue its high level of performance for an additional 30 or more years.

Environmental Performance

As discussed during our virtual site visit, any environmental exceedances were minor and were corrected, and there have been no major environmental issues since COD.

Major Contracts

At this time, there are no current problems with the counterparties or contracts. ACS's key contracts include the O&M Agreement, MMSA, the Investment Agreement, and compression services contracts. S&L finds the terms of the agreements to be reasonable and typical for this type of station.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Potential Risks

Refer to Table ES-28 for potential risks at the Altamira plant.

Table ES-28 — Potential Risks Altamira

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Changes in demand	8.5	3	Demand has dropped over the past 4 years. Changes to scheduled CAPEX projects, overhauls, and major maintenance may be necessary considering changes in demand over the next several years.

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

S&L's 2021 review of the Altamira Compression Station has not found any current unaddressed issues which could impact the availability and performance of the station. The average daily volume of compressed gas has decreased each year from 2016 to 2020. Therefore, changes to scheduled CAPEX projects, overhauls, and major maintenance may be necessary considering changes in demand over the next several years.

S&L has found the ACS to be in good condition and has been operated and maintained according to generally accepted industry practices and forced outages and other issues have been appropriately addressed. If the plant continues its practices for O&M inspections, monitoring, and overhauls, S&L believes the plant can continue its high level of performance through its 35-year design life and beyond. Technical risks are considered minimal at this time.

EL SAUZ COMPRESSION PROJECT

El Sauz Compression Station (El Sauz) provides natural gas compression and transmission services. El Sauz is comprised of two projects:

- Compression Bajío, S. de R.L. de C.V. ("CB") – Units 1, 2, and 3; and
- Green Energy Libramiento, S. de R.L. de C.V. ("GEL") – Units 4, 5, and 6.

GEL also includes a 65-km long, 24-inch diameter pipeline. CB achieved its commercial operation date (COD) in 2001, and GEL achieved COD in 2007. Each of the six units has the capacity to compress 50 million standard cubic feet per day (MMSCFD). Since each of the two projects is designed so that two units operate at a time while the third unit is in standby, the total capacity of El Sauz is 200 MMSCFD. All six units are comprised of a gas compressor and a Caterpillar gas-fired reciprocating engine as the driver. S&L visited the site in March 2021.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Operations & Maintenance Management

El Sauz is staffed by a team of 20 workers. During the site visit, S&L met with key managerial personnel at El Sauz. The station organization is lean, utilizing external support for most major maintenance activities. S&L finds the staffing level to be adequate for the operation and maintenance of the station.

Safety performance is tracked by a metric called Total Recordable Case Frequency (TRCF). The highest TRCF was 0.91 in August 2018 versus an industry benchmark of 1.5. In 2020, the TRCF was recorded as zero. More than 5,000 days have passed since the last lost-time accident. Plant personnel receive regular safety training as part of Saavi Energia standards.

S&L discussed preventative maintenance (PM) and major maintenance (MM) activities with the staff. The three major components at El Sauz—engines, compressors, and pipeline—receive scheduled maintenance at set intervals. Since there is no long-term service agreement (LTSA) in place, outside contractors are engaged for major work and electrical testing. Since the units have logged very few operating hours in the last several years, major overhaul work on the engines/compressors has not been required recently. S&L finds that the O&M requirements for PM and MM planning comply with generally accepted industry practices in the natural gas industry.

Assessment of Plant Conditions

During the site visit, the Caterpillar engines and compressors were found to be in good condition. No fluid leaks were noticeable. Maintenance on the Libramiento pipeline and valve stations is performed by CENAGAS, since the El Sauz staff is precluded from working on the pipeline.

In 2016 and 2019, unauthorized connections to the Libramiento pipeline were identified. The damaged pipeline locations were excavated and repaired. In 2020, a CAPEX project was started to use satellite communication systems to reinforce security surveillance of the pipeline. During our site visit, it was found that there are no outstanding issues with the pipeline. CENAGAS follows maintenance practices aligned with industrial norms. If the plant continues its practices for PM inspections, monitoring, and overhauls when required, S&L believes the plant can continue operating for another 20 years and beyond.

Operations & Maintenance Costs

Projected yearly O&M expenditures for 2021 through 2023 are summarized in Table ES-29.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table ES-29 — El Sauz Projected O&M Costs (2021–2023) (Nominal USDx1000)

	2021	2022	2023	Average 2021–2023
Total O&M Expenditures	$ 3,182	$ 1,410	$ 1,409	$ 2,000
Total Fixed Costs	$ 3,130	$ 1,364	$ 1,363	$ 1,952
Plant MMSCFD Rating	–	–	–	200
Fixed Costs, US$/Rated MMSCFD per Year	–	–	–	$ 9,762
Total Variable Costs	$ 52	$ 46	$ 46	$ 48
Variable Costs, US$/MMSCFD per Year	–	–	–	See Note

Note: The daily average volume of compressed gas (MMSCFD) was not available for review. Since El Sauz has been in reserve since late 2016, the daily amount of compressed gas had been very low.

S&L finds the magnitude of the O&M costs to be reasonable for the size, type, and age compression station.

Capital Costs

The capital costs projected by the Owner, including life extension costs, are indicated in Table ES-30.

Table ES-30 — El Sauz Projected Capital Costs (Including Life Extension)

	2021	2022	2023	2024	2025	2026	2027/After
Compression Bajío (CB)							
Total	$0	$0	$0	$0	$0	$0	$0
Green Energy Libramiento (GEL)							
Large CAPEX	$0	$0	$0	$1,060,168	$0	$0	$0
Major Maintenance CAPEX/Pipeline/Other	$0	$0	$2,681,325	$171,945	$2,136,017	$175,619	$2,661,709
CAPEX Allocation	$427,736	$247,860	$79,513	$79,513	$79,513	$79,513	$473,988
Total	$427,736	$247,860	$2,760,838	$1,311,626	$2,215,530	$255,132	$3,135,697

Notes: Costs in Nominal US$ | Does not show an approximately $79,000 annual allocation for miscellaneous projects from 2023 onward | 2021 cost includes fire protection system improvement project | Breakdown of the GEL costs was not available at the time of issuance of this report.

As noted in Table ES-30, the breakdown of the capital cost was not available at the time of our review. Without a breakdown or further explanation, the years with $2 Million of capital cost expenditures for GEL appears to be on the conservative side.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Performance

El Sauz's operational summary from 2015 through 2020 is shown in Table ES-31.

Table ES-31 — El Sauz Average Performance 2015–2020

	Total Hours of Operation (All Units)	Daily Average Volume of Compressed Gas (MMSCFD)	Primary Fuel Consumption (mmBtu)	Unit Consumption (Btu/scf)	Equivalent Availability Factor
Average	6,501	(1)	(1)	(1)	99.70%

Note: Since 2017, El Sauz has been operating in reserve. El Sauz did not provide the Daily Average Volume of Compressed Gas, Primary Fuel Consumption, or Unit Consumption during that period as it can reasonably be considered de minimis.

El Sauz has been operating in a reserve mode since 2017; the total hours of operation during the 4-year period from 2017 through 2020 was only 420 hours. As a result, the monthly report KPIs indicate 100% availability for those four years. Before the reserve period, El Sauz processed daily average volumes of 174 MMSCFD and 200 MMSCFD in 2015 and 2016 respectively, close to the 200 MMSCFD plant capacity. There have been no major unplanned outages in the past three years. Based on the trends for the last six years, we find that El Sauz's staff is managing the plant's inspections and maintenance to maintain reliable performance and high availability.

Environmental Performance

As discussed during our site visit, any environmental exceedances were minor and were corrected, and there have been no major environmental issues since COD.

Major Contracts

El Sauz key contracts include the Natural Gas Compression Service Agreement, the Investment Agreement, and Shared Facilities Agreement. CB and GEL are contracted to PEMEX for compression services. There is no LTSA for major equipment maintenance; the plant contracts externally when overhaul work is needed. This is a reasonable approach for maintenance on the compressors and their reciprocating engine drivers.

Potential Risks

Refer to Table ES-32 for potential risks at the El Sauz station.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table ES-32 — Potential Risks El Sauz

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Pipeline security & maintenance	9	3	Most of the highlighted risks from the station's monthly report were related to the pipeline security & proper maintenance, which is coordinated with CENAGAS. Damage or unplanned pipeline could be disruptive to station operation. While the station has indicated that improved pipeline security measure are being implemented and maintenance is coordinate with CENAGAS, a review of pipeline security and maintenance practices could mitigate the risk to operational disruption.

(**Note**: 1 = Most important; 2 = Moderate; 3 = Lower importance)

The station's monthly reports identified several recent issues pertaining to the 65 km Libramiento pipeline. Apart from the risks on the pipeline, S&L has found that the El Sauz Compressor Station to be in good condition and has been operated and maintained according to generally accepted industry practices If the plant continues its practices for O&M inspections, monitoring, and overhauls, and maintains good communications with CENAGAS regarding pipeline conditions, S&L believes the plant can continue its high level of availability and reliable performance for an additional 20 years and beyond.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

1. INTRODUCTION

1.1. S&L SCOPE OF WORK

Sargent & Lundy LLC (S&L) was engaged by Global Infrastructure Management, LLC (GIM) to conduct an asset review of the following existing projects in Mexico:

- Bajío Combined-Cycle Project
- Campeche Combined-Cycle Project
- Chihuahua Combined-Cycle Project
- LaRosita Units 1 and 2 Combined-Cycle Projects
- San Luis de la Paz (SLP) Combined-Cycle Project
- Altamira Compression Station
- El Sauz Compression Station

We understand that GIM is in the process of acquiring the above facilities from the current Owner, Saavi Energía ("Saavi"), and GIM is presently in discussions with potential lenders to complete the transaction. To support GIM in this phase, S&L has prepared this Lender's Report. As previously discussed GIM, this Lender's Report consists of useful information to potential lenders excerpted from S&L's earlier May 2021 reports for GIM on these projects. This Lender's Report focuses on the following aspects of the above projects:

- General information: Location, plant configuration, fuel, plant rating, original startup date, other info as needed
- Identification of engineering, procurement, and construction (EPC) contractors who built the original units
- Description of interconnections (transmission, fuel, water, others if any)
- High level description of plant condition
- High level description of plant operation and maintenance (O&M):
    - Staffing
    - Safety statistics
    - Long Term Service Agreement (LTSA)
    - Major maintenance practices and inspections: e.g., timing vs. original equipment manufacturers' (OEM) recommendations for major equipment; other major issues such as inspections of heat recovery steam generators (HRSG) and high energy piping

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- Plant performance: Include table of last four years average of availability, forced outage, planned outage heat rate. Discuss major forced outages or problems. Provide assessment of how the unit compares to the expected range.
- Environmental: confirm if any issues or exceedances, or none in recent years
- Projected capital costs total; provide short description of major expenditures expected.
- Trends of total fixed and variable O&M costs, including benchmark vs. expected industry range for fixed and variable costs
- Any issues with major contracts; e.g., suspension of fuel gas supply at Campeche
- Summary of major risks

S&L acquired information to conduct this review from several sources:

- Documentation provided by Saavi management and plant personnel, including both historical and forecasted information.
- Discussions with Saavi management and plant personnel during March 2021. As indicated in this report, S&L personnel visited some of the project sites; and for those not visited in person, "virtual" site visits were conducted with the plant staff including a video walk through by plant personnel viewed through internet linkup.

A separate section is provided below for each of the above listed projects. S&L reviewed and opined on the reasonableness of the project information provided, which is included each of the project sections below.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

2. CHIHUAHUA COMBINED-CYCLE POWER PROJECT

2.1. PLANT DESCRIPTION

Energia Chihuahua SA de C.V. (otherwise known as the "Chihuahua Power Plant", "Chihuahua" or "Project Company") is a 271-megawatt (MW) nominal nameplate capacity combined-cycle power plant located in the state of Chihuahua, Mexico, about 40 km south the city of Juarez, Mexico that began commercial operation in September 2003. The plant is fully owned by Saavi Energía ("Saavi").

The plant is a single fuel (natural gas), combined-cycle thermal power plant, which was originally rated at 271 MW when commissioned in 2003, and is configured in a 2 x 2 x 1 arrangement using two General Electric (GE)/Alstom GT11N2 gas turbines (GTs), each associated with a duct-fired, three-pressure level heat recovery steam generator (HRSG), one steam turbine (ST) and an air cooled condenser (ACC). The plant was originally designed and built by the engineering, procurement, and construction (EPC) contractor, Jacobs Engineering Group Inc. ("Jacobs").

Overall, the plant has been operating at a high performance level, with an average availability of 95.6% and an average heat rate (a measure of plant efficiency) of 7,708 Btu/kwh-HHV (higher heating value basis) over the last four years.

Based on GT and ST upgrades currently in progress, the plant is projected to generate 283 MW when upgrading plans are completed in the fourth quarter of 2021. The electricity generated by Chihuahua is primarily dedicated to the Comisión Federal de Electricidad ("CFE," the Federal Electricity Commission of Mexico). Additional power generated beyond the 259 MW committed to CFE is sold to local industrial customers.

2.1.1. Main Equipment

The Chihuahua power plant consists of the following major components:

- Two GE/Alstom GT11N2 "E"-class GTs with silo combustor modules and dry low nitrogen oxide (NO_X) environmental ("EV") type burners
- Two Cerrey horizontal, triple-pressure HRSGs, equipped with duct-burner supplemental firing
- One Siemens Westinghouse reheat-condensing ST
- Three GE/Alstom electric generators; one for each GT and one for the ST
- One ACC to cool the ST exhaust
- Water treatment facility

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- Main distributed control system (DCS), supplied by ABB Advent
- Three main generator step-up transformers; one for each of two GTs, and one for the ST. All three transformers were manufactured by Ferranti Packard.

2.2. MAJOR PLANT INTERCONNECTIONS

The major external interconnections to the plant are described below.

- Natural Gas

  The primary delivery point for the fuel is the nearby El Paso Keystone Permian Basin Pool. There is a Gas Transportation Services Agreement between the Project Company and CFE to transport fuel from the El Paso Keystone Permian Basin Pool to Chihuahua. The Saavi staff noted that there are parallel pipelines on the USA side of the border, but an interconnection of a parallel pipeline to the Chihuahua plant on the Mexican side of the border is not yet in place as a full backup path. However, generally, the full gas supply has been reliable, and the gas quality has been stable and satisfactory.

  Chihuahua's Fuel Supply Agreement (FSA) is between the plant and Mercuria for up to 50,000 million British thermal units (MMBtu) per day with an additional 3,500 MMBtu/Day supplied by CFE International. This is sufficient to operate the plant, including when the upgrades in progress are completed.

- Water

  Water supply to the plant is provided by two 100% well-water pumps located on site and owned by the plant. The facility's water treatment plant purifies the raw water to acceptable conditions. Chihuahua sends all wastewater to an evaporative lagoon. Per our March 2021 discussions with the plant, there are no current problems with the quantity and quality of the well water coming from the on-site pumps, although the amount and quality have declined somewhat slowly over the years. In the low probability that an additional well pump would be needed sometime in the future, an order of magnitude cost allocation of about $500,000 could be considered for the capital cost budget. See capital cost summary below in Section 2.4.2. An additional well would require authorization from Comisión Nacional del Agua (CONAGUA), the National Water Commission.

- Electricity

  Power is exported to CFE through the plant's 230 kV switchyard. Two 230-kilovolt (kV) transmission lines interconnect the facility with CFE's Samalayuca substation, located next to the Chihuahua site. This substation is interconnected to three substations through two 230-kV transmission lines each: the Reforma substation, the Moctezuma substation, and the Juárez substation. CFE owns all these transmission lines, and they dispatch the contracted capacity stipulated in their Power Purchase Agreement (PPA) with the Project Company, plus any excess capacity generated beyond the 259 MW committed to CFE. There have been no significant problems reported in the power transmission areas.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

2.3. SUMMARY OF O&M PRACTICES

S&L performed a review of the Chihuahua Plant's monthly O&M reports from 2017 through 2020, which included summaries of key operating performance indicators, fixed and variable O&M expenditures and forecasts, corrective maintenance issues, and health and safety summaries. S&L conducted conference call interviews with the Owner and Plant Management personnel in March 2021. While S&L was not able to visit the Chihuahua site in person in 2021 due to the pandemic traveling restrictions, a "virtual" site walk through was conducted via an internet video link with the plant's O&M staff.

Based on the virtual visit, the review of plant reports, and discussions with the plant staff, S&L believes that the plant equipment has been maintained in accordance with prudent industry practices. The plant's overall condition is conducive to continued safe and reliable operation. Refer to Section 2.3.4 below for additional commentary on the plant's condition.

2.3.1. Plant Staffing

Chihuahua is currently staffed with 33 shift personnel operating and performing minor maintenance on the units, a staffing level typical for a plant of its size. There are two 12-hour shifts to provide complete 24-hour coverage of the plant. 27 of the staff are members of the electrical workers' union in Mexico. S&L was informed that the labor union relationship is good, and there have been no material disputes between the Company and the union. The Project Company has personnel to self-perform most typical O&M activities, and they contract externally for additional maintenance support as needed. Specialized outside support is provided for major maintenance work, such as by the Long Term Service Agreement (LTSA) contractor, as discussed below.

The management team at Chihuahua consists of individuals with several years of experience at combined-cycle power plants. S&L considers the O&M organization and staffing to be appropriate for continued safe and reliable operation of the Chihuahua plant.

2.3.2. Safety Record

Chihuahua tracks its safety statistics using a business impact tracking system ("BITS") that allows the plant health, safety, and environmental (HSE) manager to track compliance with goals and to generate monthly reports. Chihuahua emphasizes a safety program with training, signage, and other measures typical for combined-cycle power plants. All workers, including contractors, are required to engage in the plant's safety program. Overall, S&L considered there to be a high level of safety awareness, which was discussed with the plant staff during our conference calls in March 2021.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

The plant has had no lost time incidents (LTI) in over 4000 days, which is the longest duration without an LTI for the Saavi Mexico combined-cycle fleet. Chihuahua reported that they did have one recorded incident in 2018; a contractor on site twisted an ankle. The situation was investigated and corrective measures taken.

The safety programs at Chihuahua are equal to or better than programs at similar gas-fired, combined-cycle plants. All staff are engaged in safe practices and training activities. Plant safety statistics are indicative of an effective safety program and a safe working environment.

2.3.3. LTSA & Other Maintenance Contracting

Chihuahua contracts its major maintenance work to a consortium of Power Services Group (PSG) and Liburdi Turbine Services, Inc. (Liburdi). A new agreement was signed in 2020 for a term through 2031. Although many combined-cycle plants contract the original equipment manufacturer (OEM) for LTSA services (such as GE/Alstom, the GT OEM for Chihuahua), quality non-OEM contractors, such as PSG/Liburdi, are regularly utilized for plants with GTs of approximately 240 MW rating and less, which is the case for Chihuahua (which has two 100 MW GTs).

Major component inspections and overhaul work (including GTs, ST, and electric generators) are scheduled with the plant. Major inspections are consistent with the OEMs' recommendations, which is prudent industry practice. Major inspections and maintenance of the HRSGs, high pressure piping inspections, and balance of plant (BOP) equipment inspection and maintenance are contracted to regional companies through competitive bids. The planned outage schedule is shown in Table 2-1.

Table 2-1 — Chihuahua Projected Outage Schedule

Unit	Outage Date/Description			
	2021	2022	2023	2024
GT #1	B	A	C	A
GT #2	B	A	C	A
ST	–	–	Minor	–

Note: Outage types A, B, and C are GT inspection types; MI = major inspection = "C" inspection. Outage types A and B are minor GT inspections.

The intervals between the A and B minor outages for the GTs are 7,700 equivalent operating hours (EOH) and the intervals between C outages for the GTs are 30,800 EOH. Major overhauls for the steam turbine are scheduled every 7 or 8 years, coinciding with the GT major overhauls. This schedule is typical industry practice for combined-cycle plants, which Chihuahua has been following for major maintenance scheduling.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

A key milestone in plant life extension is the replacement of the GT rotors, which is typically performed after 150,000 to 200,000 operating hours. While the Chihuahua rotors have not yet been replaced, the plant is aware of the need to replace them in the next four to five years (assuming continued base load operation), and is closely monitoring their condition to schedule their replacement during the appropriate outage.

Other key equipment items subject to long term wear and potential repairs are the HRSGs. Chihuahua has experienced a modest amount of leakage in addition to wall thinning in piping or tubing in some areas of the HRSGs due in large part to flow accelerated corrosion (FAC). This has required repairs/replacements in some HRSG sections constructed of low-grade carbon steel. Utilizing an outside specialty contractor, the plant monitors HRSG wall thickness conditions and any new leakage to make immediate repairs as needed and to schedule replacements as needed. (In addition to an extensive HRSG condition monitoring program, the plant has taken pro-active steps to reduce potential corrosion and wear, such as improving water chemistry conditions in the HRSGs.)

In 2019, the plant contracted with a specialty contractor to inspect the high energy piping systems. No major issues were found. The plant continues to inspect the major piping systems during every outage.

No significant problems have been reported with the electric generators, and auxiliary electrical equipment or systems. The plant will install improved on-line monitoring in a near term outage. Regarding the plant's main control system, the DCS, an upgrade was performed in 2016, and the upgraded system is performing well.

2.3.4. S&L Overall Assessment of Plant Condition

As noted above, S&L finds the Chihuahua plant in good condition for an 18-year old plant, based on the March 2021 virtual site visit, our review of plant records and reports, and discussions with the plant staff. We found that the plant equipment has been maintained in accordance with prudent industry practices and the plant's overall condition is conducive to continued safe and reliable operation.

As noted in Section 2.1.1 that the main original equipment manufacturers are GE/Alstom, Cerrey, and Siemens Westinghouse, who are top quality vendors in the power industry, and the original plant designer/constructor, EPC contractor, Jacobs, is also a well-known, high quality firm in the power industry. This, along with the plant's high-level performance over the years provides a strong confidence level in the quality of the plant's current condition.

Although S&L did not visit the plant in 2021, we reviewed approximately four years of plant records and participated in lengthy conference calls with the plant staff, including observing the plant during a 30-minute virtual site walk through. (A plant staff member performed a walkaround with a live video feed back to our

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

office.) It is recognized that the value of the virtual visit was limited, but the plant staff member walked down all areas we requested, including the major equipment, auxiliaries, supporting systems (e.g., water treatment system, outdoor equipment such as transformers, etc.), and the control room. No obvious significant deterioration was observed, nor other indications of operating problems (e.g., high noise levels) were noted.

Our review of the plant's inspection and maintenance reports indicates the plant has been well maintained and is performing in accordance with industry expectations. (Refer to sections below regarding capital and O&M budget trends, and performance trends.) For example, over the past four years, Chihuahua has an average forced outage rate of 0.8%, which is significantly better than the approximately 2.0% expected for this type, size, and age plant.

To summarize, if the plant continues its practices for O&M inspections, monitoring, and overhauls, including scheduling major required replacements per OEM or specialty contractor recommendations (e.g., gas turbine rotor replacement), S&L believes the plant can continue operating for an additional 20 or more years.

2.4. O&M AND CAPITAL COST BUDGET PROJECTIONS

2.4.1. O&M Costs

Projected O&M expenditures were provided to S&L for review and are summarized in this section. In general, the plant engages in an O&M approach with a corresponding budget that maintains the plant's high level of performance.

The projected O&M expenditures for 2021 through 2023 are summarized in Table 2-2. These values show a trend consistent with the actual expenditures from the plant records from 2017 to 2020. The cost data has been broken down to identify major maintenance fixed and variable costs separately from plant fixed and variable costs. LTSA costs are also broken out. The plant fixed and variable O&M costs are presented as unit rates (red text in table below) for comparison to similar types of plants in similar size ranges. The higher expenditures in 2023 in the table below reflect the Major Inspections planned for that year.

Table 2-2 — Chihuahua – Projected O&M Expenditures (2021–2023)

	2021	2022	2023	Average
LTSA Costs				
-- Fixed	$0	$0	$0	$0
-- Variable	$86	$87	$3,559	$1,244

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

	2021	2022	2023	Average
Non-LTSA Major Maintenance Costs (Variable)	$623	$210	$8,157	$2,997
Plant Fixed Costs	$3,073	$3,442	$3,503	$3,339
Plant Variable Costs	$545	$631	$665	$614
Total O&M Expenditures	**$4,327**	**$4,370**	**$15,884**	**$8,194**
Total Fixed Costs	**$3,073**	**$3,442**	**$3,503**	**$3,339**
Plant MW Rating	–	–	–	271
Fixed Costs, US$/kW per Year	–	–	–	**$12.3**
Total Variable Costs	**$1,254**	**$928**	**$12,381**	**$4,854**
MWh/Year x 1,000 Projected	2,093	2,050	1,841	1,995
US$/MWh	–	–	–	**$2.4**

Notes: Costs in thousands of US$ Nominal | Higher 2023 projected costs reflect a planned Major Inspection of the GTs in 2023

In S&L's experience, fixed costs for a combined-cycle plant typically range from US$10 to $15 per kilowatt (kW) per year. Chihuahua's fixed costs are within this range (12.3 US$/kW projected going forward), and therefore are reasonable. The plant indicated the projected fixed costs are expected to trend downward in the future primarily due to eliminating the fixed fees from the recently revised LTSA contract.

Regarding variable costs, the typical range of variable costs for a combined-cycle unit is approximately US$2.50 to $3.00 per MW-hour (MWh). Per the above table, Chihuahua's projected variable O&M costs going forward are slightly lower than the typical range at 2.4 US$/MWh, reflecting recently negotiated lower LTSA variable fees. It is noted the annual variable costs going forward will vary with the operating profile. In Table 2-2, S&L utilized the projected average annual MWh provided by the Owner.

Overall, the O&M cost levels and trends for Chihuahua are reasonable and compare well with expected ranges. Chihuahua's fixed O&M costs are within typical ranges seen for combined-cycle plants.

2.4.2. Capital Costs

The Owner's current list of projected capital cost expenses are provided in Table 2-3. The higher expenditures in 2023 reflect the Major Inspections on the GTs and ST planned for that year.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table 2-3 — Chihuahua Projected Capital Expenditures

Project Name	Project Description	2021	2022–2023	2024–2025	2026–2027	2028 and Beyond
Owner Capex Projections (Major Maintenance Related)						
GTGs and STG MI	–	–	$5,483	–	–	–
Other	–	$610	$308	–	$211	$273
Sub-total A	–	$610	$5,791	–	$211	$273
Owner Capex Projections (Other Capex)						
Network code compliance	–	$229	–	–	–	–
Duct burner scanners upgrade	–	–	$75	–	–	–
Equipment for remote operation of MCC	–	–	$65	–	–	–
Critical instrument smart positioners	–	–	$60	–	–	–
Capex allocation	–	–	$264	$470	$470	–
Subtotal B	–	$229	$464	$470	$470	See Note 2
Sargent & Lundy Suggested Capex Projections						
Additional HRSG Repair Allocation	Contingency for Replacement of HRSG Sections	–	$1,000	$1,000	$2,000	$4,000
Plant Decommissioning Cost Allocation	End of life costs, net cost	–	–	–	–	$5,600
GT Rotor Replacement (Two Rotors)	–	–	–	–	–	$6,000
Well Pump Addition	–	–	–	–	–	$500
Sub-Total C	–	–	$1,000	$1,000	$2,000	$16,100
Grand Total	–	$839	$7,255	$1,470	$2,681	$16,373

Notes: Costs in Nominal US$ x 1000 | Does not include miscellaneous annual allocation of approximately $235,000 year from 2028 onward.

S&L suggested allocating additional capex beyond the Owner's projections to cover potential HRSG repairs that may be necessary due to increased wear and potential corrosion over the long-term life of the plant in the amount of $8.0 Million covering both HRSGs. This allocation is based on 20% the cost of new HRSGs and would be spread over 10 years. (This cost is listed in Sub-total C costs at the bottom of the table above.)

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

S&L also suggests allocating $5.6 Million in decommissioning cost for Chihuahua. (This cost is also listed in Sub-total C costs in the table above.) As discussed in other sections of the report, S&L would also suggest allocations for GT rotor replacement (~$6.0 Million covering both GT rotors) and an additional well pump (~$500,000) in the event such a pump is needed later.

These S&L suggested costs are included in Table 2-3.

2.5. PLANT PERFORMANCE

The Chihuahua plant has maintained stable performance trends, and relatively high performance levels over the recent four years. Chihuahua's operational summary from 2017 through 2020 is shown in Table 2-4.

Table 2-4 — Chihuahua Annual and Average Performance 2017–2020

Year	Equivalent Availability Factor	Equivalent Forced Outage Factor	Planned Outage Factor	Net Capacity Factor	Net Unit Heat Rate (Btu/kWh) HHV
2017	97.8%	0.4%	1.6%	NA	7,678
2018	98.4%	0.1%	1.5%	94.8	7,699
2019	87.9%	1.3%	10.8%	84.1	7,718
2020	98.1%	1.2%	0.8%	91.3	7,736
Average	95.6%	0.8%	3.7%	90.1	7,708

S&L's key observations about the last four years of performance trending are as follows:

- The Equivalent Availability and Equivalent Forced Outage Factors have been better than expected for plants of this size, type and age. (Typical average Forced Outage Factor is about 2.0% and Equivalent Availability about 92%.) In 2019, Chihuahua conducted a planned major outage, contributing to a relatively low Equivalent Availability Factor of 87.9% and high Planned Outage Factor of 10.8%.
- Net Unit Heat Rate, an indicator of plant efficiency, has been stable over the last four years and is within a reasonable range for this type, size and age plant.
- The net capacity factor has been over 90% (except for the major outage year, 2019) which reflects the plant's reliably high output over the last few years.

With continuing diligent maintenance, the plant should be able to maintain its high performance level in the years ahead.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

2.6. ENVIRONMENTAL PERFORMANCE

In the period of 2017 to 2020, there were no environmental exceedances reported for air, water, or noise emissions. During our March 2021 call, the health, safety and environmental (HSE) manager discussed the various reports (monthly, quarterly, and annually) submitted to the authorities to verify compliance.

Regarding stack emissions, the GTs are equipped with dry low NOx (DLN) burner technology which allows them to meet the required emissions limits with a comfortable margin. The plant is equipped with continuous emissions monitoring systems (CEMS) that collect data and are used to report to the relevant regulatory agency on compliance with requirements. The plant is currently replacing the CEMS, due to the original units reaching their end-of-life, and commissioning of the new CEMS units is anticipated to be completed in 2021. Additionally, there are three off-site air quality monitoring stations installed to monitor ground level air quality.

Regarding wastewater, Chihuahua is a zero liquid discharge plant since all wastewater is sent to an evaporation pond, which has not experienced any problems to date. Samples are taken and analyses of the wastewater are performed as required, and the required reports are submitted to the regulatory agency. There have not been any reported incidences of wastewater noncompliance with relevant Mexican regulatory requirements.

Regarding noise levels, the plant performs a comprehensive noise test every five years. The last test was performed in 2020, and they passed. There have been no noise complaints.

2.7. MAJOR CONTRACTS

Key agreements for continuing operation of Chihuahua are listed in Table 2-5. The plant changed their primary FSA in 2019, and also changed their LTSA in 2020. At this time, there are no current problems with the counterparties or contracts.

Table 2-5 — Chihuahua Major Agreements

Agreement	Counterparty	Comments
PPA	CFE	Term through 2028; for 259 MW capacity. (Power above 259 MW can be sold to nearby industrial suppliers via Mexico's Self Supply program.)
Primary FSA	Mercuria	Primary supply contract signed in 2019; up to 50,000 MMBtu/day supply
Secondary FSA	CFE	Secondary supply contract; up to 3,500 MMBtu/day supply

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Agreement	Counterparty	Comments
Gas Transportation Services Agreement	CFE	25 years from COD, through 2028
Operation Support and Maintenance Contract (also known as an LTSA)	A consortium of Power Services Group or PSG (On-shore services) and Liburdi Turbine Services, Inc. (Off-shore services)	New agreement signed in 2020 for a term through 2031 (or after the 3rd major inspection). Early termination option at first major inspection in 2023.
Interconnection Agreement (IA)	CFE	Term to December 1, 2032; there is also an agreement with CFE to transmit an additional 50 MW above the 259 MW in the original PPA.
Water Supply Concession Agreements	–	Two concession agreements with the Mexican Government are needed for the on-site water well: • One agreement extends to 2044. • Second agreement expires in 2025. The plant submitted a request for extension in November 2020.

2.8. MAJOR RISKS

In this section, S&L assesses the potential risks at the Chihuahua plant. Please refer to Table 2-6 for our listing of potential risks. (Note that we have included items with potential additional capital costs not currently in the Owner's budget.)

Table 2-6 — Potential Risks – Chihuahua

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Future HRSG Repairs/replacements	2.3.3, 2.4.2	1	Despite the fact that there are indications of HRSG wear due to flow accelerated corrosion, the plant has not budgeted any Capex funds for potential future HRSG repair/replacement work.
GT Rotor Replacement	2.3.3, 2.4.2	1	The GT rotor replacement is not currently budgeted in the Owner's Capex projection, despite the fact that the total equivalent operating hours will reach typical end of life in 5 to 8 years, approximately.
Water supply	2.2, 2.4.2	3	Plant indicates over long term, raw water quality and quantity has dropped by a small amount, but still manageable today to support plant operations. This could potentially require another well in the future as worst case.
Decommissioning Costs	2.4.2	2	Plant indicated no decommissioning cost in their budget at the end of the project life.

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

S&L's additional comments on the items in Table 2-6 are provided below:

- As noted in Section 2.3.3 of this report, there have been repairs/replacements made to some sections of the HRSGs performed in these 18-year old units due to the effects of flow accelerated corrosion (FAC). The plant is monitoring the potential effects of continuing FAC and have adjusted the water chemistry to try to mitigate FAC. However, S&L notes that FAC can have long term effects, while not immediately evident today, could require repairs or replacement in future years. Currently, there is no capex allocation by the Owner for HRSG work in the future. Per Table 2-3 above, S&L recommended an additional capex allocation be added to the Owner's budget.
- Since the current Owner does not include the replacement cost of the GT rotors, we would propose an indicative cost of $3 Million for each of two rotors be included in the budget.
- Regarding the water supply, at this point, there are no problems with the quantity and quality of the well water coming from the on-site pumps, although the amount and quality have declined somewhat slowly over the years. In the low probability that an additional well pump would be needed in the future, an order of magnitude cost allocation of about $500,000 should be considered.
- Since no decommissioning cost was included in the Owner's budget, S&L would suggest an indicative $20,000/MW amount (times 280 MW) equals $5.6 Million, to be applied at the end of life of the project.

In summary, if the plant continues its practices for O&M inspections, monitoring, and overhauls, and implements required equipment replacements as needed (e.g., GT rotors), S&L believes that Chihuahua can continue operating for an additional 20 or more years at a high performance level.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

3. CAMPECHE COMBINED-CYCLE POWER PLANT

3.1. PLANT DESCRIPTION

Energia Campeche SA de CV (otherwise known as the "Campeche Power Plant" ("Campeche" or Project Company) is a dual-fuel combined-cycle power plant that began commercial operation in 2003, and is rated for 252 MW firing natural gas and 192 MW firing diesel oil. The plant is located in the state of Campeche, Mexico, in the city of Palizada on the Yucatán Peninsula. The plant is fully owned by Saavi Energía ("Saavi").

The plant is configured in a 1 x 1 x 1 arrangement using one Mitsubishi Heavy Industries (MHI) combustion turbine (CT), with a duct-fired, three-pressure level heat recovery steam generator (HRSG), one steam turbine (ST) and four (4) cell wet cooling tower. The plant was originally designed and built by the engineering, procurement, and construction (EPC) contractor, Jacobs Engineering Group Inc. ("Jacobs").

Overall, the plant has had some challenges operating on diesel oil the last four years, with an average availability of 89% and an average heat rate (a measure of plant efficiency) of 8,527 Btu/kwh-HHV (higher heating value basis) over the last four years. However, the plant's performance trends are improving through 2020.

The electricity generated by Campeche is primarily dedicated to the Comisión Federal de Electricidad ("CFE," the Federal Electricity Commission of Mexico).

3.1.1. Main Equipment

The Campeche power plant consists of the following major components:

- One MHI Model #501F3 CT with dry low nitrogen oxide (DLN) fuel combustion system
- One Cerrey triple-pressure HRSG with duct-burner firing
- One Mitsubishi ST equipped with three sections, high pressure (HP), intermediate pressure (IP), and low pressure (LP). The ST is installed on the same shaft as the CT, and they are interconnected with a Synchro-Self-Shifting (SSS) clutch.
- Two Mitsubishi electric generators; one for the GT and one for the ST
- One wet cooling tower with four (4) cells to cool the ST exhaust
- One Main Step-Up Transformer, provided by Ferranti Packard
- Reverse osmosis (RO) and mixed bed water treatment facilities and demineralized water storage tank
- Switchyard for grid interconnection

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- Emergency diesel generators
- Emerson Ovation main distributed control system (DCS)

3.2. MAJOR PLANT INTERCONNECTIONS

The major external interconnections to the plant are described below.

- Fuel Supply

  The unit has not operated on gas since 2017 since the gas supply is not available. In the near term there is work being performed to interconnect with the national gas system. The supply of gas is expected in two phases and currently Campeche is in negotiations with a fuel supply agreement (FSA). The operations & maintenance (O&M) managers anticipate the plant will be on gas by the end of 2021 or 2022. (However, it is S&L's understanding that the timing for resumption of fuel gas to the plant is not certain, and oil-fired operation could continue for an extended period.)

  Campeche has an on-site diesel storage tank supply for 10 days, enabling operation at 100% of guaranteed 192 MW net capacity as required by the PPA. Diesel is sourced by three different providers, such as PEMEX and/or VOPAK in the states of Tabasco and Veracruz.

- Water

  Water for Campeche is provided from four wells with an extraction volume limited to approximately 3.7 Million m3/year by the Comisión Nacional del Agua (CONAGUA), the National Water Commission permit, which is sufficient for plant operations. A water concession was granted for a period of 10 years in 2002, and was extended for 10 more years as of 2012, which expires in 2022. Plant management did not indicate any concerns with obtaining an extension.

- Electricity

  Campeche is interconnected to CFE via 400-kV transmission lines. The Santa Lucia substation, adjacent to the plant, is the interconnection point. Currently, since diesel oil is the only fuel option, Campeche cycles or is on cold reserve. Campeche operates under a long-term PPA with CFE for a guaranteed capacity of 192 MW on oil, with a fuel pass through at a guaranteed heat rate.

3.3. SUMMARY OF O&M PRACTICES

S&L performed a review of the Campeche Plant's monthly O&M reports from 2017 through 2020, which included summaries of key operating performance indicators, fixed and variable O&M expenditures and forecasts, corrective maintenance issues, and health and safety summaries. S&L conducted conference call interviews with the Owner and Plant Management personnel in March 2021. While S&L was not able to visit the Campeche site in person in 2021 due to the pandemic traveling restrictions, a "virtual" site walk through was conducted via an internet video link with the plant's O&M staff.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Based on the virtual visit, the review of plant reports, and discussions with the plant staff, S&L believes that the plant equipment has been maintained in accordance with prudent industry practices. The plant's overall condition is conducive to continued safe and reliable operation. It is important to note that Campeche has never operated continuously on oil until 2017. Our review of the available documents and our conference calls with the plant indicates that the facility has had major difficulties in recent years with oil firing operation. Unplanned outage rates have been high and O&M costs have been high as well when firing oil. While the plant appears to be on the correct path to more reliable operation on oil, the unit still needs to demonstrate a longer term of reliable service on oil without forced outages. Refer to Section 3.3.4 below for additional commentary on the plant's condition.

3.3.1. Plant Staffing

Campeche's current staffing consists of a staff of 33 (including temporary contractors) operations and maintenance employees. The staffing is made up of 24 union, 2 temporary contractors and 7 non-union employees. Campeche's operations and maintenance staffing is typical for a plant of this size.

Plant management indicated there have been no material disputes between the union and the Project Company. S&L's assessment from interviews with the plant management are that they are very capable and knowledgeable of the Campeche plant.

3.3.2. Safety Record

Based on the review of the safety data, a Lost Time Injury (LTI) occurred in July 2020. The LTI was a result of incorrect execution of the work permit procedure, per the root cause analysis (RCA). A contractor suffered a hand injury. Subsequent to that injury, Campeche has performed over 200 days without an LTI. Campeche follows the Saavi Fleet safety management and control programs that are behavior based. In addition to tracking lagging indicators such as LTIs and First Aid Cases, Campeche also tracks leading indicators including near misses and unsafe conditions.

In June 2017, a fire occurred during a routine oil filter replacement. The operator failed to completely isolate the diesel oil, which leaked on a hot surface which caused a fire. The original location of the oil skid filter was near the HRSG. The fire burned cable trays which extended the length of the outage. In order to prevent a reoccurrence, the skid was relocated, and improved filters were procured to reduce the frequency of filter changes.

The safety programs at Campeche are equal to or better than programs at similar combined-cycle plants. All staff are engaged in safe practices and training activities.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

3.3.3. LTSA & Other Maintenance Contracting

Since 2010, the Long-Term Service Agreement (LTSA) contract with Power Systems Manufacturing LLC (PSM) provides services for Campeche's CT, ST, and associated components. The LTSA also includes performance monitoring, parts supply, and maintenance support for two maintenance cycles. The LTSA has a termination for convenience option. Campeche plant management is currently reviewing options beyond 2021. Based on S&L's experience, using non-OEM service providers, such as PSM, is common in the industry up to the Frame F CT size (which is the frame size of the Campeche CT).

The historical outage plan for Campeche has focused on component life extension and upgrades in addition to scheduled inspections. The planned outage schedule is shown in Table 3-1.

Table 3-1 — Campeche Projected Outage Schedule

Unit	Outage Date/Description			
	2021	2022	2023	2024
CT	Rotor Assessment	Hot Gas Path Inspection (HGPI)	–	–
ST	Minor Inspection	Medium Inspection	–	–

The ST will be inspected during the next planned outage in 2022. Although no steam turbine generator (STG) inspection reports were provided to S&L, based on discussions with Campeche plant management, there are no critical issues with the STG.

The original CT rotor remains in operation. Currently the total equivalent operating hours (EOH) as of January 2021 is 129,794 including 23,782 on oil. Based on a desktop assessment performed by M&M Engineering in January 2020 (based on the 2016 rotor report by MHI, operating data, and operating forecast) the original CT rotor can keep operating at least until the next major inspection at approximately 153,000 EOH. In 2022, during the planned HGPI and as recommended in the desktop assessment, hardness testing will be performed on Rows 1, 2 and 4 of the CT in order to establish a trend if the hardness has been decreasing since 2016; the last hardness test.

As noted in Section 3.4.2 below, S&L recommends to include in the projected budget the replacement cost for the CT rotor since, based on operating hours, it may reach its end-of-life condition in the next one or two major overhauls.

December 2018 was the last inspection of the HRSG. The inspection report by HRST Company concluded that the HRSG is operated and maintained properly. The majority of the findings were routine maintenance items that were repaired. Based on discussion with O&M managers, there have been no tube leaks.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Although S&L has not identified any critical concerns with the HRSG, we recommend a future allocation for HRSG repairs as indicated in Section 3.4.2. HRSG condition for aged plants is often variable, depending on the conservatism of the original design, the original HRSG vendor, operating conditions, etc. However, for Campeche, there are some concerns due to firing on oil, since fuel oil has more impurities versus natural gas. HRSG inspections should be done periodically including an assessment when fuel gas is restored.

No significant problems have been reported with the major auxiliaries/balance of plant systems and equipment.

3.3.4. S&L Overall Assessment of Plant Condition

As noted above, S&L finds the Campeche plant in good condition for an 18-year old plant, based on the March 2021 virtual site visit, our review of plant records and reports, and discussions with the plant staff. We found that the plant equipment has been maintained in accordance with prudent industry practices and the plant's overall condition is conducive to continued safe and reliable operation. However, the plant staff stated when they were forced to operate on oil in 2017, they discovered that the auxiliary systems supporting oil firing (such as spraying demineralized water into the gas turbine combustors) had not been properly commissioned (since the plant initially primarily and continuously operated on natural gas). At the start of continuous oil operation some of these auxiliary systems were not working properly or not at all. Hence, equipment such as the CT oil burners and supporting auxiliary systems required adjustments, repairs, or in some cases, replacement. While the plant appears to be on the correct path to more reliable operation on oil, the unit still needs to demonstrate a longer term of reliable service on oil without forced outages.

As noted in Sections 3.1 and 3.1.1 that the main original equipment manufacturers are MHI and Cerrey who are top quality vendors in the power industry, and the original plant designer/constructor, EPC contractor, Jacobs, is also a well-known, high quality firm in the power industry. This, along with the plant diligently working toward resolving their technical problems when firing oil provides a reasonable indication that the plant will return to consistent reliable operation in 2021.

Although S&L did not visit the plant in 2021, we reviewed approximately four years of plant records and participated in lengthy conference calls with the plant staff, including observing the plant during a 30-minute virtual site walk through. (A plant staff member performed a walkaround with a live video feed back to our office.) It is recognized that the value of the virtual visit was limited, but the plant staff member walked down all areas we requested, including the major equipment, auxiliaries, supporting systems (e.g., water treatment system, outdoor equipment such as transformers, etc.), and the control room. No obvious significant deterioration was observed, nor other indications of operating problems (e.g., high noise levels) were noted.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Our review of the plant's inspection and maintenance reports indicates the plant has had some significant operating problems when firing oil. Refer to sections below regarding capital and O&M budget trends, and performance trends. Although the unplanned outage (EUOF) trend has decreased significantly from 3.9% in 2020 compared to 10.3% in 2019, an expected EUOF for this type of plant is about 2 to 3%. The plant acknowledges the deficiencies in oil fired operation thus far and appears to be moving in the right direction to correct them. However, the "break-in" period for continuous oil-fired operation has been excessively slow, and a longer problem-free operating period is still needed.

To summarize, if the plant continues its practices for O&M inspections, monitoring, and overhauls, including scheduling major required replacements per OEM or specialty contractor recommendations (e.g., CT rotor replacement), with appropriate O&M and mitigation of current problems and risks, S&L believes the plant can return to consistent reliable operation in 2021, and can continue operating for an additional 20 or more years.

3.4. O&M AND CAPITAL COST BUDGET PROJECTIONS

3.4.1. O&M Costs

Projected O&M expenditures were provided to S&L for review and are summarized in this section. In general, the plant engages in an O&M approach that is consistent with expected industry practice and is expected to improve the plant's performance level in 2021 and beyond.

The projected O&M expenditures for 2021 through 2023 are summarized in Table 3-2. The cost data has been broken down to identify major maintenance fixed and variable costs separately from plant fixed and variable costs. LTSA costs are also broken out. The plant fixed and variable O&M costs are presented as unit rates (red text in table below) for comparison to similar types of plants in similar size ranges.

Table 3-2 — Campeche – Projected O&M Expenditures (2021–2023)

	2021	2022	2023	Average
LTSA Costs				
-- Fixed	0	0	0	0
-- Variable	891	902	1,097	963
Non-OSM Major Maintenance Costs (Variable)	357	2,172	0	843
Plant Fixed Costs	3,834	3,948	3,871	3,884
Plant Variable Costs	360	732	788	627
Total O&M Expenditures	**5,442**	**7,754**	**5,756**	**6,317**

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

	2021	2022	2023	Average
Total Fixed Costs	**3,834**	**3,948**	**3,871**	**3,884**
Plant MW Rating	–	–	–	192
Fixed Costs, US$/kW per Year	–	–	–	**$20.3**
Total Variable Costs	**1,608**	**3,806**	**1,885**	**2,433**
MWh/Year x 1,000 Projected	234	253	321	269
US$/MWh	–	–	–	**$9.0**

Notes: Costs in thousands of US$, Nominal | MWh/y projections were provided by Saavi Energia | Higher 2022 projected costs reflect costs for STG MI, GT Rotor Assessment and HGPI | Plant MW rating is based on the last two years on oil

In Sargent & Lundy's experience, fixed costs for a combined-cycle plant typically range from US$10 to $15 per kilowatt (kW) per year. Campeche's fixed costs are above this range (19.3 $/kW historical and 20.3 $/kW projected going forward). The annual plant fixed costs have been stable at about $4.0 Million/year and the fixed LTSA costs have been zero, so the normalized fixed cost of a high ~$20/kW per year has been fairly constant over the last several years and a significant change is not anticipated going forward.

Regarding variable costs, the typical range of variable costs for a combined-cycle unit is approximately US$2.50 to $3.00 USD per MW-hour (MWh). Per the above tables, Campeche's projected variable O&M costs going forward are very high at 9.0 $/MWh. This is a result of greater EOH registered per operating hour when firing oil (compared to natural gas) and the greater amount of maintenance required on the CT when firing oil.

It is noted that for oil fired hours, there is a multiplier of number of hours to reflect the greater severity of oil firing vs. gas firing. For Campeche, a 1.3 factor is applied to the number of actual operating hours to calculate number of EOH. The factor for natural gas is 1.0; therefore, a major maintenance event will occur sooner in the case of an oil fired operation (i.e., the oil fired major maintenance interval will be 30% less than the actual operating hours of the major maintenance interval for gas fired operation.) In summary, when firing oil, even if the maintenance intervals are calculated based on EOH (instead of number of starts), the major maintenance events will be scheduled at shorter intervals for oil fired operation, thereby increasing the long term O&M cost versus gas fired operation. Additionally, in our experience, oil firing the CT is inherently a more severe service than gas firing and would tend to further increase O&M costs beyond the higher EOH factor.

In our opinion, based on the plant's report that oil firing problems have now been resolved, these high O&M costs will still persist until the unit is returned to natural gas firing; however, this depends on outside gas

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

suppliers. While the current Owner indicated that gas flow could return by the end of 2021 or 2022, there appears to be some uncertainty to this assumption and is beyond the control of the power plant.

3.4.2. Capital Costs

The Owner's current list of projected capital cost expenses are provided in Table 3-3. The higher expenditures in 2022 and 2025 reflect the HGPI and Major Inspection on the CT and the ST Inspections planned for those years.

Table 3-3 — Campeche Projected Capital Expenditures

Project Name	2021	2022	2023	2025
GT Rotor Life Extension Assessment	$100,000	–	–	–
ST Minor Inspection contingency parts	$249,657	–	–	–
ST Major Inspection contingency parts	–	–	–	$757,385
CTG HGPI and STG Medium Inspection	–	$2,265,418	–	–
Major Inspection	–	–	–	$3,456,871
Network Code Compliance	$384,917	–	–	–
H2 monitoring system for battery room	–	$30,000	–	–
Aux boiler fuel system improvements	–	$70,000	–	–
Waste storage area improvements	–	$35,660	–	–
Total	**$734,574**	**$2,401,078**	**$0**	**$4,214,256**

Note: Costs in Nominal US$

In addition to the above cost, S&L recommended adding the following future capital costs which were not in the Owner's original budget (which GIM has agreed to include in their budget):

- **HRSG future repair costs.** S&L suggests an allocation of 15% the cost of a new HRSG = $33M x 15% = **$5 Million spread over 10 years**.
- **CT Rotor Replacement.** S&L suggests budgeting for a rotor replacement in the next 5 to 8 years. **Budget cost: $7.5 Million.**

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- **Decommission Costs.** S&L suggests for a unit such as Campeche, a cost of $15,000/MW is included. 252 MW x $15,000 = **$3.8 Million at end of life**.

3.5. PLANT PERFORMANCE

The four-year average Equivalent Availability Factor (EAF) for Campeche is 88.95%. Based on S&L's experience, 90% to 92% EAF is expected for plants of this type and age. Campeche's operational summary from 2017 through 2020 is shown in Table 3-4:

Table 3-4 — Campeche Annual and Average Performance 2017–2020

Year	Equivalent Availability Factor (EOF)	Equivalent Unplanned Outage Factor (EUOF)	Planned Outage Factor (POF)	Net Capacity Factor	Net Unit Heat Rate (Btu/kWh) *
2017	76.9%	23.1%	0.00%	11.00%	8,468
2018	95.7%	3.6%	0.73%	27.10%	7,845
2019	87.1%	10.3%	2.60%	37.70%	7,717
2020	96.10%	3.9%	0.00%	12.20%	7,847
Average	88.95%	10.22%	0.83%	22.00%	7,969

*Heat Rate values are LHV basis for oil firing. HHV/LHV = 1.07 (approximately).

S&L's key observations about the last four years of performance trending are as follows:

- Plant trending for availability is good. Plant availability is up from 87.1% in 2019 to 96.1% in 2020 despite the significant unplanned outage events associated with firing on oil over the last few years.
- The EUOF average from 2017 to 2020 is 10.22%. The unplanned outage (EUOF) trend has decreased from 3.9% in 2020 compared to 10.3% in 2019. The major issues that caused high EOUF in 2017 (oil skid fire) and 2019 (Steam Turbine SSS Clutch) have been resolved. The plant is striving to reduce EOUF to below 3% in the coming year following completion of oil firing related repairs and adjustments.
- In 2018 and 2020 major repairs and replacements were required on the CT combustion system due damages incurred while oil firing. The corrective action to recommission the water injection system and all supporting systems for diesel operation should mitigate the issues with the failures of the combustion system.
- The POF for Campeche is 0.83% which is significantly low for an older plant. S&L expects a POF between 2% and 5% for 20-year-old plants. Since the major maintenance events may need to be scheduled at shorter intervals for oil fired operation as discussed in Section 3.4.1 S&L recommends additional planned outages to inspect the CT combustion system.
- Since the plant runs on oil, the Net Capacity of the plant normally runs well below 50%. In 2020 the capacity factor was 12.20%.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- The four-year average heat rate for Campeche is 7,969 BTU/kWh LHV. The highest heat rate for the time period occurred in 2017 with a value of 8,468 BTU/kWh LHV. The high heat rate can be attributed to the plant's first time operating on oil and low capacity factor. The heat rate was reduced by 7.4% in 2018 after an unplanned CI and reduced by an additional 1.6% after the 2019 planned CI. In 2020 the heat rate climbed to the 2018 value after the combustion basket failure.
    - Based on data provided by the plant, the expected heat rate range on oil is 7,689 BTU/kWh LHV to 8,760 BTU/kWh LHV. The current heat rate for Campeche is within the range of the expected values.

S&L expects forced outage rates to be in the range of 2 to 3% for a dual fuel type plant. Forced outage rates consistently above 3% indicate operational or component issues. The major issues that caused high EUOF in 2017 (oil skid fire) and 2019 (ST's SSS Clutch) have been resolved. The issues that impacted the CT combustion system due to operating on oil appear to have been resolved with the recommissioning of the water injection system and all supporting systems for diesel. The plant appears to acknowledge the deficiencies in oil fired operation thus far and appears to be moving in the right direction to correct them. However, the "break-in" period for continuous oil-fired operation has been excessively slow, and a longer problem-free operating period is still needed.

Based on our analysis, Campeche's staff is managing and correcting deficiencies so that the plant should be returning to consistent, reliable operation on oil in 2021.

3.6. ENVIRONMENTAL PERFORMANCE

In the period of 2017 to 2020, there were no environmental exceedances reported for air, water, or noise emissions. Even with diesel the plant runs below the environmental permit limit.

3.7. MAJOR CONTRACTS

Major project agreements for Campeche are listed in the table below. These key contracts include an LTSA for the major plant equipment and PPA. Aside from the resolution of the fuel gas supply situation, there are no other current problems with the counterparties or contracts.

At this time, there are no current problems with the counterparties or contracts.

Table 3-5 — Campeche Major Agreements

Agreement	Counterparty	Term
LTSA	PSM	15 years following effective dates or 2nd MI (with termination for convenience option at 2nd HGPI)
PPA	CFE	25 years following commercial operation (2028)

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Agreement	Counterparty	Term
FSA	Pending	Pending

- **LTSA.** Supports the CT and ST. As noted above in Section 3.3.1, LTSA contracts with non-OEM third parties have become common in the power industry for gas turbines up to the Frame F size. With the effective date of 2010 (when the plant transitioned to PSM as the LTSA provider), the LTSA term could extend to 2025. The plant has had good experience with PSM to date.
- **PPA.** Campeche supplies 192 MW of its capacity on oil and 252 MW on gas to CFE with a fuel pass-through cost at a guaranteed heat rate.
- **Natural Gas FSA.** The unit has not operated on gas since 2017 since the gas supply is not available. Currently Campeche is in negotiations for an FSA. The O&M managers anticipate the plant will be on gas by the end of 2021 or 2022, although there is some uncertainty. Diesel is sourced by multiple local providers.

3.8. MAJOR RISKS

In this section, S&L assesses the potential risks at the Campeche plant. Please refer to Table 3-6 for our listing of potential risks. (Note that we have included items with potential additional capital costs not currently in the Owner's budget.)

Table 3-6 — Potential Risks – Campeche

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Future HRSG repairs/tube replacements	3.3.3, 3.4.2	1	Despite the fact that major repairs and tube replacements have not been identified, there is a potential for future HRSG repair/replacement work that should be budgeted for Campeche; propose an allocation of $5 Million expended in the next 10 years.
CT Rotor Replacement	3.3.3, 3.4.2	1	The CT rotor has never been changed out and is in the range of end of life. (Budget cost: $7.5 Million)
Operation on oil	3.3.34, 3.4.21, 3.5	1	Decreased major maintenance intervals and higher O&M costs. Low reliability on oil. Also, it is noted that the timing of the resumption of fuel gas flow to the site is not certain, and oil operation will continue.
Decommissioning Costs	3.4.2	3	Plant indicated no decommissioning cost of $3.8 Million in their budget at the end of the project life.
Steam Turbine Electric Generator	3.3.3	3	A steam turbine generator inspection report was not provided for S&L to review thus we cannot provide a recommendation. Based on discussions with Campeche plant management, there are no critical issues.

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

S&L's additional comments on the items in Table 3-6 are provided below:

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- **HRSG.** Although S&L has not identified any critical concerns with the HRSG, we recommend a future allocation for HRSG repairs as indicated in Section 3.4.2. Historically in the industry, there have been replacements of some sections of 20-year-old HRSGs in recent years due to the effects of flow accelerated corrosion (FAC). S&L notes that FAC can have long term effects, while not immediately evident today, repairs or replacement in future years could be required. Currently, there is no Capex allocation by the Owner for HRSG work in the future. Considering the cost of a new HRSG at Campeche would be about $33 million; we would propose an allocation of $5 Million expended in the next 10 years.
- **CT Rotor Replacement.** The Campeche the CT rotor has never been changed out. The plant is monitoring the rotors' condition closely and has employed experts to advise them, but the rotor is in the range of end of life and could possibly require a change out in the next 5 to 8 years. S&L would recommend budgeting for the rotor change-outs in that time range.
- **Operation on oil.** Oil operation decreases the operating hours by 30% for major maintenance intervals as compared to gas fired operation. Therefore, major maintenance events will be scheduled at shorter intervals for oil fired operation, thereby increasing the long-term O&M cost versus gas fired operation. Also, the oil system is a high maintenance system requiring changing filters.
- Since no decommissioning cost was included in the Owner's budget, S&L would suggest an indicative $15,000 per MW amount be applied at the end of life of the project as detailed in Section 3.4.2.
- **Steam turbine electric generator.** No major issues were discussed by Campeche management; however, S&L was not provided a recent inspection report to review. As a result, we cannot provide a recommendation.

To summarize, Campeche appears to have corrected problems with oil firing and looks forward to returning to consistent, reliable operation on oil in 2021. However, at this point, a longer demonstration period is needed to confirm that all oil firing problems are resolved. If this is the case and the plant continues its practices for O&M inspections, monitoring, and overhauls, including scheduling major required equipment replacements (e.g., CT rotor replacement), S&L believes the plant can continue operating for an additional 20 or more years.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

4. LA ROSITA UNIT 1 COMBINED-CYCLE PROJECT

4.1. PLANT DESCRIPTION

Energía Azteca X, S. de R.L. de C.V., the "Project Company" for LaRosita I Power Plant ("LR I"), was originally commissioned as a 780-megawatt (MW) nominal nameplate capacity combined-cycle power plant located in Baja California, Mexico approximately 20-km west of the city of Mexicali, that began commercial operation in 2003. The plant is fully owned by Saavi Energía ("Saavi").

The plant is a single fuel (natural gas), combined-cycle thermal power plant configured in a 3 x 3 x 1 arrangement using three Siemens 501 FD2 combustion turbines ("CT" or gas turbine) each associated with a duct-fired, three-pressure level Doosan heat recovery steam generator (HRSG), one Alstom steam turbine (ST) and mechanical draft cooling towers. The plant was originally designed and built by the engineering, procurement, and construction (EPC) contractor, Bechtel Corporation (Bechtel).

An increase of 8 MW is projected for the CT-1C upgrade, when completed in 2021. The electricity generated by LR I is dedicated to the San Diego Gas & Electric Company (SDG&E) and to the Comisión Federal de Electricidad ("CFE," the Federal Electricity Commission of Mexico).

Overall, the plant has been operating at a high performance level, with an average availability of 90.3% and an average heat rate (a measure of plant efficiency) of 7,247 Btu/kwh-HHV (higher heating value basis) over the last four years. The average availability over the last 4 years was somewhat depressed due to a major outage in 2019 for a CT, ST, and upgrading of the control system. Without 2019, the average availability is 94.2% which is higher than the 92% expected for this type of plant. At 4.2%, the forced outage rate has averaged above the expected 2%, and the plant is working to reduce forced outages.

4.1.1. Main Equipment

The LR I power plant consists of the following major components:

- Three Siemens CTs, Model 501 FD2
- Three Doosan HRSG units each with three pressure levels, including a superheater with additional duct-burner firing. The duct burners are not frequently used and can provide only 2 MW of additional capacity.
- One Alstom Power ST
- Three Siemens electric generators; one for each CT
- One Alstom Power electric generator for the ST
- Selective catalytic reduction (SCR) technology for nitrogen oxide (NOx) control

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- Cooling system consisting of mechanical draft cooling towers
- Ferranti Packard Step-Up and Station Service Transformers
- Main distributed control system (DCS) - In 2019, a major replacement was performed to install a GE Marc 6 system in lieu of the ABB Advent system. All other systems were upgraded to the next generation by the manufactures (CTs are Siemens; balance of plant (BOP) systems use a Bailey Infi 90 control system).
- Common Equipment for LR I and LaRosita II (LR II)
    - Water treatment facility with clarification, softeners, filtration, ultrafiltration, reverse osmosis and storage tanks
    - Switchyard for grid interconnection
    - Marathon Electric emergency diesel generators

4.2. MAJOR PLANT INTERCONNECTIONS

The major external interconnections to the plant are described below.

- Natural Gas

  The fuel for LR I CT A and B is supplied through Exelon up to 90,000 MMBtu/day (full swing), and LR I CT C up to 45,000MMBtu/day (full swing). Fuel is transported via the North Baja Pipeline on the United States side of the border and Gasoducto de Aguaprieta on the Mexican side (both agreements are firm through 2028).

- Water

  La Rosita has a contract with CESPM (State Commission of Public Services of Mexicali) to supply water from the city sewer system into La Rosita's Sewage Treatment Plant (STP). The STP produces gray water which is delivered to La Rosita's water treatment facilities for cooling, water/steam cycle and various plant systems. The STP provides 1,720 m^3/h, which is enough supply for maximum demand for LR I and LR II.

- Electricity

  LR I is connected to two transmission lines. Line 1 is 100% owned by Energía Azteca X (EAX) and connects LR I to the local CFE grid under the La Rosita CFE PPA. Line 2 runs from La Rosita across the US/Mexico border to connect with the California Independent System Operator (CAISO) grid to provide access to the wholesale market. Line 2 is equally owned by EAX and EBC (subsidiary of Saavi Energia).

  Additional capacity during the summer is provided by mobile generators, leased by Saavi, to supply the local Baja CFE grid. During the summer months, the units operate 24/7 at base load. The summer temporary capacity projects were executed in 2019 and 2020 and planned for 2021.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

4.3. SUMMARY OF O&M PRACTICES

S&L performed a review of the LaRosita Plant's monthly O&M reports from 2017 through 2020, which included summaries of key operating performance indicators, fixed and variable O&M expenditures and forecasts, corrective maintenance issues, and health and safety summaries. S&L conducted conference call interviews with the Owner and Plant Management personnel and a site visit in March 2021.

Based on the site visit, the review of plant reports, and discussions with the plant staff, S&L believes that the plant equipment has been maintained in accordance with prudent industry practices. The plant's overall condition is conducive to continued safe and reliable operation. Refer to Section 4.3.4 below for additional commentary on the plant's condition.

4.3.1. Plant Staffing

LR I and LR II current staffing consists of a total staff of 67: 48 union and 19 non-union employees. With 39 shift operating personnel, and 12 mechanics and electrical and instrumentation (I&E) technicians, this staffing is typical for a plant of this size. Although there have been no significant changes in staffing levels since S&L's 2017 asset review, S&L did notice that the current reporting structure has the maintenance staff reporting to the Engineering Manager instead of the Production Manager. S&L has no concerns with this change.

During the March 16, 2021 site visit, S&L met with La Rosita managers and interacted with plant personnel. Plant management did not identify any material disputes between the company and union. S&L's assessment from interviews with the plant personnel are that they are very capable and knowledgeable of the La Rosita plant.

4.3.2. Safety Record

Based on the review of the safety data, LaRosita I & II has not had a recordable safety incident since 2018, which was a medical treatment case. Through December 2020, La Rosita has gone 3,387 days without a Lost Time Injury (LTI). This equates to a Total Recordable Case Frequency (TRCF) rate of zero for the year compared to the 5-year target of 0.285 and the industry benchmark of 1.5.

La Rosita follows the Saavi Fleet safety management and control programs that are behavior based. In addition to tracking lagging indicators such as LTIs and First Aid Cases, La Rosita also tracks leading indicators including near misses and unsafe conditions.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

During the site visit, S&L observed signage at several locations detailing evacuation routes, the location of safety showers, and maps of the site. Safety indicators, caution and warning tape, and other signage was observed.

4.3.3. LTSA & Other Maintenance Contracting

The Long-Term Service Agreement (LTSA) contracts PSM to provide services for all of LaRosita's combustion and steam turbines. LTSA services migrated from Siemens to PSM starting in 2015 with each units' 2nd Major Inspection (MI). Based on discussions with LaRosita management, there have been no major issues with the PSM's performance. The transition has provided financial savings, including the elimination of fixed fees. In addition, PSM has identified opportunities for gas turbine upgrades, or GTOP (Gas Turbine Optimization Package), that LaRosita will implement in 2021. Based on S&L's experience, using non-OEM service providers is common in the industry up to the Frame F CT size.

Major inspections and maintenance of the HRSGs, high pressure piping inspections, and balance of plant (BOP) equipment inspection and maintenance are contracted to regional companies through competitive bids.

The historical outage plan for LR I has focused on component life extension and upgrades in addition to scheduled inspections. The planned outage schedule is shown in Table 4-1:

Table 4-1 — LaRosita I Projected Outage Schedule

Unit	Outage Date/Description			
	2021	2022	2023	2025
CT 1A	–	HGPI	–	–
CT 1B	HGPI	–	–	MI & GTOP 6
CT 1C	GTOP 6 Lite	–	MI & GTOP 6	–
HRSG 1A		HP Evaporator	–	–
HRSG 1B	HP Evaporator	–	–	–
HRSG 1C	HP Evaporator	–	–	–
STG	–	Minor Inspection	–	–

Note: GTOP = Gas Turbine Optimization Package; HGPI = Hot Gas Path Inspection; HRSG = Heat Recovery Steam Generator; MI = Major Inspection; STG = Steam Turbine Generator

The rotors on all three CTs were changed out with refurbished rotors from 2016 to 2019. The estimated lives of the refurbished rotors are approximately 100,000 hours for each rotor. PSM has developed the Gas Turbine Optimization Packages (GTOP6) as part of the long-term service agreement (LTSA). According to PSM, GTOP offers customized options for output, heat rate improvement, interval extension, and

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

operational flexibility. For 2021, La Rosita has initially chosen the 'GTOP6 Lite' option for LR I Unit 1C which offers an increased output of 8 MW. The GTOP6 Lite is not included in the LTSA payment structure.

Other key equipment items subject to long term wear and potential repairs are the HRSGs. All three of the LR I HRSGs continue to experience recurrent unplanned outages caused by tube leaks in the high-pressure evaporators (HPEV) of each unit. Tube sampling has identified the root cause of the tube failures to be the accumulation of deposits inside the tubes that leads to the thinning and overheating of the material. The locations of most of the failures have been in the lowest 2-meter section of the tubes, which is also the hottest section of the HPEV. A root cause analysis (RCA) of the issue ruled out flow accelerated corrosion (FAC). The plant's approach to monitoring, correcting, and mitigating future HRSG problems includes short-term (repair and plug failed tubes and mechanical cleaning to remove internal fouling) and long-term (partial tube replacement of lower 2-meter section and full harp replacements) corrective actions, and preventative action, such as changing cycle water chemistry from phosphate and caustic treatment to all-volatile treatment with an oxidizing agent ("AVT-O" treatment). Long term repairs were scheduled for HRSG 1B and 1C in spring 2021. Short-term repairs will continue on HRSG 1A in 2021 with long-term repairs scheduled in 2022.

According to the 2019 steam turbine inspection report the HP, IP and LP turbine was completely disassembled. White deposits were found on the inner casing and rotors of the HP, IP and LP turbines:

- HP rotor blades rows 1 through 5 were replaced.
- IP rotor row 1 was replaced.
- LP rotating blades L-0 and L-1 were removed and sandblasted.

No open items or additional concerns were identified. Based on previous discussions with LaRosita management, during the major inspection in 2019 replacement of selected rows of the IP rotor blades was required, due to the clearance tolerances being excessive. During the site visit, La Rosita management stated that there are no significant issues based on last inspections and no issues after the IP rotor blade replacement. A minor inspection is scheduled for 2022.

No significant problems have been reported with the CT electric generators, balance of plant, or auxiliary electrical equipment or systems. However, in 2019, minute imperfections were identified in the ST generator; future inspections were recommended. Based on various electrical tests and visual inspections performed, the report concluded that the condition of the generator was satisfactory.

During the site visit, the O&M management noted that the LaRosita site experienced a 7+ rated earthquake (Richter scale) which did not cause any damage to LR I equipment or structures. The assessment studies found no further major changes or repairs were necessary.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

4.3.4. S&L Overall Assessment of Plant Condition

As noted above, S&L finds the plant facilities, equipment, and systems to be in good condition and free of any major visible defects. This was confirmed during our site visit on March 16, 2021. Our review of the available documents indicates that the facility has been following appropriate Original Equipment Manufacturer (OEM) maintenance protocols to ensure long-term equipment reliability. Finally, the information provided to Sargent & Lundy indicates that the facility is in compliance with applicable environmental, health, and safety requirements.

As noted in Section 4.1.1, the main original equipment manufacturers are Siemens, Doosan and Alstom Power, who are top quality vendors in the power industry, and the original plant designer/constructor, EPC contractor, Bechtel, is also a well-known, high quality firm in the power industry. This, along with the plant's good performance over the years and staff correcting deficiencies to maintain performance, provides a strong confidence level in the quality of the plant's current condition.

An S&L representative visited LaRosita Units I & II and the sewage treatment plant (STP) on March 16, 2021. In addition to more supplemental information on the major equipment, the site visit provided information on the condition of the plant; the balance of plant systems and equipment; and updates of issues such as contract status; O&M practices; forecasted costs; health, safety, security, environment (HSSE) aspects; and plant performance. We reviewed approximately four years of plant records and participated in lengthy conference calls with the plant staff. No obvious significant deterioration was observed, nor other indications of operating problems (e.g., high noise levels) were noted.

Our review of the plant's inspection and maintenance reports indicates the plant has been well maintained and is performing in accordance with industry expectations. (Refer to sections below regarding capital and O&M budget trends, and performance trends.) For example, four-year average the plant's equivalent availability factor (EAF) for LR I is 90.3%. Based on S&L's experience, approximately 92% EAF is expected for plants of this age. S&L expects forced outage rates for combined-cycle units to be in the range of 2%; LR I four-year average is 4.2%. Forced outage rates consistently above 3% indicate operational or component issues. This is the case with the HRSGs on LR I, however with the implementation of the long-term corrective and preventative actions, LR I has the potential of lowering its forced outage rate to be within the 2% to 3% range.

To summarize, based on the current condition of the facility and if the plant continues its practices for O&M inspections, monitoring, and overhauls, including scheduling major required replacements per OEM or specialty contractor recommendations, S&L believes the plant can continue operating for an additional 20 years or more.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

4.4. O&M AND CAPITAL COST BUDGET PROJECTIONS

4.4.1. O&M Costs

Projected O&M expenditures were provided to S&L for review and are summarized in this section. In general, the plant engages in an O&M approach with a corresponding budget that maintains the plant's improving performance.

The projected O&M expenditures for 2021 through 2023 are summarized in Table 4-2. The original values were provided on a plant basis. S&L reallocated costs on a percentage basis according to the MW rating of the units and annual outage plans. These values show a trend consistent with the actual expenditures from the plant records from 2017 to 2020, with fixed cost decrease approximately 20%. The cost data has been broken down to identify major maintenance fixed and variable costs separately from plant fixed and variable costs. LTSA costs are also broken out. The plant fixed and variable O&M costs are presented as unit rates (red text in table below) for comparison to similar types of plants in similar size ranges.

Table 4-2 — LaRosita I – Projected O&M Expenditures (2021–2023)

Expenditure	2021	2022	2023	Average
LTSA Costs				
--Fixed	0	0	0	0
--Variable	7,121	6,624	8,630	7,458
Non-OSM Major Maintenance Costs (Variable)	7,034	4,910	5,571	5,838
Plant Fixed Costs	4,884	4,857	4,857	4,866
Plant Variable Costs	2,475	2,580	2,537	2,531
Total O&M Expenditures	21,514	18,970	21,595	20,693
Total Fixed Costs	4,884	4,857	4,857	4,866
Plant MW Rating	–	–	–	774
Fixed Costs, US$/kW per Year	–	–	–	**6.3**
Total Variable Costs	16,630	14,113	16,738	15,827
MWh/Year x 1,000 Projected	4,468	4,391	4,139	4,333

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Expenditure	2021	2022	2023	Average
US$/MWh	–	–	–	**3.7**

Notes: Costs in Nominal US$ x 1000 | MWh/y projections were provided by Saavi Energia, week of March 15, 2021

In Sargent & Lundy's experience, fixed costs for a combined-cycle plant typically range from $10 to $15 USD per kilowatt (kW) per year. LaRosita I fixed costs are well below this range (6.3 $/kW projected going forward). The projected fixed costs are expected to trend downward in the future due the elimination of LTSA fixed fees that took effect in 2020 after migrating from Siemens to PSM. However, there are significant cost reductions in other categories, "Other Major Maint. Cost – Fixed' and 'Service Contracts."

Regarding variable costs, the typical range of variable costs for a combined-cycle unit is approximately $2.50 to $3.00 USD per MW-hour (MWh). Per the above tables, LaRosita I projected variable O&M costs going forward is slightly out of range at $3.7 per MWh. It is noted the annual variable costs going forward will vary with the operating profile.

It is noted that while the variable O&M costs going forward are higher than S&L's benchmark range, the very low normalized fixed costs ($6.3 per kW - year versus the low-end bench mark of $10/kW-y), basically offset the higher variable costs, and the overall O&M costs are considered reasonable.

S&L utilized the projected average annual MWh provided by the Owner.

4.4.2. Capital Costs

The Owner's current list of projected capital cost expenses are provided in Table 4-3.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table 4-3 — LaRosita I Projected Capital Expenditures

Project Name	2021	2022	2023	2025	2027
LR1 Steam Turbine contingency parts	–	–	–	–	$2,426,580
LR1 Network code compliance	$299,720	–	–	–	–
LR1 Bypass valve improvements	–	$688,500	–	–	–
LR1 CT1B HGPI	$1,300,000	–	–	–	–
LR1 HRSG HPEV (High Pressure Evaporator) 1B	$2,700,000	–	–	–	–
LR1 HRSG HPEV 1C	$2,700,000	–	–	–	–
GTOP6 Lite 1C – GT Upgrade (Growth in 8 MW)	$1,600,000	–	–	–	–
ST Adders	$1,050,248	–	–	–	–
LR1 CT1A HGPI	–	$1,300,000	–	–	–
LR1 HRSG HPEV 1A	–	$2,500,000	–	–	–
LR1 ST VI	–	$3,007,480	–	–	–
LR1 MI 1C	–	–	$2,880,072	–	–
LR1 MI 1B	–	–	–	$2,035,920	–
LR1 MI/S 1A	–	–	–	–	$6,599,000
LR1 CT1C HGPI	–	–	–	–	$1,147,900
LR1B CT Generator (re-wedge or rewind contingency)	–	–	–	$994,500	–
Total	$ 9,649,968	$ 7,495,980	$ 2,880,072	$ 3,030,420	$ 10,173,480

Notes: Costs in Nominal US$ | Does not include miscellaneous annual allocation of approximately $248,000/year from 2023 to 2032

In addition to the above cost, S&L recommended adding the following future capital costs which were not in the Owner's original budget (which GIM has agreed to include in their budget):

- **HRSG future repair costs.** S&L suggests an allocation of 20% the cost of a new HRSG = $31M x 20% = $6.2M. Since La Rosita has budgeted $2.5M for each HRSG repair in 2021 and 2022 (see table above), S&L suggests an additional allocation of $3.7M ($6.2M – $2.5M=$3.7M) per HRSG or a total of **$11.1 Million spread over 10 years**.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- **Decommission Costs.** S&L suggests for a unit such as La Rosita, a cost of $15,000/MW is included. 780 MW x $15,000 = **$11.7 Million at end of life**.

4.5. PLANT PERFORMANCE

LaRosita I operational summary from 2017 through 2020 is shown in Table 4-4:

Table 4-4 — LaRosita I Annual and Average Performance 2017–2020

Year	Equivalent Availability Factor (EAF)	Equivalent Unplanned Outage Factor (EUOF)	Planned Outage Factor (POF)	Net Heat Rate (Btu/kWh)*
2017	95.2%	3.3%	1.5%	6,474
2018	96.5%	0.9%	2.6%	6,572
2019	78.7%	4.8%	16.5%	6,541
2020	90.9%	7.8%	1.3%	6,577
Average	90.3%	4.2%	5.5%	6,541

* Heat Rate values are LHV basis. HHV Basis = LHV Basis x 1.11 (approximately)

S&L's key observations about the last four years of performance trending are as follows:

- The four-year average EAF for LR I is 90.3 %. Based on S&L's experience, approximately 92% EAF is expected for plants of this type and age.
- LR I forced outage value has continued to increase from 4.8% in 2019 to 7.8% in 2020. S&L expects forced outage rates for combined-cycle units to be in the range of 2%. Forced outage rates consistently above 3% indicate operational or component issues. This is the case with the HRSGs on LR I, however with the implementation of the long-term corrective and preventative actions, LR I has the potential lowering its forced outage rate to be within the 2% to 3% range.
- The average planned outage factor (POF) for LR I is 5.5%. In the years that major outages occur, such as in 2019 for LR I, the POF was greater than 10%. The lowest POF was approximately 1%. The POF for this unit is within a reasonable range.
- The four-year average heat rate for LR I is 6,541 BTU/kWh LHV (or 7,247 BTU/kWh -HHV). The annual heat rate has been consistent during the same period. The heat rates for LR I are within the range of the expected values.

Based on our analysis, LaRosita's staff is managing and correcting deficiencies to maintain performance.

4.6. ENVIRONMENTAL PERFORMANCE

There were no environmental exceedances reported in 2019 but two exceedances were reported in 2020 (one air and one water). The cause, severity and mitigation of the exceedances were not provided for S&L to review. During the site visit the O&M management indicated that the plant is now in compliance with all permit requirements and all permits are up to date.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

LaRosita currently participates in the Saavi fleet effort to reduce greenhouse gas emissions. This program involves tracking and reporting NOx and CO. In addition, the plant measures methane emissions from the plant including fire pumps and the emergency diesel generator.

4.7. MAJOR CONTRACTS

Key agreements for continuing operation of LR I are listed in Table 4-5. At this time, there are no current problems with the counterparties or contracts.

Table 4-5 — LaRosita I Major Agreements

Agreement	Counterparty	Term
Long Term Service Agreement (LTSA)	Power Systems Mfg. LLC	20 years following effective dates (with termination option at 3rd major inspection)
Power Purchase Agreement (PPA)	Comisión Federal de Electricidad (CFE)	25 years following commercial operation (2028)
Fuel Supply Agreement (FSA)	Exelon	Through 31 December 2028

The major agreements are detailed below:

- **LTSA.** Supports the CTs and STs. As noted above in Section 4.3.3, LTSA contracts with non-OEM third parties have become common in the power industry for gas turbines up to the Frame F size. With the effective dates ranging from 2016 to 2018 (based on which GT transitioned to PSM as the LTSA provider), the LTSA term could extend to 2036-2038. The plant has had good experience with PSM to date.
- **PPA.** La Rosita I supplies 489 MW of its capacity to CFE with fuel pass-through at a guaranteed heat rate.
- **FSA.** Currently the fuel for LR I is supplied by Exelon. There have been no significant problems or interruptions reported in recent years.

4.8. MAJOR RISKS

In this section, S&L assesses the potential risks at the LaRosita I plant. Please refer to the Table 4-6 for our listing of potential risks. (Note that we have included items with potential additional capital costs not currently in the Owner's budget; i.e. potential HRSG repairs and decommissioning costs.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table 4-6 — Potential Risks – LaRosita I

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Future HRSG Repairs/tube replacements	3.3.3, 3.4.2	1	Despite the fact that major repairs and tube replacements have been identified for all three of LaRosita I HRSG's, there is a potential future HRSG repair/replacement work that should be budgeted for LaRosita I.
LR I HRSG 1A	3.3.3, 3.4.2	1	Long-Term corrective actions are not scheduled until 2022. If Short-Term corrective actions fail to slow the rate of tube failures, procure parts for repair/replacement work in 2021.
LR I Steam Turbine	3.3.3	2	According to the 2019 steam turbine inspection report, white deposits were found on the inner casing and rotors of the HP, IP and LP turbines. Based on the concerns with the carryover of deposits from the HRSG, non-destructive testing of the last stage of the steam turbine blades should be performed. During the site visit, no major issues were identified.
Decommissioning Costs	3.4.2	3	Plant indicated no decommissioning cost in their budget at the end of the project life.
Environmental	4.6	2	The December 2020 Monthly Report identified that two exceedances were reported in 2020, one air and one water. The cause, severity and mitigation of the exceedances were not provided for S&L to review.

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

S&L's additional comments on the items in Table 4-6 are provided below:

- As noted in Section 3.3.3 of this report, all three of La Rosita I HRSG's are scheduled for partial tube replacement of the lower 2-meter section and full tube harp replacements in 2021 and 2022. Future repair/tube replacements should be anticipated for the low-pressure evaporator based on the potential for tube failures, until an inspection can be performed to verify the condition of the tubes in this area. Future repairs could also be required on La Rosita II HRSG.

  Although flow accelerated corrosion (FAC) was ruled out for the cause of the LR I tube failures, historically in the industry, there have been replacements of some sections of 20-year-old HRSGs in recent years due to the effects of FAC. S&L notes that FAC can have long term effects, while not immediately evident today, repairs or replacement in future years could be required. Currently, there is no Capex allocation by the Owner for HRSG work in the future. Considering the cost of a new HRSG at La Rosita I would be about $31 million; we would propose an allocation of $3 million to $4 million for each of the three LR I HRSGs be considered expended in the next 10 years. This would be in addition to Saavi's current budget of $7.5 million for La Rosita I HRSGs as identified in the capital expenditures in Section 3.4.2.

- Continued tube failures of 1A will negatively impact the availability and reliability of the unit. S&L recommends that Saavi consider procuring parts for the long-term repair in 2021 in the event the tube failures become unmanageable before the 2022 outage.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- According to the 2019 steam turbine inspection report white deposits were found on the inner casing and rotors of the HP, IP and LP turbines. In addition, based on RCAs conducted on potential carry over of contaminants from the HRSG, non-destructive testing of the last stage of the steam turbine blades should be performed.
- Since no decommissioning cost was included in the Owner's budget, S&L would suggest an indicative $15,000 per MW amount be applied at the end of life of the project as detailed in Section 3.4.2.
- Environmental – La Rosita needs to verify that exceedances were mitigated to the satisfaction of the regulatory agency. During the site visit the O&M management indicated that the plant is in compliance with all permit requirements and all permits are up to date.

In summary, if the plant continues its diligence in mitigating HRSG issues thereby reducing forced outages, and continues its practices for O&M inspections, monitoring, and overhauls, S&L believes the LR I can continue operating for an additional 20 or more years.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

5. LA ROSITA UNIT 2 COMBINED-CYCLE PROJECT

5.1. PLANT DESCRIPTION

Energía de Baja California, S. de R.L. de C.V., the "Project Company" for the LaRosita II Power Plant (LR II or LR 2) was originally commissioned as a 320-megawatt (MW) nominal nameplate capacity combined-cycle power plant located in Baja California, Mexico approximately 20-km west of the city of Mexicali, that began commercial operation in 2003. The plant is fully owned by Saavi Energía ("Saavi").

The plant is a single fuel (natural gas), combined-cycle thermal power plant configured in a 1 x 1 x 1 arrangement using one Siemens 501 FD2 combustion turbine ("CT"; or "gas turbine") associated with a duct-fired, two-pressure level Foster-Wheeler heat recovery steam generator (HRSG), one Alstom steam turbine (ST) and a mechanical draft cooling tower. The plant was originally designed and built by the EPC contractor, Bechtel Corporation (Bechtel).

An increase of 8 MW is projected for the CT upgrade on LR II, when upgrading plans are completed in 2021. The electricity generated by LaRosita II primarily dedicated to the San Diego Gas & Electric Company (SDG&E).

Overall, the plant has been operating at a high performance level, with an average availability of 92.5% and an average heat rate (a measure of plant efficiency) of 8,400 Btu/kwh-HHV (higher heating value basis) over the last four years. The expected availability for this type of unit is about 92%. While the heat rate is relatively high versus peer plants, it is noted that LR II utilizes its supplemental firing of the HRSG regularly. Supplemental firing increases plant MW output, but increases plant heat rate since it is a less efficient way to operate the plant compared to the "unfired" HRSG mode. Therefore, the average heat rate for LR II is reasonable.

5.1.1. Main Equipment

The LR II power plant consists of the following major components:

- One Siemens CT, Model 501 FD2
- One Foster Wheeler double pressure HRSG with supplemental duct-burner firing
- One Alstom Power ST
- One Siemens electric generator
- One Alstom Power electric generator for the ST
- Selective catalytic reduction (SCR) technology for nitrogen oxide (NOx) control
- Cooling system consisting of mechanical draft cooling towers

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- Ferranti Packard Step-Up Transformer
- Fortune Electric Station Service Transformer
- Main distributed control system (DCS) - In 2017, a major replacement was performed to install a GE Marc 6 system in lieu of the ABB Advent system. All other systems were upgraded to the next generation by the manufactures (GTs are Siemens; balance of plant (BOP) systems use a Bailey Infi 90 control system).

Common Equipment for LaRosita I (LR I) and LR II:

- Water treatment facility with clarification, softeners, filtration, ultrafiltration, reverse osmosis and storage tanks
- Switchyard for grid interconnection
- Marathon Electric emergency diesel generators

5.2. MAJOR PLANT INTERCONNECTIONS

The major external interconnections to the plant are described below.

- Natural Gas

  LR II fuel is supplied through EDF Energy up to 59,000 MMBtu/day (full swing). Fuel is transported via the North Baja Pipeline on the United States side of the border and Gasoducto de Aguaprieta on the Mexican side (both agreements are firm through 2028).

- Water

  LaRosita has a contract with CESPM (State Commission of Public Services of Mexicali) to supply water from the city sewer system into La Rosita's Sewage Treatment Plant (STP). The STP produces gray water which is delivered to La Rosita's water treatment facilities for cooling, water/steam cycle and various plant systems. The STP provides 1,720 m^3/h, which is enough supply for maximum demand for LaRosita I and LaRosita II.

- Electricity

  LR II sells power on a merchant basis to the US. Line 2 runs from La Rosita across the US/Mexico border to connect with the California Independent System Operator (CAISO) grid to provide access to the wholesale market. Line 2 is equally owned by EAX and EBC (subsidiary of Saavi Energia).

5.3. SUMMARY OF O&M PRACTICES

S&L performed a review of the LaRosita Plant's monthly O&M reports from 2017 through 2020, which included summaries of key operating performance indicators, fixed and variable O&M expenditures and forecasts, corrective maintenance issues, and health and safety summaries. S&L conducted conference call interviews with the Owner and Plant Management personnel and a site visit in March 2021.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Based on the site visit, the review of plant reports, and discussions with the plant staff, S&L believes that the plant equipment has been maintained in accordance with prudent industry practices. The plant's overall condition is conducive to continued safe and reliable operation. Refer to Section 5.3.4 below for additional commentary on the plant's condition.

5.3.1. Plant Staffing

LR I and LR II current staffing consists of a total staff of 67: 48 union and 19 non-union employees. With 39 shift operating personnel, and 12 mechanics and electrical and instrumentation (I&E) technicians, this staffing is typical for a plant of this size. Although there have been no significant changes in staffing levels since S&L's 2017 asset review, S&L did notice that the current reporting structure has the maintenance staff reporting to the Engineering Manager instead of the Production Manager. S&L has no concerns with this change.

During the March 16, 2021 site visit, S&L met with La Rosita managers and interacted with plant personnel. Plant management did not identify any material disputes between the company and union. S&L's assessment from interviews with the plant personnel are that they are very capable and knowledgeable of the La Rosita plant.

5.3.2. Safety Record

Based on the review of the safety data, LaRosita I & II has not had a recordable safety incident since 2018, which was a medical treatment case. Through December 2020, La Rosita has gone 3,387 days without a Lost Time Injury (LTI). This equates to a Total Recordable Case Frequency (TRCF) rate of zero for the year compared to the 5-year target of 0.285 and the industry benchmark of 1.5.

La Rosita follows the Saavi Fleet safety management and control programs that are behavior based. In addition to tracking lagging indicators such as LTIs and First Aid Cases, La Rosita also tracks leading indicators including near misses and unsafe conditions.

During the site visit, S&L observed signage at several locations detailing evacuation routes, the location of safety showers, and maps of the site. Safety indicators, caution and warning tape, and other signage was observed.

5.3.3. LTSA & Other Maintenance Contracting

The Long-Term Service Agreement (LTSA) contracts PSM to provide services for all of La Rosita's combustion and steam turbines. LTSA services migrated from Siemens to PSM starting in 2015 with each units' 2nd Major Inspection (MI). Based on discussions with La Rosita management, there have been no

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

major issues with the PSM's performance. The transition has provided financial savings, including the elimination of fixed fees. In addition, PSM has identified opportunities for gas turbine upgrades, or GTOP (Gas Turbine Optimization Package), that La Rosita will implement in 2021. Based on S&L's experience, using non-OEM service providers is common in the industry up to the Frame F CT size.

Major inspections and maintenance of the HRSGs, high pressure piping inspections, and balance of plant (BOP) equipment inspection and maintenance are contracted to regional companies through competitive bids.

The historical outage plan for LR II has focused on component life extension and upgrades in addition to scheduled inspections. The planned outage schedule is shown in Table 5-1:

Table 5-1 — LaRosita II Projected Outage Schedule

Unit	Outage Date/Description			
	2021	2022	2023	2025
CT	GTOP 6 Lite	HGPI	–	–
STG	–	Minor Inspection & IP Section	–	–

Note: GTOP = Gas Turbine Optimization Package; HGPI = Hot Gas Path Inspection; HRSG = Heat Recovery Steam Generator; MI = Major Inspection; STG = Steam Generator

The CT rotor was replaced in 2017 with a refurbished rotor with a projected life of approximately 100,000 hours. PSM has developed the Gas Turbine Optimization Packages (GTOP6) as part of the long-term service agreement (LTSA). According to PSM, GTOP offers customized options for output, heat rate improvement, interval extension, and operational flexibility. For 2021, La Rosita has initially chosen the 'GTOP6 Lite' option for LR II which offers an increased output of 8 MW. The GTOP6 Lite is not included in the LTSA payment structure.

Other key equipment items subject to long term wear and potential repairs is the HRSG. The LR II HRSG is manufactured by Foster-Wheeler and is susceptible to degradation due to age and cycling. Based on the findings of the LR I HRSG's, which are manufactured by Doosan, consideration should be given to reinspect the HRSG HP & LP evaporator at the next available outage, to determine the current condition. Also, it would be prudent to discuss provisions for potential retrofits with the HRSG manufacturer, to increase the HRSG cycling duty. The cycle water chemistry will be changed from phosphate and caustic treatment to all-volatile treatment with an oxidizing agent (AVT-O) in April 2021. We also recommend an allocation for future HRSG repair for the LR II HRSG (see Section 5.4.2), although a lesser allocation since there has been less wear on the LR II HRSG versus LR I.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

During the site visit, S&L observed the exterior condition of the HRSG, HRSG bypass stack and stack. The stacks show signs of discoloration. Site management explained that the bypass stack is seldom used. There were no visible leaks or other issues, however the condition of the damper is not known. The purpose of the damper is to bypass the HRSG to enable the CT to operate in simple cycle mode. La Rosita should confirm the damper can operate, especially if GIM wants to operate the unit in Simple Cycle.

During the spring of 2022, the ST LP section will be inspected since signs of corrosion was detected during the 2017 outage. Also based on deposit carry over issues identified with LR I the site should verify that the last stage blades were inspected for potential pitting or cracking.

No significant problems have been reported with the electric generators, balance of plant, or auxiliary electrical equipment or systems.

During the site visit, the O&M management noted that the LaRosita site experienced a 7+ rated earthquake (Richter scale) causing a moderate amount of damage to the LR II switchyard. The plant staff indicated that following post-earthquake assessment studies of the plant condition, the LR II switchyard was relocated immediately adjacent to the original LR II switchyard. The assessment studies found no further major changes or repairs were necessary.

5.3.4. S&L Overall Assessment of Plant Condition

As noted above, S&L finds the plant facilities, equipment, and systems to be in good condition and free of any major visible defects. This was confirmed during our site visit on March 16, 2021. Our review of the available documents indicates that the facility has been following appropriate Original Equipment Manufacturer (OEM) maintenance protocols to ensure long-term equipment reliability. Finally, the information provided to Sargent & Lundy indicates that the facility is in compliance with applicable environmental, health, and safety requirements.

As noted in Section 5.1.1, the main original equipment manufacturers are Siemens, Foster-Wheeler and Alstom Power, who are top quality vendors in the power industry, and the original plant designer/constructor, EPC contractor, Bechtel, is also a well-known, high quality firm in the power industry. This, along with the plant's good performance over the years and staff correcting deficiencies to maintain performance, provides a strong confidence level in the quality of the plant's current condition.

A S&L representative visited LaRosita I & II and the sewage treatment plant (STP) on March 16, 2021. In addition to more supplemental information on the major equipment, the site visit provided information on the condition of the plant; the balance of plant systems and equipment; and updates of issues such as contract status; O&M practices; forecasted costs; health, safety, security, environment (HSSE) aspects;

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

and plant performance. We reviewed approximately four years of plant records and participated in lengthy conference calls with the plant staff. No obvious significant deterioration was observed, nor other indications of operating problems (e.g., high noise levels) were noted.

Our review of the plant's inspection and maintenance reports indicates the plant has been well maintained and is performing in accordance with industry expectations. (Refer to sections below regarding capital and O&M budget trends, and performance trends.) For example, four-year average EAF for LR II is 92.5%. Based on S&L's experience, approximately 92% EAF is expected for plants of this age. S&L expects forced outage rates for combined-cycle units to be in the range of 2%. The forced outage rate for LR II between 2017–2019 has experienced a low of 1.5% to a high of 3%. LR-2's forced outage rate of 4.8% in 2020 was primarily due to the failure of the 1 x 100% boiler feed pump variable drive. As a mitigant against a future recurrence, the plant has purchased major spares (including pump, motor, gears and shaft for variable drive for storage on site.)

To summarize, based on the current condition of the facility and if the plant continues its practices for O&M inspections, monitoring, and overhauls, including scheduling major required replacements per OEM or specialty contractor recommendations, S&L believes the plant can continue operating for an additional 20 or more years.

5.4. O&M AND CAPITAL COST BUDGET PROJECTIONS

5.4.1. O&M Costs

Projected O&M expenditures were provided to S&L for review and are summarized in this section. In general, the plant engages in an O&M approach with a corresponding budget that maintains the plant's improving performance.

The projected O&M expenditures for 2021 through 2023 are summarized in Table 5-2. The original values were provided on a plant basis. S&L reallocated costs on a percentage basis according to the MW rating of the units and annual outage plans. These values show a trend consistent with the actual expenditures from the plant records from 2017 to 2020, with fixed cost decrease approximately 20%. The cost data has been broken down to identify major maintenance fixed and variable costs separately from plant fixed and variable costs. LTSA costs are also broken out. The plant fixed and variable O&M costs are presented as unit rates (red text in table below) for comparison to similar types of plants in similar size ranges.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table 5-2 — LaRosita II – Projected O&M Expenditures (2021–2023)

Expenditure	2021	2022	2023	Average
LTSA Costs				
--Fixed	0	0	0	0
--Variable	2,921	2,717	-	1,880
Non-OSM Major Maintenance Costs (Variable)	2,886	2,014	-	1,633
Plant Fixed Costs	2,003	1,992	1,992	1,996
Plant Variable Costs	1,016	1,058	1,041	1,038
Total O&M Expenditures	8,826	7,782	3,033	6,547
Total Fixed Costs	2,003	1,992	1,992	1,996
Plant MW Rating	–	–	–	318
Fixed Costs, US$/kW per Year	–	–	–	6.3
Total Variable Costs	6,823	5,790	1,041	4,551
MWh/Year x 1,000 Projected	1,833	1,801	1,698	1,777
US$/MWh	–			2.6

Notes: Costs in thousands of US$ Nominal | MWh/y projections were provided by Saavi Energia, week of March 15, 2021

In Sargent & Lundy's experience, fixed costs for a combined-cycle plant typically range from $10 to $15 USD per kilowatt (kW) per year. LaRosita II fixed costs are well below this range (6.3 $/kW projected going forward). The projected fixed costs are expected to trend downward in the future due the elimination of LTSA fixed fees that took effect in 2020 after migrating from Siemens to PSM. However, there are significant cost reductions in other categories, 'Other Major Maint. Cost – Fixed' and 'Service Contracts.'

Regarding variable costs, the typical range of variable costs for a combined-cycle unit is approximately $2.50 to $3.00 USD per MW-hour (MWh). Per the above tables, LaRosita II projected variable O&M costs going forward is within the range at $2.6 per MWh. It is noted the annual variable costs going forward will vary with the operating profile.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

S&L utilized the projected average annual MWh provided by the Owner.

5.4.2. Capital Costs

The Owner's current list of projected capital cost expenses are provided in Table 5-3.

Table 5-3 — LaRosita II Projected Capital Expenditures

	2021	2022	2023	2025	2027
LR 2 Steam Turbine contingency parts	–	–	–	–	$995,520
LR 2 CEMS upgrade	$143,858	–	–	–	–
LR 2 Duct burner upgrade	$829,550	–	–	–	–
LR 2 Other	–	$963,900	–	–	–
LR 2 Steam Turbine IP Section additional scope	–	$1,349,460	–	–	–
LR 2 GT interval extension scope	$1,410,284	–	–	–	–
LR 2 GTOP6 Lite – GT Upgrade	$1,600,000	–	–	–	–
Total	$3,983,692	$2,313,360	$0	$0	$995,520

Notes: Costs in Nominal US$ | Does not include miscellaneous annual allocation of approximately $107,000/year from 2022 to 2032

In addition to the above costs, S&L recommended adding the following future capital costs which were not in the Owner's original budget (which GIM has agreed to include in their budget):

- **HRSG future repair costs.** S&L suggests an allocation of 5% the cost of a new HRSG = $31M x 5% = **$1.6 Million spread over 10 years**.
- **Decommission Costs.** S&L suggests for a unit such as La Rosita, a cost of $15,000/MW is included. 320 MW x $15,000 = **$4.8 Million at end of life**.

5.5. PLANT PERFORMANCE

LaRosita II operational summary from 2017 through 2020 is shown in Table 5-4.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table 5-4 — LaRosita II Annual and Average Performance 2017–2020

Year	Equivalent Availability Factor (EAF)	Equivalent Unplanned Outage Factor (EUOF)	Planned Outage Factor (POF)	Net Heat Rate (Btu/kWh)*
2017	84.0%	1.5%	14.5%	7,276
2018	94.8%	3.0%	2.2%	7,780
2019	96.6%	2.5%	0.9%	7,503
2020	94.6%	4.8%	0.6%	7,711
Average	92.5%	3.0%	4.5%	7,568

*Heat Rate values are LHV basis and based on partial duct burner usage. HHV basis = LHV x 1.11 (approximately)

S&L's key observations about the last four years of performance trending are as follows:

- The four-year average EAF for LR II is 92.5%. Based on S&L's experience, approximately 92% EAF is expected for plants of this age.
- Until 2020, LR II three-year (2017 to 2019) average forced outage rate was 2.3%. In 2020 the forced outage rate was 4.8% due to a feedwater pump coupling failure. A recurrence of this issue has been mitigated with the procurement of spare parts. (A forced outage rate of about 2% is expected for this type of plant.)
- The average planned outage factor (POF) for LR II is 4.5%. In the years that major outages occur, such as in 2017 for LR II, the POF was greater than 10%. The lowest POF was 0.6%. The POF for this unit is within a reasonable range.
- The heat rate is much higher for LR II due to the greater usage of supplemental duct firing of the Unit 2 HRSG to increase ST load. The four-year average heat rate of 7,568 BTU/kWh-LHV is based on "partial duct burner" operation (i.e., a levelized average of duct burning use over a year). During warmer periods LR II frequently uses duct burner firing to obtain more MW output capacity. (The duct burner system is capable of generating additional steam to generate up to an additional 70 MW in the Unit 2 ST.) However, the incremental heat rate of duct firing (BTU/h of fuel input divided by MW generated) is much higher than the heat rate of a combined-cycle unit without duct firing. Therefore, the typical heat rate for LR II will range between 6,596 Btu/kWh-LHV (heat rate value without duct firing) and 7,568 Btu/kWh-LHV (partial duct firing). The heat rates for LR II are within the range of the expected values.

Based on our analysis, LaRosita's staff is managing the O&M for LR II to resolve technical issues that arise to maintain its good performance level.

5.6. ENVIRONMENTAL PERFORMANCE

There were no environmental exceedances reported in 2019 but two exceedances were reported in 2020 (one air and one water). The cause, severity and mitigation of the exceedances were not provided for S&L

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

to review. During the site visit the O&M management indicated that the plant is now in compliance with all permit requirements and all permits are up to date.

LaRosita currently participates in the Saavi fleet effort to reduce greenhouse gas emissions. This program involves tracking and reporting NOx and CO. In addition, the plant measures methane emissions from the plant including fire pumps and the emergency diesel generator.

During the site visit, the O&M management explained that since power from LR II is exported to California, the plant has a non-contractual agreement to meet emission standards in the United States. However, S&L was not provided with documentation that supports this agreement.

5.7. MAJOR CONTRACTS

Key agreements for continuing operation of LR II are listed in Table 5-5. At this time, there are no current problems with the counterparties or contracts.

Table 5-5 — LaRosita II Major Agreements

Agreement	Counterparty	Term
Long Term Service Agreement (LTSA)	Power Systems Mfg. LLC	20 years following effective dates (with termination option at 3rd major inspection)
Fuel Supply Agreement (FSA)	EDF Energy	Through 31 December 2028

Details regarding the agreements are as follows:

- **LTSA.** Supports the CTs and STs. As noted above in Section 53.3.3, LTSA contracts with non-OEM third parties have become common in the power industry for gas turbines up to the Frame F size. With the effective dates ranging from 2016 to 2018 (based on which GT transitioned to PSM as the LTSA provider), the LTSA term could extend to 2036-2038. The plant has had good experience with PSM to date.
- **FSA.** Currently the fuel for LR II is supplied by EDF Energy. There have been no significant problems or interruptions reported in recent years.

5.8. MAJOR RISKS

In this section, S&L assesses the potential risks at the LaRosita II plant. Please refer to Table 5-6 for our listing of potential risks. (Note that we have included items with potential additional capital costs not currently in the Owner's budget; i.e., future HRSG repairs and decommissioning costs.)

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table 5-6 — Potential Risks – LaRosita II

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Future HRSG Repairs/tube replacements	3.3.3, 3.4.2	1	There is a potential future HRSG repair/replacement work that should be budgeted for LaRosita II.
Decommissioning Costs	3.4.2	3	Plant indicated no decommissioning cost in their budget at the end of the project life.
Environmental	4.6	2	The December 2020 Monthly Report identified that two exceedances were reported in 2020, one air and one water. The cause, severity and mitigation of the exceedances were not provided for S&L to review.
LR II Bypass Stack	3.3.3	3	LaRosita should confirm the damper can operate, especially if GIP wants to operate the unit in Simple Cycle.

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

S&L's additional comments on the items in Table 5-6 are provided below.

- Future repair/tube replacements should be anticipated for the low-pressure evaporator based on the potential for tube failures, until an inspection can be performed to verify the condition of the tubes in this area.

  $1 million to $2 million for LR II HRSG be considered expended in the next 10 years as identified in the capital expenditures in Section 5.4.2.

- Since no decommissioning cost was included in the Owner's budget, S&L would suggest an indicative $15,000 per MW amount be applied at the end of life of the project as detailed in Section 5.4.2.

- Environmental – La Rosita needs to verify that exceedances were mitigated to the satisfaction of the regulatory agency. During the site visit the O&M management indicated that the plant is in compliance with all permit requirements and all permits are up to date.

- LR II Bypass Stack – Site management explained that the bypass stack is seldom used. La Rosita should confirm the damper can operate, especially if GIM wants to operate the unit in Simple Cycle.

In summary, if the plant continues its practices for O&M inspections, monitoring, and overhauls, S&L believes that LR II can continue operating for an additional 20 or more years.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

6. BAJÍO COMBINED-CYCLE PROJECT

6.1. PLANT DESCRIPTION

Energía Azteca VIII, S. de R.L. de C.V. ("EAVIII") is the Project Company for the Bajío Power Plant ("Bajío"), which is a 645 MW combined-cycle plant arranged in a 3x3x1 configuration with three combustion turbines (CTs) each associated with a heat recovery steam generator (HRSG) that feed a common steam turbine (ST). EAVIII's shareholders are Saavi Energía S. de R.L. de C.V. ("Saavi" or "Holding Company") (51%) and Tokyo Gas Bajío B.V. (49%). The plant started operations in 2002 and is located in San Luis de la Paz, in the state of Guanajuato, Mexico. Each CT and the ST is equipped with an electric generator. Cooling for the steam turbine is provided by a mechanical-draft air-cooled condenser. The CTs have dual fuel capability with natural gas as a primary fuel and diesel (No. 2 oil) as a backup. The plant was originally built by the EPC contractor Bechtel. Although the plant was tested to achieve 670 MW following upgrading work, it is currently limited to 645 MW due to interconnection limitations.

The Bajío Power Plant has a Power Purchase Agreement (PPA) with the Comisión Federal de Electricidad (CFE) for 495 MW. The balance of the capacity is sold to regional industries. Current contracts include Praxair, Ford and Jatco.

Overall, the plant has been operating at a high performance level, with an average availability of 94% and an average heat rate (a measure of plant efficiency) of 6,924 Btu/kwh-HHV (higher heating value basis) over the last four years.

6.1.1. Main Equipment

The following list details major equipment.

- Three General Electric (GE) model 7FA.04 (Upgraded from 7FA.03) CTs; Nominal rating for each is 146 MW; 3,600-rpm nominal speed.
- Three GE 7FH2 hydrogen-cooled generators (CTGs);
- Three Heat Recovery Steam Generators (HRSGs), Cerrey, triple-steam reheat configuration with no duct firing, horizontal, three-pressure steam with reheat.
- One GE model DL11, 220-MW nominal rating steam turbine (ST);
- One GE model D11, hydrogen cooled steam turbine generator (STG);
- One Air-Cooled Condenser to cool the ST exhaust.
- Three CTG Step-Up Transformers, 18 kV to 230 kV.
- One STG Step-Up Transformers, 18 kV to 230 kV

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- Two Auxiliary Transformers
- Distributed Control System (DCS), ABB Symphony Plus. (Upgraded in March 2015).
- One Emergency Diesel Generator
- Demineralized Water System, 2 x 100% trains, sufficient for both Bajío and adjacent SLP while firing natural gas.
- Water treatment facilities and demineralized water storage tanks for water supplied by Bajío Sewer Treatment Plant (STP)

6.2. MAJOR PLANT INTERCONNECTIONS

The major external interconnections to the plant are described below.

- Natural Gas

  Fuel supply agreements are in place with CFE for fuel to support the CFE Power Purchase Agreement (PPA) and Compresión Bajío for fuel to support third-party agreements. In addition, CFE Energía (Fuel Supply) supplies additional fuel to support the advanced gas path (AGP) upgrades that have been completed for all three CTs. Natural gas is supplied to both the Bajío and SLP site at a pressure of 60 bar and is then regulated to 45 bar at the station where gas enters the site. The line entering the site branches off from the Los Ramones pipeline to the north. The plant is also connected to a line that leads to the El Sauz compression station approximately 65-km south. The gas supply has been reliable, and the gas quality has been stable and satisfactory. One notable exception was during the February 2021 'polar vortex' event which curtailed gas supply to the plant for some days. Back up diesel fuel was fired for this period.

- Water

  Filtered gray water is provided to the site by the Bajío Sewage Treatment Plant (STP). The management at Bajío and SLP also manage the STP. The STP receives black water from the nearby San Luis de la Paz municipality and processes the black water for use at the plant. Typically, STP filters more water than required by the Bajío and San Luis de la Paz (SLP) plants to operate continuously at full load.

  Water is processed further at the Bajío plant to create demineralized water for steam cycle makeup. The demineralized water system consists of a pre-filtration system, a reverse osmosis (RO) system, followed by an electrodeionization (EDI) system. The demineralized water system is configured as a full 2x100% redundancy while firing natural gas. During periods of oil firing, both trains need to operate to supply makeup water to both Bajío and SLP. Additionally, demineralized storage tanks have sufficient capacity for 3 days of full load operation. Potable water is brought to the site separately by truck. The site is equipped with tanks for filtered, demineralized, and potable water.

  S&L considers the water supply system and makeup water system appropriate in size and redundancy for the needs of Bajío and SLP. The system has no redundancy during periods

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

of fuel oil operation, but prolonged periods of operation on oil have not been a frequent occurrence, and therefore does not pose a significant risk.

- Electricity

  Bajío and the adjacent SLP plant have separate switchyards that interconnect with the CFE grid at CFE's switchyard north of the site. The Bajío switchyard is a ring-bus design that provides redundancy in case of circuit breaker failure. The voltage at the point of interconnection is 230 kV. Power is transmitted from the CFE interconnection switchyard to the grid after stepping up to 400 kV at CFE's Las Delicias substation. All the electric power generated at Bajío and SLP is distributed through the Las Delicias interconnection.

  The full plant capacity resulting from the recent advanced gas path (AGP) upgrade work cannot yet be offloaded due to limitations in the interconnection capacity. With the AGPs now fully implemented, the plant is capable of 670 MW. The limitations in the interconnection capacity, however, will limit the net out of the plant to 645 MW. The limitation with the interconnection may only be alleviated with an additional high voltage line, which will not likely be implemented due to cost considerations.

6.3. SUMMARY OF O&M PRACTICES

S&L performed a review of the Bajío Plant's monthly O&M reports from 2017 through 2020, which included summaries of key operating performance indicators, fixed and variable O&M expenditures and forecasts, corrective maintenance issues, and health and safety summaries. S&L conducted a site walkdown in March 2021 with the Owner and Plant Management personnel.

Based on the site visit, the review of plant reports, and discussions with the plant staff, S&L believes that the plant equipment has been maintained in accordance with prudent industry practices. The plant's overall condition is conducive to continued safe and reliable operation. Refer to Section 6.3.4 below for additional commentary on the plant's condition.

6.3.1. Plant Staffing

The management at Bajío also manages the adjacent SLP plant and the Bajío STP. The operating staffs at Bajío, Bajío STP, and SLP are hired through three separate contracts with unionized companies. The operating staffs are divided into four groups: Production; Health, Safety, Security, and Environment (HSSE); Engineering; and Administration. The Production team includes the production manager who oversees four shift supervisors, and a Plant Chemist. Each of the five shift supervisors has a team of operators for Bajío, STP and for SLP. The Engineering Manager oversees a mechanical supervisor, an I&C/electrical supervisor, a planner, and plant performance engineer. The discipline supervisors oversee technicians that cover work at all three plants. The total staff is 73 people for the three facilities, including three contractors and three temporary operators needed for COVID-19 measures put in place since March 2020. S&L was informed that there have been no material disputes between the Company and the union.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

The management team at Bajío consists of individuals with several years of experience at combined-cycle power plants. S&L considers the O&M organization and staffing to be appropriate for continued safe and reliable operation of the Bajío combined-cycle plant and the associated sewage treatment plant.

6.3.2. Safety Record

To monitor safety on site, Bajío and SLP track the number of incidents by six levels of safety incidents ranging in severity from "Unsafe Conditions/Unsafe Acts", "Near Misses", "First Aid", "Medical Treatment Case (MTC)", "Restricted Work Case (RWC)", to "Lost Time Injury (LTI)". Safety performance is tracked by a metric called Total Recordable Case Frequency (TRCF) which is the total recordable lost time injury rate, per million hours worked. These statistics are tracked over time to measure the safety performance of the site and are documented in the monthly O&M reports. All personnel working at the site, including contractors, are required to abide by safety rules and participate in the plant's safety program. Bajío's safety program utilizes training, posting danger and warning signage, work group meetings, site inspections, and other measures typical for combined-cycle power plant safety programs.

The 2020 cumulative Total Recordable Case Frequency (TCRF) was below the plant's 5-year cumulative rolling average of 0.406 recordables per 1 million hours which is a very good result.

Based on our review from the site visit, management presentation, and O&M reports, the station has an acceptable safety program that includes proper training for employees, and procedures that support safe working practices. S&L finds the site's safety culture, operational procedures, and emergency plans to be acceptable.

6.3.3. LTSA & Other Maintenance Contracting

Major plant and associated component inspections are scheduled to coincide with CT outages. Typical CT maintenance practice in the electric power generation industry is to engage the OEM directly in a long-term service agreement for parts and repair services. Bajío has engaged GE to provide an LTSA for the three CTs, the ST, and all four electric generators. The current LTSA expires at the earlier of 2027 or seven HGPIs/MIs. As of 2020, CTG 1A and 1C have completed five MI/HGPIs and CTG 1B has completed four MI/HGPIs. Major maintenance of the HRSGs and other balance of plant (BOP) equipment is contracted to regional companies through competitive bid.

Site-specific parts supply for the CTs are provided under the terms of the LTSA. Consumables, materials, and other small parts that are required are inventoried before and after overhaul by GE. This minimizes the site's need to preorder materials for any CT and CTG outages.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

All CTs have undergone rotor replacements. In 2015, Unit B's rotor was replaced with a new rotor following approximately 100,000 hours of operation. The old Unit B rotor was refurbished and installed in Unit A in early 2018 and the removed Unit A rotor was then refurbished and installed in Unit C in 2020. The old Unit C rotor has been refurbished and stored as a spare for the three units and the one unit at the neighboring SLP plant, which are also GE 7FA frame CTs. Costs of the rotor refurbishments and exchanges are coved under the LTSA budget.

Two phases of AGP upgrades have been completed for all three gas turbines with the final phase implemented in the February 2020 Major Inspection outage. A summary of historical and projected outage schedules is summarized in Table 6-1. These outage schedules are reasonable based on the anticipated hours of operation for the Bajío CTs.

Table 6-1 — Bajío – Historical and Projected Major Outages

Unit	Historical Outage Date/Description				Projected Outage Date/Description			
	2017	2018	2019	2020	2021	2022	2023	2024
A	–	MI; New Rotor (Refurbished from B); AGP	–	AGP TL	–	HGPI	–	SI; BI
B	–	–	–	AGP TL	–	WW; BI	–	MI
C	–	–	–	MI; New Rotor (Refurbished from A); AGP TL	–	WW; BI	–	HGPI
ST	–	–	–	Minor; N2 Packing	–	–	–	MI

Note: MI = Major Inspection; HGPI = Hot-Gas-Path Inspection; AGP = Advanced Gas Path, Phase 1; AGP TL= Advanced Gas Path, Tech Lite, DLN 2.6+; WW = Offline Water Wash; SI = Safety Inspection; BI = Borescope Inspection

6.3.4. S&L Overall Assessment of Plant Condition

As noted above, S&L finds the Bajío combined-cycle plant and the associated sewage treatment plant in good condition for an 19-year old plant, based on the March 2021 site visit, our review of plant records and reports, and discussions with the plant staff. We found that the plant equipment has been maintained in accordance with prudent industry practices and the plant's overall condition is conducive to continued safe and reliable operation.

As noted in Section 6.1.1, the main original equipment manufacturers are GE and Cerrey, who are top quality vendors in the power industry, and the original plant designer/constructor, EPC contractor, Bechtel,

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

is also a well-known, high quality EPC firm in the power industry. This, along with the plant's high-level performance over the years provides a strong confidence level in the quality of the plant's current condition.

In addition to the site visit, S&L also reviewed approximately four years of plant records and participated in lengthy conference calls with the plant staff.

During the site visit, S&L did not see any observable major flaws nor any evidence of poor maintenance, bad housekeeping, improper storage of wastes, unlocked gates, water leakage issues, oil leaks, excessive rust, equipment not working, etc. Overall, the station can be described as better than average condition for plants of this type and age.

Our review of the plant's inspection and maintenance reports indicates the plant has been well maintained and is performing in accordance with industry expectations. (Refer to sections below regarding capital and O&M budget trends, and performance trends.) For example, over the past four years, Bajío has had an average forced outage rate of 1.6%, which is better than the approximately 2.0% expected for this type, size, and age plant.

During the scheduled outage in 2020, inspections and modifications were performed on all three HRSGs. As part of the AGP uprate study, it was determined revisions should be performed to address thermal creep and over-stresses previously observed in selected areas of the HRSGs. Thermal issues in the HRSG are expected to increase due to the gas temperature increases resulting from the AGPs. During the 2020 outage, Bajío installed several design modifications on all three HRSGs. S&L finds that Bajío has implemented measures to address thermal fatigue in the high temperature section of the HRSGs, however the effectiveness of the modifications will need to be verified by future inspections and nondestructive examinations (NDE).

The outage inspection reports prepared by Tetra Engineering detail several other specific recommendations for future inspections and outage work at each of the boilers. Of note is the following recommendation made for each boiler:

- The lower pressure (LP) belly plate was perforated and eroded in the interior. Also, there was pitting that extended to the LP and intermediate pressure (IP) evaporator upper headers and tubes. Tetra Engineering recommends a water chemistry study and thermal audit to evaluate all potential risks contributing to future Economizer and Evaporator failure.

This pitting could be the result of Flow Accelerated Corrosion (FAC) in this section of the boiler. There are no previous indications of FAC issues at the Bajío HRSGs, however S&L recommends a study to confirm the pitting observed is due to FAC and to determine the cause of the LP belly plate erosion.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Based on observations during the site visit and discussions with the plant manager and O&M managers, and a review of the 2020 outage reports, the units have been well-maintained and are in good condition. As the plant continues to follow good maintenance practices, the units can be expected to reach a full-service life of 35 years and beyond.

6.3.5. Impacts of Advanced Gas Path Upgrades

Two phases of Advanced Gas Path Upgrades have been completed for all three Gas Turbines with the final phase implemented in the February 2020 Major Inspection outage. Post retrofit testing conducted by GE have confirmed successful achievement of the guaranteed net output increase of + 5.7% and improved net heat rate of -2.39%. These values are reported in the performance test summary and are corrected to site guarantee conditions and have been corrected for the effects of degradation.

The additional capacity resulting from the APGs cannot yet be offloaded due to limitations in the interconnection capacity. With the AGPs now fully implemented, the plant is capable of 670 MW, as reported in the performance test report. The limitations in the interconnection capacity, however, will limit the net output of the plant to 645 MW. It was reported by plant operations that the limitation with the interconnection may only be alleviated with the addition of an additional high voltage line, which will not likely be implemented due to cost considerations.

Based on the GE performance test report, the post AGP heat rate reduction corresponded to a 2.39% reduction in net heat rate. This level of performance improvement is typical of AGPs for the 7F turbines which have demonstrated between 1% and 3% improvement.

S&L has reviewed studies associated with AGP work at Bajío, which included the gas turbine and steam turbine generators and balance-of-plant (BOP) impacts. These upgrades increase temperatures and pressures in the HRSG with higher HP steam production. Typically, when AGPs are planned, there are accompanying studies performed to confirm impacts on the water/steam cycle and balance of plant systems (BOP) systems. The scope of these studies is to confirm that these systems will function within design limitations after the uprates are fully implemented. During discussions with the Bajío managers, it was confirmed that in addition to the evaluation of the GT generators, the following evaluations and studies were performed:

- Generator Step-Up (GSU) MVA ratings
- HRSGs and attemperators, fin and tube metal temperatures, and header temperatures, and drain systems
- Boiler Feed Pump and Condensate Pump Capacity and remaining margin
- Safety Relief Valve flow capacity and lift margins

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- Steam turbine bypass system capacity
- Feedwater and drum level control valves
- Closed cooling water system
- ACC Heat Rejection at uprated conditions
- Fuel conditioning skid
- Water usage

Most of these uprate studies were performed or managed by GE, for the CT generators and GSUs, Kiewit for other BOP, and the results indicated that only the modifications to the HRSG attemperators were required. This attemperator modification work has been performed for all three HRSGs. With regard to other BOP impacts, Kiewit concluded that the while the gas turbine GSUs were previously upgraded to support the increased output of the CTGs, the STG GSU and generator may need to be upgraded depending on which heat balance model is used. Their findings also show that the plant is expected to be derated when ambient conditions begin to exceed 32°C due to increasing condenser back pressure.

We also note that Tetra Engineering, the contractor who performed the 2020 boiler inspections and supervised the modifications, recommended a 'second thermal study' to evaluate the impact of the final AGP work on internal boiler components.

The nameplate MVA ratings for CTG transformers are insufficient for the uprated CTG output conditions. A study was performed by GE to re-calculate the transformer ratings based on the design and based on repowered cooling that was previously implemented. The nameplate maximum rating of 145 MVA was re-calculated to be 175 MVA. The GE report indicates that the transformers can withstand this new power without changes due to the forced cooling upgrades and because the original design of the transformers incorporated 25% more radiators.

Based on discussions with the O&M manager and our review of the historical maintenance information, the transformers are in good condition. However, Sargent & Lundy recommends that GE re-certification of the transformer rating be reviewed and confirmed by the OEM of the transformers.

6.4. O&M AND CAPITAL COST BUDGET PROJECTIONS

6.4.1. O&M Costs

Projected O&M expenditures were provided to S&L for review and are summarized in this section. In general, the plant engages in an O&M approach with a corresponding budget that maintains the plant's high level of performance.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

The projected O&M expenditures for 2021 through 2023 are summarized in Table 6-2. These values show a trend consistent with the actual expenditures from the plant records from 2017 to 2020. The cost data has been broken down to identify major maintenance fixed and variable costs separately from plant fixed and variable costs. LTSA costs are also broken out. The plant fixed and variable O&M costs are presented as unit rates (red text in table below) for comparison to similar types of plants in similar size ranges. The higher expenditures in 2023 in the table below reflect the Major Inspections planned for that year.

Table 6-2 — Bajío – Projected O&M Expenditures (2021–2023)

	2021	2022	2023	Average
LTSA Fixed	$ 195	$ 195	$195	$ 195
LTSA Variable	$ 6,252	$7,395	$9,369	$ 7,672
Major Maintenance Costs (Fixed)	$ 0	$ 0	$ 0	$ 0
Major Maintenance Costs (Variable)	$1,107	$ 2,245	$ 860	$ 1,404
Plant Fixed Costs	$ 4,794	$ 4730	$ 4712	$ 4,745
Plant Variable Costs	$ 646	$ 645	$ 645	$ 645
Total O&M Expenditures	**$ 12,994**	**$ 15,210**	**$ 15,781**	**$ 14,662**
Total Fixed Costs	**$ 4,989**	**$ 4,925**	**$ 4,907**	**$ 4.940**
Plant MW Rating	645	645	645	645
Fixed Costs, US$/kW per Year	$ 7.73	$ 7.64	$ 7.61	$ 7.66
Total Variable Costs	**$ 8,005**	**$ 10,285**	**$10,874**	**$ 9,721**
MWh/Year x 1,000 Projected	4,232	4,261	4,216	4,236
US$/MWh	$ 1.89	$ 2.41	$ 2.58	$ 2.29

Notes: Costs in thousands of US$, Nominal x 1000 | MWh/y projection provided by Saavi, week of March 15, 2021 | A plant rating of 645 MW has been applied for all as the normalization factor for Total Fix Costs

In Sargent & Lundy's experience, fixed costs for a combined-cycle plant typically range from US$10 to $15 per kilowatt (kW) per year. For years 2017 through 2020, Bajío's fixed costs were within this range (10.7 $/kW per year historical) with the AGPs charged against the fixed costs. Eliminating the AGPs, the average fixed cost for years 2017 through 2020 for Bajío was $8.46/kW-year and $7.66/kW-year projected going forward through 2023. These fixed costs adjusted for the AGP expenses are lower than our expectations for combined-cycle plants. (We would expect larger size plants to generally trend lower for fixed costs, on a normalized $/kW per year basis.) The lower fixed cost may be the result of the integrated management implemented and shared contract services with the adjacent SLP plant.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

The plant's projected fixed costs through 2023 are forecasted to be reduced by 10% compared to the previous four-year average. A review of the "30 Line" data presented in the monthly reports indicates that most of this reduction is from lower forecasted non-routine maintenance expenses. Given that the plant has had a major overhaul in 2020, it is not unreasonable to expect lower routine maintenance costs for the years immediately following such an overhaul, but we would expect that the costs for routine maintenance would start to increase in 2024 to the levels spent in the period 2017 through 2020.

Regarding variable costs, the typical range of variable costs for a combined-cycle unit is approximately US$2.50 to $3.00 per MW-hour (MWh). Bajío's historical variable O&M costs averaged slightly below this range at $ 2.41/MWh. Bajío's projected variable O&M costs going forward are also lower than the typical range at $2.29/MWh. A major driver for the lower projected variable costs is the reduced LTSA variable cost due to decreased projected annual generation. The average projected annual generation for 2021-2023 is 20% lower than the previous four-year average.

Overall, the O&M cost levels and trends for Bajío are reasonable and compare well with expected ranges. Bajío Fixed O&M costs are lower than typical ranges seen for combined-cycle plants, which may be the result of shared management and services with the adjacent SLP plant.

6.4.2. Capital Costs

The Owner's current list of projected capital cost expenses are provided in Table 6-3.

The planned capex for the period 2021 through 2025 is focused on the planned inspections and plant life extension capital. Table 6-3 shows the planned Plant Life Extension Capital and recommendations for other major capex.

The major capex is forecasted for the 2024 outage which corresponds to the steam turbine major inspection. The capex for contingency parts for this STG MI is reasonable, based on S&L's experience with similar facilities. Based on our understanding of the generator cap to cap blocking modifications, this work is intended to extend the operating period before re-wedge or rewinds are needed. Therefore, we believe that the capex for re-wedge or rewind contingency would not be performed in conjunction with the end cap blocking modifications during the 2024 outage. The HRSG Life Extension Project was identified in the Management Presentation, but the scope of this has not been communicated or whether some of this work has already been performed in the 2020 outage work.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table 6-3 — Bajío – Plant Life Extension Capital Expenditures

Project Name	Project Description	2021	2022–2023	2024–2025	2026–2027	2028 and Beyond
Owner Capex Projections						
HP and HRH steam header block valves replacement	Replacement of valves subject to wear of stellite hard-faced mating areas	$202	$290	–	–	–
BFP minimum recirculation valves replacement	Replacement of valves subject to wear of spring-loaded mechanism.	–	$240	–	–	–
HP and HRH Bypass valves replacement	Replacement of valves subject to wear on mating areas and thermal cracking.	–	$150	–	–	–
ABB DCS updates for cybersecurity enhancements	Hardware and software updates to enhance protection against cyber risks to our critical infrastructure.	–	$218	–	–	–
Generator Unit A, B, C and STG (re-wedge or rewind contingency)	Possible generator stator or rotor major repairs required at the 3rd Major inspection	–	–	$900	–	$500
Steam Turbine Major Inspection contingency parts	Contingency spare parts at the 3rd Major Inspection or approx. 150k EOH as per OEM recommendation	–	–	$4,000	–	–
Unit 1B Generator Cap to Cap Blocking modification	OEM recommended modification on stator windings to improve unit reliability and extend useful life	–	–	$500	–	–
STG Generator Cap to Cap Blocking modification	OEM recommended modification on stator windings to improve unit reliability and extend useful life	–	–	$600	–	–
Unit 1A Generator Cap to Cap Blocking modification	OEM recommended modification on stator windings to improve unit reliability and extend useful life	–	–	$620	–	–
Unit 1C Generator Cap to Cap Blocking modification	OEM recommended modification on stator windings to improve unit reliability and extend useful life	–	–	–	–	$538
HRSGs Life Extension Provision (Note 3)	Note 3	–	–	$1,800	–	–

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Project Name	Project Description	2021	2022–2023	2024–2025	2026–2027	2028 and Beyond
Sub-total A		$202	$898	$8,420	0	$1,038
Owner Capex Projections (Major Maintenance Related						
Hot Gas P Inspection 1A			$1,345			
Major Inspection 1B				$1,800		
Hot Gas P Inspection 1C				$1,300		
Steam Gas Turbine MI				$2,233		
Major Inspection 1A						$2,292
Hot Gas P Inspection 1B						$1,253
Major Inspection 1C						$2,180
Other		$882				$652
Sub-total B		$882	$1,345	$5,333	0	$6,377
Owner Capex Projections (Other Capex)						
AGP Tech Payment		$6,075				
Network code compliance		$400				
STP MCC equipment improvements		$100				
Ultrasonic flow meter for custody transfer		$150				
CEMS Upgrade			$320			
HRSG sample panel upgrade			$180			
Generator part discharge and flux probe			$100			
Capex allocation		$366	$229			
Subtotal C		$7,091	$829			
Sargent & Lundy Suggested Capex Projections						
Additional HRSG Repair Allocation	Contingency for Replacement of HRSG Sections	–	$2,000	$2,000	$3,000	$8,000
Plant Decommissioning Cost Allocation	End of life costs, net cost	–	–	–	–	$9,700

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Project Name	Project Description	2021	2022–2023	2024–2025	2026–2027	2028 and Beyond
Sub-Total D	–		$2,000	$2,000	$3,000	$17,700
Grand Total		$8,175	$5,072	$15,753	$3,000	$25,115

Notes:

1. Costs in Nominal US$ (1000's)
2. Does not include miscellaneous annual allocation of approximately $710,000 year from 2023 onward.
3. HRSG Life Extension work identified in Management Presentation. Scope of work description has not been provided.

Sargent & Lundy suggests allocating additional capex to HRSG repairs that may be necessary due to increased creep fatigue of high temperature components or to mitigate risks associated with flow accelerated corrosion. This allocation is based on 20% of the cost of a new HRSG = $28M x 20% = $5.6M/HRSG. Subtracting the $1.8 Million of HRSG Life extension above, the cost totals $15M. These costs would be spread over 10 years. (This cost is listed in Sub-total D costs above.)

Sargent & Lundy also suggests allocating decommissioning cost for a larger unit such as Bajío. This allocation is based on a typical cost of $15,000/MW for decommissioning. (This cost is also listed in Sub-total D costs above.)

6.5. PLANT PERFORMANCE

The Bajío plant has maintained stable performance trends, and relatively high performance levels over the recent four years. Bajío's operational summary from 2017 through 2020 is shown in Table 6-4:

Table 6-4 — Bajío Annual and Average Performance 2017–2020

Year	Equivalent Availability Factor (EAF)	Equivalent Forced Outage Factor (EFOF)	Planned Outage Factor (POF)	Net Capacity Factor	Net Unit Heat Rate (Btu/kWh) LHV
2017	94.7%	1.0%	1.6%	94.3	6,266
2018	93.9%	3.2%	2.9%	89.8	6,228
2019	97.0%	1.7%	1.3%	88.5	6,271
2020	90.0%	0.7%	9%	88.2	6,196
Average	93.9%	1.6%	3.7%	90.2%	6,240

Note: Regarding heat rate, HHV basis = LHV basis x 1.11 (approximately)

S&L's key observations about the last four years of performance trending are as follows:

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- Bajío's average annual Equivalent Availability Factor (EAF) since 2017 is 93.9%. which is higher than the previous four-year average by more than 2%. In 2020, Bajío conducted a planned major outage, contributing to a relatively low EAF of 90.0%. However, Bajío's 93.9% EAF average over the last four years is considered above average for this size and type of power plant (with the expected EAF being about 92%).
- When reviewing plant availability and outage factors, it is also important to assess the Net Capacity Factor (NCF) to identify if the unit was being dispatched differently so that the operating mode (i.e., base-load, cycling, and/or peaking modes) and any trends from year to year are assessed. Bajío's NCF from 2017 through 2020 remained consistently high. A high NCF indicates that Bajío is utilized as a base-load plant and, as such, operates frequently and for long periods of time when dispatched.
- Bajío's net plant heat rate (on lower heating value LHV basis) ranged from 6,266 Btu/kWh in 2017 to 6,196 Btu/kWh in 2020. The average net plant heat rate over the four years was 6,240 Btu/kWh. In 2020, the AGPs were completed on all CTs, and the post-upgrade performance test confirmed heat rate improvement of 2.4% corrected for degradation. The trend shows a decrease in heat rate in 2020 of about 0.9% from the previous three-year averages which seems to confirm the improvements from the AGP upgrade.

6.6. ENVIRONMENTAL PERFORMANCE

In the period of 2017 to 2020, there were two air emissions exceedances reported. The cause, severity and mitigation of the exceedances were not provided for S&L to review. It is our understanding, however, that these were not chronic, recurring problems. In addition, other environmental issues associated with spills and hazardous and non-hazardous material were reported, but these were minor issues.

With the retrofit dry low NOx combustion technology, the CTs can operate at or below 9 ppm, which is well below regulatory limits of 375 ppm. Oil firing NOx emissions are much higher and require demineralized water injection to control target levels.

Bajío receives filtered gray water from the STP. Treated gray water (service water) is used for fire protection and service water on site. Service water is further treated to provide demineralized water to the plant. Water discharge is sampled and analyzed quarterly. The plant maintains a permit to discharge fire protection water, condensate, process water, and sanitary water. All water discharged from the plant is returned to STP for processing. There are no outstanding water quality issues at the plant or wastewater emissions issues.

6.7. MAJOR CONTRACTS

Key agreements for continuing operation of Bajío are listed in Table 6-5. Per discussions with the plant, there have been no significant contract issues over the past few years.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table 6-5 — Bajío Major Agreements

Agreement	Counterparty	Term
Operations Support and Maintenance Service Agreement (or Long-Term Service Agreement [LTSA])	General Electric	Earlier of 2035, or completion of fourth CT hot gas path or major inspection (Since January 2014), or at the expiration of the FFH of the CTGs (approx. 271K hours)
Power Purchase Agreements (PPAs)	CFE and six industrial customers	25 years for CFE, 10 years for one industrial, and one-year renewable for remaining industrials.
Fuel Supply Agreements (FSA)	CFE for fuel to support CFE PPA and Compresión Bajío for fuel to support third-party agreements CFE Energía (Fuel Supply) for additional fuel supply due to the AGP upgrades	25 years for fuel to support CFE PPA and one-year renewable for fuel to support third-party agreements. Fuel Supply with CFEnergía expires in 2023 but there is no risk of entering into a new agreement as there are other providers available.
Electrical Interconnection Agreement	CFE	25 years to support CFE/Bajío PPA; durations of other PPAs vary.
Water Supply Agreement	JAPASP	25 years, coinciding with term of CFE/Bajío PPA.
Management Services Agreement	Servicios Azteca, S de RL de CV	25 years following COD

6.8. MAJOR RISKS

In this section, S&L assesses the potential risks at the Bajío plant. Please refer to Table 6-6 for our listing of potential risks. (Note that we have included items with potential additional capital costs not currently in the Owner's budget.)

Since the upgrade work has been completed, there are no specific plant upgrades pending or suggested at this time. A key point would be whether or not the transmission limitation of about 645 MW can be resolved so that the plant can operate at its full capacity, about 670 MW.

Table 6-6 — Bajío – Potential Risks

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
HRSG Thermal Creep Tube Failures resulting from higher temperatures after AGP upgrades	6.3.4	1	Despite the fact that major repairs and tube replacements have been implemented to relieve stresses in the superheater and reheater sections of all three HRSGs, thermal studies and increased NDE will be required in an effort to prevent additional tube failures. This is also a recommendation from Tetra Engineering.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
HRSG Flow Accelerated Corrosion	6.3.4	2	Tetra Engineering noted internal pitting and erosion in LP evaporator and economizer headers and has suggested a review of the station water chemistry. While FAC has not been an issue to date, a study should be performed to confirm.
AGP Impacts to BOP systems	6.3.5	3	A study was conducted by Kiewit to identify balance of plant systems that could be impacted by the AGP uprate. Open issues from that study include 1) the STG GSU and generator may need to be upgraded depending on which heat balance model is used; and 2) The findings also show that the plant is expected to be derated with gas turbines at part-load when ambient conditions begin to exceed 32°C due to increasing condenser back pressure.
CTG Main Transformer Ratings	6.3.5	3	The nameplate ratings for the CTG main transformers are lower than required for the uprated conditions. The GE study that was performed to re-certify the MVA ratings should be confirmed by the equipment OEM.
Decommissioning Costs	6.4.2	3	Owner indicated no decommissioning cost in their budget at the end of the project life. S&L suggests adding an estimated cost of $9.7 Million at the end of life for decommissioning.
Environmental	6.6	3	The monthly reports have identified two air emissions exceedances in 2020 and 2019. The cause, severity and mitigation of the exceedances were not provided for S&L to review. However, it is our understanding these were not chronic, recurring issues.
HRSG Repair Allocation	6.4.2	3	Owner has allocated an insufficient budget to cover contingencies for performing major repair work on the HRSGs if this becomes necessary. S&L suggests adding an additional allocation of $15 Million, which would cover all three HRSGs.

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

In summary, the Bajío plant has been well-maintained and is in good condition. As the plant continues to follow good maintenance practices, the plant can be expected to reach a full-service life of 35 years and beyond, operating at a high performance level.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

7. SAN LUIS DE LA PAZ COMBINED-CYCLE PROJECT

7.1. PLANT DESCRIPTION

Energia San Luis de la Paz SA de C.V. otherwise known as "ESLP", the "Project Company" (or "Power Plant or "SLP") is a 235-megawatt (MW) capacity combined-cycle power plant located in the state of Guanajuato, Mexico, in the city of San Luis de la Paz and began commercial operation in August 2015. The plant is fully owned by Saavi Energía ("Saavi").

The plant is a natural gas fired, combined-cycle thermal power plant, and is configured in a 1 x 1 x 1 arrangement using one General Electric (GE) 7FA.04 combustion turbine (CT), with three-pressure level heat recovery steam generator (HRSG), one steam turbine (ST) and an air-cooled condenser. The plant was originally designed and built by the EPC contractor, Samsung Engineering Co. ("Samsung").

The electricity from SLP is primarily dedicated to the Goldcorp subsidiary Minera Peñasquito, S.A. de C.V., through a 20-year Power Delivery Agreement (PDA) that ends in 2035. SLP also has a third-party sales (TPS) agreement for excess capacity not taken by Goldcorp.

Overall, the plant has been operating at a high performance level, with an average availability of 95% and an average heat rate (a measure of plant efficiency) of 6,748 Btu/kwh-HHV (higher heating value basis) over the last four years.

7.1.1. Main Equipment

The SLP power plant consists of the following major components:

- One GE 7FA.04 CT with inlet chillers and dry low nitrogen oxide (DLN) fuel combustion system
- One Doosan, horizontal, triple-pressure HRSG
- One Siemens 700/900 two-casing ST equipped with three sections, high pressure (HP), intermediate pressure (IP), and low pressure (LP).
- One GE 7FH2 LU hydrogen-cooled electric generator for the CT
- One Siemens SGEN6-100A-2P electric generator for the ST
- One SPX air-cooled condenser with 12 fans arranged in a 3x4 array
- Two Hyosung Main Power, Step-Up and Station Service Transformers for the CT and ST
- A switchyard for grid interconnection
- Emergency diesel generator

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- Main distributed control system (DCS) by Emerson Ovation

7.2. MAJOR PLANT INTERCONNECTIONS

The major external interconnections to the plant are described below.

- Fuel Supply

  Pemex Transformacíon Industrial (Pemex) and ESLP, have a Fuel Supply and Transportation Agreement (FSA) for a term of 20 years. Natural gas is delivered to SLP via an existing Pemex pipeline gas hub called "Los Ramones". Additionally, in order to produce additional capacity from 220 MW to 240 MW, ESLP has entered into contracts with CFEnergía S.A. de C.V. (CFEnergía) and Centro Nacional de Control del Gas Natural (CENAGAS). This is also delivered at the same delivery point of "Los Ramones".

- Water

  Water supply and discharge services are provided to SLP by the adjacent Bajío plant under a 35-year Water Supply and Discharge Agreement. Bajío currently purchases black water from the local water utility where it is treated at the Sewer Treatment Plant (STP) located in the city of San Luis de la Paz to produce gray water. This water is sent to the Bajío water treatment plant (WTP) for further treatment to produce filtered and demineralized water. There is an interconnecting pipe bridge which transports the treated water to the SLP plant for storage and use.

- Electricity

  SLP and the Comisión Federal de Electricidad ("CFE," the Federal Electricity Commission of Mexico) have an Electrical Interconnection and Transmission Agreement for the connection of SLP to CFE's power grid. There is currently no interconnection limit imposed after the increased capacity from the recent advanced gas path (AGP) upgrades on the CT. See Section 7.3.3 below for more information regarding the completed AGP upgrade.

7.3. SUMMARY OF O&M PRACTICES

S&L performed a review of the SLP Plant's monthly O&M reports from 2017 through 2020, which included summaries of key operating performance indicators, fixed and variable O&M expenditures and forecasts, corrective maintenance issues, and health and safety summaries. S&L conducted conference call interviews with the Owner and Plant Management personnel and also conducted a site visit in March 2021.

Based on the site visit, the review of plant reports, and discussions with the plant staff, S&L opines that the plant equipment has been maintained in accordance with prudent industry practices. The plant is still in relatively new condition and the overall condition is conducive to continued safe and reliable operation. Refer to Section 7.3.4 below for additional commentary on the plant's condition.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

7.3.1. Plant Staffing

SLP's current staffing consists of a staff of 38 (including temporary contractors) operations and maintenance employees. The staffing is made up of 16 union and 4 temporary contractors. The management group which consists of non-union employees except for one union employee, oversees operations of the SLP plant in addition to the adjacent Bajío plant. SLP's operations and maintenance staffing is typical for a plant of this size.

S&L was informed that the labor union relationship is good, and there have been no material disputes between the Company and the union. S&L's assessment from interviews with the plant management are that they are very capable and knowledgeable of the SLP plant.

7.3.2. Safety Record

Based on the review of the safety data and interviews with HSSE personnel, as of March 2021, SLP has not had a total recordable case (TRC) in 1,640 days. Additionally, there have been no lost-time incidents (LTI) since COD, and the Total Recordable Case Frequency (TRCF) was zero for the year 2020 and 0.84 for the 5-year operating period. The industry benchmark is 1.5. SLP follows the Saavi Fleet safety management and control programs that are behavior based. In addition to tracking lagging indicators such as LTIs and First Aid Cases, SLP also tracks leading indicators including near misses and unsafe conditions.

The safety programs at SLP are equal to or better than programs at similar gas-fired, combined-cycle plants. All staff are engaged in safe practices and training activities. Plant safety statistics are indicative of an effective safety program and a safe working environment.

7.3.3. LTSA & Outside Maintenance Contracting

Since 2017, the Operation Support & Maintenance Service Agreement which is a type of Long-Term Service Agreement (LTSA) contract with General Electric, provides services for SLP's CT. There is no major maintenance agreement for the ST and costs for parts are allocated in the plant's O&M budget. It is typical to perform major maintenance on the ST through the plant's O&M budget instead of having an LTSA. The LTSA also includes performance monitoring, parts supply and maintenance support for 36 years following the effective date of the contract or the date on which the third major inspection of the CT has been performed.

The SLP plant is still relatively new and the outage plan to date for SLP has focused on completing the recent AGP upgrades in addition to scheduled minor inspections. (The AGP upgrade on the CT was completed in 2019 and resulted in increasing the plant's MW output by 12 MW to 235 MW presently.) It is

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

noted that the first major inspections are planned for 2023. The planned outage schedule is shown in Table 7-1.

Table 7-1 — SLP Projected Outage Schedule

Unit	Outage Date/Description			
	2021	2022	2023	2024
CT	–	–	CT Major Inspection	–
STG	–	–	STG Major Inspection	–

The original rotors remain in operation and due to the relatively young age of the SLP plant, replacement of the rotor is far away into the late 2020s to early 2030s.

March 2019 was the last inspection of the HRSG. The main reason for the inspection was to evaluate the condition of the HRSG due to the AGP upgrades performed on the CT. The inspection report by Tetra Engineering Group, Inc. (Tetra) concluded that the HRSG was in good condition with no serious issues identified. However, Tetra recommended that weld connections and hot spots be monitored. Additionally, it was recommended to perform maintenance and adjustments to existing pipe hangers including preparation of an inspection plan to monitor spring hangers (constant and variable). This procedure manual is targeted for completion in the third quarter of 2021.

The Tetra report also referenced a previous study performed by a third party that recommended replacement of the high pressure (HP) superheater (SH) interstage piping and attemperator spray. This was recommended to be done due to the higher temperature and flow conditions as a result of the AGP upgrades. The SLP plant confirmed the HP-SH was replaced in March 2019 and was completed in April 2019. From discussions and visual inspections during the site visit, no further issues or evidences of leakages were observed. Monitoring of the HRSG and high energy piping continues. Although S&L has not identified any critical concerns with the HRSG, we recommend a future allocation for HRSG repairs as indicated in Section 77.4.2. HRSG condition for aged plants is often variable, depending on the conservatism of the original design, the original HRSG vendor, operating conditions, etc.

No significant problems have been reported with the major auxiliaries/balance of plant systems and equipment.

7.3.4. S&L Overall Assessment of Plant Condition

As noted above, S&L finds the SLP plant in good condition for a 6-year old plant, based on the March 2021 site visit, our review of plant records and reports, and discussions with the plant staff. We found that the

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

plant equipment has been maintained in accordance with prudent industry practices and the plant's overall condition is conducive to continued safe and reliable operation.

As noted in Section 7.1.1, the main original equipment manufacturers are GE, Siemens and Doosan who are top quality vendors in the power industry, and the original plant designer/constructor, EPC contractor, Jacobs, is also a well-known, high quality firm in the power industry. This, along with the plant diligently performing preventative inspections and maintenance provides a strong confidence level in the quality of the plant's current condition.

From the site visit, review of approximately four years of plant records and conference calls with the plant staff, no obvious significant deterioration was observed, nor other indications of operating problems (e.g., high noise levels) were noted. No environmental issues were observed, and housekeeping was excellent throughout the site.

Our review of the plant's inspection and maintenance reports indicates the plant has been well maintained and is performing in accordance with industry expectations. (Refer to sections below regarding capital and O&M budget trends, and performance trends.) For example, the unplanned outage trend has been low and remained consistent since 2017 except for 2019 which was higher when unplanned outage work was performed during 2019. See Section 7.5.

To summarize, if the plant continues its practices for O&M inspections, monitoring, and overhauls, including scheduling major required replacements per OEM or specialty contractor recommendations (e.g., CT rotor replacement when required), with appropriate O&M and mitigation of current problems and risks, S&L believes the plant can continue operating for an additional 30 or more years.

7.4. O&M AND CAPITAL COST BUDGET PROJECTIONS

7.4.1. O&M Costs

Projected O&M expenditures were provided to S&L for review and are summarized in this section. In general, the plant engages in an O&M approach with a corresponding budget that maintains the plant's high level of performance.

The projected O&M expenditures for 2021 through 2023 are summarized in Table 7-2. These values show a trend consistent with the actual expenditures from the plant records from 2017 to 2020. The cost data has been broken down to identify major maintenance fixed and variable costs separately from plant fixed and variable costs. LTSA costs are also broken out. The plant fixed and variable O&M costs are presented as unit rates (red text in Table 7-2) for comparison to similar types of plants in similar size ranges. The higher expenditures in 2023 in Table 7-2 reflect the Major Inspections planned for that year.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table 7-2 — SLP – Projected O&M Expenditures (2021–2023)

Expenditure	2021	2022	2023	Average
LTSA Costs				
-- Fixed	67	67	67	67
-- Variable	2,244	2,092	1,949	2,095
Non-OSM Major Maintenance Costs (Variable)	219	120	4,795	1,711.3
Plant Fixed Costs	2,627	2,572	2,581	2,593.3
Plant Variable Costs	236	236	236	236
Total O&M Expenditures	**5,395**	**5,089**	**9,630**	**6,704.7**
Total Fixed Costs	**2,694**	**2,639**	**2,648**	**2,660.3**
Plant MW Rating	237	237	237	237
Fixed Costs, US$/kW per Year	11.37	11.14	11.17	**$11.23**
Total Variable Costs	**2,701**	**2,450**	**6,982**	**4,044.3**
MWh/Year x 1,000 Projected	1,693.76	1,815.57	1,724.09	1,744.47
US$/MWh	1.59	1.35	4.05	**$2.33**

Notes: Non-LTSA Major Maintenance costs are the Owner's costs during major maintenance work. Since 2023 has Major Inspections scheduled for the CT and ST, the Owner's costs will be higher than the other years. (The total cost of STG inspections and maintenance are covered by the Owner since STG is not included in the LTSA.) | Costs in thousands of US$, Nominal | MWh/y projections were provided by Saavi Energia.

In Sargent & Lundy's experience, fixed costs for a combined-cycle plant typically range from US$10 to $15 per kilowatt (kW) per year. SLP's fixed costs are within this range (11.75 $/kW historical and 11.23 $/kW projected going forward), and therefore are reasonable. The annual plant fixed costs have been stable at just over $2.5 Million/year and the fixed LTSA costs have been 67, so the normalized fixed cost of ~$11.23/kW per year has been fairly constant over the last several years and a significant change is not anticipated going forward.

Regarding variable costs, the typical range of variable costs for a combined-cycle unit is approximately US$2.50 to $3.00 USD per MW-hour (MWh). Per the above tables, SLP's historical variable O&M costs averaged below this range at 1.65 $/MW and SLP's projected variable O&M costs going forward are slightly lower than the typical range at 2.33 $/MWh. It is noted the annual variable costs going forward will vary with the operating profile. In Table 7-2, S&L used the projected operating profile provided by the Owner which is slightly lower than the historical profile.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

The higher expenditures in 2019 pertained to the AGP tech upgrade, CT's hot gas path inspection (HGPI) and ST minor inspection performed that year. In terms of the projected O&M expenditures for the next three years, the major costs correspond to the schedule of planned inspections. Sargent & Lundy considers the O&M budget projection to be a realistic and a well-planned execution of long-term asset maintenance. The next substantial planned outage work is in 2023, when the CT will undergo the first major inspection and the STG will also undergo a major inspection.

7.4.2. Capital Costs

The Owner's current list of projected capital cost expenses are provided in Table 7-3:

Table 7-3 — SLP Project Capital Expenditures

Project Name	2021	2022	2023	2024	2025	2026	2027–2032	Comments
Life extension capital expenditures provided by Owner								
Steam Turbine Contingency Parts	–	–	–	–	–	–	$998,039	CapEx provision reserved for contingency spare parts at the 2nd Major Inspection or approx.130k EOH as per OEM recommendation
Major maintenance capital expenditures provided by Owner								
CTG & STG Major Inspection	–	–	–	–	–	–	–	–
Other	$214,398	$135,867	$16,161	–	$15,534	$169,945	$2,011,439	–
Projection of annual capital expenditures for other smaller capital expenditure items provided by Owner								
Change of Instrument Air Compressor	$30,000	–	–	–	–	–	–	Modify shed and foundations to relocate new compressors in previous location
Change DCS of computer equipment to attend Cybersecurity problems	$270,000	–	–	–	–	–	–	–

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Project Name	2021	2022	2023	2024	2025	2026	2027–2032	Comments
Permission to sell energy to the Mercado Eléctrico Mayorista (MEM) "Wholesale Electricity Market" and increase in generation	$60,000	–	–	–	–	–	–	–
Increase in capacity of ACC and CCW	–	$100,000	$50,000	–	–	–	–	–
Additional cooling for transformers to extend useful lie or repowering	–	$100,000	–	–	–	–	–	–
Hydrogen generator for 7H2	–		$200,000	–	–	–	–	–
Manlift for maintenance activities	$90,000	–	–	–	–	–	–	–
Demin. Water tank (larger capacity)	–	$189,000	–	–	–	–	–	–
Capex allocation	$62,527	$186,360	$384,272	$381,957	$379,661	$266,418	$1,588,161	–
Items not listed by Owner and recommended by Sargent & Lundy								
HRSG Repair Allocation	–	$250,000	–	–	–	$350,000	$2,200,000	S&L suggests an allocation of 10% the cost of a new HRSG = $28M x 10% = $2.8M. Spread over 25 years: $2.8 / 25 = $115,000/year. Schedule costs curing Major Outages years
Decommissioning Cost	–	–	–	–	–	–	$4,600,000	S&L suggests for a small unit such as SLP, a cost of $20,000/MW is included. 230 MW x $20,000 = $4,600,000 at end of life.
Total:	**$360,000**	**$450,000**	**$250,000**			**$350,000**	**$7,800,000**	

Note: Costs in 2019 US$

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Sargent & Lundy reviewed the magnitude of the capital costs and found them to be within a reasonable range. SLP is a relatively new unit and no large Capex projects are foreseen in the near term for the steam turbine. There is an upcoming major inspection outage for the gas turbine which would be covered by the LTSA. Replacement of the CT rotor is still not foreseen in the near term.

Based on S&L's review the major maintenance and life extension capital expenditures, S&L recommends the addition of the following projects, which GIM has agreed to include in their budget. (These items are included in the above table.)

- **HRSG future repair costs.** S&L suggests an allocation of 10% the cost of a new HRSG = $28M x 10% = **$2.8 Million spread over 25 years**.
- **Decommission Costs.** S&L suggests for a unit such as SLP, a cost of $20,000/MW is included. 230 MW x $20,000 = **$4.6 Million at end of life**.

7.5. PLANT PERFORMANCE

The four-year average EAF for SLP is 94.9%. Based on S&L's experience, 90% to 92% EAF is expected for plants of this age. SLP's operational summary from 2017 through 2020 is shown in Table 7-4.

Table 7-4 — SLP Annual and Average Performance 2017–2020

Year	Equivalent Availability Factor (EAF)	Equivalent Unplanned Outage Factor (EUOF)	Planned Outage Factor (POF)	Net Unit Heat Rate (Btu/kWh) HHV Basis
2017	95.5%	1.6%	2.9%	6,765
2018	97.2%	1.6%	1.2%	6,737
2019	90.1%	2.5%	7.4%	6,778
2020	96.8%	1.2%	2.1%	6,710
Average	94.9%	1.7%	3.4%	6,748

S&L's key observations about the last four years of performance trending are as follows:

- Plant trending for availability is good. Plant availability has been consistently high except for 2019 which was lower due to planned inspections. (Expected EAF is approximately 92% for this type of plant.)
- The EUOF average from 2017 to 2020 is 1.7%. The EUOF has remained consistent with the trend not indicating that it is increasing or getting worse. The EUOF was greater in 2019 to account for unplanned outage work performed on the HRSG. There were also additional forced outage events in July and August 2019 that contributed to the EUOF, however these were corrected and have not continued to be recurrent issues. For a plant of this size and type, we would expect an EUOF of about 2%, which SLP has been bettering, on average.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- The POF for SLP is 3.4% and has been low for the plant. It varies with planned inspections but has generally been consistent and is within reasonable range. The largest POF was for 2019, which resulted in a 7.4% planned outage rate due to the planned outage of the AGP Tech Lite upgrade, HGPI performed on the CT and a minor inspection of the STG. The next planned major outage event is scheduled for 2022 for major maintenance for the GT and ST.
- The four-year average heat rate for SLP is 6,748 BTU/kWh HHV. When comparing the annual average heat rate from 2017-2019 with the 2020 annual average, it is about 0.75% lower. This is reasonable, since typically, there is a break-in period for a new unit where the operations team is working toward improving and maximizing efficiency and often times, efficiencies are a little lower during the early break-in period. Although the trend has been consistent, the average heat rate is slightly above the expected summer and winter heat rate values of 6,652 Btu/kWh and 6,672 Btu/kWh, respectively.
- During the site visit S&L inquired further on the plants opinion regarding the heat rate degradation trend. They stated that the 2020 heat rate was higher than target, but improvements have been made. The plant observed the heat rate to have degraded faster after the AGP Tech Lite upgrade. However, after outage work performed in September 2020, the heat rate degradation has improved. Furthermore, in February 2021, the plant reported an oil leak was repaired on the oil bearing #1 of the gas turbine that resolved the heat rate degradation previously observed. The plant was able to observe more improvement beyond replacement of the media and filter in September 2020. S&L recommends continue monitoring of the heat rate trend for the duration of 2021.

S&L expects forced outage rates for combined-cycle units to be in the range of 2%. Forced outage rates consistently above 3% indicate operational or component issues. The plant has experienced some trips, but these resulted in short duration forced outage events that were quickly addressed. There were no recent reported outage events that resulted in long outage durations. SLP provided S&L with a list of forced outage events with the majority resulting in less than 1 day of unavailability.

7.6. ENVIRONMENTAL PERFORMANCE

In the period of 2017 to 2020, there were no environmental exceedances reported for air, water, or noise emissions.

7.7. MAJOR CONTRACTS

Major project agreements for SLP are listed in Table 7-5. These key contracts include the LTSA for the CT and PPA. At this time, there are no current problems with the counterparties or contracts.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table 7-5 — SLP Major Agreements

Agreement	Counterparty	Term
Operation Support & Maintenance Service Agreement	General Electric consortium of General Electric International, Inc., General Electric International Operations Company, Inc., and G.E. Energy Parts, Inc.	Earlier of September 1, 2050 (36 years following the effective date), or the date on which the third major inspection of the CT has been performed. On the 28th of November 2018, effective day of the First Amendment related to the AGP Tech Lite upgrade.
Power Delivery Agreement	Minera Peñasquito S.A. de C.V.	20 years after COD (2035); may be extended for three optional five-year periods
Fuel Supply Agreement (FSA)	Pemex Transformación Industrial S.A. de C.V. (Pemex) (fuel supply and transportation) for the first 2020 MW CFE Energía (Fuel Supply) and CENAGAS (Fuel Transportation) from 2020 MW to 240 MW	20 years after COD (2035) Fuel Transportation with CENGAS is renewable every year. Fuel Supply with CFEnergía expires in 2023 but there is no risk of entering into a new agreement as there are other providers available.

Details regarding the agreements are as follows:

- **LTSA.** Supports the CT. As noted above and in Section 7.3.3 the LTSA contract is with GE who is well qualified to service its equipment. The plant is still relatively young, and the contract will still be in effect for a while. The plant has had good experience with GE to date.
- **PPA.** SLP supplies the majority of the energy to Goldcorp through the PPA that will end in 2035. However, Goldcorp has the option for three five-year extensions. Any excess capacity not taken by Goldcorp is delivered to other users through third-party sales.
- **Natural Gas FSA.** The FSA with Pemex is a firm supply agreement with a term of 20 years. Additionally, due to the increased gas use as a result of the APG upgrades, SLP currently has an FSA with CFEnergia and a Gas Transportation Agreement with CENAGAS. No major issues were reported in the supply of gas except for the weather events experienced in Texas in early February 2021.

7.8. MAJOR RISKS

In this section, S&L assesses the potential risks at the SLP plant. Please refer to Table 7-6 for our listing of potential risks. (Note that we have included items with potential additional capital costs not currently in the Owner's budget.)

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table 7-6 — Potential Risks – SLP

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Future HRSG Repairs	7.3, 7.4.2	1	The SLP HRSG is still relatively new and the plant has not allocated any Capex funds for the foreseeable future. Potential future HRSG repair/replacement work should be budgeted.
Decommissioning costs	7.4.2	1	There are no decommissioning costs allocated in the budget for the end of the project useful life.
STG	-	2	Recommend replacement of the space heaters at the earliest opportunity. Maintain stator winding temperature 5 °C above the ambient temperature to avoid the entry of humidity. The plant reported this will be performed during the major inspection outage. Recommend installation of online Partial Discharge meter which will monitor continuous insulation condition status of the stator windings of the generators while in operation.
CTG and STG	-	2	Recommend installing a magnetic flux probe. Rotor flux monitoring involves measuring the magnetic flux in the generator airgap to determine if field winding degradation or turn to turn shorts have occurred in the rotor poles

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

S&L's additional comments on the items in Table 7-6 are provided below.

- **HRSG.** The HRSG is still relatively new and the only major work performed in 2019 was for replacement of the high pressure (HP) superheater (SH) interstage piping and attemperator spray. This was recommended to be done due to the higher temperature and flow conditions as a result of the AGP upgrades. Although currently the HRSG is operating without issues and the plant continues to operate as a base loaded plant. SLP should allocate costs for potential future repair/tube replacements, given the higher operating temperatures. Recent inspections by Tetra has not found any major issues but has recommended the plant continue monitoring welds and hot spots. Additionally, while currently not evident due the age of SLP, flow accelerated corrosion (FAC) can have longer term effects that may require future repair work. Sargent & Lundy recommends SLP allocate 10% of the cost of a new HRSG (10% of US$28M = US$2.8M) to be spread over 25 years: $2.8 / 25 = $115,000/year. Schedule costs curing Major Outages years.
- **Decommissioning.** Since no decommissioning costs were included in the Owner's budget, S&L would suggest an indicative cost of US$20,000/MW (230 MW x US$20,000) equal to US$ 4.6M, to be applied at the end of life of the project.
- **Steam turbine electric generator.** The STG item in the above for replacement of the space heaters will be covered under the plant's capex budget since the STG is not covered by an LTSA. From discussions with the plant, this work will be performed during the major inspection outage.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

The plant is still relatively new, and Sargent & Lundy has not observed areas that require potential improvement. The plant has allocated costs for smaller items in its capex which Sargent & Lundy has reviewed and agrees. In summary, if the plant continues its practices for O&M inspections, monitoring, and overhauls, including scheduling major required replacements per OEM or specialty contractor recommendations (e.g., CT rotor replacement when required), S&L believes the plant can continue operating for an additional 30 or more years.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

8. ALTAMIRA GAS COMPRESSION STATION

8.1. PLANT DESCRIPTION

Compresión Altamira, S.A. de C.V. (otherwise known as the Altamira Compression Station, ACS, or Project Company) is located in the Puerto Industrial de Altamira, State of Tamaulipas, near the city of Tampico, Mexico. The station consists of four natural gas centrifugal compressors that provide natural gas compression and transmission services, and its Commercial Operation Date (COD) was December 2014. The station was designed for continuous operation for 35 years.

The compression station is designed to operate in a 4x33% configuration including one redundant compression train. Each Solar Turbines' ("Solar") centrifugal natural gas compressor is driven by a Solar gas turbine package with associated equipment on a skid. The station provides gas compression and transmission services to the 48-inch Cactus-Reynosa main gas pipeline, and has a capacity of 1,388 million standard cubic feet per day (MMSCFD). The pipeline is rated for a maximum allowable working pressure (MAWP) of 1,013 pounds per square inch gauge (psig) or 70 barg. The operating pressures of the suction and discharge of the station are approximately 45 barg and 69 barg (653 and 1,001 psig), respectively. The station's Project Company is 100% owned by Saavi Energia. The plant was originally designed and built by the EPC contractor, Samsung.

The average Equivalent Availability Factor for the plant is 96%, and the plant achieved 100% availability in 2020.

8.1.1. Main Equipment

ACS is configured with four individual compression trains in a 4x33% arrangement. Each compression train consists of the following:

- One Solar gas compressor, Model C402
- One Solar gas turbine, Model Taurus 70/C40 to drive the gas compressor
- Turbine and compressor gauge panels
- Compressor gas sealing system
- Auxiliaries to support the compressor-gas turbine train

Balance of station systems are included to facilitate the station operation, including such systems as:

- Distributed control system (DCS), recently upgraded from the original Emerson Delta V 11.3.1 to a more current Delta V 14.3.1 system
- Gas filters, metering, and control systems

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

- Gas emergency shutdown and station vent system
- 1.5-MW Cummins gas-fired generator for emergency power for essential house loads

8.2. MAJOR PLANT INTERCONNECTIONS

The major external interconnections to the compression station are described below.

A 36-inch natural gas supply line, which ties into the 48-inch Cactus-Reynosa main line, provides process natural gas to ACS. After passing through the station's compressors, process gas is cooled by the station's after-coolers to below 50°C. The process line provides all the natural gas that fuels the gas turbines and emergency generator. The natural gas fuel is conditioned by removing liquids, filtered, and regulated to the required input pressure to the gas turbines and emergency generator.

Natural gas drawn from the compressor discharge side from the 36-inch plant line is used as sealing gas. Small booster compressors increase the seal gas pressure to seal the compressors during station shutdown, startup, or other transient or settle-out conditions. During normal operation, the seal-gas booster compressors do not operate, since the normal process compressor discharge pressure is sufficient to seal the compressors, which includes a balance-to-suction dry gas sealing system.

8.3. SUMMARY OF O&M PRACTICES

S&L performed a review of the ACS's monthly O&M reports from 2017 through 2020, which included summaries of key operating performance indicators, fixed and variable O&M expenditures and forecasts, corrective maintenance issues, and health and safety summaries. S&L conducted conference call interviews with the Owner and Plant Management personnel in March 2021. While S&L was not able to visit the Altamira site in person in 2021 due to the pandemic traveling restrictions, a "virtual" site visit and walk through was conducted via an internet video link with the plant's O&M staff.

Based on the virtual visit, the review of plant reports, and discussions with the plant staff, S&L believes that the plant equipment has been maintained in accordance with prudent industry practices. The plant's overall condition is conducive to continued safe and reliable operation. Refer to Section 8.3.4 below for additional comments on the plant's condition.

8.3.1. Plant Staffing

ACS is currently staffed by a team of 25 workers. The station organization is divided into six categories under the direction of the plant manager: Operations & Maintenance Supervisor; Engineering Supervisor; Quality, Health, Safety, Security and the Environmental (QHSSE); Information Technology; Human Resources; and Procurement. The supervisors of each group reports to the project manager. The personnel

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

work 12-hour shifts, with rotating days off in a modified DuPont schedule. The station's Human Resource and Procurement departments are shared with the El Sauz Compression Station.

During the virtual site visit, S&L conducted discussions with key managerial personnel at Altamira. The station organization is lean, utilizing external support for major maintenance activities (e.g. major equipment inspections and maintenance) and routine services (e.g., landscaping, scaffolding, etc.). Personnel receive regular safety and related training as part of Saavi Energia standards. S&L finds the staffing level and structure to be adequate for the operation and maintenance of the station.

8.3.2. Safety Record

ACS tracks six levels of safety incidents ranging in severity from "Unsafe Conditions/Unsafe Acts", "Near Misses", "First Aid", "Medical Treatment Case (MTC)", "Restricted Work Case (RWC)", to "Lost Time Injury (LTI)". Safety performance is tracked by a metric called Total Recordable Case Frequency (TRCF). In 2017, the station had a TRCF goal of 1.14 or below, which was later changed to 0.846 in 2018. According to the station, the industry benchmark is 1.5. The highest TRCF was 1.111 in May 2018. The number and severity of safety incidents has been low from 2017 through 2020. In 2020, the TRCF was recorded as 0 for the entire year. There has not been a lost-time accident involving either station personnel or contractors working on the units since COD in 2014 through the time of the virtual site visit, March 17, 2021.

Based on our review from the virtual site visit, management presentation, and O&M reports, the station appears to have an acceptable safety program that includes proper training for employees, and procedures that support safe working practices. The station management promptly addresses concerns from individuals and is concerned about the safety of employees, contractors, visitors, and the equipment. Safety performance is considered to be a key performance indicator.

8.3.3. Machine Management Services Agreement (Major Equipment Maintenance)

ACS's staff performs the required minor preventative maintenance (PM) activities for the Solar gas-turbine-driven compression sets per the original equipment manufacturer's (OEM's) requirements, with the assistance of Solar gas turbine technical advisors in accordance with the Machine Management Services Agreement (MMSA), which is similar to a Long Term Service Agreement (LTSA). The MMSA also covers the major maintenance activities on the units which Solar is responsible for. Solar defines maintenance intervals as 4,000 hours for a combustion inspection of the gas turbines. A hot-gas-path inspection of a turbine can be performed in one day. Major inspections (MIs) for Solar gas turbine overhauls are planned at 30,000-hour intervals (or longer based on Solar's condition assessment). Solar's scope under an MI includes performing a major overhaul on the gas turbine driver or exchanging the driver for a new or

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

refurbished equipment that will be used until the next major overhaul. The gas compressor is suitable for five years of continuous operation before a major inspection.

ACS's O&M team provided the projected outage schedule for review. Each of the four units have scheduled annual and semi-annual inspection outages, which are staggered to prevent multiple units from being out of service at once. Plant wide outages are also scheduled when necessary. Major overhauls for the gas turbines are scheduled for 2022 and 2023. (See Section 8.4.1 below.)

S&L finds that the Solar O&M practices for preventive and major maintenance comply with generally accepted industry practices in the natural gas industry.

8.3.4. S&L Overall Assessment of Plant Condition

As noted in Section 8.1.1 that the main original equipment manufacturer is Solar Turbines. As a division of the Caterpillar Corporation, Solar a well-recognized, quality manufacturer of the small size gas turbines utilized in compressor driver applications, such as at ACS. The original plant designer/constructor, EPC contractor Samsung, is also a well-known, high quality design/construction firm. This, along with the plant's high-level performance over the years provides a strong confidence level in the quality of the plant's original design and current condition.

The Solar turbines were determined by S&L to be in good condition based on the reports provided and our virtual visit and discussions with the plant. All control systems are in place and are functioning, and no fluid leaks were reported. There were no indications of abnormal operating conditions, temporary piping, temporary electrical connections, or other temporary workarounds for normal unit operation. The inlet filters, lube oil system, cooling system and fin-fan coolers, and fire protection systems appeared to be in good working order, and noise levels observed were typical for this type and size of facility and within the required noise limits.

The gas turbine-driven compressors were packaged by Solar on a single skid arrangement with the gas turbines. As with the turbines, the Solar compressors appeared to be in good condition. No fluid leaks were noted. All control systems are in place and functioning. There were no indications of abnormal operating conditions, temporary piping, or temporary electrical connections.

In 2017, the station reported gas contamination in the process gas, which provides fuel for the gas turbines. The plant took several steps to address the issue such as adding a coalescing fuel filtration system, heat tracing and thermal insulation in some areas, and electric heaters and other operational adjustments to improve combustion. The gas conditions have also improved since the early years of operation and this

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

coupled with the above counter measures have solved the issue. No further problems are expected from this issue since corrective measures were implemented.

In December 2020, Solar Turbines provided a 'Condition Assessment Report' for each of the four trains at ACS. Overall, this report verified the good working condition of the turbines and compressors, and recommended some relatively minor adjustments or maintenance on some of the auxiliary systems.

Station piping and tubing were found to be in good condition, as no leaks or failures were reported. Electrical panel equipment in the main control building was observed to be well organized and maintained. There were no known risks identified in the reports S&L reviewed. Although ACS is located near the Gulf of Mexico, there has not been unusual levels of corrosion observed. Overall, the station was found to be in good condition. The relatively minor issues identified in the Solar Turbines Condition Assessment can be addressed by the site's O&M team.

To summarize, if the plant continues its practices for O&M inspections, monitoring, and overhauls, S&L believes the plant can continue operating to its 35-year design life and beyond.

8.4. O&M AND CAPITAL COST BUDGET PROJECTIONS

8.4.1. O&M Costs

Projected O&M expenditures were provided to S&L for review and are summarized in this section. In general, the plant engages in an O&M approach with a corresponding budget that maintains the plant's high level of performance.

Table 8-1 — Altamira Projected O&M Costs (2021–2023) (Nominal USDx1000)

Expenditure	2021	2022	2023	Average 2021 - 2023
MMSA Costs				
-Fixed	$318	$ 324	$ 330	$ 324
-Variable	$ -	$ 4,193	$ 2,197	$ 2,130
Non-MMSA Major Maintenance Costs (Variable)	$ 271	$ 515	$ 355	$ 380
Plant Fixed Costs	$ 1,616	$ 1,610	$1,610	$ 1,612
Plant Variable Costs	$ 117	$ 118	$120	$ 118
Total O&M Expenditures	$ 2,322	$ 6,760	$ 4,612	$ 4,565

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Expenditure	2021	2022	2023	Average 2021 - 2023
Total Fixed Costs	$ 1,934	$ 1,934	$ 1,940	$ 1,936
Plant MMSCFD Rating	–	–	–	1,388
Fixed Costs, US$/Rated MMSCFD per Year	–	–	–	$ 1,395
Total Variable Costs	$ 388	$ 4,826	$ 2,672	$ 2,629
Variable Costs, US$/MMSCFD per Year (Note)	–	–	–	$ 6.00

Note: $/MMSCFD based on Saavi's projection for average MMSCFD

The projected fixed O&M costs are consistent with the actual fixed O&M costs over the past several years. The variable costs increase significantly in 2022 and 2023 to coincide with costs related to the Machine Management Service Agreement (MMSA) for a gas turbine major overhaul scheduled in 2022 and one scheduled in 2023. S&L reviewed the magnitude of the O&M costs and find them to be reasonable for the size, type, and age compression station.

8.4.2. Capital Costs

The capital costs projected by the Owner, including life extension costs, are indicated in Table 8-2.

Table 8-2 — Altamira Projected Capital Costs (Including Life Extension)

Expense	2021	2022	2023	2024	2025	2026	2027/After
Update DCS, TCS and Batteries (Life Extension)	–	–	–	–	–	–	1,101,660
Non LTSA covered: Overhauls and Planned Inspections (Parts / Services)	271,272	515,100	355,429	1,318,438	633,624	633,624	4,636,000
HazMat storage area improvements	25,000	–	–	–	–	–	–
Gas cylinder storage area improvements	20,000	–	–	–	–	–	–
Main gas vent column redesign	71,130	–	–	–	–	–	–
Site access system improvements	–	$36,000	–	–	–	–	–

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Expense	2021	2022	2023	2024	2025	2026	2027/After
Wi-Fi network extension to process area	–	25,000	–	–	–	–	–
Emergency external connection in MCC	–	51,861	–	–	–	–	–
Total	**$387,402**	**$627,961**	**$355,429**	**$1,318,438**	**$633,624**	**$633,624**	**$5,737,700**

Notes:

1. Costs in Nominal US$
2. Above table does not include an approximately $100,000 annual allocation for miscellaneous projects from 2023 onward

During the period 2018-2020, approximately $1 million appeared in the life extension project budget to update station control systems. As noted in Section 8.1.1, the original control system was recently upgraded, utilizing some of this budget. Additionally, future upgrades/replacement of the control system is projected for 2029 when the existing system is expected to be obsolete. This is a reasonable budget for this work, in our view.

From 2023 through 2032, an average of $103,500 has been allocated each year for miscellaneous projects such as 'Hazmat and Cylinder Storage Area Improvements,' 'Main Gas Vent Column Redesign,' and 'Site Access System Improvements. (See Note 2 for Table 8-2.)

8.5. PLANT PERFORMANCE

ACS's operational summary from 2015 through 2020 is shown in Table 8-3:

Table 8-3 — Altamira Annual and Average Performance 2015–2020

Year	Total Hours of Operation (All Units)	Daily Average Volume of Compressed Gas (MMSCFD)	Primary Fuel Consumption (mmBtu)	Unit Consumption (Btu/scf)	Equivalent Availability Factor	Contractual Availability
2015	22,624	1,152	3,135,286	7.46	91.3%	99.4%
2016	23,755	1,268	1,771,764	3.83	89.6%	98.0%
2017	18,528	1,154	1,273,943	3.03	99.3%	99.9%
2018	13,556	961	953,599	2.72	99.3%	99.7%
2019	9,101	672	644,500	2.63	99.2%	100.0%
2020	6,347	364	326,133	2.63	100.0%	100.0%
Average	**15,652**	**928**	**1,350,871**	**3.72**	**96%**	**100%**

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

ACS operates based on demand dispatch. Generally, ACS will match the demand with the number of compressor trains in operation. Currently, ACS can meet all required dispatch with one train in operation. The performance table shows that average daily volume of compressed gas has decreased each year from 2016 to 2020. The average daily volume of compressed gas (from 2015 to 2020) is 928 MMSCFD. During the virtual site visit, the plant's O&M team indicated that demand has decreased due to a new external compressor station coming on-line, new gas sources in the United States, and decreased industrial demand in 2020 coinciding with the COVID 19 pandemic. ACS's O&M procedures have shifted to consider the lower demand. Only one or two compressors operate at a time and the operation hours of the compressors is controlled to help stagger the hours-based overhauls. The lower operating hours allows the station to delay major overhauls. Availability has been maintained at a high level.

Unit consumption (the fuel required per volume of gas compressed) has improved (decreased) from 7.46 Btu/scf in 2015 to 2.64 Btu/scf in 2020, and remained steady from 2019 to 2020. The plant's O&M team indicated that the Average Annual Consumption Rate from 2016 through 2020 is 2.9 BTU/SCF. This decrease in unit consumption over the station's six years in service shows that the station has improved operation after a period of correcting startup issues in 2015. Availability has also improved over the years from 91.30% in 2015 to 100% in 2020. Demand in terms of hours of operation, and compressed gas has decreased each year since 2016. For the last two years, the contractual availability has been 100%, and the equivalent availability factor (EAF) was 100% in 2020.

The station experienced some forced outages in 2015 to 2016 due to a gas compressor foreign object damage (FOD) event and subsequent suction strainer removal activities affected the entire station. This outage lasted 84 days until the compressor was repaired by Solar and reinstalled. For most of this outage, the station was able to operate normally and to boost the gas pressure at the required throughput by utilizing the spare compression train while the damaged unit was being repaired. Suction strainers on the other units were removed in a systematic manner, and there have been no further events of this type.

Our assessment indicates that Altamira has experienced a high average availability over the last four years after the start-up period following COD. Based on the trends for the last six years, we find that Altamira's staff is managing and correcting deficiencies to maintain performance and availability. If the plant continues its practices for O&M inspections, monitoring, and overhauls, S&L believes the plant can continue its high level of performance.

8.6. ENVIRONMENTAL PERFORMANCE

ACS has a number of permits in place to establish the station's compliance requirements. The Formato de la Cédula de Operación Anual (COA, a Certificate of Operation) defines the conditions for station operation. This document is produced by station staff once per year and submitted to Mexico's Secretaría de Medio

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Ambiente y Recursos Naturales (SEMARNAT, the Secretariat of Environmental and Natural Resources) for approval. Altamira has continually maintained a valid COA since the start of commercial operation. The ACS's O&M staff indicated that there are currently no major environmental issues. Sargent & Lundy is not aware of any outstanding permit issues.

During the virtual site visit, the O&M team indicated that NOx, CO, and SO_2 emissions are tested and reported on an annual basis to regulators, and the station has complied with all stack emission regulations.

Regarding noise requirements, all equipment was purchased to meet near and far-field noise requirements, which includes silencers, attenuation blanketing, and necessary materials to limit noise. No noise complaints have been reported.

Regarding liquid waste, station industrial wastes are stored in a central location with secondary containment. The monthly operating reports indicated several minor spills have occurred in the past 3 years.

In summary, as discussed during our virtual site visit, the station's O&M team indicated that any environmental exceedances were minor and were corrected, and there have been no major environmental issues since COD.

8.7. MAJOR CONTRACTS

At this time, there are no current problems with the counterparties or contracts.

ACS's key contracts include the O&M Agreement, the Machinery Management Services Agreement (MMSA), the Investment Agreement, and compression services contracts. (The Investment Agreement indicates that Pemex is responsible for providing the gas to be compressed by Altamira.) The major project agreements for Altamira are listed in Table 8-4:

Table 8-4 — Altamira Major Agreements

Agreement	Counterparty	Term
Machinery Management Services Agreement	Solar Turbines International Company	12 years from the "Start Date" (2014)
Investment Agreement	Comisión Federal de Electricidad; Energía San Luis de la Paz, S.A. de C.V.; Pemex Gas y Petroquímica Básica	20 years following COD
Natural Gas Compression Services Contract	Comisión Federal de Electricidad (CFE)	20 years following COD
Natural Gas Compression Services Contract	Energía San Luis de la Paz, S.A. de C.V.	20 years following COD

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

S&L finds the terms of the agreements to be reasonable and typical for this type of station.

8.8. MAJOR RISKS

In this section, S&L assesses the potential risks at the Altamira Compression Station. Please refer to Table 8-5 for our listing of potential risks.

Table 8-5 — Potential Risks and Improvements

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Changes in demand	8.5	3	Demand has dropped over the past 4 years. Changes to scheduled CAPEX projects, overhauls, and major maintenance may be necessary considering changes in demand over the next several years.

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

As noted above, since COD in December 2014, ACS has experienced some operation issues that were addressed appropriately but have been resolved and have not recurred. S&L's 2021 review of the Altamira Compression Station has not found any current unaddressed issues which could impact the availability and performance of the station.

ACS operates based on demand dispatch. As indicated in Table 8-3 above, the average daily volume of compressed gas has decreased each year from 2016 to 2020. Therefore, changes to scheduled CAPEX projects, overhauls, and major maintenance may be necessary considering changes in demand over the next several years.

The MMSA includes the opportunity to terminate the agreement after the 1st overhaul at 30,000 operating hours, which is scheduled for 2022 (2 units) and 2023 (2 units). Saavi believes that more competitive terms could be negotiated at that time, which could result in economic benefits to the project while maintaining the technical and operating capabilities. The negotiation had not started at the time this report was prepared.

The station was designed for continuous operation for 35 years. The units are designed to operate in a 4x33% configuration with one redundant unit. Our performance analysis shows that Altamira has experienced a high average availability over the last four years after the start-up period following COD. Based on the trends for the last six years, we find that Altamira's staff is managing and correcting deficiencies to maintain performance.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

S&L has found that the Altamira Compressor Station to be in good condition and has been operated and maintained according to generally accepted industry practices and forced outages and other issues have been appropriately addressed. If the plant continues its practices for O&M inspections, monitoring, and overhauls, S&L believes the plant can continue its high level of performance through its 35-year design life and beyond. Technical risks are considered minimal at this time.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

9. EL SAUZ GAS COMPRESSION PROJECT

9.1. PLANT DESCRIPTION

El Sauz Compression Station (El Sauz) is located in the town of El Sauz, in the Pedro Escobedo municipality, Queretaro state, Mexico. El Sauz station consists of six natural gas compression units that are split between two projects:

- Compression Bajío, S. de R.L. de C.V. ("CB") – Units 1, 2, and 3; and
- Green Energy Libramiento, S. de R.L. de C.V. ("GEL") – Units 4, 5, and 6.

The GEL project also includes a 65-km long, 24-inch diameter pipeline. GEL is 100% owned by Saavi Energia. CB is 51% owned by Saavi Energia and 49% owned by Tokyo Gas.

Natural gas enters the site via a 36-inch pipeline south of the station at the Venta de Carpio terminal near Guadalajara, Mexico. CB achieved commercial operation date (COD) in 2001. CB has a long-term, compression services contract with Pemex Gas y Petroquimica Básica (Pemex), the term of which was scheduled to end in 2021. (Contract extension negotiations were in progress in the first quarter of 2021 at the time of S&L's review and visit to El Sauz.) CB was built to support the nearby Bajío combined-cycle power plant project. GEL achieved its COD in 2007. GEL has no separate compression services contract; however, the Investment Agreement covers compression services with Pemex, and this agreement extends to 2027. (See Section 9.7 below for additional information on El Sauz's main contracts.)

Each unit at El Sauz Station has the capacity to compress approximately 50.0 million standard cubic feet per day (MMSCFD) of natural gas. However, each of the two projects is designed such that only two units operate at a time while the third is in standby. Therefore, the total nominal capacity of the El Sauz Station is 200.0 MMSCFD. The El Sauz plant was originally designed and built by EPC contractor, Techint.

9.1.1. Main Equipment

El Sauz includes the following major equipment:

Compression Bajío (CB) Project

- Three Ariel compressors, Model #JGC/2,
- Three Caterpillar Model #G3608 2,370-hp gas-fired engines to drive compressors
- Three cooling systems with two fans per system
- Additional auxiliaries to support the three compressor-engine trains

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Green Energy Libramiento (GEL) Project

- Three Ariel compressors, Model #JGC/2,
- Three Caterpillar Model #G3608 2,370-hp gas-fired engines to drive compressors
- Three cooling systems with two fans per system
- Additional auxiliaries to support the three compressor-engine trains

Common balance of station systems are included to facilitate the station operation, including the following systems:

- Telvent control system, model OASyS DNA, version 7.1 (Telvent was purchased by Schneider Electric in 2011)
- Gas filters, metering, and control systems
- Gas emergency shutdown and station vent system
- Two gas-fired Caterpillar emergency generators: one Model #G3406 (primary) and one Model #G3412 (standby)

The underground 24-inch diameter, 65-km long Libramiento pipeline connects El Sauz to the Querétaro Industrial Park, and is buried under land that is marked as a natural gas pipeline right-of-way. There are three isolation valve stations, one interconnection valve, and two external interconnections on the Libramiento pipeline. The pipeline maintenance and any required repairs are included in GEL's budget; however, all work on the pipeline is actually performed by Centro Nacional de Control del Gas Natural (CENAGAS).

9.2. MAJOR PLANT INTERCONNECTIONS

The major external interconnections to the plant are described below.

Natural gas is supplied to El Sauz via a 36-inch supply line that begins at the Venta de Carpio terminal south of the station near Guadalajara, Mexico. A 36-inch pipeline conveys natural gas at an average pressure of 650 psig (45 Barg), and it enters El Sauz at approximately 625 psig (43 Barg). Typically, natural gas pressure is increased (compressed) in the station to between 835 to 1,005 psig (58 to 69 Barg). Natural gas passes through a cooler to maintain the temperature below 50°C before exiting the station, and the gas volume exiting the station is typically between 130 to 200 MMSCFD.

9.3. SUMMARY OF O&M PRACTICES

S&L performed a review of El Sauz's monthly operation and maintenance (O&M) reports from 2017 through 2020, which included summaries of key operating performance indicators, fixed and variable O&M expenditures and forecasts, corrective maintenance issues, and health and safety summaries. S&L

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

discussed operations and maintenance (O&M) practices with the station manager and other key managers during conference calls and during our site visit on March 17, 2021.

Based on our site visit, the review of plant reports, and discussions with the plant staff, S&L believes that the plant equipment has been maintained in accordance with prudent industry practices. The plant's overall condition is conducive to continued safe and reliable operation. Refer to Section 9.3.4 below for additional commentary on the plant's condition.

9.3.1. Plant Staffing

El Sauz is currently staffed by a team of 20 workers. The station organization is divided into six categories under the direction of the plant manager: Operations & Maintenance Supervisor; Engineering Supervisor; Quality, Health, Safety, Security and the Environmental (QHSSE); Information Technology; Human Resources; and Procurement. The supervisors of each group reports to the plant manager. The station's Human Resource and Procurement departments are shared with the Altamira Compression Station.

Personnel receive regular safety and related training as part of Saavi Energia standards.

During the site visit, S&L met with key managerial personnel at El Sauz. The station organization is lean, utilizing external support for most major maintenance activities. S&L finds the staffing level and structure to be adequate for the operation and maintenance of the station.

9.3.2. Safety Record

El Sauz tracks six levels of safety incidents ranging in severity from "Unsafe Conditions/Unsafe Acts", "Near Misses", "First Aid", "Medical Treatment Case (MTC)", "Restricted Work Case (RWC)", to "Lost Time Injury (LTI)". Safety performance is tracked by a metric called Total Recordable Case Frequency (TRCF). In 2017, the TRCF was not recorded in the monthly reports. The industry benchmark was recorded as 1.8 in 2018, 1.7 in 2019, and 1.5 in 2020. The 2020 target TRCF is below 0.745, which has been achieved with a TRCF of 0 for the entire 2020 year. The highest TRCF was 0.909 in August 2018. The number and severity of safety incidents has been low from 2017 through 2020. More than 5,000 days have passed since the last Lost Time Incident at El Sauz.

S&L finds the site's operational procedures, emergency plans, and equipment protection to be acceptable.

Based on our review from the site visit, management presentation, and O&M reports, the station appears to have an acceptable safety program that includes proper training for employees, and procedures that support safe working practices. The station management promptly addresses concerns from individuals

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

and is concerned about the safety of employees, contractors, visitors, and the equipment. Safety performance is considered to be a key performance indicator.

El Sauz is equipped with closed-circuit television cameras and a security presence.

9.3.3. Preventative & Major Maintenance

During the site visit, S&L discussed the following routine preventative maintenance (PM) activities with the staff:

- Vibration monitoring and analysis is performed on all major rotating station equipment (engines and compressors).
- Lube oil sampling and testing on all major equipment are analyzed bimonthly.
- Thermography inspections are performed annually by a contractor every year and by the operating staff every four months. Key electrical equipment is inspected.
- Pipe thickness analysis is performed annually.

The three major components that make up the projects at El Sauz—engines, compressors, and pipeline—receive scheduled maintenance at set intervals, per Table 9-1. In addition, each of the six units have scheduled annual and semi-annual PM outages, which are staggered to prevent multiple units from being out of service at once. Plant wide outages are scheduled when necessary.

Corrective maintenance requests are entered by the station planner as conditions are discovered. Routine and minor corrective maintenance is completed by station personnel. Since there is no long-term service agreement in place for El Sauz, contractors are engaged for major work and electrical testing. It was noted that since the units have logged very few operating hours in the last several years (per Section 9.5 below), major overhaul work on the engines/compressors has not been required recently.

A warehouse of spare parts is maintained at the site. Replacement parts for the Caterpillar engines are purchased from an authorized Caterpillar parts distributer, TRACSA, S.A.P.I. de C.V. Likewise, parts for Ariel compressors are purchased from Hoerbiger, a company that manufactures original components for Ariel. This is prudent planning since a long-term service agreement (which would typically include replacement parts supply) is not in place at El Sauz.

S&L finds that the O&M requirements for preventive maintenance and major maintenance planning comply with generally accepted industry practices in the natural gas industry.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table 9-1 — El Sauz Scheduled Major Maintenance Intervals

Engines	
Maintenance	**Interval**
Minor Maintenance	10,000 hours
Major Overhaul	50,000 hours
Top End	25,000 hours
Turbocharger Replacement	20,000 hours
Compressors	
Maintenance	**Interval**
Minor	8,000 hours
Major	24,000 hours
Pipeline	
Maintenance	**Interval**
Wall Thickness Test	Performed annually
Pigging	3 years

9.3.4. S&L Overall Assessment of Plant Condition

As noted in Section 9.1.1 that the main original equipment manufacturers are well-known, high quality manufacturers: Ariel Corporation for the gas compressors and Caterpillar for the engines driving the compressors. The original plant designer/constructor, EPC contractor Techint Engineering & Construction, is also a well-known, high quality design/construction firm. This provides a strong confidence level in the quality of the plant's original design and construction.

During the site visit, the Caterpillar engines were found to be in good condition. No fluid leaks were noticeable. All control systems are in place and functioning, and there were no abnormal operating conditions, temporary piping, temporary electrical connections, or other temporary workarounds for normal unit operation were observed. The inlet filters, lube oil system, cooling system and radiators, and fire protection systems appear to be in good working order. Based on our observations during the site visit and our discussions with the station manager and O&M staff, the engines are in good condition and have been properly maintained.

The Ariel gas compressors were observed to be in good condition, and no fluid leaks were noticed during the site visit. All control systems are in place and functioning, and no abnormal operating conditions, temporary piping, or temporary electrical connections were observed. Based on our observations during

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

the site visit and our discussions with the station manager and O&M staff, the compressors are in good condition and have been properly maintained.

The Libramiento pipeline is maintained by CENAGAS through an Investment Agreement with Green Energy, S. de R.L. de C.V. Maintenance issues on the pipeline and valve stations are tended to by CENAGAS; the staff at El Sauz is precluded from inspecting or working on the pipeline.

Since 2007, pigging has been performed on the Libramiento pipeline approximately every three years. The most recent pigging event was in November 2020, and the pipe was determined to be adequately clean.

In January 2016, an unauthorized connection to the Libramiento pipeline was identified. The damaged pipeline location was excavated and repaired. During S&L's site visit, the stations O&M managers indicated that a second unauthorized connection was discovered in February 2019, which was subsequently repaired. In 2020, a $75,000 CAPEX project was started to use satellite communication systems to reinforce security surveillance of the pipeline. During our site visit, this issue was discussed with the Operator, and there are no outstanding issues with the pipeline. CENAGAS follows maintenance practices aligned with industrial norms.

To summarize, if the plant continues its practices for PM inspections, monitoring, and overhauls when required, S&L believes the plant can continue operating for another 20 years and beyond. As noted above, while El Sauz does not maintain the Libramiento pipeline, regular communications are maintained with CENAGAS to correct any potential issues with the pipeline at the earliest time. The recently installed security surveillance system of the pipeline will assist with the objective of preventing vandalism or unauthorized connections to the pipeline.

9.4. O&M AND CAPITAL COST BUDGET PROJECTIONS

9.4.1. O&M Costs

Table 9-2 shows the projected O&M costs from 2021 through 2023 for the two projects at El Sauz: Compression Bajío and Green Energy Libramiento. The presented information is based on data from the monthly station reports. Note that the monthly O&M reports show the O&M expenditures combined for CB and GEL as simply the El Sauz O&M expenditures.

The projected fixed and variable O&M costs were consistent with the previous four years of actual fixed and variable O&M costs. There have been no major maintenance activities in the past few years since the station has been in stand-by or reserve status. (See Section 9.5.)

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Table 9-2 — El Sauz Projected O&M Expenditures (2021–2023)

	2021	2022	2023	Average 2021 - 2023
Major Maintenance Contract Costs				
-Fixed	$ -	$ -	$ -	$ -
-Variable	$ -	$ -	$ -	$ -
Other Major Maintenance Costs (Variable)	$ -	$ -	$ -	$ -
Plant Fixed Costs	$ 3,130	$ 1,364	$ 1,363	$ 1,952
Plant Variable Costs	$ 52	$ 46	$ 46	$ 48
Total O&M Expenditures	**$ 3,182**	**$ 1,410**	**$ 1,409**	**$ 2,000**
Total Fixed Costs	$ 3,130	$ 1,364	$ 1,363	$ 1,952
Plant MMSCFD Rating	–	–	–	200
Fixed Costs, US$/Rated MMSCFD per Year	–	–	–	$ 9,762
Total Variable Costs	$ 52	$ 46	$ 46	$ 48
Variable Costs, US$/MMSCFD per Year	–	–	–	Note 2

Notes:

1. Costs in thousands of US$ Nominal
2. The daily average volume of compressed gas (MMSCFD) was not available for review. Since El Sauz has been in reserve since late 2016, the daily amount of compressed gas had been very low.

S&L finds the magnitude of the O&M costs to be reasonable for the size, type, and age compression station.

9.4.2. Capital Costs

Table 9-3 shows the projected capital costs projected by the Owner, including life extension costs.

Table 9-3 — El Sauz Projected Capital Costs (Including Life Extension)

	2021	2022	2023	2024	2025	2026	2027/After
Compression Bajío (CB)							
Total	$0	$0	$0	$0	$0	$0	$0
Green Energy Libramiento (GEL)							
Large CAPEX	$0	$0	$0	$1,060,168	$0	$0	$0

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

	2021	2022	2023	2024	2025	2026	2027/After
Major Maintenance CAPEX/ Pipeline / Other	$0	$0	$2,681,325	$171,945	$2,136,017	$175,619	$2,661,709
CAPEX Allocation	$427,736	$247,860	$79,513	$79,513	$79,513	$79,513	$473,988
Total	$427,736	$247,860	$2,760,838	$1,311,626	$2,215,530	$255,132	$3,135,697

Notes:

1. Costs in Nominal US$
2. Above table does not show an approximately $79,000 annual allocation for miscellaneous projects from 2023 onward.
3. 2021 cost includes fire protection system improvement project.
4. Breakdown of the GEL costs was not available at the time of issuance of this report.

As noted in Note 4 in Table 9-3, the breakdown of the capital cost was not available at the time of our review. Without a breakdown or further explanation, the years with $2 Million of capital cost expenditures for GEL appears to be on the conservative side.

9.5. PLANT PERFORMANCE

El Sauz's operational summary from 2015 through 2020 is shown in Table 9-4:

Table 9-4 — El Sauz Annual and Average Performance 2015–2020

Year	Total Hours of Operation (All Units)	Daily Average Volume of Compressed Gas (MMSCFD)	Primary Fuel Consumption (mmBtu)	Unit Consumption (Btu/scf)	Equivalent Availability Factor
2015	22,770	174	11,948,800	5.33	98.60%
2016	15,817	200	8,691,435	3.37	99.60%
2017	132	(1)	(1)	(1)	100.00%
2018	36	(1)	(1)	(1)	100.00%
2019	190	(1)	(1)	(1)	100.00%
2020	62	(1)	(1)	(1)	100.00%
Average	**6,501**	(1)	(1)	(1)	**99.70%**

Note: Since 2017, El Sauz has been operating in reserve. El Sauz did not provide the Daily Average Volume of Compressed Gas, Primary Fuel Consumption, or Unit Consumption during that period as it can reasonably be considered de minimis.

During the site visit, the plant's O&M team advised that El Sauz has been operating in a reserve mode since 2017, and the total hours of operation during the 4 year period from 2017 through 2020 was 420 hours, as shown in Table 9-4. As a result, the monthly report KPIs indicate 100% availability. The fuel consumption and compressed gas quantities were not provided to S&L, but can be considered de minimis.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Before the reserve period, El Sauz operated for 22,770 hours and 15,817 hours in 2015 and 2016, respectively. The daily average volume of compressed gas was 174 MMSCFD and 200 MMSCFD in 2015 and 2016, respectively. Also, the unit consumption (the fuel required per volume of gas compressed) improved (decreased) from 5.33 Btu/scf in 2015 to 3.37 Btu/scf in 2016. If the unit consumption were calculated during the reserve period, the result would not be representative of the major equipment average efficiency since the operating period was so short.

S&L also notes the following:

- As shown in Table 9-4, the equivalent availability factor has been 100% during the reserve period. Each compressor unit has 50.0 MMSCFD capacity, but the station's nominal capacity is 200.0 MMSCFD since only 4 of the 6 units are designed to operate at a time. This arrangement supports each project's ability to achieve high availability.
- The station's O&M team indicated that there have been no major unplanned outages in the past 3 years.

Based on the trends for the last six years, we find that El Sauz's staff is managing the plant's inspections and maintenance to maintain reliable performance and high availability. With continuing diligent inspections and maintenance, the plant should be able to maintain reliable performance and high availability for 20 years and more.

9.6. ENVIRONMENTAL PERFORMANCE

El Sauz has a number of permits in place to establish the station's compliance requirements. The Formato de la Cédula de Operación Anual (COA, a Certificate of Operation) defines the conditions for station operation. This document is produced by station staff once per year and submitted to Mexico's Secretaría de Medio Ambiente y Recursos Naturales (SEMARNAT, the Secretariat of Environmental and Natural Resources) for approval. El Sauz has continually maintained a valid COA since the start of commercial operation. The El Sauz O&M staff indicated that there are currently no major environmental issues. S&L is not aware of any outstanding permit issues.

The station tracks NOx and CO_2 stack emissions. Since the station was in reserve from 2017 through 2020, the emissions have been de minimis and were reported as zero. During the site visit, the O&M team indicated that stack emissions are measured and reported on an annual basis to regulators, and the station has complied with all emission regulations.

Regarding noise requirements, the primary noise generators in the station are the engine-driven compressors and after-coolers. All equipment was purchased to meet near- and far-field noise requirements. No noise issues were indicated by the provided operating information.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

Regarding liquid waste, station industrial wastes are stored in a central location with secondary containment. The monthly operating reports indicated a few minor spills have occurred in the past 2 years.

In summary, as discussed during our site visit and verified by the plant's records, any environmental exceedances were minor and were corrected, and there have been no major environmental issues since COD.

9.7. MAJOR CONTRACTS

El Sauz key contracts include the Natural Gas Compression Service Agreement, the Investment Agreement, and Shared Facilities Agreement. Major project agreements for El Sauz are listed in Table 9-5. This section provides a summary the status and term of these key contracts.

Table 9-5 — El Sauz Compression Project Major Agreements

Agreement	Party	Counterparty	Term
Natural Gas Compression Services Contract	Compresión Bajío, S. de. R.L. de C.V. [CB]	Pemex Gas y Petroquimica Básica	20 years following COD (March 2001) Amendment signed August 7, 2014 to agree to electronic communication. Extension being negotiated in 2021.
Natural Gas Compression Services Contract	Compresión Bajío, S. de. R.L. de C.V. [CB]	Energía Azteca VIII, S. de R.L. de C.V.	Initially through December 31, 2001, with automatic one-year extensions
Natural Gas Sales Agreement	Compresión Bajío, S. de. R.L. de C.V. [CB]	Pemex Gas y Petroquimica Básica	Automatically renewed each year
Investment Agreement	Green Energy, S. de R.L. de C.V.	Pemex Gas y Petroquimica Básica	20 years following COD (until 2027).
Shared Facilities Agreement	Compresión Bajío, S. de. R.L. de C.V. [CB] and Green Energy Libramiento, S. de R.L. de C.V.[GEL]	Agreement between Compresión Bajío and Libramiento	20 years from the commencement date (until 2026)

The Saavi management presentation indicates that CB and GEL are contracted to PEMEX for 20-year terms starting in March 2001 and September 2007, respectively. Saavi is in negotiations with Pemex to extend their compression services contract for CB. (Note that the Pemex compression contract with CB covers up to 126 MMSCFD whereas the Energisa Azteca compression contract covers only 17 MMSCFD.)

The Saavi management presentation indicated that the monthly fixed tariff to CB and GEL are $860,000 and $1,358,454, respectively. The CB and GEL tariffs are subject to monthly and annual adjustments, respectively, according to the consumer price index (CPI) for all Urban Consumers.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

As noted above, there is no LTSA for the major equipment since major overhaul work is required very infrequently due to the minimal operating hours per year. The plant contracts externally when overhaul work is needed. This is a reasonable approach for maintenance the compressors and their reciprocating engine drivers.

9.8. POTENTIAL RISKS

In this section, S&L assesses the potential risks to the El Sauz Compression Station. Please refer to Table 9-6 for our listing of potential risks.

Table 9-6 — El Sauz Compression Station Potential Risks

Potential Risk Item	Reference Section in This Report	Importance Level (1 = Highest)	Description
Pipeline security & maintenance	9	3	Most of the highlighted risks from the station's monthly report were related to the pipeline security & proper maintenance, which is coordinated with CENAGAS. Damage or unplanned pipeline could be disruptive to station operation. While the station has indicated that improved pipeline security measure are being implemented and maintenance is coordinate with CENAGAS, a review of pipeline security and maintenance practices could mitigate the risk to operational disruption.

(**Note:** 1 = Most important; 2 = Moderate; 3 = Lower importance)

The station's monthly reports identified several risks to the station, mostly concerning the 65 km Libramiento pipeline. Examples of these risk items are as follows:

- In 2019, apparent vandalism to the natural gas pipeline was detected, which could require emergency shutdown of the pipeline. A capital project was implemented to upgrade security surveillance on the pipeline.
- The integrity of people and assets were reviewed involved with pipeline maintenance, due to some instances of appropriate maintenance on the gas pipeline not being carried out. The issue is resolved between GEL and CENAGAS. (As noted above, CENAGAS must perform all maintenance and repairs on the pipeline.)
- A mechanical valve failure was identified in pipeline. A failure by actuator movement in the valve that can cause a gas leak in the line. El Sauz staff are in process of resolving this item with CENAGAS.

Apart from the aforementioned risks, S&L's review of the El Sauz Compression Station has not found any significant problems that have not been appropriately addressed, which would impact the availability and performance of the station. S&L has found that the El Sauz Compressor Station to be in good condition and has been operated and maintained according to generally accepted industry practices. If the plant

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

continues its practices for O&M inspections, monitoring, and overhauls, and maintains good communications with CENAGAS regarding pipeline conditions, S&L believes the plant can continue its high level of availability and reliable performance for an additional 20 years and beyond.

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

10. REFERENCES

1. Chihuahua Power Station, Independent Assessment; Sargent & Lundy; May 7, 2021 (Revision 1)
2. Campeche Power Plant, Independent Assessment; Sargent & Lundy; May 7, 2021 (Revision 1)
3. LaRosita Power Plant, Independent Assessment; Sargent & Lundy; May 7, 2021 (Revision 1)
4. Bajío Power Station, Independent Assessment; Sargent & Lundy; May 11, 2021 (Revision 1)
5. San Luis de la Paz Power Plant, Independent Assessment; Sargent & Lundy; May 7, 2021 (Revision 1)
6. Altamira Compression Station, Independent Assessment; Sargent & Lundy; May 7, 2021 (Revision 1)
7. El Sauz Station, Independent Assessment; Sargent & Lundy; May 7, 2021 (Revision 1)

This document contains information that is confidential and proprietary to Sargent & Lundy, L.L.C. (S&L). It shall not be reproduced in whole or in part or released to any third party without the prior written consent of S&L. Copyright S&L 2021; all rights reserved.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

	Page
Electricidad Firme de México Holdings, S.A. de C.V. and subsidiaries, Unaudited Consolidated Statements of Financial Position as of June 30, 2021 and 2020 and Consolidated Statements of Income and Comprehensive Income, Change in Stockholders' Equity and Cash Flows for the half year ended as of June 30, 2021 and 2020	
Consolidated Statements of Financial Position (Unaudited)	F-4
Consolidated Statements of Income and Comprehensive Income (Unaudited)	F-5
Consolidated Statement of Changes in Stockholders' Equity (Unaudited)	F-6
Consolidated Statements of Cash Flows (Unaudited)	F-8
Notes to the financial statements	F-9
Electricidad Firme de México Holdings, S.A. de C.V. and subsidiaries, Consolidated Statements of Financial Position as of December 31, 2020 and Consolidated Statements of Income and Comprehensive Income, Change in Stockholders' Equity and Cash Flows for the year ended as of December 31, 2020	
Report of Independent Auditors	F-34
Consolidated Statements of Financial Position	F-37
Consolidated Statements of Income and Comprehensive Income	F-38
Consolidated Statement of Changes in Stockholders' Equity	F-39
Consolidated Statements of Cash Flows	F-40
Notes to the financial statements.	F-41
Electricidad Firme de México Holdings, S.A. de C.V. and subsidiaries, Consolidated Statements of Financial Position as of December 31, 2019 and Consolidated Statements of Income and Comprehensive Income, Change in Stockholders' Equity and Cash Flows for the year ended as of December 31, 2019	
Report of Independent Auditors	F-94
Consolidated Statements of Financial Position	F-97
Consolidated Statements of Income and Comprehensive Income	F-98
Consolidated Statement of Changes in Stockholders' Equity	F-99
Consolidated Statements of Cash Flows	F-100
Notes to the financial statements	F-101
Electricidad Firme de México Holdings, S.A. de C.V. and subsidiaries, Consolidated Statements of Financial Position as of December 31, 2018 and Consolidated Statements of Income and Comprehensive Income, Change in Stockholders' Equity and Cash Flows for the year ended as of December 31, 2018	
Report of Independent Auditors	F-154
Consolidated Statements of Financial Position	F-157
Consolidated Statements of Income and Comprehensive Income	F-158
Consolidated Statement of Changes in Stockholders' Equity	F-159
Consolidated Statements of Cash Flows	F-160
Notes to the financial statements	F-161

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Interim Statements of Financial Position as of June 30, 2021 and December 31, 2020 and Consolidated Interim Statements of Income and Comprehensive Income, Change in Stockholders' Equity and Cash Flows for the half-year ended as of June 30, 2021 and 2020

Blvd. Miguel de Cervantes Saavedra 301-11 | Granada | Miguel Hidalgo, 11520, CDMX

Table of Contents

Page

Consolidated financial statements:

Consolidated Interim statements of financial position....1
Consolidated Interim statements of income and comprehensive income....2
Consolidated Interim statements of changes in stockholders' equity....3
Consolidated Interim statements of cash flows....5

Notes to the consolidated financial statements

Note 1 History, Company activities and relevant events....6
Note 2 Basis of preparation....8
Note 3 Summary of significant accounting policies....8
Note 4 Segment information....8
Note 5 Financial assets and financial liabilities....10
Note 6 Related party balances and transactions....11
Note 7 Property, plant and equipment, net....13
Note 8 Investments accounted for using the equity method....16
Note 9 Goodwill and intangibles assets, net....18
Note 10 Debt....19
Note 11 Other long-term liabilities....20
Note 12 Stockholders' equity....20
Note 13 Analysis of revenues....22
Note 14 Analysis of cost of sales and general and administrative expenses....23
Note 15 Analysis of the financing cost, net....24
Note 16 Income tax....24
Note 17 Consolidated Interim statements of cash flows....25
Note 18 Commitments and contingencies....26
Note 19 Subsequent events....27
Note 20 Authorization of issuance of the consolidated interim financial statements....28

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Interim Statements of Financial Position
June 30, 2021 and December 31, 2020

Figures in thousands of U.S. Dollars

Assets	Notes	2021	2020
CURRENT ASSETS:			
Cash and cash equivalents		$ 22,403	$ 43,331
Accounts receivable		46,216	44,843
Contract assets	13	66,575	40,172
Accounts receivable from related parties	6	3,447	4,985
Inventories		7,760	9,323
Prepayments and other current assets		30,162	29,730
Investments classified as held for sale	8		43,511
Total current assets		176,563	215,895
Property, plant and equipment, net	7	813,862	824,337
Investments accounted for using the equity method	8	144,073	136,718
Intangible assets, net	9	114,177	119,328
Goodwill	9	68,908	71,537
Deferred income tax assets		27,500	27,090
Notes receivable with relates parties	6		20,637
Other non-current assets		543	548
Total assets		$1,345,626	$1,416,090
Liabilities and Equity			
CURRENT LIABILITIES:			
Accounts payable and accrued expenses		$ 103,857	$ 92,683
Accounts payable to related parties	6	2,497	1,965
Current portion of other long-term liabilities	11	2,402	5,822
Current portion of long-term debt	10	75,430	82,887
Total current liabilities		184,186	183,357
Long-term debt	10	927,349	1,021,407
Deferred income tax liabilities		113,732	105,189
Deferred rent		42,909	38,426
Other long-term liabilities	11	20,377	20,665
Pension and other post-retirement obligations		25,487	22,671
Total liabilities		1,314,040	1,391,715
EQUITY:			
Capital stock	12	11,389	52,344
Accumulated income (loss)		7,918	(30,369)
Other comprehensive income		12,279	2,400
Total equity		31,586	24,375
Total liabilities and equity		$1,345,626	$1,416,090

The accompanying notes are an integral part of these consolidated financial statements.

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Interim Statements of Income and Comprehensive Income
For the half-year ended on June 30, 2021 and 2020

Figures in thousands of U.S. Dollars

	Notes	2021	2020
Revenues	4 and 13	$382,417	$238,537
Cost of sales and services	14	(327,987)	(164,332)
Gross profit		54,430	74,205
General and administrative expenses	14	(17,564)	(16,741)
Other income	8	26,695	
Share of net profit of joint ventures accounted for using the equity method	8	11,363	10,339
Operating profit		74,924	67,803
Financing income	15	1,423	95
Financing cost	15	(41,110)	(36,687)
Financing cost, net		(39,687)	(36,592)
Income before income tax		35,237	31,211
Income tax expense	16	(9,236)	(14,386)
Net income		26,001	16,825
Comprehensive income:			
Items that will not be reclassified income:			
Remeasurement of pension and other post-retirement obligations - consolidated entities		145	(1,143)
Items that may be reclassified to income:			
Interest rate swap in joint ventures cancellation		9,662	
Interest rate swap in joint ventures		72	(6,201)
Interest rate swap in joint ventures, net	8	9,734	(6,201)
Comprehensive income		$ 35,880	$ 9,481

The accompanying notes are an integral part of these consolidated interim financial statements.

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Interim Statements of Changes in Stockholders' Equity

For the half-year ended on June 30, 2021 and December 30, 2020

Figures in thousands of U.S. Dollars

	Note	Capital stock	Accumulated loss	Other comprehensive income	Total
Balance at December 31, 2019		$ 92,710	$ 56,006	$ 5,826	$ 154,542
Comprehensive income:					
Net income			16,825		16,825
Items that will not be reclassified to income:					
Pension and other post-retirement obligations, net of tax - consolidated entities				(1,143)	(1,143)
Items that may be reclassified to income:					
Interest rate swap amortization in unconsolidated affiliates	8			(6,201)	(6,201)
			16,825	(7,344)	9,481
Balance at June 30, 2020		$ 92,710	$ 72,831	($ 1,518)	$ 164,023

The accompanying notes are an integral part of these consolidated interim financial statements.

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Interim Statements of Changes in Stockholders' Equity

For the half-year ended on June 30, 2021 and December 30, 2020

Figures in thousands of U.S. Dollars

	Note	Capital stock	Accumulated loss	Other comprehensive income	Total
Balance at December 31, 2020		$ 52,344	($ 30,369)	$ 2,400	$ 24,375
Shareholders' transaction:					
Capital stock decrease	12	(12,118)			(12,118)
Dividends	12		(16,551)		(16,551)
Accumulated losses compensation	12	(28,837)	28,837		
		(40,955)	12,286		(28,669)
Comprehensive income:					
Net income			26,001		26,001
Items that will not be reclassified to income:					
Pension and other post-retirement obligations, net of tax - consolidated entities				145	145
Items that may be reclassified to income:					
Interest rate swap amortization in unconsolidated affiliates	8			9,734	9,734
			26,001	9,879	35,880
Balance at June 30, 2021		$ 11,389	$ 7,918	$ 12,279	$ 31,586

The accompanying notes are an integral part of these consolidated interim financial statements.

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Interim Statements of Cash Flows
For the half-year ended on June 30, 2021 and 2020

Figures in thousands of U.S. Dollars

	Notes	June 30, 2021	June 30, 2020
Cash flows from operating activities			
Income before income tax		$ 35,237	$ 31,211
Adjustments for investing activities related items:			
Depreciation and amortization	7 and 14	21,039	19,611
Share of net profit of joint ventures accounted for using the equity method	8	(11,363)	(10,339)
Gain on disposal of investments	8	(26,695)	
Interest income		(577)	
Adjustments for financing activities related items:			
Interest expense	15 and 17	37,323	34,979
Amortization of deferred financing costs	15 and 17	857	500
		55,821	75,962
Change in assets and liabilities resulting from operating activities:			
Accounts receivable		(36,309)	12,402
Income tax		(7,614)	(14,701)
Accounts receivable from unconsolidated affiliates		776	(425)
Inventories		1,563	(773)
Prepayment and other current assets		(432)	(3,573)
Other non-current assets		5	22
Accounts payable and accrued expenses		25,354	(58,119)
Accounts payable to unconsolidated affiliates		532	9,384
Deferred rent		4,483	4,694
Other liabilities		(3,708)	(1,006)
Pension and other post-retirement obligations		2,917	2,108
Net cash provided by operating activities		**43,388**	**25,975**
Cash flows from investing activities			
Payments for property, plant and equipment	7	(5,413)	(1,338)
Interest received	8	670	-
Proceeds from investment held for sale		83,405	
Dividends from joint ventures	8	4,080	-
Equity distribution from joint ventures	8		12,626
Net cash provided by investing activities		**82,742**	**11,288**
Cash flows from financing activities			
Proceeds from working capital facility	17		30,000
Repayment of working capital facility	17		(30,000)
Repayment of long-term debt	17	(101,694)	(15,573)
Interest paid	15	(38,001)	(36,935)
Dividend	12	(7,363)	
Net cash used in financing activities		**(147,058)**	**(52,508)**
Net decrease in cash and cash equivalents		(20,928)	(15,245)
Cash and cash equivalents at beginning of the period		43,331	46,508
Cash and cash equivalents at end of the period		**$ 22,403**	**$ 31,263**
Non-cash financing and investing activities	17.2		

The cash paid for income taxes for the half-year ended June 30, 2021 and 2020 was $7,614 and $14,701, respectively.

The accompanying notes are an integral part of these consolidated interim financial statements.

Figures in thousands of U.S. Dollars ($)

Note 1 - History, Company activities and relevant events:

1.1 History and Company activities

Electricidad Firme de México Holdings, S. A. de C. V. (collectively with its subsidiaries, Electricidad Firme, we, our, us, Company or Group) is a direct subsidiary of El Aguila Holdings B. V. an indirect subsidiary on Actis LLP, and was incorporated on March 6, 2018 in Mexico City, with an indefinite duration.

Electricidad Firme indirectly owns Cometa Energía, S. A. de C. V. (Cometa) who owns, operates, acquires, and develops a diverse portfolio of electric generation facilities, gas compression facilities, and related infrastructure.

The portfolio includes subsidiaries that are consolidated and joint ventures accounted for under the equity method, that own and operate six natural gas-fired Combined Cycle Power Plants (CCPP) and a Wind Farm (WF). Some other characteristics of the plant portfolio, such as the total megawatts, location, year of commercial operation, and characteristic of the permits to generate electric power in accordance with the Mexican Regulation such as: a) Independent Power Producer (IPP); b) External Producer (EP); c) Self Supply (SS); d) Qualified Supply (QS)* and e) Electric Power Generation (EPG) are as follows:

		Interest held by us	Year of commercial operation	Permits	Plant characteristics		
					Megawatts	Location	Type
Equity Method:							
Energía Azteca VIII	(1)	51.0	2002	IPP, SS/QS*	625	Guanajuato, Mexico	CCPP
Energía Sierra Juárez	(2 and 3)	50.0	2015	EP	155	Mexicali, Mexico	WF
Consolidated:							
Energía Campeche	(2)	100.0	2003	IPP	252	Campeche, Mexico	CCPP
Energía Chihuahua	(2)	100.0	2003	IPP, SS/QS*	271	Chihuahua, Mexico	CCPP
Energía Azteca X	(2)	100.0	2003	IPP, SS	760	Mexicali, Mexico	CCPP
Energía de Baja California	(1)	100.0	2003	EP, EPG	320	Mexicali, Mexico	CCPP
Energía San Luis de la Paz	(2)	100.0	2015	SS	230	Guanajuato, Mexico	CCPP

* The generator permit has been granted on October 29, 2020, to be able to operate under the wholesale market and offer its products to Qualified Suppliers or other market participants.

The portfolio also includes subsidiaries and a joint venture that own and operate Gas Compression plants; the permits of those plants were awarded by Centro Nacional de Gas (CeNaGas). Their characteristics, such as the Million Cubic Feet (MCF) per day are as follows:

		Interest held by us	Year of commercial operation	Plant characteristics	
				MCF	Location
Equity Method:					
Compresión Bajío	(1)	51.0	2001	100.0	Querétaro, Mexico
Consolidated:					
Compresión Altamira	(2)	100.0	2014	1,300.0	Tamaulipas, Mexico
Green Energy Libramiento	(1)	100.0	2007	100.0	Querétaro, Mexico

Finally, our portfolio includes 2 subsidiaries, GDD de Personal [(1)] and Saavi Operaciones México [(2)], who provide personnel services to the companies mentioned above, as well as sub holding companies including 23 subsidiaries incorporated in the Netherlands and 3 subsidiaries incorporated in the United Kingdom.

(1) A limited liability company, S. de R. L. de C. V. with a $0.1 fixed portion of equity without withdrawal rights.

(2) A limited liability company, S. A. de C. V. with a $25 fixed portion of equity without withdrawal rights.

(3) On November 22, 2020, we celebrated an Option and Purchase and Sale Agreement with Controladora Sierra Juárez, and IEnova Holdco and finally on March 19, 2021, we sold our Joint Venture of Energía Sierra Juárez. See Note 8, *Investments accounted for using the equity method.*

1.2 Relevant events

Considering the actual context and market conditions under the COVID-19 environment and post outbreak, at June 30, 2021 there are no significant financial impacts on the consolidated interim statements of financial position and our consolidated interim cash flow.

On April 30, 2021, the investment agreement between our joint venture Compresión Bajío and CenaGas (originally entered with Pemex Gas Petroquímica Básica) concluded, At the date of this report the Company´s Management is negotiating a new agreement with CenaGas and expect to conclude it in the near future.

1.3 Relevant events concluded after June 30, 2021

On April 20, 2021 the Mexican Congress approved a new legislation that modify the tax and labor treatment of outsourced services in Mexico, that is mandatory for periods after September 30, 2021. These legal reforms had human resources considerations, amendments to labor agreements, transfer of the personnel within our subsidiaries approved and performed after June 30, 2021 and before the date of the consolidated interim financial statements. These legal reforms had non-significant financial impacts.

Note 2 - Basis of preparation:

These consolidated interim financial statements as at June 30, 2021 and for the half-year then ended are unaudited and have been prepared in accordance with IAS 34 "Interim financial reporting". The consolidated interim consolidated interim financial statements should be read in conjunction with the audited consolidated interim financial statements for the year ended December 31, 2020, which have been prepared in accordance with International Financial Reporting Standards (IFRS) issued by the International Accounting Standards Board (IASB).

The accompanying consolidated interim financial statements have been prepared to be used in a debt offering.

New accounting standards and interpretations have been published that are mandatory for periods after January 1, 2021. These standards did not have a material impact on the consolidated interim financial statements: Amendments to IFRS 16, *Leases*, rent concessions granted to lessees. and b) Amendments to IFRS 9, *Financial Instruments*, IAS 39, *Financial Instruments: Recognition and Measurement* IFRS 7, *Financial Instruments: Disclosures*, IFRS 4 *Insurance Contracts* and IFRS 16, *Leases*, to address the issues that arise during the reform of an interest rate benchmark rate.

Note 3 - Summary of significant accounting policies:

The accounting policies adopted are consistent with those of the previous financial year, except for:

Income tax

Taxes on income in the interim periods are accrued using the tax rate that would be applicable to expected total annual profit or loss (estimated average annual tax rate). See Note 16, *Income tax.*

Note 4 - Segment information:

4.1 Description of segments and principal activities.

CEO, CFO and FP&A (denominated as CODM under IFRS 8, *Operating Segments*), examine the Group's performance per type of revenues and has identified four (4) reportable-operating segments of its business. a) Electricity generation, b) Gas compression, c) Joint ventures and d) Corporate.

4.2 Performance of the reportable-operating segments.

The Company CODM primarily uses the operating profit to assess the performance of the reportable operating segments. However, the Management also receives information about the segments revenue and assets on a monthly basis.

4.3 Statements of financial position and statements of income on Management's report.

The statements of financial position at June 30, 2021 and December 31, 2020 and the statements of income on Management's report for the half-year ended as of June 30, 2021 and 2020 of the reportable-operating segments are as follows:

	2021				
	Electricity generation	Gas compression	Joint ventures	Corporate	Total
Interim statement of financial position:					
Property, plant and equipment, net	$ 740,366	$ 71,384	$	$ 2,112	$ 813,862
Investments accounted for using the equity method			144,073		144,073
Intangible assets, net	81,093	33,084			114,177
Goodwill	49,571	403	18,934		68,908
Other assets	157,545	26,193		20,868	204,606
Total assets [1]	$ 1,028,575	$ 131,064	$ 163,007	$ 22,980	$ 1,345,626
Debt	($ 44)	$	$	($ 1,002,735)	($ 1,002,779)
Other liabilities	(239,597)	(12,412)		(59,252)	(311,261)
Total liabilities [1]	($ 239,641)	($ 12,412)	$	($ 1,061,987)	($ 1,314,040)

	2021				
	Electricity generation	Gas compression	Joint ventures	Corporate	Total
Interim statement of income on Management's report:					
Revenues:					
Lease	$ 33,979	$ 23,471	$	$	$ 57,450
Deferred rent	(4,483)				(4,483)
Lease - Net	29,496	23,471			52,967
Electricity	304,067				304,067
Operating and maintenance	24,394				24,394
Other services and others	989				989
	358,946	23,471			382,417
Cost of sales and services	(326,192)	(1,795)			(327,987)
Gross profit	32,754	21,676			54,430
General and administrative expenses and other	(13,545)	(1,427)		(2,592)	(17,564)
Other income			26,695		26,695
Share of net profit of joint ventures			11,363		11,363
Operating profit	$ 19,209	$ 20,249	$ 38,058	($ 2,592)	$ 74,924

	2020				
	Electricity generation	Gas compression	Joint ventures	Corporate	Total
Interim statement of financial position:					
Property, plant and equipment, net	$ 749,214	$ 73,297	$	$ 1,826	$ 824,337
Investments accounted for using the equity method			136,718		136,718
Investments classified as held for sale			43,511		43,511
Intangible assets, net	84,081	35,247			119,328
Goodwill	49,571	403	21,563		71,537
Other assets	130,578	27,466		62,615	220,659
Total assets [1]	$ 1,013,444	$ 136,413	$ 201,792	$ 64,441	$ 1,416,090
Debt	($ 504)	$	$	($ 1,103,790)	($ 1,104,294)
Other liabilities	(208,162)	(18,664)		(60,595)	(287,421)
Total liabilities [1]	($ 208,666)	($ 18,664)	$	($ 1,164,385)	($ 1,391,715)

	2020				
	Electricity generation	Gas compression	Joint ventures	Corporate	Total
Interim statement of income on Management's report:					
Revenues:					
Lease	$ 17,333	$ 22,731	$	$	$ 40,064
Deferred rent	(4,694)				(4,694)
Lease - Net	12,639	22,731			35,370
Electricity	183,269				183,269
Operating and maintenance	18,748				18,748
Other services and others	1,150				1,150
	215,806	22,731			238,537
Cost of sales and services	(162,773)	(1,559)			(164,332)
Gross profit	53,033	21,172			74,205
General and administrative expenses and other	(12,049)	(2,882)		(1,810)	(16,741)
Share of net profit of joint ventures			10,339		10,339
Operating profit	$ 40,984	$ 18,290	$ 10,339	($ 1,810)	$ 67,803

[4] Segment assets and liabilities are measured in the same way as in the interim financial statements. These assets are allocated based on the operations of the segment.

Note 5 - Financial assets and financial liabilities:

5.1 This note provides information about the Group's financial instruments, including:

- An overview of all financial instruments held by the Group.
- Specific information about each type of financial instrument.
- Accounting policies.
- Information about determining the fair value of the instruments, including judgements and estimation uncertainty involved.

5.2 We hold the following financial instruments as of June 30, 2021 and December 31, 2020:

	2021	2020
Accounts receivable	$ 46,216	$ 44,843
Accounts receivable from related parties	3,447	4,985
Notes receivable with related parties		20,637
Financial assets	$ 49,663	$ 70,465
Accounts payable and accrued expenses	$ 103,857	$ 92,683
Accounts payable to related parties	2,497	1,965
Current portion of other long-term liabilities	2,402	5,822
Current portion of long-term debt	75,430	82,887
Long-term debt	927,349	1,021,407
Other long-term liabilities	16,024	16,528
Financial liabilities	$ 1,127,559	$ 1,221,292

The maximum exposure to credit risk at the end of the reporting period is the carrying amount of each class of financial assets mentioned above.

Note 6 - Related party balances and transactions:

6.1 Balances with related parties at June 30, 2021 and December 31, 2020 were as follows:

	2021	2020
Accounts receivable from unconsolidated joint ventures:		
Servicios Azteca VIII, S. de R. L. de C. V.	$ 810	$ 1,021
Energía Azteca VIII, S. de R. L. de C. V.		2,627
Other unconsolidated joint ventures and shareholders'	2,637	1,337
Accounts receivable from related parties	$ 3,447	$ 4,985
Notes receivable with relates parties long-term		
El Aguila Limited	$	$ 20,637
Accounts payable to unconsolidated joint ventures:		
Operaciones Compresión Bajío, S. de R. L. de C. V.	$ 1,658	$ 1,052
Other unconsolidated joint ventures	839	913
Accounts payable to related parties	$ 2,497	$ 1,965

6.2 Transactions income/(expense) with related parties for the half-year ended as of June 30, 2021 and 2020 were as follows:

	2021	2020
General and administrative expenses:		
Others - (ultimate Holding)	$	($ 42)
Financing income:		
Interest from El Aguila Limited	577	
Interest from others	4	
Financing expenses:		
Interest to El Aguila Investments S. A. R. L.		(7,946)

6.3 Transactions with related parties are described as follows:

Administrative services provided by others, may also incur costs on behalf of the Company and its affiliates, which are then directly billed to each associated entity. These primarily include employee costs, as well as legal and other third-party costs related to the Company's operation.

We have recorded these costs as general and administrative expenses in the consolidated interim statements of income and comprehensive income, for the half-year ended as of June 30, 2021 and December 31, 2020.

El Aguila Investment S. A. R. L.: 3 Promissory notes amounting $162,512, at December 31, 2019 bearing interest at market rate. Interest was payable in annual installments on April 20, of each year. Principal and its interest were liquidated on September 29, 2020.

El Aguila Limited: On September 28, and December 18, 2020, the Company granted Loans to El Aguila Limited, for $153,642 Note "A" and $36,000 Note "B" with an 8.00% of interest rate. Interest is capitalized annually and starting on this date is recorded in the finance expense line of the consolidated interim statements of income and comprehensive income. See Note 15, Analysis of the financing cost, net. The principal will be paid on September 28, and December 18, 2030, nevertheless the Borrower shall have the right at any time and from time to time to prepay the outstanding principal amount of the loan, in whole or in part and/or its interest.

On December 29, 2020, we declared and distributed in kind dividends to our shareholders for $172,136, See Note 12, *Stockholders' Equity*, with a portion of the notes receivables to El Aguila Limited for $169,005 and $3,131 of interest. Therefore, at December 31, 2020 we held only $20,637 of Note "B".

6.4 The total amount of employee's benefits granted to key Management staff or directors of the entity, overall, grouped in each of the following categories is shown as follows:

	2021	2020
Wage and salaries	$1,005	$1,004
Short and long-term direct benefits	610	602
Other benefits	79	77

There are no loans granted by the Company to its key Management staff.

Note 7 - Property, plant and equipment, net:

7.1 At June 30, 2021 and December 31, 2020 the components of plant were as follows:

	December 31, 2019	Acquisition	Depreciation	December 31, 2020	Acquisition	Depreciation	June 30, 2021
Power plants	$ 964,191	$ 1,514	$	$ 965,705	$ 5,239	$	$ 970,944
Depreciation	(68,982)		(42,383)	(111,365)		(21,061)	(132,426)
Power plant, net	895,209	1,514	(42,383)	854,340	5,239	(21,061)	838,518
Compression plants	107,465	883		108,348	92		108,440
Depreciation	(11,413)		(6,862)	(18,275)		(3,428)	(21,703)
Compression plant, net	96,052	883	(6,862)	90,073	92	(3,428)	86,737
Power and compression plants, net	$ 991,261	$ 2,397	($49,245)	$ 944,413	$ 5,331	($24,489)	$ 925,255

7.2 At June 30, 2021 and December 31, 2020 the components of property, plant and equipment were as follows:

	December 31, 2019	Acquisition	Depreciation	December 31, 2020	Acquisition	Depreciation	June 30, 2021
Power and compression Plants, net	$ 991,261	$ 2,397	($49,245)	$944,413	$5,331	($24,489)	$925,255
Office equipment and others	3,492			3,492	82		3,574
Depreciation	(1,080)		108	(972)		(25)	(997)
Office equipment and others, net	2,412		108	2,520	82	(25)	2,577
Right-of-use assets	1,294	6		1,300			1,300
Depreciation	(644)		(459)	(1,103)			(1,103)
Right-of-use assets, net	650	6	(459)	197			197
Unfavorable term of the contract	(173,060)			(173,060)			(173,060)
Depreciation	28,755		17,252	46,007		8,626	54,633
Unfavorable term of the Contract, net	(144,305)		17,252	(127,053)		8,626	(118,427)
Land	4,260			4,260			4,260
Property, plant and equipment, net	$ 854,278	$ 2,403	($32,344)	$824,337	$5,413	($15,888)	$813,862

7.3 The table below presents our unfavorable terms of the contract, liabilities amount at June 30, 2021 and December 31, 2020, which are reflected in our consolidated interim statements of financial position:

Contract	End of contract	2021	2020
Energía Campeche	April- 28	$ 29,018	$ 31,142
Energía Chihuahua	Aug-28	14,655	15,665
Energía Azteca X	Jun-28	56,975	61,044
Green Energy Libramiento	Sep-27	17,779	19,202
		$ 118,427	$ 127,053

7.4 At June 30, 2021 and December 31, 2020, our property accounted for as operating lease were as follows:

	2021	2020
Plants	$ 741,207	$ 741,207
Depreciation	(123,695)	(104,164)
Plants accounted for as operating lease	617,512	637,043
Land	3,085	3,085
Property accounted for as operating lease	$ 620,597	$ 640,128

7.5 At June 30, 2021 and December 31, 2020, the consolidated interim statements of financial position show the following amounts as a lessor:

	2021	2020
Within property, plant and equipment:		
Right-of-use assets	$1,300	$1,300
Depreciation	(1,103)	(1,103)
Total right-of-use assets	$ 197	$ 197
Within the following liabilities:		
Accounts payable and accrued expenses	$ 303	$ 303
Other long-term liabilities		
Total lease liabilities	$ 303	$ 303

Note 8 - Investments accounted for using the equity method:

The interests in joint ventures balances reflected in the consolidated interim statements of financial position include unrecognized gains (losses) from our share of Accumulated Other Comprehensive Income (AOCI)- Net of applicable taxes, related to derivative instruments entered into by the joint ventures.

8.1 At June 30, 2021 and December 31, 2020 our interests in joint ventures accounted for under the equity method is as follows:

	Energía Sierra Juárez		Bajío		
	Equity Investment	Share of AOCI	Equity Investment	Share of AOCI	Total equity
December 31, 2019	$ 54,998	($ 6,206)	$ 149,346	($ 863)	$ 197,275
Shareholders' transaction:					
Equity distribution	(7,578)				(7,578)
Dividends			(17,593)		(17,593)
Comprehensive income pro rata share accounted for using the equity method:					
Net profit	5,753		5,581		11,334
Interest rate swap amortization		(3,456)		247	(3,209)
December 31, 2020	53,173	(9,662)	137,334	(616)	180,229
Shareholders' transaction:					
Equity distribution	(53,173)				(53,173)
Dividends			(4,080)		(4,080)
Share of AOCI cancellation		9,662			9,662
Comprehensive income pro rata share accounted for using the equity method:					
Net profit			11,363		11,363
Interest rate swap amortization				72	72
June 30, 2021	$ -	$ -	$ 144,617	($ 544)	$ 144,073

8.2 The statements of financial position as of June 30, 2021 and December 31, 2020 of our equity method investments are summarized below:

	2021		2020	
	Bajío [2][3]	ESJ	Bajío [2][3]	ESJ
Statement of financial position:				
Current assets	$ 86,459	$	$ 83,891	$ 32,579
Noncurrent assets	277,797		277,575	319,358
Total assets	364,256		361,466	351,937
Current liabilities [3]	30,171		36,396	23,544
Debt, current and long-term [4]				249,928
Other noncurrent liabilities	154,174		160,460	33,298
Total liabilities	184,345		196,856	306,770
Total equity	$ 179,911	$	$ 164,610	$ 45,167
Share of equity	51%	%	51%	50%
Company's pro rata share of equity [1]	$ 91,755	$	$ 83,951	$ 22,583

8.3 The results of operations for the half-year ended as of June 30, 2021 and 2020, of our equity method investments are summarized below:

	2021		2020	
	Bajío	ESJ	Bajío	ESJ
Statement of income:				
Net revenues [3]	$ 196,718	$ 13,165	$ 131,731	$ 22,782
Net income	22,282	1,276	5,090	15,487
Company's pro rata share of net income	11,363	638	2,596	7,743

(1) The difference between our Interests in joint ventures balance and our pro rata share of equity is the fair value adjustment recognized as part of the business combination at the acquisition date.

(2) The statements of financial position and income statements for the Bajío Project represents the assets, liabilities, equity, revenue and costs of Energía Azteca VIII and Compresión Bajío.

(3) Within total revenues for the Energía Azteca VIII there is approximately $17,846 and $10,316 of intercompany revenues for the half-year ended June 30, 2021 and 2020 respectively. There are offsetting costs of revenues included within the operating profit line. These revenues and costs represent transactions between the Energía Azteca VIII and Compresión Bajío and are presented on a gross basis in the above summary. In addition, the associated intercompany accounts receivable and accounts payable as of June 30, 2020 and December 31, 2020 of approximately $7,447 and $7,874 are also presented on a gross basis within the current assets and current liabilities lines.

(4) The current portion of long-term debt of ESJ as of December 31, 2020 is $11,790 respectively.

8.4 On November 22, 2020, we celebrated an Option and Purchase and Sale Agreement with Controladora Sierra Juárez, and IEnova Holdco due to a commercial strategy. On March 19, 2021, we closed the transaction, whereby we sold our Joint Venture of Energía Sierra Juárez through the sale of our subsidiary IG Sierra Juárez.

The financial information related to the sale is as follows:

Total consideration received	$ 83,405
Carrying amount of net assets sold (5)	(56,710)
Gain on sale before income tax	26,695
Income tax expense on gain (6)	-
Gain on sale after income tax	$ 26,695

(5) The carrying amount of the net assets sold as of the date of the sale is as follows:

Subtotal as of December 31, 2020	43,511
Interest rate swap amortization of IG Sierra Juárez recognized in OCI	9,662
Goodwill	2,629
Net assets of IG Sierra Juárez	908
Carrying amount of net assets sold	$ 56,710

(6) The tax expense was amortized with the tax loss carry forward of Cometa Energía.

Note 9 - Goodwill and intangibles assets, net:

9.1 At June 30, 2021 and December 31, 2020 the components of customer relationship (customer) and goodwill were as follows:

	December 31 2019	Amortization	December 31, 2020	Equity Sale	Amortization	June 31, 2021
Customer	$ 146,798	$	$ 146,798	$	$	$ 146,798
Amortization	(17,169)	(10,301)	(27,470)		(5,151)	(32,621)
Customer relationship, net	$ 129,629	($ 10,301)	$ 119,328		($ 5,151)	$ 114,177
Goodwill	$ 71,537	$	$ 71,537	($ 2,629)	$	$ 68,908

Note 10 - Debt:

10.1 At June 30, 2021 and December 31, 2020 our consolidated long-term debt consisted of the following:

	Final maturity	2021 Current	2021 Long-term	2021 Total	2020 Current	2020 Long-term	2020 Total
Senior Secured Notes	Apr-35	$ 32,685	$ 753,167	$ 785,852	$ 32,680	$ 773,140	$ 805,820
GIP Spectrum loan	Nov-30	31,923	204,310	236,233	38,707	278,793	317,500
VAT Loan			44	44		503	503
Accrued interest		10,822		10,822	11,500		11,500
Deferred financing costs, net			(30,172)	(30,172)		(31,029)	(31,029)
		$ 75,430	$ 927,349	$ 1,002,779	$ 82,887	$1,021,407	$1,104,294

10.2 Senior Secured Notes offered by the Group in U. S. dollars, bearing interest at 6.375%, through April 2035. Principal and interest are payable in semi-annual installments in accordance with the amortization schedule started on October 2018, through April 2035.

10.3 Amortization of deferred financing cost for the half-year ended as of June 30, 2021 and 2020 was $857 and $500 respectively. See Note 15, *Analysis of the financing cost, net*.

10.4 As of June 30, 2021 and December 31, 2020, the market value of the Senior Secured Notes traded at 118.31 and 113.02, respectively. Senior Secured Notes are classified in level 1 on public stock exchanges for which quoted prices are readily available.

10.5 The Senior Secured Notes and the Loan with GIP establish certain positive and negative covenants, which have been duly met by June 30, 2021 and December 31, 2020.

The following is a summary of the main covenants of the debt above mentioned:

- Limitations on capital investments.
- Permits.
- Know-Your-Customer's documentation.
- Restrictions on dividend payments.
- Restrictions on incurrence of debt.
- Insurance payments.
- Restrictions on sales, transfers or leases of properties.
- Not make any loans other than permitted ones.
- Not issue any equity interests or any other security convertible into any other equity interests in the borrower's capital to any person other than to the sponsor and the equity holder.
- Not make any restricted payments unless each of the applicable conditions are satisfied.
- Not enter into any agreement that modifies any finance document or creates any Lien

As of June 30, 2021, and December 31, 2020, the Group complied with the covenants mentioned above.

10.6 On April 2020, a new revolving credit was agreed, for up to $180,000, bearing interest at Libor plus 1.75%, and it expires on April 2025. The finance cost paid for the credit amount $1,149. At December 31, 2020 there are no pending balances.

10.7 On June 2020, a new loan was agreed between Campeche and InterGen N. V., denominated in Mexican pesos by $766, the loan finance the value added tax (VAT) paid by Campeche to CFE for certain cost and expenses, bears interest at 10.28% and expires on June 2025, however payments are being done with the recoverable VAT received by Campeche and other factors.

10.8 On September, 2020, a new loan was agreed between The Company and GIP Spectrum Saavi Luxco, S. A. R. L. (GIP), by$325,000, bearing interest at 7.75%, principal and interest are payable in semi-annual installments in accordance with the amortization schedule started on November 2020, through November 2030. The fair value of the debt is similar to the carrying amount due to the short term between the date on which the loan was contracted, and the year end.

Note 11 - Other long-term liabilities:

11.1 At June 30, 2021 and December 31, 2020, Other long-term liabilities were as follows:

	2021				2020			
	Current		Non-current		Current		Non-current	
	Principal	Interest	Principal	Interest	Principal	Interest	Principal	Interest
Energía San Luis de la Paz	$ 2	$ 47	$10,148	$ 5,876	$ 2	$ 27	$ 10,621	$ 5,907
Green Energy Libramiento			3,230	1,123			3,014	1,123
Other								
Contingent consideration	2,400				5,820			
Total	$2,402	$ 47	$13,378	$ 6,999	$ 5,822	$ 27	$ 13,635	$ 7,030

11.2 Energía San Luis de la Paz acquired plant equipment that will be paid in accordance with the Equivalent Operating Hours (EOH) of our power plant until 2038 in accordance with our forecast, interest was computed using a 5% discount rate.

11.3 The Maintenance fee of Green Energy Libramiento is deferred until a maintenance occurs, we do not expect to have a maintenance in the following year, therefore it is shown as part of the non-current liabilities. Interest was computed using a 5% discount rate.

11.4 Contingent consideration arise from the business acquisition held on 2018 and depends on the future performance of the cash flow projected on the generation of electricity by Energía Campeche. This consideration may be payable semi-annually on the following 3 years to InterGen N. V. if certain conditions are met.

Note 12 - Stockholders' equity:

12.1 At an extraordinary Stockholders' Meeting held on May 5, 2021, the stockholders compensated accumulated losses of the capital stock by $28,837 and decrease the capital stock in kind by $12,118 with a portion of the notes receivables to El Aguila Limited.

At an extraordinary Stockholders' Meeting held on October 29, 2020 the stockholders compensated accumulated losses of the capital stock by $40,366.

12.2 After the previous increases, capital stock at June 30, 2021 and December 31, 2020, is composed as follows:

	Shares		Amount	
Description	2021	2020	2021	2020
Class I, representing the fixed portion of equity without withdrawal right	50,000	50,000	$ 3	$ 3
Class II representing the variable portion of equity with withdrawal rights	1,705,198,215	1,705,198,215	11,386	52,341
Total			$ 11,389	$ 52,344

12.3 Class I shares have the following characteristics: grant voting rights at any Shareholders meeting to be held. Class II shares have the following characteristics: grant voting rights at any Shareholders meeting to be held.

12.4 Net income under Mexican Financial Reporting Standards of every subsidiary is subject to the legal requirement that at least 5% of the income for each year is intended to increase the legal reserve until it is equal to one fifth of the amount of the capital stock.

12.5 Dividends to be paid of the subsidiaries will be free from income tax if they come from Net Tax Profit Account (CUFIN, by its Spanish acronym). Any dividends paid in excess of CUFIN and Reinvested CUFIN will cause a tax equivalent to 42.86% if they are paid on 2021. The current tax is payable by the Company and may be credited against its income tax of the year or the following two years. Dividends paid coming from profit previously taxed by income tax are not subject to tax withholding or additional tax payment. The Net Contribution Capital Account (CUCA, by its Spanish acronym) represents, the capital stock contributions free from income tax when it is returned.

At June 30, 2021 and December 31, 2020, the CUFIN and CUCA is as follows:

	2021	2020
Net tax profit account	$ 668	$ 668
Net contribution capital account	94,343	94,343

12.6 At an extraordinary Stockholders' Meeting held on December 29, 2020 the stockholders declared and distributed in kind dividends to our shareholders for $172,136 with a portion of the notes receivables to El Aguila Limited for $169,005 and $3,131 of interest.

At an extraordinary Stockholders' Meeting held on May 5, 2021 the stockholders declared and distributed in kind dividends to our shareholders for $9,188 with a portion of the notes receivables to El Aguila Limited by $8,519 and $669 of interest. Furthermore, at an extraordinary Stockholders' Meeting held on May 30, 2021 the stockholders agreed to distribute dividends to our shareholders by $7,363 by and means of cash distributions.

Substantially, all consolidated Company earnings were generated by its Subsidiaries. Retained earnings can be distributed to the Company's Shareholders to the extent that the Subsidiaries have distributed earnings to the Company.

Note 13 - Analysis of revenues:

13.1 An analysis of the revenues for the half-year ended June 30, 2021 and December 31, 2020 is shown in the Note 4, *Segment information*.

13.2 Our electricity generation segment derives revenue from the transfer of goods (electricity) and ancillary services (maintenance and other) over time.

13.3 For the half-year ended at June 30, 2021 and, 2020 we recognized the following assets related to contracts:

	2020	Reverse	Post	2021
Operating and maintenance services	$ 2,153	($ 2,153)	$ 2,337	$ 2,337
Electricity sales	38,019	(38,019)	64,238	64,238
Total assets	$ 40,172	($40,172)	$66,575	$66,575

	2019	Reverse	Post	2020
Operating and maintenance services	$ 3,706	($ 3,706)	$ 2,549	$ 2,549
Electricity sales	49,599	(49,599)	37,571	37,571
Noncurrent assets	1,349	(1,349)		
Total assets	$54,654	($54,654)	$40,120	$40,120

13.4 Significant changes in contract assets - Contract assets are billed and collected in the following month period in all cases, the contract assets of the electricity sales are determined in accordance with the gas consumptions and electricity consumptions at the rates stipulated in our contracts. There are no liabilities unrecognized in relation to costs to fulfill our gas supply contracts.

13.5 The amount from operation and maintenance revenues, for the remaining performance obligations after June 30, 2021 and December 31, 2020 are shown below:

	2021	2020
2021	$ 23,344	$ 46,687
2022	46,692	46,692
2023	46,692	46,692
2024	46,707	46,707
2025	46,734	46,734
Thereafter	260,777	260,777
Total	$470,946	$ 494,289

13.6 Due to the characteristics of the power purchase contracts at the Energía Azteca X, Energía Campeche, Energía Chihuahua, Energía San Luis de La Paz, and Compression Services of Compresión Altamira and Green Energy Libramiento consolidated subsidiaries, the power capacity and compression services are represented under IFRS 16, *Leases*, as operating leases. Operating lease income includes minimum lease payments, such as capacity payments and contingent rentals, and was $52,967 and $35,360 for the half-year ended and of June 30, 2021 and 2020.

13.7 Estimated minimum lease receivables, which do not include contingent rentals, to be received under operating leases subsequent to June 30, 2021 and December 31, 2020, are as follows:

	2021	2020
2021	$ 53,886	$ 107,772
2022	97,781	97,781
2023	94,475	94,475
2024	93,923	93,923
2025	93,377	93,377
Thereafter	603,613	603,613
	$ 1,037,055	$ 1,090,941

Note 14 - Analysis of cost of sales and general and administrative expenses:

An analysis of the nature of relevant costs and expenses classified by function in the consolidated interim statements of income and comprehensive income for the half-year ended and of June 30, 2021 and 2020 is as follows:

	2021	2020
Fuel	$ 209,903	$ 86,874
Operation and maintenance	42,690	21,619
Interconnection	37,826	27,761
Fuel transportation	21,040	15,108
Depreciation	15,694	15,957
Pension plan and other	818	342
Currency exchange loss (gains)	16	(3,329)
Costs	327,987	164,332
Amortization of intangible assets	5,151	3,434
Wage, salaries and technology information	4,871	4,491
Management service and fee	3,054	2,564
Insurance	2,475	5,101
Duties and non-site property taxes	1,819	931
Depreciation	194	220
Expenses	17,564	16,741
Total	$ 345,551	$ 181,073

Note 15 - Analysis of the financing cost, net:

15.1 The financing income for the half-year ended and of June 30, 2021 and 2020 is composed as follows:

	2021	2020
Banks deposits and others	$ 846	$ 95
Interest - Intercompany loans	577	
Financing income	$ 1,423	$ 95

15.2 The financing cost for the half-year ended of June 30, 2021 and 2020 is composed as follows:

	2021	2020
Long-term debt	($ 37,323)	($ 34,979)
Other interest expense	(2,150)	(685)
Interest expense	(39,473)	(35,664)
Letter of credit and fees	(598)	
Finance expenses and fees	(182)	(280)
Amortization of deferred financing cost	(857)	(500)
Change in law financing expenses		(243)
Other financial expenses	(1,637)	(1,023)
Financing cost	($ 41,110)	($ 36,687)

Note 16 - Income tax:

16.1 Income tax expense is recognized based on management's estimate of the weighted average effective annual income tax rate expected for the full financial year. The estimated average annual tax rate used for the half-year to June 30, 2021 is 26%, compared to 46% for the half-year ended June 30, 2020. The tax rate is lower in 2021 due to the recognition of previously unrecognized carried forward tax.

Note 17 - Consolidated Interim Statements of cash flows:

17.1 The reconciliation between the opening and closing balances in the statements of financial position for liabilities arising from financing activities, are shown below:

	2021	2020		
	Long-term debt	Related party	Long-term debt	Total
Balances at January 1	$ 1,104,294	$ 164,277	$ 817,717	$ 981,994
Proceeds from issuance of long-term debt working capital			30,000	30,000
Repayment of long-term debt working capital			(30,000)	(30,000)
Payment of deferred financing cost			(6,805)	(6,805)
Proceeds from long-term debt			325,000	325,000
Repayment of debt	(101,694)	(162,512)	(34,517)	(197,029)
Amortization of deferred financing costs	857		1,139	1,139
Interest expense	37,323	11,465	59,469	70,934
Interest paid	(38,001)	(13,230)	(57,709)	(70,939)
Balances at December 31	1,002,779		1,104,294	1,104,294
Current portion of long-term debt	(75,430)		(82,887)	(82,887)
Debt	$ 927,349	$	$ 1,021,407	$ 1,021,407

17.2 At June 30, 2021 non-cash transaction of financing activities consist in a) a capital stock decrease in kind and b) a declared and distributed in kind dividend, both satisfied with the notes receivables to El Aguila Limited by $12,118 and $9,188 respectively, at December 31, 2020 non-cash transaction of financing activities consist in a declared and distributed in kind dividend satisfied with a portion of the notes receivables to El Aguila Limited for $172,136.

Note 18 - Commitments and contingencies:

18.1 Power sales contract: Several of our power plants rely on power sales and gas compression contracts with one or a limited number of entities for the majority, and in some cases, all of the relevant plant's output over the term of the power sales contract. The minimum terms of power sales contracts for projects currently in operation expire between 2027 and 2035. The operations of these plants are dependent on the continued performance by customers of their obligations under the relevant power sales contracts, and in particular, on the credit quality of the purchasers. If a substantial portion of our long-term power sales contracts were modified or terminated, this could increase our exposure to market price volatility, and we could be adversely affected to the extent that we would be unable to find other customers at the same level of contract profitability. We have also contracted with various fuel suppliers and transportation providers to supply and transport fuel to our power plants.

18.2 Long term sales agreement: Certain of our subsidiaries have entered into gas turbine major maintenance LTSAs with the original equipment manufacturer of the particular gas turbines or other qualified third parties. These agreements provide for labor and supervision during scheduled inspections, repairs and overhauls of gas turbine equipment, including provisions for forced outage support. The agreements (with the exception of the agreement of Chihuahua) further allow for the supply of replacement, refurbished and critical capital spare parts required for the maintenance of the equipment in accordance with prudent industry practice.

These agreements have terms typically accommodating two or three major maintenance cycles which varies based on the equipment for each power subsidiary. These agreements may or may not contain termination provisions by us at our convenience, based on certain conditions in exchange for a fixed fee. Equivalent Operating Hours (EOH) accrued vary with output, plant cycling regimes, contractual guidelines and gas turbine events, such as trips and load shedding. The estimated annual fixed and variable amounts due under the LTSAs as of June 31, 2021 and December 31, 2020 is expected to total approximately $22,969 and $33,879 respectively. Due to the variable nature of these payments we only estimate 18 months and two years of commitments respectively.

18.3 Fuel purchase commitments: We have committed to purchase gas from different suppliers without a minimum volume of gas.

18.4 Letters of Credit (LOC): We are often required to provide guarantees and/or letters of credit to ensure contractual obligations with respect to bid performance, financing, construction and operations of our subsidiaries. We may issue guarantees in connection with obligations under our power purchase agreements, operations and maintenance contracts, management service agreements and obligations we have as determined in various purchase and sale agreements. Letters of credit relate primarily to debt service requirements, electricity sales agreements and trading requirements. The beneficiary of the guarantee and/or LOC has the ability to draw against the commitments to the extent that the contractual obligations, as defined in the related agreements, allow such draws to be made.

Cometa have maximum exposure under LOCs issued and outstanding at June 30, 2021 and December 31, 2020, are as follows:

	2021		2020	
Subsidiaries and Joint Ventures [1]	Amounts outstanding	Expirations date [2]	Amounts outstanding	Expirations date
Energía Azteca X	$ 24,778	2021	$ 24,778	2021
Saavi Energy Solutions	10,584	2021	20,584	2021
Energía Campeche	15,355	2021	15,355	2021
Energía Chihuahua	15,000	2021	15,000	2021
Energía San Luis de la Paz	12,649	2023	12,652	2023
Energía Azteca VIII	10,531	2021	10,531	2021
Compresión Altamira	7,221	2021	7,249	2021
Saavi Energía	4,884	2021	4,884	2021
Compresión Bajío	4,550	2023	4,550	2023
Energía de Baja California	838	2021	838	2021
	$106,390		$116,421	

[1] Letters of credit outstanding related to these subsidiaries and joint ventures were issued under letters of credit provided by Electricidad Firme de México Holdings, S. A. de C. V.

[2] Some letters of credit have a 2021 expiration date but automatically extend annually.

Electricidad Firme de México Holdings, S. A. de C. V. pays LOC fees of 1.75% per annum.

Each account party pays LOC fees ranging from 2.63% to 2.75% per annum on outstanding LOCs.

18.5 Legal proceedings - We are involved in certain legal proceedings in the normal course of business. We are under the opinion that none of these proceedings will have a material adverse effect on our consolidated financial position or cash flows, individually or in the aggregate.

Note 19 - Subsequent events:

For the period ended June 30, 2022, subsequent events have been evaluated through August 27, 2021, the date which the consolidated interim financial statements were available to be issued.

19.1 On August 19, 2021, the following events occurred:

a) GIP EM Bronco Luxco, S. A. R. L. acquired El Aguila Coöperatief B. V., a direct owner of El Aguila Holdings B. V., without financial impacts on the consolidated interim statements of financial position and our consolidated interim cash flow, however effective on this date, EFM is an indirect subsidiary of GIP EM Bronco Luxco, S. A. R. L.

b) EFM acquired a new loan from: JP Morgan Chase Bank, N. A., Mizuho Bank Ltd. and The Bank of Nova Scotia by $275,500, bearing interest at Libor rate plus a margin between 2.25% and 3,90%, interest will be paid on Semiannual basis starting on November 30, 2021 and principal is payable in February 19, 2023. The resources were mainly used to pay the loan and its interest to GIP Spectrum Saavi Luxco, S. A. R. L. and partially fund a cash collateral payment.

c) EFM acquired a new subordinated loan from GIP EM Bronco Luxco S. À. R. L. for $19,350 bearing interest at market rate. Interest will be paid on annual basis and principal is payable on August 19th, 2024. The sources were used to serve as a cash collateral for a letter of credit posted by the Cometa Energía. The loan is subordinated to any senior financing that EFS and its subsidiaries has, including the Notes.

Note 20 - Authorization of issuance of the consolidated interim financial statements:

The accompanying consolidated interim financial statements and notes were issued on August 27, 2021, by Mauricio del Valle (Chief Financial Officer) and Francisco Villalón (Controller).

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statements of Financial Position as of December 31, 2020 and 2019 and Consolidated Statements of Income and Comprehensive Income, Change in Stockholders' Equity and Cash Flows for the years ended as of December 31, 2020 and 2019

Blvd. Miguel de Cervantes Saavedra 301-11 | Granada | Miguel Hidalgo, 11520, CDMX

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Table of contents

December 31, 2020 and December 31, 2019

Table of Contents

Page

Independent Auditor's Report ..... 1 to 3

Consolidated financial statements:

Consolidated statements of financial position 4
Consolidated statements of income and comprehensive income 5
Consolidated statements of changes in stockholders' equity 6
Consolidated statements of cash flows 7

Notes to the consolidated financial statements

Note 1 History, Company activities and relevant events 8
Note 2 Basis of preparation 9
Note 3 Summary of significant accounting policies 11
Note 4 Critical accounting estimates and judgments 27
Note 5 Financial risk Management 28
Note 6 Segment information 31
Note 7 Financial assets and financial liabilities 33
Note 8 Cash and cash equivalents 33
Note 9 Accounts receivable 34
Note 10 Related party balances and transactions 34
Note 11 Inventories 36
Note 12 Property, plant and equipment, net 37
Note 13 Investments accounted for using the equity method 40
Note 14 Goodwill and intangibles assets, net 42
Note 15 Debt 43
Note 16 Deferred rent 44
Note 17 Other long-term liabilities 44
Note 18 Pension and post-retirement obligations 45
Note 19 Stockholders' equity 49
Note 20 Analysis of revenues 50
Note 21 Analysis of cost of sales and general and administrative expenses 51
Note 22 Analysis of the financing cost, net 52
Note 23 Income tax 52
Note 24 Consolidated statements of cash flows 56
Note 25 Commitments and contingencies 57
Note 26 Subsequent events 58
Note 27 Authorization of issuance of the consolidated financial statements 58



Independent Auditor's Report

To the Shareholders and Directors of
Electricidad Firme de México Holdings, S. A. de C. V.

Opinion

We have audited the consolidated financial statements of Electricidad Firme de México Holdings, S. A. de C. V. and its subsidiaries (Company), which comprise the consolidated statement of financial position as at December 31, 2020, and the related consolidated statements of net income and comprehensive income, of changes in Stockholders' equity and of cash flows for the year then ended and notes to the consolidated financial statements, including a summary of significant accounting policies and other explanatory information.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2020, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

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 Consolidated Financial Statements* section of our report. We are independent of the Company in accordance with the Ethics Standards of Mexican Institute of Public Accountants together with other requirements applicable to our audit of the consolidated financial statements in Mexico. We have fulfilled our other ethical responsibilities in accordance with these requirements and standards. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRS and for such internal control as Management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated 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 Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company and subsidiaries to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the Company and subsidiaries audit. We remain solely responsible for our audit opinion.



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, S. C.

Antonio Nivon Trejo
Audit Partner

Mexico City, April 21, 2021

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statements of Financial Position
December 31, 2020 and 2019

Figures in thousands of U.S. Dollars

Assets	Notes	2020	2019
CURRENT ASSETS:			
Cash and cash equivalents	8	$ 43,331	$ 46,508
Accounts receivable	9	44,843	51,944
Contract assets	20	40,172	54,654
Accounts receivable from related parties	10	4,985	2,298
Inventories	11	9,323	11,690
Prepayments and other current assets	3.13	29,730	25,099
Investments classified as held for sale	13	43,511	
Total current assets		215,895	192,193
Property, plant and equipment, net	12	824,337	854,278
Investments accounted for using the equity method	13	136,718	197,275
Intangible assets, net	14	119,328	129,629
Goodwill	14	71,537	71,537
Deferred income tax assets	23	27,090	23,094
Notes receivable with relates parties	10	20,637	
Other non-current assets		548	811
Total assets		$1,416,090	$1,468,817
Liabilities and Equity			
CURRENT LIABILITIES:			
Accounts payable and accrued expenses	3.22	$ 92,683	$ 178,170
Accounts payable to related parties	10	1,965	484
Current portion of other long-term liabilities	17	5,822	
Current portion of long-term debt	15	82,887	37,260
Current portion of related party long-term debt			1,765
Total current liabilities		183,357	217,679
Long-term debt	15	1,021,407	780,457
Related party long-term debt	10		162,512
Deferred income tax liabilities	23	105,189	88,231
Deferred rent	16	38,426	27,744
Other long-term liabilities	17	20,665	23,554
Pension and other post-retirement obligations	18	22,671	14,098
Total liabilities		1,391,715	1,314,275
EQUITY:			
Capital stock	19	52,344	92,710
Accumulated income		(30,369)	56,006
Other comprehensive income		2,400	5,826
Total equity		24,375	154,542
Total liabilities and equity		$1,416,090	$1,468,817

The accompanying notes are an integral part of these consolidated financial statements.

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statements of Income and Comprehensive Income
For the years ended December 31, 2020 and 2019

Figures in thousands of U.S. Dollars

	Notes	2020	2019
Revenues	20	$596,093	$677,618
Cost of sales and services	21	(415,610)	(545,073)
Gross profit		180,483	132,545
General and administrative expenses	21	(40,668)	(32,811)
Share of net profit of joint ventures accounted for using the equity method	13	11,334	23,761
Operating profit		151,149	123,495
Financing income	22	3,561	1,145
Financing cost	22	(76,020)	(83,898)
Financing cost, net		(72,459)	(82,753)
Income before income tax		78,690	40,742
Income tax expense	23	(33,295)	(25,176)
Net income		45,395	15,566
Comprehensive income:			
Items that will not be reclassified income:			
Remeasurement of pension and other post-retirement obligations - consolidated entities	18	(217)	293
Items that may be reclassified to income:			
Interest rate swap in joint ventures, net	13	(3,209)	255
Comprehensive income		$ 41,969	$ 16,114

The accompanying notes are an integral part of these consolidated financial statements.

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statements of Changes in Stockholders' Equity

For the years ended December 31, 2020 and 2019

Figures in thousands of U.S. Dollars

	Notes	Capital stock	Accumulated income	Other comprehensive income	Total
Balance at December 31, 2018		$92,710	$ 40,440	$5,278	$138,428
Comprehensive income:					
Net income			15,566		15,566
Items that will not be reclassified to income:					
Pension and other post-retirement obligations, net of tax - consolidated entities	18			293	293
Items that may be reclassified to income:					
Interest rate swap amortization in unconsolidated affiliates	13			255	255
			15,566	548	16,114
Balance at December 31, 2019		92,710	56,006	5,826	154,542
Shareholders' transaction:					
Non-cash dividends	19		(172,136)		(172,136)
Accumulated losses compensation	19	(40,366)	40,366		
		(40,366)	(131,770)		(172,136)
Comprehensive income:					
Net income			45,395		45,395
Items that will not be reclassified to income:					
Pension and other post-retirement obligations, net of tax - consolidated entities	18			(217)	(217)
Items that may be reclassified to income:					
Interest rate swap amortization in unconsolidated affiliates	13			(3,209)	(3,209)
			45,395	(3,426)	41,969
Balance at December 31, 2020		$52,344	($ 30,369)	$2,400	$ 24,375

The accompanying notes are an integral part of these consolidated financial statements.

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statements of Cash Flows
For the years ended December 31, 2020 and 2019

Figures in thousands of U.S. Dollars

	Notes	2020	2019
Cash flows from operating activities			
Income before income tax		$ 78,690	$ 40,742
Adjustments for investing activities related items:			
Depreciation and amortization	12 and 14	42,645	42,390
Share of net profit of joint ventures accounted for using the equity method	13	(11,334)	(23,761)
Interest income	22	(3,200)	
Adjustments for financing activities related items:			
Interest expense	22 and 24	70,934	75,213
Amortization of deferred financing costs	22 and 24	1,139	955
		178,874	135,539
Change in assets and liabilities resulting from operating activities:			
Accounts receivable		27,950	(9,706)
Income tax		(19,009)	(21,264)
Accounts receivable from unconsolidated affiliates		(2,594)	1,012
Inventories		2,367	211
Prepayment and other current assets		(4,631)	12,013
Other non-current assets		263	516
Accounts payable and accrued expenses		(87,336)	14,336
Accounts payable to unconsolidated affiliates		1,481	(331)
Deferred rent		10,682	16,519
Other liabilities		2,933	(15,370)
Pension and other post-retirement obligations		2,514	1,580
Net cash provided by operating activities		**113,494**	**135,055**
Cash flows from investing activities			
Payments for property, plant and equipment	12	(2,403)	(16,947)
Proceeds from loan from related parties			3,159
Notes receivable with related parties		(192,773)	
Interest received		3,107	109
Dividends from joint ventures	13	17,593	16,849
Equity distribution from joint ventures	13	7,578	1,954
Net cash provided by investing activities		**(166,898)**	**5,124**
Cash flows from financing activities			
Proceeds from working capital facility	24	30,000	20,000
Repayment of working capital facility	24	(30,000)	(20,000)
Proceeds from issuance of long-term debt	24	325,000	
Repayment of long-term debt	24	(34,517)	(15,480)
Payment of related party long-term debt	24	(162,512)	(68,155)
Payment of deferred financing cost	24	(6,805)	
Interest paid	22 and 24	(70,939)	(87,633)
Net cash provided by financing activities		**50,227**	**(171,268)**
Net decrease in cash and cash equivalents		(3,177)	(31,089)
Cash and cash equivalents at beginning of the year		46,508	77,597
Cash and cash equivalents at end of year	**8**	**$ 43,331**	**$ 46,508**
Non-cash financing and investing activities	24.2		

The cash paid for income taxes for the year ended December 31, 2020 and 2019 was $19,010 and $21,264, respectively.

The accompanying notes are an integral part of these consolidated financial statements.

Figures in thousands of U.S. Dollars ($)

Note 1 - History, Company activities and relevant events:

1.1 History and Company activities

Electricidad Firme de México Holdings, S. A. de C. V. (collectively with its subsidiaries, Electricidad Firme, we, our, us, Company or Group) is a direct subsidiary of El Aguila B. V. an indirect subsidiary on Actis LLP, and was incorporated on March 6, 2018 in Mexico City, with an indefinite duration.

Electricidad Firme indirectly owns Cometa Energía, S. A. de C. V. (Cometa) who owns, operates, acquires, and develops a diverse portfolio of electric generation facilities, gas compression facilities, and related infrastructure.

The portfolio includes subsidiaries that are consolidated and joint ventures accounted for under the equity method, See Note 3.1, *Principles of consolidation and equity accounting* for further information, that own and operate six natural gas-fired Combined Cycle Power Plants (CCPP) and a Wind Farm (WF); Some other characteristics of the plant portfolio, such as the total megawatts, location, year of commercial operation, and characteristic of the permits to generate electric power in accordance with the Mexican Regulation such as: a) Independent Power Producer (IPP); b) External Producer (EP); c) Self Supply (SS); d) Qualified Supply (QS)* and e) Electric Power Generation (EPG) are as follows:

		Interest held by us	Year of commercial operation	Permits	Plant characteristics		
					Megawatts	Location	Type
Equity Method:							
Energía Azteca VIII	(1)	51.0	2002	IPP, SS/QS*	625	Guanajuato, Mexico	CCPP
Energía Sierra Juárez	(2)	50.0	2015	EP	155	Mexicali, Mexico	WF
Consolidated:							
Energía Campeche	(2)	100.0	2003	IPP	252	Campeche, Mexico	CCPP
Energía Chihuahua	(2)	100.0	2003	IPP, SS/QS*	271	Chihuahua, Mexico	CCPP
Energía Azteca X	(2)	100.0	2003	IPP, SS	760	Mexicali, Mexico	CCPP
Energía de Baja California	(1)	100.0	2003	EP, EPG	320	Mexicali, Mexico	CCPP
Energía San Luis de la Paz	(2)	100.0	2015	SS	230	Guanajuato, Mexico	CCPP

* The generator permit has been granted on October 29, 2020, to be able to operate under the wholesale market and offer its products to Qualified Suppliers or other market participants.

The portfolio also includes subsidiaries and a joint venture that own and operate Gas Compression plants; the permits of those plants were awarded by Centro Nacional de Gas. Their characteristics, such as the Million Cubic Feet (MCF) per day are as follows:

		Interest held by us	Year of commercial operation	Plant characteristics	
				MCF	Location
Equity Method:					
Compresión Bajío	(1)	51.0	2001	100.0	Querétaro, Mexico
Consolidated:					
Compresión Altamira	(2)	100.0	2014	1,300.0	Tamaulipas, Mexico
Green Energy Libramiento	(1)	100.0	2007	100.0	Querétaro, Mexico

Finally, our portfolio includes 2 subsidiaries, GDD de Personal [(1)] and Saavi Operaciones México [(2)], who provide personnel services to the companies mentioned above, as well as sub holding companies including 23 subsidiaries incorporated in the Netherlands and 3 subsidiaries incorporated in the United Kingdom.

(1) A limited liability company, S. de R. L. de C. V. with a $0.1 fixed portion of equity without withdrawal rights.

(2) A limited liability company, S. A. de C. V. with a $25 fixed portion of equity without withdrawal rights.

1.2 Relevant events

Considering the actual context and market conditions under the COVID-19 environment and post outbreak, at December 31, 2020 there are no significant financial impacts on the consolidated statements of financial position and our consolidated cash flow.

Note 2 - Basis of preparation:

The accompanying consolidated financial statements of the Company have been prepared in accordance with International Financial Reporting Standards (IFRS) and interpretations issued by the IFRS Interpretations Committee applicable to companies reporting under IFRS. The financial statements comply with IFRS as issued by the International Accounting Standards Board (IASB).

New accounting standards and interpretations have been published that are mandatory for periods after January 1, 2020. These standards did not have a material impact on the consolidated financial statements:

2.1 Definition of Material - Amendments to IAS 1 and IAS 8

The IASB has made amendments to IAS 1 Presentation of Financial Statements and IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors which use a consistent definition of materiality throughout International Financial Reporting Standards and the Conceptual Framework for Financial Reporting, clarify when information is material and incorporate some of the guidance in IAS 1 about immaterial information. In particular, the amendments clarify:

- That the reference to obscuring information addresses situations in which the effect is similar to omitting or misstating that information, and that an entity assesses materiality in the context of the financial statements as a whole, and

- The meaning of "primary users of general purpose financial statements" to whom those financial statements are directed, by defining them as "existing and potential investors, lenders and other creditors" that must rely on general purpose financial statements for much of the financial information they need.

2.2 Revised Conceptual Framework for Financial Reporting

The IASB has issued a revised Conceptual Framework which will be used in standard-setting decisions with immediate effect. Key changes include:

-

increasing the prominence of stewardship in the objective of financial reporting
- reinstating prudence as a component of neutrality
- defining a reporting entity, which may be a legal entity, or a portion of an entity
- revising the definitions of an asset and a liability
- removing the probability threshold for recognition and adding guidance on derecognition
- adding guidance on different measurement basis, and
- stating that profit or loss is the primary performance indicator and that, in principle, income and expenses in other comprehensive income should be recycled where this enhances the relevance or faithful representation of the financial statements.

No changes will be made to any of the current accounting standards. However, entities that rely on the Framework in determining their accounting policies for transactions, events or conditions that are not otherwise dealt with under the accounting standards will need to apply the revised Framework from 1 January 2020. These entities will need to consider whether their accounting policies are still appropriate under the revised Framework.

The following standards and interpretations had been issued but were not mandatory for annual reporting periods ending on December 31, 2020, we do not expect to have an impact on the consolidated financial statements.

2.3 Classification of Liabilities as Current or Non-current - Amendments to IAS 1

The narrow-scope amendments to IAS 1 Presentation of Financial Statements clarify that liabilities are classified as either current or non-current, depending on the rights that exist at the end of the reporting period. Classification is unaffected by the expectations of the entity or events after the reporting date (eg the receipt of a waver or a breach of covenant). The amendments also clarify what IAS 1 means when it refers to the "settlement" of a liability.

The amendments could affect the classification of liabilities, particularly for entities that previously considered management's intentions to determine classification and for some liabilities that can be converted into equity.

They must be applied retrospectively in accordance with the normal requirements in IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors.

In May 2020, the IASB issued an Exposure Draft proposing to defer the effective date of the amendments to 1 January 2023.

2.4 Property, Plant and Equipment: Proceeds before intended use - Amendments to IAS 16, with an effective date is on January 2022

The amendment to IAS 16 Property, Plant and Equipment (PP&E) prohibits an entity from deducting from the cost of an item of PP&E any proceeds received from selling items produced while the entity is preparing the asset for its intended use. It also clarifies that an entity is 'testing whether the asset functioning properly' when it assesses the technical and physical performance of the asset. The financial performance of the asset is not relevant to this assessment.

Entities must disclose separately the amounts of proceeds and costs relating to items produced that are not an output of the entity's ordinary activities.

2.5 Onerous Contracts - Cost of Fulfilling a Contract Amendments to IAS 37, with an effective date is on January 2022

The amendment to IAS 37 clarifies that the direct costs of fulfilling a contract include both the incremental costs of fulfilling the contract and an allocation of other costs directly related to fulfilling contracts. Before recognizing a separate provision for an onerous contract, the entity recognizes any impairment loss that has occurred on assets used in fulfilling the contract.

2.6 Annual Improvements to IFRS Standards 2018 - 2020, with an effective date is on January 2022

IFRS 9 Financial Instruments - clarifies which fees should be included in the 10% test for derecognition of financial liabilities.

IFRS 16 Leases - amendment of illustrative example 13 to remove the illustration of payments from the lessor relating to leasehold improvements, to remove any confusion about the treatment of lease incentives.

2.7 Sale or contribution of assets between an investor and its associate or joint venture - Amendments to IFRS 10 and IAS 28

The IASB has made limited scope amendments to IFRS 10 Consolidated financial statements and IAS 28 Investments in associates and joint ventures.

The amendments clarify the accounting treatment for sales or contribution of assets between an investor and its associates or joint ventures. They confirm that the accounting treatment depends on whether the non-monetary assets sold or contributed to an associate or joint venture constitute a "business" (as defined in IFRS 3 Business Combinations).

Where the non-monetary assets constitute a business, the investor will recognize the full gain or loss on the sale or contribution of assets. If the assets do not meet the definition of a business, the gain or loss is recognized by the investor only to the extent of the other investor's interests in the associate or joint venture. The amendments apply prospectively.

In December 2015 the IASB decided to defer the application date of this amendment until such time as the IASB has finalized its research project on the equity method.

Note 3 - Summary of significant accounting policies:

This note provides a list of the significant accounting policies adopted in the preparation of these consolidated financial statements. Our consolidated financial statements consist of Electricidad Firme de México Holdings, S. A. de C. V. and its subsidiaries.

3.1 Principles of consolidation and equity accounting

The consolidated financial statements include all the assets, liabilities, revenues, expenses and cash flows of the Company.

These consolidated financial statements include the accounts of the Company and all other entities in which we have a controlling financial interest and equity-method investments where we have significant influence. All material intercompany transactions and balances between consolidated entities have been eliminated. The net effect of the settlement of these intercompany transactions is reflected in net parent investment in the consolidated statements of financial position and in net distributions to parent in the financing activities section of the consolidated statements of cash flows.

Subsidiaries.

Subsidiaries are all entities over which the Company has control, those entities are fully consolidated. The Company controls an entity when the Company is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power to direct the activities of the entity.

Intercompany transactions, balances and unrealized gains on transactions between Group companies are eliminated. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the transferred asset. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by us.

Joint arrangements

Under IFRS 11, *Joint Arrangements,* investments in joint arrangements are classified as either joint operations or joint ventures. The classification depends on the contractual rights and obligations of each investor, rather than the legal structure of the joint arrangement. With regards to joint agreements, the Company only has joint ventures.

Joint ventures

Interests in joint ventures are accounted for using the equity method (see below), after initially being recognized at cost in the consolidated statements of financial position.

We do not consolidate Energía Sierra Juárez, Energía Azteca VIII and Compresión Bajío because we have determined that control is shared between unrelated parties and that no one party has the power to direct the activities that most significantly impact the entities economic performance. The partners must agree on all major decisions for each of the partnerships; as a result, we are not the primary beneficiary of them.

For total assets and liabilities of them refer to Note 13, *Investments accounted for using the equity method*.

The carrying amount of equity-accounted investments is tested for impairment in accordance with the policy adopted by us.

Equity method

Under the equity method of accounting, the investments are initially recognized at cost and adjusted thereafter to recognize the Company's share of the post-acquisition profits or losses of the investee in profit or loss, and the Company's share of movements in Other Comprehensive Income (OCI) of the investee in OCI. Dividends received or receivable from joint ventures are recognized as a reduction in the carrying amount of the investment.

When the Company's share of losses in an equity-accounted investment equals or exceeds its interest in the entity, including any other unsecured long-term receivables, the Company does not recognize further losses, unless it has incurred obligations or made payments on behalf of the other entity.

Unrealized gains on transactions between the Company and its joint ventures are eliminated to the extent of the Group's interest in these entities. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Accounting policies of equity accounted investees have been changed where necessary to ensure consistency with the policies adopted by us.

3.2 Segment reporting

Reportable-operating segments are reported in a manner consistent with the internal reporting provided to the Board. Chief Executive Officer (CEO), Chief Financial Officer (CFO) and the Finance Planning and Analysis Manager (FP&A) assesses the financial performance and position of the Group and makes strategic decisions.

3.3 Rounding of amounts

All amounts disclosed in the consolidated financial statements and notes have been rounded off to the nearest thousand currency units unless otherwise stated.

3.4 Financial instruments

The carrying amounts of cash and cash equivalents, restricted cash, receivables, accounts payable and accrued liabilities approximate fair value because of the short-term maturity of these instruments.

Classification

We classify the financial assets at amortized cost, when both of the following criteria are met:

- The asset is held within a business model whose objective is to collect the contractual cash flows, and
- The contractual terms give rise to cash flows that are solely payments of principal and interest.

We reclassify debt and investments when and only when its business model for managing those assets and liabilities changes.

Recognition and derecognition

Regular way purchases and sales of financial assets are recognized on trade-date, the date on which the Group commits to purchase or sell the asset. Financial assets are derecognized when the rights to receive cash flows from the financial assets have expired or have been transferred and we have transferred substantially all the risks and rewards of ownership.

Measurement

At initial recognition, we measure a financial asset at its fair value, plus transaction costs that are directly attributable to the acquisition of the financial asset.

Debt instruments

Subsequent measurement of debt instruments is represented under amortized cost methodology. These debt instruments are financial assets that are held for collection of contractual cash flows where those cash flows represent solely payments of principal and interest and are measured at amortized cost. Interest income from these financial assets is included in financing income using the effective interest rate method.

Impairment

We assess on a forward-looking basis the expected credit loss associated with debt instruments carried at amortized cost. The impairment methodology applied depends on whether there has been a significant increase in credit risk.

For accounts receivables, the Group applies the simplified approach permitted by IFRS 9, *Financial Instruments,* which requires expected lifetime losses to be recognized from initial recognition of the receivables. See Note 3.11, *Accounts receivable* and Note 9, *Accounts receivable.*

3.5 Fair value measurements

Financial instruments recorded at fair value are classified by the valuation method used for each instrument, as follows:

Level 1 - Quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 - Information (inputs) other than budget prices included in level 1 that can be confirmed for the asset or liability, either directly (i.e., specific prices) or indirectly (i.e., derived from specific prices).

Level 3 - Information (inputs) on the asset or liability not based on data that can be confirmed in active markets (i.e., financial models and unobservable information).

Level 2 - Interest rate swap of our Joint Venture of Energía Sierra Juárez.

The fair value measurements would incorporate various factors such as the credit standing of the counterparties involved, the nonperformance risk on the liabilities, the applicable exit market and specific risks inherent in the instrument. Credit standing and related credit discounting incorporates, as applicable and available, counterparty ratings from nationally recognized ratings agencies and credit default swap implied default probabilities as of the fair value measurement date.

Level 3 - Fair value measurement provisions in goodwill.

The starting point of the process for determining the non-recurring Level 3 fair value measurements used to recognize the impairments for goodwill are the cash flow projections based on each Cash Generating Units (CGU) business plan, including revenue and generation forecast and projected capital and maintenance expenditures. For periods not covered by contractual arrangements or that other market data is not available, these projections are dependent on the Company's views of revenue and generation forecasts, gas and carbon pricing, and projected capital and maintenance expenditures.

A financial asset or liability's classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

3.6 Foreign currency translation

Functional and presentation currency

Items included in the financial statements of each of the Company's subsidiaries are measured using the currency of the primary economic environment in which the entity operates ('the functional currency'). The consolidated financial statements are presented in US dollars, which is the Company's functional and presentation currency.

Transactions and balances

Foreign currency transactions are translated into the functional currency. We recognize in the consolidated statements of income and comprehensive income, foreign exchange gains and losses resulting from:

a) Settlement of the transactions using the exchange rates at the dates of the transactions.

b) Translation of monetary assets and liabilities denominated in foreign currencies using the exchange rate at year end.

Foreign exchange gains and losses related to borrowings are presented in the consolidated statements of income and comprehensive income, within financing costs. All other foreign exchange gains and losses (such as: accounts receivables and payables) are presented in the consolidated statements of income and comprehensive income on a net basis within Cost of sales and services.

3.7 Revenue recognition

Revenues from the Company recognized in the statements of income and comprehensive income from: i) electricity sales, ii) other ancillary services and iii) power capacity and compression services. Due to the characteristics of the power capacity and compression services, they are represented under IFRS 16, *Leases,* as operating leases.

Identification of separate performance obligations

We evaluate separate performance obligations within a contract when it identifies a promise to transfer a good or service to the costumer that is distinct or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to the costumer. The Transaction price is allocated to each performance obligation based on the stand-alone selling prices. Where these are not directly observable, they are estimated based on expected cost-plus margin.

Contract assets or liabilities

We obtain rights to receive consideration from the customer and assume obligations to transfer goods or services to the customer (performance obligations) in certain contracts with a customer. The combination of those rights and performance obligations gives rise to an asset or a liability depending on the relationship between the remaining rights and the performance obligations. If the goods transferred or services rendered by us exceed the payment, a contract asset is recognized. If the payments exceed the goods transferred or services rendered, a contract liability is recognized.

Customers are invoiced on a monthly basis and consideration is payable when invoiced. Unbilled sales or services are based and adjusted to the amount billed, therefore there are no significant changes to revenue amounts recognized. As of December 31, 2020 and 2019, there are no contract liabilities.

Billing requirements to our customers generally result in a monthly basis billing in the following month of the good or service delivered. Once billed, payment is generally required within a month. Based on the terms of our agreements, payment is generally received at or shortly after delivery of the good or service. During the year ended December 31, 2020 and 2019, there were no material credit or impairment losses recognized relating to accounts receivable balances associated with contracts with customers.

Financing components

The Group does not expect to have any contracts where the period between the transfer of the promised goods or services to the customer and payment by the customer exceeds one year. As a consequence, the Group does not adjust any of the transaction prices for the time value of money.

Revenue from electricity

We recognize revenues from sales of electricity and gas since the incorporation date in accordance with IFRS 15, *Revenue from contracts with customers*. The analysis on revenue recognition shows that we record revenues from the sale of electricity and gas under long-term contracts based upon the output delivered provided at rates specified under the contract, unless the contract pricing terms are fixed, in this sense, revenue is recognized over time, when the client simultaneously receives and consumes the electricity and gas.

We applied the right to invoice practical expedient, when the right to consideration directly corresponds to the costumer value of our performance completed to date.

Revenues from the physical sale of electricity under short-term contracts or via the Mexican Wholesale Market (MEM) are at contractual or market rates based on the volumes delivered.

Sales are recognized when control of the products has transferred, being when the products are delivered to the client, the client has full discretion over the product and price to sell the products, and there is no unfulfilled obligation that could affect the client's acceptance of the products. Delivery occurs when the products have been delivered, and either the wholesaler has accepted the products in accordance with the sales contract, the acceptance provisions have lapsed, or the Group has objective evidence that all criteria for acceptance have been satisfied.

Revenue from these sales is recognized based on the price specified in the contract. A receivable is recognized when the products are delivered as this is the point in time that the consideration is unconditional because only the passage of time is required before the payment is due.

Other ancillary services

In addition to our generation activities, we manage as well as perform the operations and maintenance services under service contracts for certain subsidiaries in which we have an interest. Revenues from consolidated subsidiaries are eliminated in consolidation.

Revenue from providing services is recognized in the accounting period in which the services are rendered. For fixed-price contracts, revenue is recognized based on the actual service provided to the end of the reporting period as a proportion of the total services to be provided because the customer receives and uses the benefits simultaneously.

Power capacity and compression services

We analyzed power sales and compression services contracts and amendments to existing contracts in accordance with IFRS 16, *Leases*. Currently, the power sales contracts and compression services contracts in place at the Energía Azteca X, Energía San Luis de la Paz, Energía Campeche, Energía

Chihuahua and Energía Azteca VIII and Energía Sierra Juarez (equity method investee) power companies, as well as the Green Energy Libramiento and Compresión Altamira, meet the criteria for lease treatment. Accordingly, these power sales and compression services contracts are accounted for as operating leases. The non-contingent lease rental revenues reported under these contracts for the consolidated subsidiaries are included in lease rentals derived from power purchase and compression services agreements in the consolidated statements of income and comprehensive income.

Lease income from operating leases where the Group is a lessor is recognized in income on a straight-line basis over the lease term, See Note 3.8 *Deferred rent*. Initial direct costs incurred in obtaining an operating lease are added to the carrying amount of the underlying asset and recognized as expense over the lease term on the same basis as lease income. The respective leased assets are included in the consolidated statements of financial position based on their nature. We did not need to make any adjustments to the accounting for assets held as lessor as a result of adopting the new leasing standard.

Financing income

Financing income from a financial asset is recognized when economic benefits will likely flow to the company and the amount of revenue can be measured reliably. The interest income is booked on a timely manner, in reference to the outstanding principal and the rate of applicable effective interest. Financing income is shown after the operating profit in the consolidated statements of income and comprehensive income.

3.8 Deferred rent

Revenues from leases are recognized on a straight-line basis (levelized) in the consolidated statements of income and comprehensive income, the difference between the lease payment and the income levelized are recognized in our consolidated statements of financial position as a Deferred rent.

In a business combination, we do not recognize the acquirer's deferred rent using the acquisition method because it does not meet the definition of an asset or liability. We recognize the liability related to deferred rent starting from the acquisition date. See Note 16, *Deferred rent*.

3.9 Insurance recoveries

We enter into insurance policies with various carriers to provide for reimbursement of incurred costs during unplanned outages as well as recovery of lost revenues. We consider "incurred costs" to be repair and maintenance costs and replacement power costs incurred in order to deliver power under a contracted position. Business interruption recoveries for lost revenues are those recoveries that relate to un-hedged positions or capacity revenues under a long-term power sales agreement.

When the insurance recovery relates to reimbursement of an incurred cost, the amount is recorded as a receivable from the insurance provider when collection is deemed probable by Management. The amount is recorded as an offset to the line item in the consolidated statements of income and comprehensive income where the incurred cost is recorded, or where the lost capacity revenue under the long-term power sales agreement would have been recorded.

For recovery of business interruption that is not directly calculable, it is our policy to recognize these recoveries only when the amount has been collected or when payment has been explicitly confirmed by the insurance provider(s), and therefore is assured of collection. The Company recognized nil of income for the proceeds received for business interruption in lease rentals - power purchase and compression services agreements in the consolidated statements of income and comprehensive income for the year ended as of December 31, 2020 and 2019.

For the year ended at December 31, 2020 and 2019, we collect insurance recoveries by $nil and $671 respectively; and were recorded as other services contracts in the consolidated statements of income and comprehensive income.

3.10 Cash and cash equivalents

We consider all highly liquid investments that are readily convertible to cash and have an original maturity when purchased of three months or less to be cash equivalents. Cash and cash equivalents held by certain consolidated subsidiaries are not restricted to specific uses within them; however, the terms of Green Energy Libramiento limit our ability to distribute those funds and use them for corporate purposes. See Note 8, *Cash and cash equivalents*, for further information on these balances.

3.11 Accounts receivable

Accounts receivable represent amounts due from customers and contracts assets and are generated by sales of goods or services provided in the normal course of the Company's operations. When collection is expected in a period of one year or less from the closing date (or in the normal operating cycle of the business if this cycle exceeds this period), they are presented as current assets. If this is not met, they are presented as non-current assets.

Other accounts receivable represent amounts arising from the Value Added Tax (VAT) in the normal course of Company's operations, which are expected to be collected over a period of one year or less from the closing date (or in the normal cycle of business operations in the event that this cycle exceeds this period), are presented as current asset. If the above is not met, they are presented as non-current assets.

Accounts receivable are recognized at fair value, less the allowance for un-collectability, when applicable. See Note 9, *Accounts receivable*.

3.12 Inventories

Inventories represents amounts of Liquid Fuel (Diesel) in certain power plants, to dispatch at the full capacity, 10 days of energy production approximately and Emission allowances inventory.

At December 31, 2020 and 2019 inventories are expressed at their cost, determined through averaging. Values determined like this do not exceed their net realization value. The inventory is classified as current assets or non-current assets if it is expected to deliver said inventory within a period greater than one year from the date of consolidated statements of financial position. Cash inflows and outflows are classified as an operating activity in the consolidated statements of cash flows.

In each accounting period inventories are subject to impairment tests with the purpose of identifying obsolescence, damaged items or low market value. In the event that the amount of future economic benefits from inventory, i.e., its estimated net realization value, is lower than its net carrying amount, an impairment loss is recognized which is recorded in the cost of sales of the period presented. See Note 11, *Inventories*.

3.13 Prepayments

Prepayments represent such expenditures made by the Company where the risks and benefits inherent to the goods to be acquired or services to be received have not been transferred. Prepayments are recorded at their cost and presented in the consolidated statements of financial position as current or non-current assets, depending on the destination item. Prepayment of goods and/or services related to property, plant and equipment are included in this line. Advance payments in foreign currency are recognized at the exchange rate of the date of the transaction, without modification by subsequent exchange rate fluctuations between currencies.

Once goods and/or services related to prepayments are received, they should be recognized as an expense or an asset in the accounting period, according to their respective nature.

3.14 Property, plant and equipment, net

Property, plant and equipment, which consists mainly of land, power and compression plants, capital spares and other equipment, is stated at historical cost less depreciation. Significant additions or improvements that increase cash flows or extend asset lives are capitalized while expenditures for maintenance and repairs to maintain facilities in operating condition are expensed as the work is incurred.

The cost of our property, plant and equipment is depreciated over the estimated useful life of the asset using the straight-line method less a residual value as follows:

	Useful life (years)
Power plants	15 - 40
Compression plants	20 - 40
Office equipment and other	3 - 10

Power plants and compression plants are integrated by different components that have different useful lives. The main individual components are depreciated over their individual useful life. Depreciation related to power plants and compression plants is recorded as a component of cost of sales and services in the consolidated statements of income and comprehensive income. Depreciation related to office equipment and other non-operating assets is recorded as a component of general and administrative expenses.

We evaluate the recoverability of our long-lived assets if events or changes in circumstances indicate the carrying value of these assets may not be fully recoverable. Such circumstances may include a significant decrease in the market price of a long-lived asset, a significant long-term adverse change in the manner the asset is being used or in its physical condition or a history of operating cash flow losses associated with the use of the asset. Under this guidance, impairment has occurred if an estimate of undiscounted future cash flows attributable to the long-lived assets is less than the carrying value of the assets. If impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the fair value of the assets and

recording a loss only if the fair value is less than the carrying value. See Note 12, *Property, plant and equipment, net*.

Componentization requires each part of the property, plant and equipment with a cost that is significant in relation to the total cost of the items to be depreciated separately. The Company allocates the amount initially recognized in respect of an item of property, plant and equipment to its significant parts and depreciates separately each such part.

3.15 Unfavorable terms of contract

Unfavorable terms of the contract (UTC) represent a property, plant and equipment decrease, that were recognized, as part of the business combination, for operating lease arrangements, whose terms are unfavorable compared to current market terms, which is depreciated to the end of the contract using the straight-line method. See Note 12, *Property, plant and equipment, net*.

3.16 Leases as a lessee

We recognized lease liabilities measured at the present value of the remaining lease payments, discounted using the lessee's incremental borrowing rate. The weighted average lessee's incremental borrowing rate applied to the lease liabilities was 3%. The associated right-of-use assets were measured at the amount equal to the lease liability.

The Company leases different right-to-use assets. Rental contracts are typically made for fixed periods but may have extension options. Contracts may contain both lease and non-lease components. The Company allocates the consideration in the contract to the lease and non-lease components based on their relative stand-alone prices. The right-of-use asset is depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis.

Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions.

The right-of-use asset from the lease are recognized as property, plant and equipment and a corresponding liability at the date at which the leased asset is available for use by the Company. Each lease payment is allocated between the liability and financing cost. The financing cost is charged to consolidated statements of income over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period.

Assets and liabilities arising from a lease are initially measured on a present value basis. Lease liabilities include the net present value of the following lease payments:

- Fixed payments (including in-substance fixed payments), less any lease incentives receivable.
- Variable lease payments that are based on an index or a rate.
- Lease payments to be made under certain potential extension options are also included in the measurement of the liability.

The lease payments are discounted using the incremental borrowing rate, being the rate that the individual lessee would have to pay to borrow the funds necessary to obtain an asset of similar value to the right-of-use assets in a similar economic environment with similar terms, security and conditions.

To determine the incremental borrowing rate, the Company where possible, uses recent third-party financing received by the individual lessee as a starting point, adjusted to reflect changes in financing conditions since third party financing was received.

The Company is exposed to potential future increases in variable lease payments based on an index or rate, which are not included in the lease liability until they take effect. When adjustments to lease payments based on an index or rate take effect, the lease liability is reassessed and adjusted against the right-of-use assets.

Right-of-use assets are measured at cost comprising the following:

The amount of the initial measurement of the lease liability.

Any lease payments made at or before the commencement date less any lease incentives received.

3.17 Goodwill

The Company applies the following accounting guidelines to business acquisitions: i) purchase method is used only as a valuation rule, which requires the purchase price to be assigned to acquired assets and assumed liabilities based on their fair values at acquisition date; ii) acquired intangible assets are identified, valued and recognized, and iii) the non-assigned portion of the purchase price represents goodwill.

Goodwill is not amortized but it is tested for impairment annually, or more frequently if events or changes in circumstances indicate that it might be impaired and is carried at cost less accumulated impairment losses. Gains and losses on the disposal of an entity include the carrying amount of goodwill relating to the entity sold, See Note 14, *Goodwill and intangibles assets, net*.

3.18 Intangible assets, net

Customer-related intangible assets include, but are not limited to customer contracts and related customer relationships, acquired in a business combination, those customer relationships meet the definition of an intangible asset when legal rights are identified to protect customer relationships since it provides evidence that the entity is nonetheless able to control the expected future economic benefits flowing from the customer relationship, and are recognized at fair value at the acquisition date.

All intangible assets with finite useful lives are amortized over their useful lives (10 to 18 years). Intangible assets include the value of acquired power sales contracts. The value assigned to these contracts is being amortized on a straight-line basis over the term of the contracts. See Note 14, *Goodwill and intangibles assets, net*.

3.19 Impairment of assets

Goodwill and intangible assets that have an indefinite useful life are not subject to amortization and are tested annually for impairment, or more frequently if events or changes in circumstances indicate that they might be impaired. Other assets are tested for impairment whenever events or changes in 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. The recoverable amount is the higher of an asset's fair value less costs of disposal and value in use.

Non-financial assets other than goodwill that suffered an impairment are reviewed for possible reversal of the impairment at the end of each reporting period.

3.20 Income taxes

The income tax expense or benefit for the period is the tax payable on the current period's taxable income based on the applicable income tax rate for each jurisdiction adjusted by changes in deferred tax assets and liabilities attributable to temporary differences and to unused tax losses.

The current income tax charge is calculated on the basis of the tax laws enacted or substantively enacted at the end of the reporting period in the countries where the Company and its subsidiaries and associates operate and generate taxable income. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. It establishes provisions where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred income tax is provided in full, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements. However, deferred tax liabilities are not recognized if they arise from the initial recognition of goodwill. Deferred income tax is also 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 income or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the end of the reporting period and are expected to apply when the related deferred income tax asset is realized, or the deferred income tax liability is settled.

Deferred tax assets are recognized only if it is probable that future taxable amounts will be available to utilize those temporary differences and losses.

Deferred tax liabilities and assets are not recognized for temporary differences between the carrying amount and tax bases of investments in foreign operations where the company is able to control the timing of the reversal of the temporary differences and it is probable that the differences will not reverse in the foreseeable future.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the entity has a legally enforceable right to offset and intends either to settle on a net basis, or to realize the asset and settle the liability simultaneously.
Current and deferred tax is recognized in the consolidated statements of income and comprehensive income, except to the extent that it relates to items recognized in OCI or directly in equity. In this case, the tax is also recognized in OCI or directly in equity, respectively.

On adoption of IFRIC 23, there were no impacts identified about tax provisions considered in tax calculations or tax events related to its transactions.

3.21 Uncertain tax position

Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation and considers whether it is probable that a taxation authority will accept an uncertain tax treatment. We measures its tax balances either based on the most likely amount or the expected value, depending on which method provides a better prediction of the resolution of the uncertainty.

3.22 Accounts payable and accrued expenses

This item includes obligations with suppliers and other payables for purchases of goods or services acquired in the normal course of Company's operations as well as the VAT and other taxes different than the income tax. When payment is expected in a period of one year or less from the closing date, they are presented as current liabilities.

3.23 Derecognition of financial liabilities

We derecognize a financial liability only when it is extinguished either when the Group:

- Discharges the liability by paying the creditor.
- Is legally released from primary responsibility for the liability.

When the Group makes an exchange with an existing lender of debt instruments with substantially different terms, the Group extinguishes the original financial liability and recognizes a new financial liability.

The terms are substantially different if the discounted present value of the cash flows under the new terms, including any deferred financing cost not amortized, is at least 10 per cent different from the discounted present value of the remaining cash flows of the original financial liability.

When the condition above is not met, the Group applies a qualitative assessment of the terms, based on the specific facts and circumstances in each case, for the derecognition of the financial liability. Additionally, a substantial modification of the terms of an existing financial liability or a part of it is accounted for as an extinguishment of the original financial liability and the recognition of a new financial liability.

The difference between the carrying amount of an extinguished or transferred financial liability (or part of a financial liability) and the consideration paid, including any non-cash assets transferred or liabilities assumed, is recognized in the consolidated statements of income and comprehensive income.

3.24 Debts

Debts are initially recognized at fair value, net of transaction costs incurred. Debts are subsequently measured at amortized cost. Any difference between the proceeds (net of transaction costs) and the redemption amount is recognized in profit or loss over the period of the Debts using the effective interest method.

Debts are removed from the balance sheet when the obligation specified in the contract is discharged, cancelled or expired.

Debts are classified as current liabilities unless the Group has an unconditional right to defer settlement of the liability for at least 12 months after the reporting period.

3.25 Deferred financing cost

Incremental costs incurred that are directly attributable to the acquisition, issue or disposal of a financial asset or financial liability. These costs include fees and commissions paid to third parties

but exclude debt premiums or discounts, financing costs or internal administrative or holding costs. Deferred financing costs are those that would not have been incurred if the Group had not acquired, issued or disposed of the financial instrument.

When there is an exchange of debt instruments or modification of terms accounted for as an extinguishment, any costs or fees incurred are recognized as part of the gain or loss on the extinguishment. If the exchange or modification is accounted for as modification, costs or fees incurred, should adjust the carrying amount of the liability and are amortized over the remaining term of the modified liability.

Our debt issuance costs related to a recognized debt liability are presented as a direct deduction from the carrying amount of the related debt liability, which is consistent with the presentation of debt discounts. See Note 15, *Debt*.

Deferred financing cost is amortized using the effective interest rate of the associated financial liability. The amortization is presented as part of the financial cost in the consolidated statements of income and comprehensive income.

3.26 Other long-term liabilities

Energía San Luis de la Paz has liabilities related to plant equipment previously acquired that will be paid in accordance with the schedule of the Long-Term Service Agreement (LTSA). Deferred income in Green Energy Libramiento, will be incurred with future maintenance and are shown within accounts payable and other long-term liabilities in the consolidated statements of financial position. See Note 17, *Other long-term liabilities*.

3.27 Pension and other post-retirement obligations

Certain wholly owned subsidiaries of the Company maintain tax-qualified, non-contributory pension plans that cover all union employees, as well as a postretirement medical plan for eligible retirees. In addition, these subsidiaries also provide for legally required termination indemnity and seniority

premiums. In applying these accounting policies, the Company has made estimates related to actuarial assumptions, including discount rates, health care cost trends and future compensation. See Note 18, *Pension and post-retirement obligation*.

Defined benefits

A benefit plan is considered to be an amount receivable by employees at retirement, usually depending on one or more factors such as age, years of service and compensation.

The liability recognized in the statements of financial position in relation to defined benefit plans is the present value of defined benefit obligations at the date of the statements of financial position, less the fair value of plan assets. Defined Benefit Obligations (DBO) are calculated annually by independent actuaries using the projected unit-cost method.

The present value of DBO is determined by discounting estimated future cash flows at the discount rates established in IAS 19, expressed in the currency in which the benefits are to be paid and with maturities approximating the terms of pension liabilities.

Actuarial gains and losses arising from adjustments and changes to actuarial assumptions are recorded directly in stockholders' equity under OCI in the year in which they accrue.

The Company determines its net financial expense (income) applying the discount rate to the net liability (asset) for defined benefits, net. Past service costs are recognized immediately in the consolidated statements of income.

Retirement benefits

Retirement benefits are paid when the employee reaches certain age and seniority conditions for the payments of these benefits.

The Company recognizes retirement benefits as a constructive obligation that will be paid to all employees once retirement ages have been reached.

Employees' Statutory Profit Sharing (ESPS) payable

The Company recognizes a liability and an expense for bonuses and ESPS, the latter based on a calculation that considers the current Tax Law. The Group recognizes a provision when it is contractually bound or when there is a past practice that gives rise to a constructive obligation.

Short-term benefits

The Company provides short-term employee benefits, which can include wages, salaries, annual bonuses and bonuses payable over the following 12 months. The Group recognizes a provision without discount, when is it contractually obligated or when the former practice has created an obligation.

3.28 Contributed equity

Ordinary shares class I and II are classified as equity.

3.29 Dividends

Provision is made for the amount of any dividend declared, being appropriately authorized and no longer at the discretion of the entity, on or before the end of the reporting period but not distributed at the end of the reporting period.

Note 4 - Critical accounting estimates and judgments:

Estimates and judgments used in preparing the consolidated financial statements are constantly evaluated and are based on historical experience and other factors, including projections of future events considered to be reasonable in current circumstances.

4.1 Accounting estimations and critical assumptions

The Company prepares estimations and projections of future events to recognize certain items of its consolidated financial statements. The resulting accounting estimates recognized are likely to differ from actual results or events. The estimations and projections with a higher risk of material adjustment in the future are as follows:

Estimated goodwill impairment

The Company tests whether goodwill has suffered any impairment on an annual basis or more frequently if events or changes in circumstances indicate that it might be impaired. For the impairment tests, the recoverable amount of the CGU is determined based on calculations that require the use of assumptions. The calculations use cash flow projections based on financial budgets.

4.2 Critical accounting judgments in applying the Company's accounting policies

Basis for consolidation and classification of joint arrangements

Evaluation of the existence of control in subsidiaries, joint control or significant influence over investments in joint ventures are explained in Note 3.1, *Principles of consolidation and equity accounting*.

Deferred income tax assets

The recognition of deferred tax assets is based upon whether it is more likely than not that there will be sufficient and suitable taxable profits against which to utilize the assets in the future. Judgment is required when determining probable future taxable profits, which are estimated using the budget of taxable income and deductible expenses that will result in taxable profits for future years. Prior to recording deferred tax assets for tax losses, relevant tax law is considered to determine the availability of the losses to offset against the future taxable profits.

Note 5 - Financial risk Management:

5.1 Financial risks

The Company's risk Management is predominantly controlled by the finance department under policies approved by the Board of Directors. Company Finance and Treasury identifies, evaluates and hedges financial risks in close co-operation with the Company's operating units. The Board provides written principles for overall risk Management, as Management defines policies covering specific areas, such as foreign exchange risk, interest rate risk, credit risk, use of derivative financial instruments and non-derivative financial instruments, and investment of excess liquidity.

Where all relevant criteria are met, hedge accounting would be applied to remove the accounting mismatch between the hedging instrument and the hedged item. This will effectively result in recognizing interest expense at a fixed interest rate for the hedged floating rate loans and inventory at the fixed foreign currency rate for the hedged purchases.

Credit risk

Financial instruments which potentially expose us to concentrations of credit risk consist primarily of cash, cash equivalents, restricted cash, accounts receivable and contract assets. We maintain a significant portion of our corporate cash and cash equivalent balances with several financial institutions thereby spreading the credit risk. Most of our accounts receivable are concentrated with entities engaged in the energy industry.

These industry concentrations may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, political, industry or other conditions. Receivables are generally collateralized, however the credit risk posed by industry concentration is offset by the diversification and creditworthiness of our customer base.

We are also exposed to credit risk as revenues are derived from a limited number of customers, in some cases, under long-term agreements. The prolonged failure of any of these customers to fulfill contractual obligations or make required payments could have a substantial negative impact on our consolidated results of operations and financial condition. However, Management considers that the risk derived from the above is minimal based on accounts receivables track record and since its major customers pay on a monthly basis.

The Group is responsible for managing and analyzing each of its new customer's credit risk prior to determining exposure and additional requirements. If clients are rated independently these ratings are used; otherwise we assess the quality credit of the customer based on their financial situation, past experience and other factors.

The allowance for doubtful accounts represents an estimate of the losses arising from customer inability to make required payments. Estimations are required in order to determine the allowance for doubtful accounts. The Group conducts evaluations of its customers and adjust: a) the credit limits based on payment history and b) current customer solvency information, aging of the accounts receivable portfolio, historic collection experience and legal situation.

Cash and cash equivalents are subject to limited credit risk because they are kept in financial institutions with high creditworthiness, with which the Group holds short-term investments locally rated: BBVA Bancomer (BBB+ to A-), Citibanamex (BBB+ to A-), Citibank (BBB+ to A), Intercam (A) and Invex (AA- to A+).

Liquidity risk

Cash flow projections are prepared by Management, who continually monitors cash flow projections and liquidity requirements to ensure enough cash levels. Projections consider the Company's financing plans and compliance with minimum financial ratios and legal or regulatory requirements.

The following table shows the Group's liabilities grouped per maturity date as of December 31, 2020 and 2019. The amounts shown in the table are undiscounted contractual cash flows:

2020	Less than 1 years	Between 1 and 5 years	More than 5 years	Total
Accounts payable and accrued expenses	$ 92,683	$	$	$ 92,683
Long-term debt	71,387	352,598	699,335	1,123,320
Interest of long-term debt	77,251	305,024	224,466	606,741
VAT Loan		503		503
Other long-term liabilities	5,822	4,949	15,716	26,487
Subtotal	243,169	663,074	939,517	1,845,760
Related parties	1,965			1,965
Total	$245,134	$663,074	$ 939,517	$1,847,725
2019				
Accounts payable and accrued expenses	$178,170	$	$	$ 178,170
Long-term debt	27,520	173,720	632,100	833,340
Interest of long-term debt	54,977	240,369	250,503	545,849
Other long-term liabilities		4,958	18,596	23,554
Subtotal	260,667	419,047	901,199	1,580,913
Related parties	484			484
Related party long-term debt			162,512	162,512
Interest of related party long-term debt	15,888	70,612	127,100	213,600
Total	$277,039	$489,659	$1,190,811	$1,957,509

5.2 Additional risks. We own, operate, acquire and develop non-regulated electric generation and gas compression facilities that are subject to risks that could adversely affect our results of operations, financial condition and/or cash flows. Risks include, but are not limited to, items such as shown below:

- Operations risks associated with operating the plants, including the breakdown or failure of power generation equipment, transmission lines, or other necessary equipment leading to unplanned outages or other operational issues, operator error, performance below expected output or efficiency levels, labor disputes, force majeure or other catastrophic events;

- Our marketing and trading activities of un-contracted capacity from some of our power companies do not fully remove the exposure to market risks;

- Transmission constraints within a number of our core regions;

- Our reliance on the joint venture partners, where we do not exercise day-to-day control;

- Our ability to obtain adequate insurance coverage for all losses we might incur in the event of loss or damage to a power subsidiary;

Contractual obligations and covenants (power purchase, gas compression and fuel supply agreements):

- Contractual covenants that require, among other things, project availability and generation minimums, maintenance of certain types and levels of insurance, compliance with obligations and scheduled payments and for the respective project entity to be financially viable. Should a project be out of compliance with one or more of its contractual obligations, the counterparty, if allowed under the agreement, may declare an event of default under the contract. If such an event of default were uncured it could, under certain circumstances, lead to the cancellation of the respective agreement.

- Disruption of fuel supply to the power subsidiaries or termination of fuel supply and transportation agreements.

- Campeche's fuel supply agreement. In accordance with the current Mexican energy reform, the fuel supply agreement originally provided by Pemex Gas y Petroquímica Básica (Pemex), was terminated in 2017. In consideration of Energía Campeche's location and its natural gas infrastructure, executing a new fuel supply arrangement at similar terms to the previous contract, or at all, has been difficult. This resulted in the subsidiary being dispatched on diesel, which is not as favorable as being dispatched on natural gas. However, the Company is negotiating fuel agreements with other gas suppliers in order to execute future gas agreements. The Company was in an Arbitration Procedure ruled by the International Chamber of Commerce to claim and defend its position against the notification of the event of default made by the CFE until 2019. This procedure was resolved in March 2020 with an agreement and final settlement.

5.3 Capital Management:

The Company manages its capital to ensure that it will be able to continue as a going concern and comply with applicable regulations. The capital structure of the Company consists of capital stock contributions, related party long-term debt and long-term debt, See Note 15, *Debt*. Additionally, the Company is not subject to any externally imposed requirements for the Management of its capital.

Note 6 - Segment information:

6.1 Description of segments and principal activities.

CEO, CFO and FP&A (denominated as CODM under IFRS 8, *Operating Segments*), examine the Group's performance per type of revenues and has identified four (4) reportable-operating segments of its business. a) Electricity generation, b) Gas compression, c) Joint ventures and d) Corporate.

6.2 Performance of the reportable-operating segments.

The Company CODM primarily uses the operating profit to assess the performance of the reportable operating segments. However, the Management also receives information about the segments revenue and assets on a monthly basis.

6.3 Statements of financial position and statements of income on Management's report.

The statements of financial position at December 31, 2020 and 2019 and the statements of income on Management's report for the year ended as of December 31, 2020 and 2019 of the reportable-operating segments are as shown in the next page.

	2020				
	Electricity generation	Gas compression	Joint ventures	Corporate	Total
Statement of financial position:					
Property, plant and equipment	$ 749,214	$ 73,297	$	$ 1,826	$ 824,337
Investments accounted for using the equity method			136,718		136,718
Investments classified as held for sale			43,511		43,511
Intangible assets	84,081	35,247			119,328
Goodwill	49,571	403	21,563		71,537
Other assets	130,578	27,466		62,615	220,659
Total assets [1]	$ 1,013,444	$ 136,413	$ 201,792	$ 64,441	$ 1,416,090
Debt	($ 504)	$	$	($ 1,103,790)	($ 1,104,294)
Other liabilities	(208,162)	(18,664)		(60,595)	(287,421)
Total liabilities [1]	($ 208,666)	($ 18,664)	$	($ 1,164,385)	($ 1,391,715)

	2020				
	Electricity generation	Gas compression	Joint ventures	Corporate	Total
Statement of income on Management's report:					
Revenues:					
Lease	$ 71,287	$ 45,345	$	$	$ 116,632
Deferred rent	(10,682)				(10,682)
Lease - Net	60,605	45,345			105,950
Electricity	428,613				428,613
Operating and maintenance	62,142				62,142
Other services and others	(612)				(612)
	550,748	45,345			596,093
Cost of sales and services	(408,835)	(6,775)			(415,610)
Gross profit	141,913	38,570			180,483
General and administrative expenses and other	(31,663)	(6,198)		(2,807)	(40,668)
Share of net profit of joint ventures			11,334		11,334
Operating profit	$ 110,250	$ 32,372	$ 11,334	($ 2,807)	$ 151,149

	2019				
	Electricity generation	Gas compression	Joint ventures	Corporate	Total
Statement of financial position:					
Property, plant and equipment	$ 775,639	$ 76,326	$	$ 2,313	$ 854,278
Investments accounted for using the equity method			197,275		197,275
Intangible assets	90,057	39,572			129,629
Goodwill	49,571	403	21,563		71,537
Other assets	152,402	28,502		35,194	216,098
Total assets [1]	$ 1,067,669	$144,803	$ 218,838	$ 37,507	$ 1,468,817
Debt	$	$	$	($ 817,717)	($ 817,717)
Other liabilities	(195,376)	(39,622)		(261,560)	(496,558)
Total liabilities [1]	($ 195,376)	($ 39,622)	$	($1,079,277)	($1,314,275)
Statement of income on Management's report:					
Revenues:					
Lease	$ 86,440	$ 45,611	$	$	$ 132,051
Deferred rent	(16,519)				(16,519)
Lease - Net	69,921	45,611			115,532
Electricity	495,402				495,402
Operating and maintenance	51,245				51,245
Other services and others	15,439				15,439
	632,007	45,611			677,618
Cost of sales and services	(537,868)	(7,188)		(17)	(545,073)
Gross profit	94,139	38,423		(17)	132,545
General and administrative expenses and other	(22,770)	(6,344)		(3,697)	(32,811)
Share of net profit of joint ventures			23,761		23,761
Operating profit	$ 71,369	$ 32,079	$ 23,761	$ (3,714)	$ 123,495

(3) Segment assets, liabilities are measured in the same way as in the financial statements. These assets are allocated based on the operations of the segment.

Note 7 - Financial assets and financial liabilities:

7.1 This note provides information about the Group's financial instruments, including:

- An overview of all financial instruments held by the Group.
- Specific information about each type of financial instrument.
- Accounting policies.
- Information about determining the fair value of the instruments, including judgements and estimation uncertainty involved.

7.2 We hold the following financial instruments as of December 31, 2020 and 2019:

	2020	2019
Accounts receivable	$ 44,936	$ 51,944
Accounts receivable from related parties	4,892	2,298
Notes receivable with related parties	20,637	
Financial assets	$ 70,465	$ 54,242
Accounts payable and accrued expenses	$ 88,709	$ 177,944
Accounts payable to related parties	1,965	484
Current portion of long-term debt	82,887	37,260
Current portion of other long-term liabilities	5,822	
Long-term debt	1,021,407	780,457
Other long-term liabilities	16,528	19,635
Financial liabilities	$ 1,217,318	$ 1,015,780

The Group's exposure to various risks associated with the financial instruments is discussed in Note 5, *Financial risk Management*. The maximum exposure to credit risk at the end of the reporting period is the carrying amount of each class of financial assets mentioned above.

Note 8 - Cash and cash equivalents:

8.1 For purposes of the consolidated statements of cash flows, cash and cash equivalents include cash in banks and investments in money market instruments with maturities of less than 90 days and restricted cash. Cash and cash equivalents are integrated as follows:

	2020	2019
Cash at bank and in hand	$ 39,013	$ 41,144
Deposits at call		1,449
Restricted cash	4,318	3,915
Cash and cash equivalents	$ 43,331	$ 46,508

8.2 Restricted cash - As of December 31, 2020 and 2019, $4,318 and $3,915 of the cash balances are restricted to pay Operating and Maintenance costs of Green Energy Libramiento under its investment agreements.

Restricted cash is invested in highly liquid investments and is presented within the cash and cash equivalents in the consolidated statements of financial position and in the consolidated statements of cash flows.

Note 9 - Accounts receivable:

9.1 At December 31, 2020 and 2019 the components of accounts receivable were as follows:

	2020	2019
Trade	$ 17,444	$ 14,065
Other	27,399	37,879
Accounts receivable	$ 44,843	$ 51,944

9.2 At December 31, 2020 and 2019, there is no impairment of financial assets. Consequently, we have not recognized any allowance for doubtful accounts.

Note 10 - Related party balances and transactions:

10.1 Balances with related parties at December 31, 2020 and 2019 were as follows:

	2020	2019
Accounts receivable from unconsolidated joint ventures:		
Servicios Azteca VIII, S. de R. L. de C. V.	$ 1,021	$ 938
Energía Azteca VIII, S. de R. L. de C. V.	2,627	1,210
Other unconsolidated joint ventures and shareholders'	1,337	150
Accounts receivable from related parties	$ 4,985	$ 2,298
Notes receivable with relates parties long-term		
El Aguila Limited	$ 20,637	$
Accounts payable to unconsolidated joint ventures:		
Operaciones Compresión Bajío, S. de R. L. de C. V.	$ 1,052	$
Other unconsolidated joint Ventures	913	484
Accounts payable to related parties	$ 1,965	$ 484

	2019
Related party long-term debt:	
El Aguila Investments S. A. R. L. - Debt	$ 162,512
Interest	1,765
Debt	164,277
Current portion of long-term debt	(1,765)
Long-term debt	$ 162,512

10.2 Transactions income/(expense) with related parties for year ended as of December 31, 2020 and 2019 were as follows:

	2020	2019
General and administrative expenses:		
Others - (ultimate Holding)	($ 87)	($ 93)
Financing income:		
Interest from Energía Sierra Juárez, S. de R. L. de C. V.		138
Interest from El Aguila Investments S. A. R. L.	3,200	
Interest from others	8	
Financing expenses:		
Interest to El Aguila Investments S. A. R. L.	(11,474)	(21,492)

10.3 Transactions with related parties are described as follows:

Administrative services provided by others, may also incur costs on behalf of the Company and its affiliates, which are then directly billed to each associated entity. These primarily include employee costs, as well as legal and other third-party costs related to the Company's operation.

We have recorded these costs as general and administrative expenses in the consolidated statements of income and comprehensive income, for the year ended as of December 31, 2020 and 2019.

Energía Sierra Juárez (ESJ), Debt-Project Loan: the interest rate on the loan was calculated as LIBOR plus a margin of 6.375%; the interest rate was 8.72% as of December 31, 2019. Interest income by $138 was recorded in the financing cost net line of the consolidated statements of income and comprehensive income. The Loan was fully paid on February 14, 2019. See Note 22, *Analysis of the financing cost, net.*

El Aguila Investment S. A. R. L.: 3 Promissory notes amounting $162,512, at December 31, 2019 bearing interest at market rate. Interest was payable in annual installments on April 20, of each year. Principal and its interest were liquidated on September 29, 2020.

El Aguila Limited: On September 28, and December 18, 2020, El Aguila Limited acquired loans from the Company, for $153,642 Note "A" and $36,000 Note "B" with an 8.00% of interest rate. Interest is capitalized annually and starting on this date is recorded in the finance expense line of the consolidated statements of income

and comprehensive income. See Note 22, Analysis of the financing cost, net. The principal will be paid on September 28, and December 18, 2030, nevertheless the Borrower shall have the right at any time and from time to time to prepay the outstanding principal amount of the loan, in whole or in part and/or its interest.

On December 29, 2020, we declared and distributed in kind dividends to our shareholders for $172,136, See Note 19, Stockholders' Equity, with a portion of the notes receivables to El Aguila Limited for $169,005 and $3,131 of interest. Therefore, at December 31, 2020 we held only $20,637 of Note "B".

10.4 The total amount of employee's benefits granted to key Management staff or directors of the entity, overall, grouped in each of the following categories is shown as follows:

	2020	2019
Wage and salaries	$2,011	$1,610
Short and long-term direct benefits	1,207	348
Other benefits	159	382

There are no loans granted by the Company to its key Management staff.

Note 11 - Inventories:

11.1 At December 31, 2020 and 2019 the inventories were as follows:

	2020	2019
Fuel	$7,456	$ 7,019
Emission allowances	1,867	4,671
Inventories	$9,323	$11,690

11.2 Emission allowances

In the United States at the Federal and California state levels, several legislative initiatives have been introduced to address climate change through the imposition of nationwide and state level regulatory limits on the emissions of greenhouse gases. On October 2011, the California Air Resources Board (ARB) adopted a "cap and trade" regulation. Companies subject to the regulation are required to submit allowances (each the equivalent of one ton of carbon dioxide) to cover their annual emissions.
The regulation is divided into two phases: the first phase, which started in 2013, includes all major industrial sources and electricity utilities (including in-state power generators and importers of electricity from out-of-state) and the second phase, which started in 2015, includes distributors of transportation fuels and natural gases.

Energía de Baja California sold power on a merchant basis in the California market during 2020 and 2019. The plant sold 320 megawatts, which are not covered for allowances under the cap and trade regulation.

Note 12 - Property, plant and equipment, net:

12.1 At December 31, 2020 and 2019 the components of plant were as follows:

	December 31, 2018	Acquisition	Depreciation	December 31, 2019	Acquisition	Depreciation	December 31, 2020
Power plants	$ 947,314	$16,877	$	$964,191	$1,514	$	$965,705
Depreciation	(27,615)		(41,367)	(68,982)		(42,383)	(111,365)
Power plant, net	919,699	16,877	(41,367)	895,209	1,514	(42,383)	854,340
Compression plants	107,408	57		107,465	883		108,348
Depreciation	(4,572)		(6,841)	(11,413)		(6,862)	(18,275)
Compression plant, net	102,836	57	(6,841)	96,052	883	(6,862)	90,073
Power and compression plants, net	$1,022,535	$16,934	($48,208)	$991,261	$2,397	($49,245)	$944,413

12.2 At December 31, 2020 and 2019 the components of property, plant and equipment were as follows:

	December 31, 2018	Acquisition	Depreciation	December 31, 2019	Acquisition	Depreciation	December 31, 2020
Power and compression Plants, net	$ 1,022,535	$ 16,934	($ 48,208)	$ 991,261	$ 2,397	($ 49,245)	$ 944,413
Office equipment and others	3,492			3,492			3,492
Depreciation	(343)		(737)	(1,080)		108	(972)
Office equipment and others, net	3,149		(737)	2,412		108	2,520
Right-of-use assets	1,281	13		1,294	6		1,300
Depreciation	(252)		(392)	(644)		(459)	(1,103)
Right-of-use assets, net	1,029	13	(392)	650	6	(459)	197
Unfavorable term of the contract	(173,060)			(173,060)			(173,060)
Depreciation	11,506		17,249	28,755		17,252	46,007
Unfavorable term of the Contract, net	(161,554)		17,249	(144,305)		17,252	(127,053)
Land	4,260			4,260			4,260
Property, plant and equipment, net	$ 869,419	$ 16,947	($ 32,088)	$ 854,278	$ 2,403	($ 32,344)	$ 824,337

12.3 The table below presents our unfavorable terms of the contract, liabilities amount at December 31, 2020 and 2019, which are reflected in our consolidated statements of financial position:

Contract	End of contract	2020	2019
Energía Campeche	April- 28	$ 31,142	$ 35,388
Energía Chihuahua	Aug-28	15,665	17,687
Energía Azteca X	Jun-28	61,044	69,184
Green Energy Libramiento	Sep-27	19,202	22,046
		$ 127,053	$ 144,305

12.4 At December 31, 2020 and 2019, our property accounted for as operating lease were as follows:

	2020	2019
Plants	$ 741,207	$ 741,207
Depreciation	(104,164)	(65,102)
Plants accounted for as operating lease	637,043	676,105
Land	3,085	3,085
Property accounted for as operating lease	$ 640,128	$ 679,190

12.5 At December 31, 2020 and 2019, the consolidated statements of financial position show the following amounts as a lessor:

	2020	2019
Within property, plant and equipment:		
Right-of-use assets	$ 1,300	$ 1,294
Depreciation	(1,103)	(644)
Total right-of-use assets	$ 197	$ 650
Within the following liabilities:		
Accounts payable and accrued expenses	$ 303	$ 403
Other long-term liabilities		284
Total lease liabilities	$ 303	$ 687

12.6 The consolidated statements of income and comprehensive income shows the following amounts relating to leases at December 31, 2020 and 2019:

	2020	2019
General and administrative expenses:		
Depreciation	$ 459	$ 392
Interest expense:		
Lease interest	15	26
Lease	$ 474	$ 418

Note 13 - Investments accounted for using the equity method:

The interests in joint ventures balances reflected in the consolidated statements of financial position include unrecognized gains (losses) from our share of AOCI- Net of applicable taxes, related to derivative instruments entered into by the joint ventures.

13.1 At December 31, 2020 and 2019 our interests in joint ventures accounted for under the equity method is as follows:

	Energía Sierra Juárez		Bajío		
	Equity Investment	Share of AOCI	Equity Investment	Share of AOCI	Total equity
January 1, 2019	$ 55,377	($ 6,429)	$ 144,009	($ 895)	$ 192,062
Shareholders' transaction:					
Equity distribution	(1,954)				(1,954)
Dividends			(16,849)		(16,849)
Comprehensive income pro rata share accounted for using the equity method:					
Net profit	1,575		22,186		23,761
Interest rate swap amortization		223		32	255
December 31, 2019	54,998	(6,206)	149,346	(863)	197,275
Shareholders' transaction:					
Equity distribution	(7,578)				(7,578)
Dividends			(17,593)		(17,593)
Comprehensive income pro rata share accounted for using the equity method:					
Net profit	5,753		5,581		11,334
Interest rate swap amortization		(3,456)		247	(3,209)
December 31, 2020	$ 53,173	($ 9,662)	$ 137,334	($ 616)	$ 180,229

13.2 The statements of financial position as of December 31, 2020 and 2019 of our equity method investments are summarized below:

	2020		2019	
	Bajío [2][3]	ESJ	Bajío [2][3]	ESJ
Statement of financial position:				
Current assets	$ 83,891	$ 32,579	$ 123,878	$ 17,490
Noncurrent assets	277,575	319,358	283,615	268,482
Total assets	361,466	351,937	407,493	285,972
Current liabilities [3]	36,396	23,544	68,897	15,115
Debt, current and long-term [4]		249,928		206,231
Other noncurrent liabilities	160,460	33,298	180,645	7,156
Total liabilities	196,856	306,770	249,542	228,502
Total equity	$ 164,610	$ 45,167	$ 157,951	$ 57,470
Share of equity	51%	50%	51 %	50 %
Company's pro rata share of equity [1]	$ 83,951	$ 22,583	$ 80,555	$ 28,735

13.3 The results of operations for the year ended as of December 31, 2020 and 2019, of our equity method investments are summarized below:

	2020		2019	
	Bajío	ESJ	Bajío	ESJ
Statement of income:				
Net revenues [3]	$ 281,836	$ 45,564	$ 291,931	$ 47,008
Net income	10,943	11,507	43,501	3,150
Company's pro rata share of net income	5,581	5,753	22,186	1,575

(1) The difference between our Interests in joint ventures balance and our pro rata share of equity is the fair value adjustment recognized as part of the business combination at the acquisition date.

(2) The statements of financial position and income statements for the Bajío Project represents the assets, liabilities, equity, revenue and costs of Energía Azteca VIII and Compresión Bajío.

(3) Within total revenues for the Energía Azteca VIII there is approximately $23,127 and $28,018 of intercompany revenues for the years ended December 31, 2020 and 2019 respectively. There are offsetting costs of revenues included within the operating profit line. These revenues and costs represent transactions between the Energía Azteca VIII and Compresión Bajío and are presented on a gross basis in the above summary. In addition, the associated intercompany accounts receivable and accounts payable as of December 31, 2020 and 2019 of approximately $7,874 and $3,643 are also presented on a gross basis within the current assets and current liabilities lines.

(4) The current portion of long-term debt of ESJ as of December 31, 2020 and 2019 is $11,790 and $11,493 respectively.

(5) On November 22, 2020, we celebrated an Option and Purchase and Sale Agreement with Controladora Sierra Juárez, and IEnova Holdco. On March 9th, 2021 we agreed to sell our investment in IG Sierra Juárez, who directly owns our participation in ESJ.

Note 14 - Goodwill and intangibles assets, net:

14.1 At December 31, 2020 and 2019 the components of customer relationship (customer) and goodwill were as follows:

	December 31 2018	Amortization	December 31, 2019	Amortization	December 31, 2020
Customer	$ 146,798	$	$ 146,798	$	$ 146,798
Amortization	(6,867)	(10,302)	(17,169)	(10,301)	(27,470)
Customer relationship, net	$ 139,931	($ 10,302)	$ 129,629	($10,301)	$ 119,328
Goodwill	$ 71,537	$	$ 71,537	$	$ 71,537

14.2 Estimated amortization expense for our finite-lived intangible assets is expected to approximate $10,301 for each of the next five years and thereafter. We will amortize the remaining balance of Customer relationship outstanding balance over the remaining weighted average life. See Note 3.18. *Intangible assets, net*.

14.3 The Company determined a goodwill, in the acquisition held on 2018.

14.4 We test whether goodwill has suffered any impairment on annual basis determining for each Cash Generating Units (CGU), the recoverable amount using the higher between a) the fair value less costs of disposal and b) the value in use and then, comparing it to the carrying amount of the net assets excluding outflows associated with financing (interest-bearing debt, dividends and interest payable).

14.5 The fair value less costs of disposal require i) calculations of cash flow projections based on financial budgets approved by Management, including revenue and generation forecasts, projected capital and maintenance expenditures; ii) the time value of the money, applying the appropriate discount rate to those future cash flows. At December 31, 2020 and 2019 the discount rate determined was 8.4% and 8.1% respectively and no impairment was identified. The fair value analysis was based on the income approach using significant unobservable inputs (Level 3). The key assumptions used in the fair value less costs of disposal method was:

Discount rate: Reflects the specific risks related to the market rates of the industry in which we operate.

Revenue, operating costs of sales and services and general and administrative expenses: Was determined in accordance with our contractual agreement except for the fuel price which is determined in accordance with the expected market conditions

Note 15 - Debt:

15.1 At December 31, 2020 and 2019 our consolidated long-term debt consisted of the following:

	Final maturity	2020			2019		
		Current	Long-term	Total	Current	Long-term	Total
Senior Secured Notes	Apr-35	$ 32,680	$ 773,140	$ 805,820	$ 27,520	$ 805,820	$ 833,340
GIP Spectrum loan	Nov-30	38,707	278,793	317,500			
VAT Loan			503	503			
Accrued interest		11,500		11,500	9,740		9,740
Deferred financing costs, net			(31,029)	(31,029)		(25,363)	(25,363)
		$ 82,887	$1,021,407	$ 1,104,294	$ 37,260	$ 780,457	$ 817,717

15.2 Senior Secured Notes offered by the Group in U. S. dollars, bearing interest at 6.375%, through April 2035. Principal and interest are payable in semi-annual installments in accordance with the amortization schedule started on October 2018, through April 2035.

15.3 Amortization of deferred financing cost for the years ended as of December 31, 2020 and 2019 was $1,139 and $955 respectively. See Note 22, *Analysis of the financing cost, net*.

15.4 As of December 31st, 2020 and 2019, the market value of the Senior Secured Notes traded at 113.02 and 109.38, respectively. Senior Secured Notes are classified in level 1 on public stock exchanges for which quoted prices are readily available.

15.5 The Senior Secured Notes and the Loan with GIP establish certain positive and negative covenants, which have been duly met by December 31, 2020 and 2019.

The following is a summary of the main covenants of the debt above mentioned:

- Limitations on capital investments.
- Permits.
- Know-Your-Customer's documentation.
- Restrictions on dividend payments.
- Restrictions on incurrence of debt.
- Insurance payments.
- Restrictions on sales, transfers or leases of properties.
- Not make any loans other than permitted ones.
- Not issue any equity interests or any other security convertible into any other equity interests in the borrower's capital to any person other than to the sponsor and the equity holder.
- Not make any restricted payments unless each of the applicable conditions are satisfied.
- Not enter into any agreement that modifies any finance document or creates any Lien

As of December 31, 2020, and 2019, the Group complied with the covenants mentioned above.

15.6 On April 2020, a new revolving credit was agreed, for up to $180,000, bearing interest at Libor plus 1.75%, and it expires on April 2025. The finance cost paid for the credit amount $1,149. At December 31, 2020 there are no pending balances.

15.6 On June 2020, a new loan was agreed between Campeche and InterGen N. V., denominated in Mexican pesos by $766, the loan finance the value added tax (VAT) paid by Campeche to CFE for certain cost and expenses, bears interest at 10.28% and expires on June 2025, however payments will be done with the recoverable VAT received by Campeche.

15.7 On September, 2020, a new loan was agreed between The Company and GIP Spectrum Saavi Luxco, S. A. R. L. (GIP), by$325,000, bearing interest at 7.75%, principal and interest are payable in semi-annual installments in accordance with the amortization schedule started on November 2020, through November 2030. The fair value of the debt is similar to the carrying amount due to the short term between the date on which the loan was contracted, and the year end.

Note 16 - Deferred rent:

At December 31, 2020 and 2019, our Deferred rent liabilities reflected in our consolidated statements of financial position, and the timing of reversal are as follows:

Contract	Liability increase until	End of contract	2020	2019
Energía Campeche	Apr-22	Apr-28	$ 30,941	$ 20,404
Energía Chihuahua	Jan-23	Aug-28	9,568	9,742
Energía Azteca X		Jun-28	(2,083)	(2,402)
Deferred rent			$ 38,426	$ 27,744

Note 17 - Other long-term liabilities:

17.1 At December 31, 2020 and 2019, Other long-term liabilities were as follows:

	2020				2019			
	Current		Non-current		Current		Non-current	
	Principal	Interest	Principal	Interest	Principal	Interest	Principal	Interest
Energía San Luis de la Paz	$ 2	$ 27	$ 10,621	$ 5,907	$ 1,029	$ 27	$ 11,043	$ 6,499
Green Energy Libramiento			3,014	1,123			2,905	1,014
Other					403		284	
Contingent consideration	5,820						1,809	
Total	$ 5,822	$ 27	$ 13,635	$ 7,030	$ 1,432	$ 27	$ 16,041	$ 7,513

17.2 Energía San Luis de la Paz acquired plant equipment that will be paid in accordance with the Equivalent Operating Hours (EOH) of our power plant until 2038 in accordance with our forecast, interest was computed using a 5% discount rate.

17.3 The Maintenance fee of Green Energy Libramiento is deferred until a maintenance occurs, we do not expect to have a maintenance in the following year, therefore it is shown as part of the non-current liabilities. Interest was computed using a 5% discount rate.

17.4 Contingent consideration arise from the business acquisition held on 2018 and depends on the future performance of the cash flow projected on the generation of electricity by Energía Campeche. This consideration may be payable semi-annually on the following 3 years to InterGen N. V., if certain conditions are met.

Note 18 - Pension and post-retirement obligations:

18.1 Certain wholly owned subsidiaries as Saavi Operaciones México and GDD de Personal, maintain tax-qualified, non-contributory pension plans that cover all union employees. Saavi Operaciones México also has a post-retirement medical plan for eligible retirees. In addition, the two entities listed above, maintain the following:

- Termination Indemnity - legally required severance for all employees equivalent to three months of pay.
- Seniority Premium - legally required severance for all employees with fifteen or more years of employment who are dismissed, with or without cause, or who resign. This is equivalent to twelve days of pay for every year of service but cannot exceed two times an individual employee's annual salary.

All plans, as well as the termination indemnity and seniority premium liabilities, are denominated in Mexican pesos. The amounts in the following tables are all presented at the U.S. dollar to Mexican peso spot rate at December 31, 2020 and 2019.

18.2 The components of the Company's total periodic benefit costs for the year ended December 31, 2020 and 2019:

	December 31, 2020				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Service cost	$ 874	$ 51	($ 170)	$ 250	$ 1,005
Interest cost	976	42	170	216	1,404
Total periodic benefit cost	$ 1,850	$ 93	$	$ 466	$ 2,409

	December 31, 2019				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Service cost	$ 516	$ 42	$ 88	$ 66	$ 712
Interest cost	566	50	213	81	910
Expected return on plan assets	(52)				(52)
Net transition obligation amortization			12		12
Net prior service cost amortization	4			1	5
Net loss/(gain) amortization	16	(3)	2	(22)	(7)
Total periodic benefit cost	$ 1,050	$ 89	$ 315	$ 126	$ 1,580

18.3 The projected benefit obligation at December 31, 2020 and 2019 which is reflected in the Pension and other post-retirement obligations line in the consolidated statements of financial position, was as follows:

	December 31, 2020				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Projected benefit obligation at beginning of year	$ 10,288	$ 539	$ 2,348	$ 923	$ 14,098
Amount recognized in AOCI at beginning of year	(283)	(146)	(302)	394	(337)
Accrued benefit cost at beginning of year	10,005	393	2,046	1,317	13,761
Net periodic benefit cost	1,185	173	576	1,231	3,165
Benefits paid		(29)	(17)		(46)
Accrued benefit cost at end of year	11,190	537	2,605	2,548	16,880
Amount recognized in AOCI at end of year	3,488	216	426	1,661	5,791
Projected benefit obligation at end of year	$ 14,678	$ 753	$ 3,031	$ 4,209	$ 22,671

	December 31, 2019				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Projected benefit obligation at beginning of year	$ 9,086	$ 469	$ 2,303	$ 990	$ 12,848
Amount recognized in AOCI at beginning of year	(677)	(109)	(428)	200	(1,014)
Accrued benefit cost at beginning of year	8,409	360	1,875	1,190	11,834
Net periodic benefit cost	1,660	92	315	127	2,194
Benefits paid	(65)	(57)	(146)		(268)
Accrued benefit cost at end of year	10,004	395	2,044	1,317	13,760
Amount recognized in AOCI at end of year	284	146	302	(394)	338
Projected benefit obligation at end of year	$ 10,288	$ 541	$ 2,346	$ 923	$ 14,098

Only the Saavi Operaciones México pension plan has plan assets. These plan assets totaled approximately $614 and $632 at December 31, 2020 and 2019. The remaining plans remain unfunded.

18.4 Amounts related to these plans included in accumulated other comprehensive income as of December 31, 2020 and 2019 were as follows:

	December 31, 2020				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Net prior service cost	($ 665)	$ 80	$ 576	$ 660	$ 651
Other	887	(107)	(768)	(880)	(868)
AOCI	$ 222	($ 27)	($192)	($220)	($217)

	December 31, 2019				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Net transition obligation	$	$	$ 12	$	$ 12
Net prior service cost	4			1	5
Net gain (loss)	16		2	(21)	(3)
Other	399		279	(399)	279
AOCI	$ 419	$	$ 293	($ 419)	$ 293

18.5 The actuarial assumptions were as follows:

Weighted-average assumptions to determine benefit obligation at December 31, 2020 and 2019:

	2020 (%)	2019 (%)
Discount rate	6.75	9.50
Rate of compensation increase	4.50	4.50
Social security increase	3.50	3.50
Long-term inflation	3.50	3.50
Weighted-average assumptions to determine net periodic benefit cost for the years ended December 31, 2020 and 2019:		
Discount rate	6.75	8.75
Rate of compensation increase	4.50	4.50
Social security increase	3.50	3.50
Long-term inflation	3.50	3.50

18.6 The sensitivity of the defined benefit obligation to changes in the weighted principal assumptions in 2020 is:

		Impact on defined benefit obligation			
	Change in assumption	Increase in assumption		Decrease in assumption	
	2020 and 2019 (%)	2020 (%)	2019 (%)	2020 (%)	2019 (%)
Discount rate	0.25	(3.45)	(3.39)	3.65	3.55
Rate of compensation increase	0.25	2.04	2.56	(1.98)	(2.49)

The above sensitivity analysis are based on a change in an assumption while holding all other assumptions constant. In practice, this is unlikely to occur, and changes in some of the assumptions may be correlated. When calculating the sensitivity of the defined benefit obligation to significant actuarial assumptions the same method (present value of the defined benefit obligation calculated with the projected unit credit method at the end of the reporting period) has been applied as when calculating the defined benefit liability recognized in the balance sheet.

18.7 Based on current assumptions, the Company expects to make the following benefit payments over the next ten years:

	2020 -Termination Post-Retirement				
	Pension plan	Seniority premium	Indemnity	Medical	Total
2021	$ 79	$ 21	$ 314	$	$ 414
2022	91	23	305		419
2023	103	24	294		421
2024	120	26	291		437
2025	143	28	292		463
2026-2030	3,489	486	1,693		5,668

	2019 -Termination Post-Retirement				
	Pension plan	Seniority premium	Indemnity	Medical	Total
2020	$ 69	$ 63	$ 248	$	$ 380
2021	83	73	237		393
2022	94	78	230		402
2023	108	85	223		416
2024	123	93	218		434
2025-2029	3,399	505	1,651		5,555

The Company expect to make contributions by ~$200 to the Saavi Operaciones México pension plan during 2021.

Note 19 - Stockholders' equity:

19.1 At an extraordinary Stockholders' Meeting held in October 29, 2020 the stockholders compensated accumulated losses against 742,460,491 shares Class II of the capital stock by $40,366.

19.2 After the previous increases, capital stock at December 31, 2020 and 2019, is composed as follows:

	Shares		Amount	
Description	2020	2019	2020	2019
Class I, representing the fixed portion of equity without withdrawal right	50,000	50,000	$ 3	$ 3
Class II representing the variable portion of equity with withdrawal rights	962,737,724	1,705,198,215	52,341	92,707
Total			$ 52,344	$ 92,710

19.3 Class I shares have the following characteristics: grant voting rights at any Shareholders meeting to be held. Class II shares have the following characteristics: grant voting rights at any Shareholders meeting to be held.

19.4 Net income under Mexican Financial Reporting Standards of every subsidiary is subject to the legal requirement that at least 5% of the income for each year is intended to increase the legal reserve until it is equal to one fifth of the amount of the capital stock.

19.5 Dividends to be paid of the subsidiaries will be free from income tax if they come from Net Tax Profit Account (CUFIN, by its Spanish acronym). Any dividends paid in excess of CUFIN and Reinvested CUFIN will cause a tax equivalent to 42.86% if they are paid on 2020. The current tax is payable by the Company and may be credited against its income tax of the year or the following two years. Dividends paid coming from profit previously taxed by income tax are not subject to tax withholding or additional tax payment. The Net Contribution Capital Account (CUCA, by its Spanish acronym) represents, the capital stock contributions free from income tax when it is returned.

At December 31, 2020 and 2019, the CUFIN and CUCA is as follows:

	2020	2019
Net tax profit account	$ 668	$ -
Net contribution capital account	94,343	96,816

19.6 At an extraordinary Stockholders' Meeting held in December 29, 2020 the stockholders declared and distributed in kind dividends to our shareholders for $172,136 with a portion of the notes receivables to El Aguila Limited for $169,005 and $3,131 of interest.

Substantially, all consolidated Company earnings were generated by its Subsidiaries. Retained earnings can be distributed to the Company's Shareholders to the extent that the Subsidiaries have distributed earnings to the Company.

Note 20 - Analysis of revenues:

20.1 An analysis of the revenues for the year ended December 31, 2020 and 2019 is shown in the Note 6, *Segment information*.

20.2 Our electricity generation segment derives revenue from the transfer of goods (electricity) and ancillary services (maintenance and other) over time.

20.3 At December 31, 2020 and 2019 we recognized the following assets related to contracts:

	2019	Reverse	Post	2020
Operating and maintenance services	$ 3,706	($ 3,706)	$ 2,153	$ 2,153
Electricity sales	49,599	(49,599)	38,019	38,019
Noncurrent assets	1,349	(1,349)		
Total assets	$ 54,654	($54,654)	$40,172	$40,172

	2018	Reverse	Post	2019
Operating and maintenance services	$ 4,335	($ 4,335)	$ 3,706	$ 3,706
Electricity sales	53,554	(53,554)	49,599	49,599
Noncurrent assets	441	(441)	1,349	1,349
Total assets	$58,330	($58,330)	$54,654	$54,654

20.4 Significant changes in contract assets - Contract assets are billed and collected in the following month period in all cases, the contract assets of the electricity sales are determined in accordance with the gas consumptions and electricity consumptions at the rates stipulated in our contracts. There are no liabilities unrecognized in relation to costs to fulfill our gas supply contracts.

20.5 The amount from operation and maintenance revenues, for the remaining performance obligations after December 31, 2020 and 2019 are shown below:

	2020	2019
2020		$ 46,811
2021	$ 46,687	46,687
2022	46,692	46,692
2023	46,692	46,692
2024	46,707	46,707
2025	46,734	
Thereafter	260,777	307,510
Total	$494,289	$ 541,099

20.6 Due to the characteristics of the power purchase contracts at the Energía Azteca X, Energía Campeche, Energía Chihuahua, Energía San Luis de La Paz, and Compression Services of Compresión Altamira and Green Energy Libramiento consolidated subsidiaries, the power capacity and compression services are represented under IFRS 16, *Leases*, as operating leases. Operating lease income includes minimum lease payments, such as capacity payments and contingent rentals, and was $86,368 and $115,532 for the year ended and of December 31, 2020 and 2019.

20.7 Estimated minimum lease receivables, which do not include contingent rentals, to be received under operating leases subsequent to December 31, 2020 and 2019, are as follows:

	2020	2019
2020		$ 111,456
2021	$ 107,772	112,211
2022	97,781	101,311
2023	94,475	98,022
2024	93,923	97,461
2025	93,377	
Thereafter	603,613	695,898
	$ 1,090,941	$ 1,216,359

Note 21 - Analysis of cost of sales and general and administrative expenses:

An analysis of the nature of relevant costs and expenses classified by function in the consolidated statements of income and comprehensive income for the year ended and of December 31, 2020 and December 31, 2019 is as follows:

	2020	2019
Fuel	$ 194,126	$ 302,625
Operation and maintenance	57,243	83,703
Interconnection	85,366	73,619
Fuel transportation	40,583	54,017
Depreciation	31,453	31,204
Pension plan and other	2,409	1,580
Bank commission	2,956	
Currency exchange loss (gains)	1,474	(1,675)
Costs	415,610	545,073
Amortization of intangible assets	$ 10,301	$ 10,302
Wage, salaries and technology information	10,726	9,472
Management service and fee	6,332	5,339
Insurance	6,738	3,773
Contingent consideration	4,012	
Duties and non-site property taxes	1,668	3,041
Depreciation	891	884
Expenses	40,668	32,811
Total	$ 456,278	$ 577,884

Note 22 - Analysis of the financing cost, net:

22.1 The financing income for the year ended and of December 31, 2020 and 2019 is composed as follows:

	2020	2019
Banks deposits and others	$ 361	$ 1,010
Interest - Intercompany loans	3,200	135
Financing income	$ 3,561	$ 1,145

22.2 The financing cost for the year ended of December 31, 2020 and 2019 is composed as follows:

	2020	2019
Long-term debt	($ 59,469)	($ 53,721)
Related party long-term debt	(11,465)	(21,492)
Other interest expense	(2,696)	(2,765)
Interest expense	(73,630)	(77,978)
Letter of credit and fees	(5,584)	(4,145)
Finance expenses and fees	(344)	
Amortization of deferred financing cost	(1,139)	(955)
Change in law financing expenses	4,677	(820)
Other financial expenses	(2,390)	(5,920)
Financing cost	($ 76,020)	($ 83,898)

Note 23 - Income tax:

23.1 For the year ended at December 31, 2020 2019, the income tax benefit (expense) are as follows:

	2020	2019
Current income tax	($ 14,491)	($ 23,315)
Deferred income tax	(18,804)	(1,861)
	($ 33,295)	($ 25,176)

23.2 Mexico: Income tax of the year is calculated by applying a 30% rate on the taxable profit. The tax income differs from the accounting income, mainly in such items accumulated and deducted differently for accounting and tax purposes, by the recognition of inflation effects for tax purposes, as well as such items only affecting either the accounting or tax income.

On October 31, 2019, the Congress of the Union approved the Federal Income Law for the year 2020 and modifications to the Federal Tax Code, Income Tax Law and Value Added Tax Law (CFF, LISR and LIVA by its Spanish acronym, respectively), among the most prominent.

As part of this tax reform, among other changes, the following issues could have an impact on financial reports: Interest deductibility limit and the introduction of the "Disclosure of reportable schemes" regime, which requires tax advisers or taxpayers to provide information on issues identified as high risk by the tax authorities, mainly in search of obtaining a tax benefit.

The Company satisfied all the requirements of the reform and there are not uncertain tax positions as of December 31, 2020.

Netherlands: The Dutch corporate income tax rate is 25% (19% for the first EUR 200,000) in 2019. However, this rate will be reduced in the coming years as follows:

	2019	2020	2021
Taxable amount up to €200,000	19.0%	16.5%	15.0%
Taxable amount exceeding €200,000	25.0%	22.5%	20.5%

UK Tax: The current rate of UK corporation tax rate is 19% (effective from April 1, 2017). However, from April 1, 2020 the rate of UK corporation tax will fall to 17%.

US Tax: On December 22, 2017, the President of the United States signed into law tax reform bill H.R. 1 (Act) which lowers the corporate tax rate for companies from 35 to 21%. In addition, the former 20 years loss carryover provision has been replaced and newly generated tax losses carryforward from 2018 onward may now be carried forward indefinitely, subject to certain limitations. Given the limited deferred taxes that the Company has related to the United States jurisdiction, the impact to the consolidated statements of financial position and consolidated statements of income and comprehensive income, for the year ended and of December 31, 2020 and 2019 was not significant.

23.3 At December 31, 2020 and 2019, the main temporary differences on which the deferred income tax was recognized are analyzed as follows:

		Adjustment to the		
	2019	Statement of income	Equity	2020
Accrued expenses	$ 17,440	($ 8,088)	$5,842	$ 15,194
Deferred rent	8,116	1,584		9,700
Investments classified as held for sale		(12,799)		(12,799)
Property plant and equipment	(56,083)	(11,593)		(67,676)
Customer relationship	(38,889)	3,091		(35,798)
Prepaid expenses	(2,386)	(3,478)		(5,864)
Tax loss	6,665	12,479		19,144
Net deferred tax liability	($65,137)	($ 18,804)	$5,842	($78,099)

	2018	Adjustment to the Statement of income	Adjustment to the Equity	2019
Accrued expenses	$ 21,028	($ 3,551)	($ 37)	$ 17,440
Deferred rent	37,373	(29,257)		8,116
Property plant and equipment	(75,992)	19,909		(56,083)
Customer relationship	(41,979)	3,090		(38,889)
Prepaid expenses	(3,669)	1,283		(2,386)
Tax loss		6,665		6,665
Net deferred tax liability	($ 63,239)	($ 1,861)	($ 37)	($ 65,137)

23.4 As of December 31, 2020 and 2019, we had consolidated Tax losses carryforward that expire: a) Mexico in 10 years; b) Netherlands, 9 years; c) United Kingdom do not expire, and d) United States, 20 years. The Tax losses carryforwards are comprised as follows:

2020

Year of loss	Mexico	Netherlands	United Kingdom	United States
2014	$ 27,418	$ -	$ -	$ -
2015	29			
2016	14,490	4,216	1	
2017	7,964	1,237	7	
2018	62,962	8,873	332	
2019	6,793	2,827	66	
2020	90,671	7,106		
Total	$ 210,327	$ 24,259	$ 406	$

2019

Year of loss	Mexico	Netherlands	United Kingdom	United States
2014	$ 30,668	$ -	$ -	$ -
2015	30	-	-	-
2016	40,356	4,216	1	48
2017	18,570	1,237	7	161
2018	32,536	8,873	332	18,960
2019	4,535	2,827	66	10,136
Total	$ 126,695	$ 17,153	$ 406	$ 29,305

A tax losses carryforward of $173,513 and $118,192 was not included as of December 31, 2020 and 2019 in our deferred tax assets due to the low probability to be realized. Our assessment must cover all gross deferred tax assets, of which the largest asset relates to tax losses carryforward. Realization of a portion of our gross deferred tax assets is dependent on generating sufficient sources of future taxable income. Although realization is not assured, Management believes it is not probable that the net deferred tax asset will be realized in the foreseeable future, consequently the Group has not recorded deferred tax assets for these entities.

23.5 Taxing authorities routinely examine our tax returns. We are subject to different taxing jurisdictions, tax agreements and treaties. Management believes that the tax returns filed in the various tax jurisdictions may have positions that could be challenged by these tax authorities in the normal course of a tax audit.

If new information is identified in subsequent periods that would impact the Company's current position on certain tax matters, the Company will record the impact in the period when the new information is identified.

We had no unrecognized tax benefits and liabilities as of December 31, 2020 and 2019, related to uncertain tax positions.

23.6 The reconciliation of pre-tax income at our statutory rate to income tax expense presented in the consolidated statements of income and comprehensive income, for the year ended December 31, 2020 and 2019 is as follows:

	2020	2019
Income before income tax	$ 78,690	$ 40,742
Effect of subsidiaries not subject to income tax	12,575	36,362
	91,265	77,104
Statutory tax rate applied to pre-tax income	30%	30%
Pre-tax income at the Mexican statutory rate	(27,380)	(23,131)
Decrease (increase) of tax expense resulting from statutory inclusions/exclusions from taxable income:		
Foreign income not taxed at statutory rate	411	2,453
Foreign income	(2,236)	
Fluctuation exchange effect for tax purposes	(1,112)	(1,008)
Non-deductible expenses	(383)	(771)
Inflation adjustment for tax purposes	(2,595)	(2,719)
Total income tax expense	($ 33,295)	($ 25,176)

Note 24 - Consolidated statements of cash flows:

24.1 The reconciliation between the opening and closing balances in the statements of financial position for liabilities arising from financing activities, are shown below:

	2020		
	Related party	Long-term debt	Total
Balances at January 1	$ 164,277	$ 817,717	$ 981,994
Proceeds from issuance of long-term debt working capital		30,000	30,000
Repayment of long-term debt working capital		(30,000)	(30,000)
Payment of deferred financing cost		(6,805)	(6,805)
Proceeds from long-term debt		325,000	325,000
Repayment of debt	(162,512)	(34,517)	(197,029)
Amortization of deferred financing costs		1,139	1,139
Interest expense	11,465	59,469	70,934
Interest paid	(13,230)	(57,709)	(70,939)
Balances at December 31		1,104,294	1,104,294
Current portion of long-term debt		(82,887)	(82,887)
Debt	$	$ 1,021,407	$ 1,021,407

	2019		
	Related party	Long-term debt	Total
Balances at January 1	$ 244,671	$ 832,423	$ 1,077,094
Proceeds from issuance of long-term debt working capital		20,000	20,000
Repayment of long-term debt working capital		(20,000)	(20,000)
Repayment of debt	(68,155)	(15,480)	(83,635)
Amortization of deferred financing costs		955	955
Interest expense	21,492	53,721	75,213
Interest paid	(33,731)	(53,902)	(87,633)
Balances at December 31	164,277	817,717	981,994
Current portion of long-term debt	(1,765)	(37,260)	(39,025)
Debt	$ 162,512	$ 780,457	$ 942,969

24.2 At December 31, 2020 non-cash transaction of financing activities consist in a declared and distributed in kind dividend satisfied with a portion of the notes receivables to El Aguila Limited for $172,136. At December 31, 2019 there were no non-cash investing and financing activities.

Note 25 - Commitments and contingencies:

25.1 Power sales contract: Several of our power plants rely on power sales and gas compression contracts with one or a limited number of entities for the majority, and in some cases, all of the relevant plant's output over the term of the power sales contract. The minimum terms of power sales contracts for projects currently in operation expire between 2027 and 2035. The operations of these plants are dependent on the continued performance by customers of their obligations under the relevant power sales contracts, and in particular, on the credit quality of the purchasers. If a substantial portion of our long-term power sales contracts were modified or terminated, this could increase our exposure to market price volatility, and we could be adversely affected to the extent that we would be unable to find other customers at the same level of contract profitability. We have also contracted with various fuel suppliers and transportation providers to supply and transport fuel to our power plants.

25.2 Long term sales agreement: Certain of our subsidiaries have entered into gas turbine major maintenance LTSAs with the original equipment manufacturer of the particular gas turbines or other qualified third parties. These agreements provide for labor and supervision during scheduled inspections, repairs and overhauls of gas turbine equipment, including provisions for forced outage support. The agreements (with the exception of the agreement of Chihuahua) further allow for the supply of replacement, refurbished and critical capital spare parts required for the maintenance of the equipment in accordance with prudent industry practice.

These agreements have terms typically accommodating two or three major maintenance cycles which varies based on the equipment for each power subsidiary. These agreements may or may not contain termination provisions by us at our convenience, based on certain conditions in exchange for a fixed fee. Equivalent Operating Hours (EOH) accrued vary with output, plant cycling regimes, contractual guidelines and gas turbine events, such as trips and load shedding. The estimated annual fixed and variable amounts due under the LTSAs as of December 31, 2020 and 2021 is expected to total approximately $33,879 and $26,376 respectively. Due to the variable nature of these payments we only estimate two years of commitments.

25.3 Fuel purchase commitments: We have committed to purchase gas from different suppliers without a minimum volume of gas.

25.4 Letters of Credit (LOC): We are often required to provide guarantees and/or letters of credit to ensure contractual obligations with respect to bid performance, financing, construction and operations of our subsidiaries. We may issue guarantees in connection with obligations under our power purchase agreements, operations and maintenance contracts, management service agreements and obligations we have as determined in various purchase and sale agreements. Letters of credit relate primarily to debt service requirements, electricity sales agreements and trading requirements. The beneficiary of the guarantee and/or LOC has the ability to draw against the commitments to the extent that the contractual obligations, as defined in the related agreements, allow such draws to be made.

Cometa have maximum exposure under LOCs issued and outstanding at December 31, 2020 and 2019, are as follows:

	2020		2019	
Subsidiaries and Joint Ventures [1]	Amounts outstanding	Expirations date [2]	Amounts outstanding	Expirations date
Energía Azteca X	$ 24,778	2021	$ 23,047	2020
Saavi Energy Solutions	20,584	2021	11,182	2020
Energía Campeche	15,355	2021	15,000	2020
Energía Chihuahua	15,000	2021	15,000	2020
Energía San Luis de la Paz	12,652	2023	12,904	2020
Energía Azteca VIII	10,531	2021	10,200	2020
Compresión Altamira	7,249	2021	7,240	2020
Saavi Energía	4,884	2021	6,982	2020
Compresión Bajío	4,550	2023	1,083	2020
Energía de Baja California	838	2021	838	2020
	$116,421		$103,476	

[1]- Letters of credit outstanding related to these subsidiaries and joint ventures were issued under letters of credit provided by Electricidad Firme de México Holdings, S. A. de C. V.

[2]- Some letters of credit have a 2021 expiration date but automatically extend annually.

Electricidad Firme de México Holdings, S. A. de C. V. pays LOC fees of 1.75% per annum.

Each account party pays LOC fees ranging from 2.63% to 2.75% per annum on outstanding LOCs.

25.5 Legal proceedings - We are involved in certain legal proceedings in the normal course of business. We are under the opinion that none of these proceedings will have a material adverse effect on our consolidated financial position or cash flows, individually or in the aggregate.

Note 26 - Subsequent events:

For the year ended December 31, 2020, subsequent events have been evaluated through April 21, 2021, the date which the consolidated financial statements were available to be issued.

On November 22 2020, we celebrated an Option and Purchase and Sale Agreement with Controladora Sierra Juárez, and IEnova Holdco.

On March 2021 we closed the transaction, whereby we sold our 50% equity interest excluding its associated project debt for a purchase price of $79,441.

Note 27 - Authorization of issuance of the consolidated financial statements:

The accompanying consolidated financial statements and notes were issued on April 21, 2021, by Mauricio del Valle (Chief Financial Officer) and Francisco Villalón (Controller).

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statements of Financial Position as of December 31, 2019 and 2018 and Consolidated Statements of Income and Comprehensive Income, Change in Stockholders' Equity and Cash Flows for the year ended and of December 31, 2019 and for the nine-months period ended December 31, 2018

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Index

December 31, 2019 and December 31, 2018

Contents | Page

Independent Auditor's Report ..... 1 to 5

Consolidated financial statements:

Consolidated statements of financial position 6

Consolidated statements of income and comprehensive income 7

Consolidated statements of changes in stockholders' equity 8

Consolidated statements of cash flows 9

Notes to the consolidated financial statements ..... 10 to 60



Independent Auditor's Report

To the Directors and Stockholders of
Electricidad Firme de México Holdings, S. A. de C. V.

Opinion

We have audited the consolidated financial statements of Electricidad Firme de México Holdings, S. A. de C. V. and its subsidiaries (the Company), which comprise the consolidated statement of financial position as at December 31, 2019, and the related consolidated statements of income and comprehensive income, of changes in stockholders' equity and of cash flows for year ended and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated 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 as issued by the International Accounting Standards Board (IFRS).

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 Consolidated Financial Statements* section of our report. We are independent of the Company in accordance with the Ethics Standards of Mexican Institute of Public Accountants together with other requirements applicable to our audit of the consolidated financial statements in Mexico. We have fulfilled our other ethical responsibilities in accordance with these requirements and standards. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRS and for such internal control as Management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated 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 Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company and subsidiaries to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the Company and subsidiaries audit. We remain solely responsible for our audit opinion.



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, S. C.

Antoni Nivon Trejo
Audit Partner
April 28, 2020

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statements of Financial Position
December 31, 2019, December 31, 2018 and March 6, 2018

Figures in thousands of U.S. Dollars

Assets	Notes	December 2019	December 2018	March 2018
CURRENT ASSETS:				
Cash and cash equivalents	9	$ 46,508	$ 77,597	$
Accounts receivable	10	51,944	46,969	3
Contract assets	21	54,654	58,330	
Accounts receivable from related parties	11	2,298	6,578	
Inventories	12	11,690	11,901	
Prepayments and other current assets	3.13	25,099	37,112	
Total current assets		192,193	238,487	3
Property, plant and equipment, net	13	854,278	869,419	
Investments accounted for using the equity method	14	197,275	192,062	
Intangible assets, net	15	129,629	139,931	
Goodwill	15	71,537	71,537	
Deferred income tax assets	24	23,094	11,300	
Other non-current assets		811	1,327	
Total assets		$ 1,468,817	$ 1,524,063	$ 3
Liabilities and Equity				
CURRENT LIABILITIES:				
Accounts payable and accrued expenses	3.21	$ 178,170	$ 170,190	$
Accounts payable to related parties	11	484	815	
Current portion of long-term debt	16	37,260	25,401	
Current portion of related party long-term debt		1,765	48,938	
Total current liabilities		217,679	245,344	
Long-term debt	16	780,457	807,022	
Related party long-term debt		162,512	195,733	
Deferred income tax liabilities	24	88,231	74,539	
Deferred rent	17	27,744	11,225	
Other long-term liabilities	18	23,554	38,924	
Pension and other post-retirement obligations	19	14,098	12,848	
Total liabilities		1,314,275	1,385,635	
EQUITY:				
Capital stock	20	92,710	92,710	3
Accumulated income		56,006	40,440	
Other comprehensive income		5,826	5,278	
Total equity		154,542	138,428	3
Total liabilities and equity		$ 1,468,817	$ 1,524,063	$ 3

The accompanying notes are an integral part of these consolidated financial statements.

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statements of Income and Comprehensive Income
For the year ended December 31, 2019 and for the period of nine-months ended as of December 31, 2018

Figures in thousands of U.S. Dollars

	Notes	2019	2018
Revenues	21	$677,618	$480,630
Cost of sales and services	22	(545,073)	(377,797)
Gross profit		132,545	102,833
General and administrative expenses	22	(32,811)	(21,645)
Share of net profit of joint ventures accounted for using the equity method	14	23,761	14,175
Operating profit		123,495	95,363
Financing income	23	1,145	2,533
Financing cost	23	(83,898)	(58,550)
Financing cost, net		(82,753)	(56,017)
Income before income tax		40,742	39,346
Income tax (expense) benefit	24	(25,176)	1,094
Net income		15,566	40,440
Comprehensive income:			
Items that will not be reclassified income:			
Remeasurement of pension and other post-retirement obligations - consolidated entities	19	293	73
Items that may be reclassified to income:			
Interest rate swap in joint ventures		364	7,436
Income tax relating to these items		(109)	(2,231)
	14	255	5,205
Comprehensive income		$ 16,114	$ 45,718

The accompanying notes are an integral part of these consolidated financial statements.

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statements of Changes in Stockholders' Equity

For the year ended December 31, 2019 and for the period of nine-months ended as of December 31, 2018

Figures in thousands of U.S. Dollars

	Notes	Capital stock	Accumulated income	Other comprehensive income	Total
Balance at March 6, 2018	20	$ 3	$	$	$ 3
Shareholders' transaction: Capital stock increase	20	92,707			92,707
Comprehensive income: Net income			40,440		40,440
Items that will not be reclassified to income: Pension and other post-retirement obligations, net of tax - consolidated entities	19			73	73
Items that may be reclassified to income: Interest rate swap amortization in unconsolidated affiliates	14			5,205	5,205
			40,440	5,278	45,718
Balance at December 31, 2018		92,710	40,440	5,278	138,428
Comprehensive income: Net income			15,566		15,566
Items that will not be reclassified to income: Pension and other post-retirement obligations, net of tax - consolidated entities	19			293	293
Items that may be reclassified to income: Interest rate swap amortization in unconsolidated affiliates	14			255	255
			15,566	548	16,114
Balance at December 31, 2019		$ 92,710	$ 56,006	$ 5,826	$ 154,542

The accompanying notes are an integral part of these consolidated financial statements.

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statements of Cash Flows
For the year ended December 31, 2019 and for the period of nine-months ended as of December 31, 2018

Figures in thousands of U.S. Dollars

	Notes	2019	2018
Cash flows from operating activities			
Income before income tax		$ 40,742	$ 39,346
Adjustments for investing activities related items:			
Depreciation and amortization	13 & 15	42,390	28,143
Share of net profit of joint ventures accounted for using the equity method	14	(23,761)	(14,175)
Interest income	23	(135)	(236)
Adjustments for financing activities related items:			
Interest expense	23 & 25	75,213	51,337
Amortization of deferred financing costs	23 & 25	955	677
		135,404	105,092
Change in assets and liabilities resulting from operating activities:			
Accounts receivable		(9,706)	(20,367)
Income tax		(21,264)	
Accounts receivable from unconsolidated affiliates		1,012	3,001
Inventories		211	3,475
Prepayment and other current assets		12,013	(17,641)
Other non-current assets		516	374
Accounts payable and accrued expenses		14,336	22,966
Accounts payable to unconsolidated affiliates		(331)	(10,318)
Deferred rent		16,519	11,225
Other liabilities		(15,370)	(4,174)
Pension and other post-retirement obligations		1,580	4,630
Net cash provided by operating activities		134,920	98,263
Cash flows from investing activities			
Consideration paid for a business combination; net of cash acquired	7		(816,342)
Payments for property, plant and equipment	13	(16,947)	(2,424)
Proceeds from loan from related parties		3,159	2,223
Interest received		244	222
Dividends from joint ventures	14	16,849	
Equity distribution from joint ventures	14	1,954	
Net cash provided by (used in) investing activities		5,259	(816,321)
Cash flows from financing activities			
Proceeds from issuance of long-term debt	25		860,000
Proceeds from working capital facility	25	20,000	67,500
Proceeds from issuance of related party long-term debt	25		230,667
Repayment of working capital facility	25	(20,000)	(67,500)
Repayment of long-term debt	25	(15,480)	(11,180)
Payment of related party long-term debt	25	(68,155)	
Payment of deferred financing cost	25		(26,995)
Payment and cancellation for original long-term debt	25		(318,845)
Payment of derivative financial instrument			(3,290)
Capital stock contribution	20		92,710
Interest paid	23 and 25	(87,633)	(27,412)
Net cash provided by financing activities		(171,268)	795,655
Net (decrease) increase in cash and cash equivalents		(31,089)	77,597
Cash and cash equivalents at beginning of the year and period		77,597	
Cash and cash equivalents at end of the year	9	$ 46,508	$ 77,597
Non-cash financing and investing activities	25.2		

The cash paid for income taxes for the year ended December 31, 2019 and for the nine-months period ended December 31, 2018 was $21,264 and $17,498 respectively.

The accompanying notes are an integral part of these consolidated financial statements.

Figures in thousands of U.S. Dollars ($)

Note 1 - History, Company activities and relevant events:

1.1 ***History and Company activities***

Electricidad Firme de México Holdings, S. A. de C. V. (collectively with its subsidiaries, Electricidad Firme, we, our, us, Company or Group) is a direct subsidiary of El Aguila B. V. an indirect subsidiary on Actis LLP, and was incorporated on March 6, 2018 in Mexico City, with an indefinite duration.

Electricidad Firme indirectly owns Cometa Energía, S. A. de C. V. (Cometa) who owns, operates, acquires, and develops a diverse portfolio of electric generation facilities, gas compression facilities, and related infrastructure.

The portfolio includes subsidiaries that are consolidated and joint ventures accounted for under the equity method, See Note 3.1, *Principles of consolidation and equity accounting* for further information, that own and operate six natural gas-fired Combined Cycle Power Plants (CCPP), and a Wind Farm (WF); Some other characteristics of the plant portfolio, such as the total megawatts, location, year of commercial operation, and characteristic of the permits to generate electric power in accordance with the Mexican Regulation such as: a) Independent Power Producer (IPP); b) External Producer (EP); c) Self Supply (SS); and d) Electric Power Generation (EPG) are as follows:

		Interest held by us	Year of commercial operation	Permits	Plant characteristics		
					Megawatts	Location	Type
Equity Method:							
Energía Azteca VIII	(1)	51.0	2002	IPP, SS	625	Guanajuato, Mexico	CCPP
Energía Sierra Juárez	(2)	50.0	2015	SS	155	Mexicali, Mexico	WF
Consolidated:							
Energía Campeche	(2)	100.0	2003	IPP	252	Campeche, Mexico	CCPP
Energía Chihuahua	(2)	100.0	2003	IPP, SS	271	Chihuahua, Mexico	CCPP
Energía Azteca X	(2)	100.0	2003	IPP, SS	760	Mexicali, Mexico	CCPP
Energía de Baja California	(1)	100.0	2003	EP, EPG	320	Mexicali, Mexico	CCPP
Energía San Luis de la Paz	(2)	100.0	2015	SS	230	Guanajuato, Mexico	CCPP

The portfolio also includes subsidiaries and a joint venture that own and operate Gas Compression plants; the permits of those plants were awarded by Centro Nacional de Gas. Their characteristics, such as the Million Cubic Feet (MCF) per day are as follows:

		Interest held by us	Year of commercial operation	Plant characteristics	
				MCF	Location
Equity Method:					
Compresión Bajío	(1)	51.0	2001	100.0	Querétaro, Mexico
Consolidated:					
Compresión Altamira	(2)	100.0	2014	1,300.0	Tamaulipas, Mexico
Green Energy Libramiento	(1)	100.0	2007	100.0	Querétaro, Mexico

Finally, our portfolio includes 2 subsidiaries, GDD de Personal [1] and Saavi Operaciones México [2], who provide personnel services to the companies mentioned above, as well as sub holding companies including 23 subsidiaries incorporated in the Netherlands and 3 subsidiaries incorporated in the United Kingdom.

[1] A limited liability company, S. de R. L. de C. V. with a $0.1 fixed portion of equity without withdrawal rights.

[2] A limited liability company, S. A. de C. V. with a $25 fixed portion of equity without withdrawal rights.

1.2 Relevant events

On April 26, 2018, Cometa purchased InterGen (International) B. V. (now Saavi Energia B. V.), its subsidiaries, and its joint ventures mentioned above from InterGen N. V.

The authorization of Federal Energy Regulatory Commission (FERC), the U. S. federal agency that regulates the transmission and wholesale sale of electricity and the authorization of Comisión Federal de Competencia Económica (COFECE) a Mexican organism, responsible for monitoring and guaranteeing free competition in the Mexican market, was received on March 5, 2018 and April 9, 2018, respectively.

Note 2 - Basis of preparation:

The accompanying consolidated financial statements of the Company have been prepared in accordance with International Financial Reporting Standards (IFRS) and interpretations issued by the IFRS Interpretations Committee applicable to companies reporting under IFRS. The financial statements comply with IFRS as issued by the International Accounting Standards Board (IASB). These are the Company's first consolidated financial statements prepared in accordance with IFRS.

Note 3 - Summary of significant accounting policies:

This note provides a list of the significant accounting policies adopted in the preparation of these consolidated financial statements. Our consolidated financial statements consist of Electricidad Firme de México Holdings, S. A. de C. V. and its subsidiaries.

3.1 Principles of consolidation and equity accounting

The consolidated financial statements include all the assets, liabilities, revenues, expenses and cash flows of the Company.

These consolidated financial statements include the accounts of the Company and all other entities in which we have a controlling financial interest and equity-method investments where we have significant influence. All material intercompany transactions and balances between consolidated entities have been eliminated. The net effect of the settlement of these intercompany transactions is reflected in net parent investment in the consolidated statements of financial position and in net distributions to parent in the financing activities section of the consolidated statements of cash flows.

Subsidiaries.

Subsidiaries are all entities over which the Company has control, those entities are fully consolidated. The Company controls an entity when the Company is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power to direct the activities of the entity.

Intercompany transactions, balances and unrealized gains on transactions between Group companies are eliminated. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the transferred asset. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by us.

Joint arrangements

Under IFRS 11, *Joint Arrangements,* investments in joint arrangements are classified as either joint operations or joint ventures. The classification depends on the contractual rights and obligations of each investor, rather than the legal structure of the joint arrangement. With regards to joint agreements, the Company only has joint ventures.

Joint ventures

Interests in joint ventures are accounted for using the equity method (see below), after initially being recognized at cost in the consolidated statements of financial position.

We do not consolidate Energía Sierra Juárez, Energía Azteca VIII and Compresión Bajío because we have determined that control is shared between unrelated parties and that no one party has the power to direct the activities that most significantly impact the entities economic performance. The partners must agree on all major decisions for each of the partnerships; as a result, we are not the primary beneficiary of them.

For total assets and liabilities of them refer to Note 14, *Investments accounted for using the equity method.*

The carrying amount of equity-accounted investments is tested for impairment in accordance with the policy adopted by us.

Equity method

Under the equity method of accounting, the investments are initially recognized at cost and adjusted thereafter to recognize the Company's share of the post-acquisition profits or losses of the investee in profit or loss, and the Company's share of movements in Other Comprehensive Income (OCI) of the investee in OCI. Dividends received or receivable from joint ventures are recognized as a reduction in the carrying amount of the investment.

When the Company's share of losses in an equity-accounted investment equals or exceeds its interest in the entity, including any other unsecured long-term receivables, the Company does not recognize further losses, unless it has incurred obligations or made payments on behalf of the other entity.

Unrealized gains on transactions between the Company and its joint ventures are eliminated to the extent of the Group's interest in these entities. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Accounting policies of equity accounted investees have been changed where necessary to ensure consistency with the policies adopted by us.

3.2 Segment reporting

Reportable-operating segments are reported in a manner consistent with the internal reporting provided to the Board. The Chief Executive Officer (CEO), Chief Financial Officer (CFO) and the Finance Planning and Analysis Manager (FP&A) assesses the financial performance and position of the Group and make strategic decisions.

3.3 Business combination

The acquisition method of accounting is used to account for all business combinations, regardless of whether equity instruments or other assets are acquired. The consideration transferred for the acquisition of a subsidiary comprises the following:

Fair values of the assets transferred.
Liabilities incurred by the former owners of the acquired business.
Equity interests issued by the Group.
Fair value of any asset or liability resulting from contingent consideration arrangements.
Fair value of any pre-existing equity interest in the subsidiary.

Identifiable assets acquired and liabilities and contingent considerations assumed in a business combination are, with limited exceptions, measured initially at their fair values at the acquisition date.

Acquisition-related costs are expensed as incurred.

The excess of the: i) consideration transferred, and ii) acquisition-date fair value of any previous equity interest in the acquired entity, over the fair value of the net identifiable assets acquired is recorded as goodwill.

Where settlement of any part of cash consideration is deferred, the amounts payable in the future are discounted to their present value as at the date of exchange. The discount rate used is the entity's incremental borrowing rate, being the rate at which a similar borrowing could be obtained from an independent financier under comparable terms and conditions.

Contingent considerations are classified as financial liabilities and are subsequently remeasured to fair value with changes in fair value recognized in the consolidated statements of income and comprehensive income.

3.4 Financial instruments

The carrying amounts of cash and cash equivalents, restricted cash, receivables, accounts payable and accrued liabilities approximate fair value because of the short-term maturity of these instruments.

Classification

We classify the financial assets at amortized cost, when both of the following criteria are met:

- The asset is held within a business model whose objective is to collect the contractual cash flows, and

- The contractual terms give rise to cash flows that are solely payments of principal and interest.

We reclassify debt and investments when and only when its business model for managing those assets and liabilities changes.

Recognition and derecognition

Regular way purchases and sales of financial assets are recognized on trade-date, the date on which the Group commits to purchase or sell the asset. Financial assets are derecognized when the rights to receive cash flows from the financial assets have expired or have been transferred and we have transferred substantially all the risks and rewards of ownership.

Measurement

At initial recognition, we measure a financial asset at its fair value, plus transaction costs that are directly attributable to the acquisition of the financial asset.

Debt instruments

Subsequent measurement of debt instruments is represented under amortized cost methodology. These debt instruments are financial assets that are held for collection of contractual cash flows where those cash flows represent solely payments of principal and interest and are measured at amortized cost. Interest income from these financial assets is included in financing income using the effective interest rate method.

Impairment

From March 6, 2018, we assess on a forward-looking basis the expected credit loss associated with debt instruments carried at amortized cost. The impairment methodology applied depends on whether there has been a significant increase in credit risk.

For accounts receivables, the Group applies the simplified approach permitted by IFRS 9, *Financial Instruments,* which requires expected lifetime losses to be recognized from initial recognition of the receivables. See Note 3.11, *Accounts receivable* and Note 10, *Accounts receivable*.

3.5 Fair value measurements

Financial instruments recorded at fair value are classified by the valuation method used for each instrument, as follows:

Level 1 - Quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 - Information (inputs) other than budget prices included in level 1 that can be confirmed for the asset or liability, either directly (i.e., specific prices) or indirectly (i.e., derived from specific prices).

Level 3 - Information (inputs) on the asset or liability not based on data that can be confirmed in active markets (i.e., financial models and unobservable information).

Level 2 - Interest rate swap of our Joint Venture of Energía Sierra Juárez.

The fair value measurements would incorporate various factors such as the credit standing of the counterparties involved, the nonperformance risk on the liabilities, the applicable exit market and specific risks inherent in the instrument. Credit standing and related credit discounting incorporates, as applicable and available, counterparty ratings from nationally recognized ratings agencies and credit default swap implied default probabilities as of the fair value measurement date.

Level 3 - Fair value measurement provisions in goodwill.

The starting point of the process for determining the non-recurring Level 3 fair value measurements used to recognize the impairments for goodwill are the cash flow projections based on each Cash Generating Units (CGU) business plan, including revenue and generation forecast and projected capital and maintenance expenditures. For periods not covered by contractual arrangements or that other market data is not available, these projections are dependent on the Company's views of revenue and generation forecasts, gas and carbon pricing, and projected capital and maintenance expenditures.

A financial asset or liability's classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

3.6 Foreign currency translation

Functional and presentation currency

Items included in the financial statements of each of the Company's subsidiaries are measured using the currency of the primary economic environment in which the entity operates ('the functional currency'). The consolidated financial statements are presented in US dollars, which is the Company's functional and presentation currency.

Transactions and balances

Foreign currency transactions are translated into the functional currency. We recognize in the consolidated statements of income and comprehensive income, foreign exchange gains and losses resulting from:

a) Settlement of the transactions using the exchange rates at the dates of the transactions.

b) Translation of monetary assets and liabilities denominated in foreign currencies using the exchange rate at year end.

Foreign exchange gains and losses related to borrowings are presented in the consolidated statements of income and comprehensive income, within financing costs. All other foreign exchange gains and losses (such as: accounts receivables and payables) are presented in the consolidated statements of income and comprehensive income on a net basis within Cost of sales and services or general and administrative expenses.

3.7 Revenue recognition

Revenues from the Company recognized in the statements of income and comprehensive income from: i) electricity sales, ii) other ancillary services and iii) power capacity and compression services. Due to the characteristics of the power capacity and compression services, they are represented under IFRS 16, *Leases,* as operating leases.

Identification of separate performance obligations

We evaluate separate performance obligations within a contract when it identifies a promise to transfer a good or service to the costumer that is distinct or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to the costumer. The Transaction price is allocated to each performance obligation based on the stand-alone selling prices. Where these are not directly observable, they are estimated based on expected cost-plus margin.

Contract assets or liabilities

We obtain rights to receive consideration from the customer and assume obligations to transfer goods or services to the customer (performance obligations) in certain contracts with a customer. The combination of those rights and performance obligations gives rise to an asset or a liability depending on the relationship between the remaining rights and the performance obligations. If the goods transferred or services rendered by us exceed the payment, a contract asset is recognized. If the payments exceed the goods transferred or services rendered, a contract liability is recognized. Customers are invoiced on a monthly basis and consideration is payable when invoiced. Unbilled sales or services are based and adjusted to the amount billed, therefore there are no significant changes to revenue amounts recognized. As of December 31, 2019 and 2018, there are no contract liabilities.

Billing requirements to our customers generally result in a monthly basis billing in the following month of the good or service delivered. Once billed, payment is generally required within a month. Based on the terms of our agreements, payment is generally received at or shortly after delivery of the good or service. During the year ended December 31, 2019 and the period of nine-months ended December 31, 2018, there were no material credit or impairment losses recognized relating to accounts receivable balances associated with contracts with customers.

Financing components

The Group does not expect to have any contracts where the period between the transfer of the promised goods or services to the customer and payment by the customer exceeds one year. As a consequence, the Group does not adjust any of the transaction prices for the time value of money.

Revenue from electricity

We recognize revenues from sales of electricity and gas since the incorporation date in accordance with IFRS 15, *Revenue from contracts with customers*. The analysis on revenue recognition shows that we record revenues from the sale of electricity and gas under long-term contracts based upon the output delivered provided at rates specified under the contract, unless the contract pricing terms are fixed, in this sense, revenue is recognized over time, when the client simultaneously receives and consumes the electricity and gas.

We applied the right to invoice practical expedient, when the right to consideration directly corresponds to the costumer value of our performance completed to date.

Revenues from the physical sale of electricity under short-term contracts or via the Mexican Wholesale Market (MEM) are at contractual or market rates based on the volumes delivered.

Sales are recognized when control of the products has transferred, being when the products are delivered to the client, the client has full discretion over the product and price to sell the products, and there is no unfulfilled obligation that could affect the client's acceptance of the products. Delivery occurs when the products have been delivered, and either the wholesaler has accepted the products in accordance with the sales contract, the acceptance provisions have lapsed, or the Group has objective evidence that all criteria for acceptance have been satisfied.

Revenue from these sales is recognized based on the price specified in the contract. A receivable is recognized when the products are delivered as this is the point in time that the consideration is unconditional because only the passage of time is required before the payment is due.

Other ancillary services

In addition to our generation activities, we manage as well as perform the operations and maintenance services under service contracts for certain subsidiaries in which we have an interest. Revenues from consolidated subsidiaries are eliminated in consolidation.

Revenue from providing services is recognized in the accounting period in which the services are rendered. For fixed-price contracts, revenue is recognized based on the actual service provided to the end of the reporting period as a proportion of the total services to be provided because the customer receives and uses the benefits simultaneously.

Power capacity and compression services

We analyzed power sales and compression services contracts and amendments to existing contracts in accordance with IFRS 16, *Leases*. Currently, the power sales contracts and compression services contracts in place at the Energía Azteca X, Energía San Luis de la Paz, Energía Campeche, Energía Chihuahua and Energía Azteca VIII and Energía Sierra Juarez (equity method investee) power companies, as well as the Green Energy Libramiento and Compresión Altamira , meet the criteria for lease treatment. Accordingly, these power sales and compression services contracts are accounted for as operating leases. The non-contingent lease rental revenues reported under these contracts for the consolidated subsidiaries are included in lease rentals derived from power purchase and compression services agreements in the consolidated statements of income and comprehensive income.

Lease income from operating leases where the Group is a lessor is recognized in income on a straight-line basis over the lease term, See Note 3.8, *Deferred rent*. Initial direct costs incurred in obtaining an operating lease are added to the carrying amount of the underlying asset and recognized as expense over the lease term on the same basis as lease income. The respective leased assets are included in the consolidated statements of financial position based on their nature. We did not need to make any adjustments to the accounting for assets held as lessor as a result of adopting the new leasing standard.

Financing income

Financing income from a financial asset is recognized when economic benefits will likely flow to the company and the amount of revenue can be measured reliably. The interest income is booked on a timely manner, in reference to the outstanding principal and the rate of applicable effective interest. Financing income is shown after the operating profit in the consolidated statements of income and comprehensive income.

3.8 Deferred rent

Revenues from leases are recognized on a straight-line basis (levelized) in the consolidated statements of income and comprehensive income, the difference between the lease payment and the income levelized are recognized in our consolidated statements of financial position as a Deferred rent.

In a business combination, we do not recognize the acquirer's deferred rent using the acquisition method because it does not meet the definition of an asset or liability. We recognize the liability related to deferred rent starting from the acquisition date. See Note 17, *Deferred rent*.

3.9 Insurance recoveries

We enter into insurance policies with various carriers to provide for reimbursement of incurred costs during unplanned outages as well as recovery of lost revenues. We consider "incurred costs" to be repair and maintenance costs and replacement power costs incurred in order to deliver power under a contracted position. Business interruption recoveries for lost revenues are those recoveries that relate to un-hedged positions or capacity revenues under a long-term power sales agreement.

When the insurance recovery relates to reimbursement of an incurred cost, the amount is recorded as a receivable from the insurance provider when collection is deemed probable by Management. The amount is recorded as an offset to the line item in the consolidated statements of income and comprehensive income where the incurred cost is recorded, or where the lost capacity revenue under the long-term power sales agreement would have been recorded.

For recovery of business interruption that is not directly calculable, it is our policy to recognize these recoveries only when the amount has been collected or when payment has been explicitly confirmed by the insurance provider(s), and therefore is assured of collection. The Company recognized nil of income for the proceeds received for business interruption in lease rentals - power purchase and compression services agreements in the consolidated statements of income and comprehensive income for the year ended as of December 31, 2019 and the period of nine-months ended December 31, 2018.

For the year ended at December 31, 2019 and the period of nine-months ended December 31, 2018, we collect insurance recoveries by $671 and nil respectively; and were recorded as other services contracts in the consolidated statements of income and comprehensive income.

3.10 Cash and cash equivalents

We consider all highly liquid investments that are readily convertible to cash and have an original maturity when purchased of three months or less to be cash equivalents. Cash and cash equivalents held by certain consolidated subsidiaries are not restricted to specific uses within them; however, the terms of Green Energy Libramiento limit our ability to distribute those funds and use them for corporate purposes. See Note 9, *Cash and cash equivalents*, for further information on these balances.

3.11 Accounts receivable

Accounts receivable represent amounts due from customers and contracts assets and are generated by sales of goods or services provided in the normal course of the Company's operations. When collection is expected in a period of one year or less from the closing date (or in the normal operating cycle of the business if this cycle exceeds this period), they are presented as current assets. If this is not met, they are presented as non-current assets.

Other accounts receivable represent amounts arising from the Value Added Tax (VAT) in the normal course of Company's operations, which are expected to be collected over a period of one year or less from the closing date (or in the normal cycle of business operations in the event that this cycle exceeds this period), are presented as current asset. If the above is not met, they are presented as non-current assets.

Accounts receivable are recognized at fair value, less the allowance for un-collectability, when applicable. See Note 10, *Accounts receivable.*

3.12 Inventories

Inventories represents amounts of Liquid Fuel (Diesel) in certain power plants, to dispatch at the full capacity, 10 days of energy production approximately and Emission allowances inventory.

At December 31, 2019 and 2018 inventories are expressed at their cost, determined through averaging. Values determined like this do not exceed their net realization value. The inventory is classified as current assets or non-current assets if it is expected to deliver said inventory within a period greater than one year from the date of consolidated statements of financial position. Cash inflows and outflows are classified as an operating activity in the consolidated statements of cash flows.

In each accounting period inventories are subject to impairment tests with the purpose of identifying obsolescence, damaged items or low market value. In the event that the amount of future economic benefits from inventory, i.e., its estimated net realization value, is lower than its net carrying amount, an impairment loss is recognized which is recorded in the cost of sales of the period presented. See Note 12, *Inventories*.

3.13 Prepayments

Prepayments represent such expenditures made by the Company where the risks and benefits inherent to the goods to be acquired or services to be received have not been transferred. Prepayments are recorded at their cost and presented in the consolidated statements of financial position as current or non-current assets, depending on the destination item. Prepayment of goods and/or services related to property, plant and equipment are included in this line. Advance payments in foreign currency are recognized at the exchange rate of the date of the transaction, without modification by subsequent exchange rate fluctuations between currencies.

Once goods and/or services related to prepayments are received, they should be recognized as an expense or an asset in the accounting period, according to their respective nature.

3.14 Property, plant and equipment, net

Property, plant and equipment, which consists mainly of land, power and compression plants, capital spares and other equipment, is stated at historical cost less depreciation. Significant additions or improvements that increase cash flows or extend asset lives are capitalized while expenditures for maintenance and repairs to maintain facilities in operating condition are expensed as the work is incurred.

The cost of our property, plant and equipment is depreciated over the estimated useful life of the asset using the straight-line method less a residual value as follows:

	Useful life (years)
Power plants	15 - 40
Compression plants	20 - 40
Office equipment and other	3 – 10

Power plants and compression plants are integrated by different components that have different useful lives. The main individual components are depreciated over their individual useful life. Depreciation related to power plants and compression plants is recorded as a component of cost of sales and services in the consolidated statements of income and comprehensive income. Depreciation related to office equipment and other non-operating assets is recorded as a component of general and administrative expenses.

We evaluate the recoverability of our long-lived assets if events or changes in circumstances indicate the carrying value of these assets may not be fully recoverable. Such circumstances may include a significant decrease in the market price of a long-lived asset, a significant long-term adverse change in the manner the asset is being used or in its physical condition or a history of operating cash flow losses associated with the use of the asset. Under this guidance, impairment has occurred if an estimate of undiscounted future cash flows attributable to the long-lived assets is less than the carrying value of the assets. If impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the fair value of the assets and recording a loss only if the fair value is less than the carrying value. See Note 13, *Property, plant and equipment, net*.

Componentization requires each part of the property, plant and equipment with a cost that is significant in relation to the total cost of the items to be depreciated separately. The Company allocates the amount initially recognized in respect of an item of property, plant and equipment to its significant parts and depreciates separately each such part.

3.15 Unfavorable terms of contract

Unfavorable terms of the contract (UTC) represent a property, plant and equipment decrease, that were recognized, as part of the business combination, for operating lease arrangements, whose terms are unfavorable compared to current market terms, which is depreciated to the end of the contract using the straight-line method. See Note 13, *Property, plant and equipment, net*.

3.16 Leases as a lessee

The Company has made the early adoption of IFRS 16, *Leases*, as of March 6, 2018 on the right-of-use the assets of our corporate office. On adoption of IFRS 16, *Leases*, we recognized lease liabilities measured at the present value of the remaining lease payments, discounted using the lessee's incremental borrowing rate. The weighted average lessee's incremental borrowing rate applied to the lease liabilities on April 26, 2018 was 3%. The associated right-of-use assets were measured at the amount equal to the lease liability.

The Company leases different right-to-use assets. Rental contracts are typically made for fixed periods but may have extension options. Contracts may contain both lease and non-lease components. The Company allocates the consideration in the contract to the lease and non-lease components based on their relative stand-alone prices. The right-of-use asset is depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis.

Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions.

The Right-of-use asset from the lease are recognized as property, plant and equipment and a corresponding liability at the date at which the leased asset is available for use by the Company. Each lease payment is allocated between the liability and financing cost. The financing cost is charged to consolidated statements of income over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period.

Assets and liabilities arising from a lease are initially measured on a present value basis. Lease liabilities include the net present value of the following lease payments:

- Fixed payments (including in-substance fixed payments), less any lease incentives receivable.
- Variable lease payments that are based on an index or a rate.
- Lease payments to be made under certain potential extension options are also included in the measurement of the liability.

The lease payments are discounted using the incremental borrowing rate, being the rate that the individual lessee would have to pay to borrow the funds necessary to obtain an asset of similar value to the right-of-use assets in a similar economic environment with similar terms, security and conditions.

To determine the incremental borrowing rate, the Company where possible, uses recent third-party financing received by the individual lessee as a starting point, adjusted to reflect changes in financing conditions since third party financing was received.

The Company is exposed to potential future increases in variable lease payments based on an index or rate, which are not included in the lease liability until they take effect. When adjustments to lease payments based on an index or rate take effect, the lease liability is reassessed and adjusted against the right-of-use assets.

Right-of-use assets are measured at cost comprising the following:

- The amount of the initial measurement of the lease liability.
- Any lease payments made at or before the commencement date less any lease incentives received.

3.17 Goodwill

The Company applies the following accounting guidelines to business acquisitions: i) purchase method is used only as a valuation rule, which requires the purchase price to be assigned to acquired assets and assumed liabilities based on their fair values at acquisition date; ii) acquired intangible assets are identified, valued and recognized, and iii) the non-assigned portion of the purchase price represents goodwill.

Goodwill is measured as described in Note 7, *Business combination*, and is included in the consolidated statements of financial position. Goodwill is not amortized but it is tested for impairment annually, or more frequently if events or changes in circumstances indicate that it might be impaired and is carried at cost less accumulated impairment losses. Gains and losses on the disposal of an entity include the carrying amount of goodwill relating to the entity sold, See Note 15, *Goodwill and intangibles assets, net*.

3.18 Intangible assets, net

Customer-related intangible assets include, but are not limited to customer contracts and related customer relationships, acquired in a business combination, those customer relationships meet the definition of an intangible asset when legal rights are identified to protect customer relationships since it provides evidence that the entity is nonetheless able to control the expected future economic benefits flowing from the customer relationship, and are recognized at fair value at the acquisition date.

All intangible assets with finite useful lives are amortized over their useful lives (10 to 18 years). Intangible assets include the value of acquired power sales contracts. The value assigned to these contracts is being amortized on a straight-line basis over the term of the contracts. See Note 15, *Goodwill and intangibles assets, net*.

3.19 Impairment of assets

Goodwill and intangible assets that have an indefinite useful life are not subject to amortization and are tested annually for impairment, or more frequently if events or changes in circumstances indicate that they might be impaired. Other assets are tested for impairment whenever events or changes in 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. The recoverable amount is the higher of an asset's fair value less costs of disposal and value in use. Non-financial assets other than goodwill that suffered an impairment are reviewed for possible reversal of the impairment at the end of each reporting period.

3.20 Income taxes

The income tax expense or benefit for the period is the tax payable on the current period's taxable income based on the applicable income tax rate for each jurisdiction adjusted by changes in deferred tax assets and liabilities attributable to temporary differences and to unused tax losses.

The current income tax charge is calculated on the basis of the tax laws enacted or substantively enacted at the end of the reporting period in the countries where the Company and its subsidiaries and associates operate and generate taxable income. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. It establishes provisions where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred income tax is provided in full, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements. However, deferred tax liabilities are not recognized if they arise from the initial recognition of goodwill. Deferred income tax is also 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 income or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the end of the reporting period and are expected to apply when the related deferred income tax asset is realized, or the deferred income tax liability is settled.

Deferred tax assets are recognized only if it is probable that future taxable amounts will be available to utilize those temporary differences and losses.

Deferred tax liabilities and assets are not recognized for temporary differences between the carrying amount and tax bases of investments in foreign operations where the company is able to control the timing of the reversal of the temporary differences and it is probable that the differences will not reverse in the foreseeable future.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the entity has a legally enforceable right to offset and intends either to settle on a net basis, or to realize the asset and settle the liability simultaneously.

Current and deferred tax is recognized in the consolidated statements of income and comprehensive income, except to the extent that it relates to items recognized in OCI or directly in equity. In this case, the tax is also recognized in OCI or directly in equity, respectively.

The Company has made the early adoption of IFRIC 23 "Uncertainty Tax Provision" as of March 6, 2018. On adoption of IFRIC 23, there were no impacts identified about tax provisions considered in tax calculations or tax events related to its transactions.

3.21 Accounts payable and accrued expenses

This item includes obligations with suppliers and other payables for purchases of goods or services acquired in the normal course of Company's operations as well as the VAT and other taxes different than the income tax. When payment is expected in a period of one year or less from the closing date, they are presented as current liabilities.

3.22 Derecognition of financial liabilities

We derecognize a financial liability only when it is extinguished either when the Group:

- Discharges the liability by paying the creditor.
- Is legally released from primary responsibility for the liability.

When the Group makes an exchange with an existing lender of debt instruments with substantially different terms, the Group extinguishes the original financial liability and recognizes a new financial liability.

The terms are substantially different if the discounted present value of the cash flows under the new terms, including any deferred financing cost not amortized, is at least 10 per cent different from the discounted present value of the remaining cash flows of the original financial liability.

When the condition above is not met, the Group applies a qualitative assessment of the terms, based on the specific facts and circumstances in each case, for the derecognition of the financial liability. Additionally, a substantial modification of the terms of an existing financial liability or a part of it is accounted for as an extinguishment of the original financial liability and the recognition of a new financial liability.

The difference between the carrying amount of an extinguished or transferred financial liability (or part of a financial liability) and the consideration paid, including any non-cash assets transferred or liabilities assumed, is recognized in the consolidated statements of income and comprehensive income.

3.23 Deferred financing cost

Incremental costs incurred that are directly attributable to the acquisition, issue or disposal of a financial asset or financial liability. These costs include fees and commissions paid to third parties but exclude debt premiums or discounts, financing costs or internal administrative or holding costs. Deferred financing costs are those that would not have been incurred if the Group had not acquired, issued or disposed of the financial instrument.

When there is an exchange of debt instruments or modification of terms accounted for as an extinguishment, any costs or fees incurred are recognized as part of the gain or loss on the extinguishment. If the exchange or modification is accounted for as modification, costs or fees incurred, should adjust the carrying amount of the liability and are amortized over the remaining term of the modified liability.

Our debt issuance costs related to a recognized debt liability are presented as a direct deduction from the carrying amount of the related debt liability, which is consistent with the presentation of debt discounts. See Note 16, *Debt*.

Deferred financing cost is amortized using the effective interest rate of the associated financial liability. The amortization is presented as part of the financial cost in the consolidated statements of income and comprehensive income.

3.24 Other long-term liabilities

Energía San Luis de la Paz has liabilities related to plant equipment previously acquired that will be paid in accordance with the schedule of the Long-Term Service Agreement (LTSA). Deferred income in Green Energy Libramiento, will be incurred with future maintenance and are shown within accounts payable and other long-term liabilities in the consolidated statements of financial position. See Note 18, *Other long-term liabilities*.

3.25 Pension and other post-retirement obligations

Certain wholly owned subsidiaries of the Company maintain tax-qualified, non-contributory pension plans that cover all union employees, as well as a postretirement medical plan for eligible retirees. In addition, these subsidiaries also provide for legally required termination indemnity and seniority premiums. In applying these accounting policies, the Company has made estimates related to actuarial assumptions, including discount rates, health care cost trends and future compensation. See Note 19, *Pension and post-retirement obligation*.

Defined benefits

A benefit plan is considered to be an amount receivable by employees at retirement, usually depending on one or more factors such as age, years of service and compensation.

The liability recognized in the statements of financial position in relation to defined benefit plans is the present value of defined benefit obligations at the date of the statements of financial position, less the fair value of plan assets. Defined Benefit Obligations (DBO) are calculated annually by independent actuaries using the projected unit-cost method.

The present value of DBO is determined by discounting estimated future cash flows at the discount rates established in IAS 19, expressed in the currency in which the benefits are to be paid and with maturities approximating the terms of pension liabilities.

Actuarial gains and losses arising from adjustments and changes to actuarial assumptions are recorded directly in stockholders' equity under OCI in the year in which they accrue.

The Company determines its net financial expense (income) applying the discount rate to the net liability (asset) for defined benefits, net. Past service costs are recognized immediately in the consolidated statements of income.

Retirement benefits

Retirement benefits are paid when the employee reaches certain age and seniority conditions for the payments of these benefits.

The Company recognizes retirement benefits as a constructive obligation that will be paid to all employees once retirement ages have been reached.

Employees' Statutory Profit Sharing (ESPS) payable

The Company recognizes a liability and an expense for bonuses and ESPS, the latter based on a calculation that considers the current Tax Law. The Group recognizes a provision when it is contractually bound or when there is a past practice that gives rise to a constructive obligation.

Short-term benefits

The Company provides short-term employee benefits, which can include wages, salaries, annual bonuses and bonuses payable over the following 12 months. The Group recognizes a provision without discount, when is it contractually obligated or when the former practice has created an obligation.

Note 4 - Critical accounting estimates and judgments:

Estimates and judgments used in preparing the consolidated financial statements are constantly evaluated and are based on historical experience and other factors, including projections of future events considered to be reasonable in current circumstances.

4.1 Accounting estimations and critical assumptions

The Company prepares estimations and projections of future events to recognize certain items of its consolidated financial statements. The resulting accounting estimates recognized are likely to differ from actual results or events. The estimations and projections with a higher risk of material adjustment in the future are as follows:

Estimated goodwill impairment

The Company tests whether goodwill has suffered any impairment on an annual basis or more frequently if events or changes in circumstances indicate that it might be impaired. For the impairment tests, the recoverable amount of the CGU is determined based on calculations that require the use of assumptions. The calculations use cash flow projections based on financial budgets.

4.2 Critical accounting judgments in applying the Company's accounting policies

Basis for consolidation and classification of joint arrangements

Evaluation of the existence of control in subsidiaries, joint control or significant influence over investments in joint ventures are explained in Note 3.1, *Principles of consolidation and equity accounting*.

Deferred income tax assets

The recognition of deferred tax assets is based upon whether it is more likely than not that there will be sufficient and suitable taxable profits against which to utilize the assets in the future. Judgment is required when determining probable future taxable profits, which are estimated using the budget of

taxable income and deductible expenses that will result in taxable profits for future years. Prior to recording deferred tax assets for tax losses, relevant tax law is considered to determine the availability of the losses to offset against the future taxable profits.

Note 5 - Financial risk Management:

5.1 Financial risks

The Company's risk Management is predominantly controlled by the finance department under policies approved by the Board of Directors. Company Finance and Treasury identifies, evaluates and hedges financial risks in close co-operation with the Company's operating units. The Board provides written principles for overall risk Management, as Management defines policies covering specific areas, such as foreign exchange risk, interest rate risk, credit risk, use of derivative financial instruments and non-derivative financial instruments, and investment of excess liquidity.

Where all relevant criteria are met, hedge accounting would be applied to remove the accounting mismatch between the hedging instrument and the hedged item. This will effectively result in recognizing interest expense at a fixed interest rate for the hedged floating rate loans and inventory at the fixed foreign currency rate for the hedged purchases.

Credit risk

Financial instruments which potentially expose us to concentrations of credit risk consist primarily of cash, cash equivalents, restricted cash, accounts receivable and contract assets. We maintain a significant portion of our corporate cash and cash equivalent balances with several financial institutions thereby spreading the credit risk. Most of our accounts receivable are concentrated with entities engaged in the energy industry.

These industry concentrations may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, political, industry or other conditions. Receivables are generally collateralized, however the credit risk posed by industry concentration is offset by the diversification and creditworthiness of our customer base.

We are also exposed to credit risk as revenues are derived from a limited number of customers, in some cases, under long-term agreements. The prolonged failure of any of these customers to fulfill contractual obligations or make required payments could have a substantial negative impact on our consolidated results of operations and financial condition. However, Management considers that the risk derived from the above is minimal based on accounts receivables track record and since its major customers pay on a monthly basis.

The Group is responsible for managing and analyzing each of its new customer's credit risk prior to determining exposure and additional requirements. If clients are rated independently these ratings are used; otherwise we assess the quality credit of the customer based on their financial situation, past experience and other factors.

The allowance for doubtful accounts represents an estimate of the losses arising from customer inability to make required payments. Estimations are required in order to determine the allowance for doubtful accounts. The Group conducts evaluations of its customers and adjust: a) the credit limits based on payment history and b) current customer solvency information, aging of the accounts receivable portfolio, historic collection experience and legal situation.

Cash and cash equivalents are subject to limited credit risk because they are kept in financial institutions with high creditworthiness, with which the Group holds short-term investments locally rated: BBVA Bancomer (BBB+ to A-), Citibanamex (BBB+ to A-), Citibank (BBB+ to A), Intercam (A) and Invex (AA- to A+).

Liquidity risk

Cash flow projections are prepared by Management, who continually monitors cash flow projections and liquidity requirements to ensure enough cash levels. Projections consider the Company's financing plans and compliance with minimum financial ratios and legal or regulatory requirements.

The following table shows the Group's liabilities grouped per maturity date as of December 31, 2019 and 2018. The amounts shown in the table are undiscounted contractual cash flows:

2019	Less than 1 years	Between 1 and 5 years	More than 5 years	Total
Accounts payable and accrued expenses	$ 178,170	$	$	$ 178,170
Related parties	484			484
Long-term debt	27,520	173,720	632,100	833,340
Interest of long-term debt	54,977	240,369	250,503	545,849
Related party long-term debt			162,512	162,512
Interest of related party long-term debt	15,888	70,612	127,100	213,600
Other long-term liabilities		4,958	18,596	23,554
Total	$ 277,039	$ 489,659	$ 1,190,811	$ 1,957,509

2018	Less than 1 years	Between 1 and 5 years	More than 5 years	Total
Accounts payable and accrued expenses	$ 170,190	$	$	$ 170,190
Related parties	815			815
Long-term debt	15,480	143,620	689,720	848,820
Interest of long-term debt	56,554	208,202	347,888	612,644
Related party long-term debt			195,733	195,733
Interest of related party long-term debt	20,045	69,856	187,370	277,271
Other long-term liabilities		16,566	22,358	38,924
Total	$ 263,084	$ 438,244	$ 1,443,069	$ 2,144,397

5.2 Additional risks; We own, operate, acquire and develop non-regulated electric generation and gas compression facilities that are subject to risks that could adversely affect our results of operations, financial condition and/or cash flows. Risks include, but are not limited to, items such as shown below.

- Operations risks associated with operating the plants, including the breakdown or failure of power generation equipment, transmission lines, or other necessary equipment leading to unplanned outages or other operational issues, operator error, performance below expected output or efficiency levels, labor disputes, force majeure or other catastrophic events;

- Our marketing and trading activities of un-contracted capacity from some of our power companies do not fully remove the exposure to market risks;

- Transmission constraints within a number of our core regions;

- Our reliance on the joint venture partners, where we do not exercise day-to-day control;

- Our ability to obtain adequate insurance coverage for all losses we might incur in the event of loss or damage to a power subsidiary;

Contractual obligations and covenants (power purchase, gas compression and fuel supply agreements):

- Contractual covenants that require, among other things, project availability and generation minimums, maintenance of certain types and levels of insurance, compliance with obligations and scheduled payments and for the respective project entity to be financially viable. Should a project be out of compliance with one or more of its contractual obligations, the counterparty, if allowed under the agreement, may declare an event of default under the contract. If such an event of default were uncured it could, under certain circumstances, lead to the cancellation of the respective agreement.

- Disruption of fuel supply to the power subsidiaries or termination of fuel supply and transportation agreements.

- Campeche's fuel supply agreement. In accordance with the current Mexican energy reform, the fuel supply agreement originally provided by Pemex Gas y Petroquímica Básica (Pemex), was terminated in 2017. In consideration of the Energía Campeche's location and its natural gas infrastructure, executing a new fuel supply arrangement at similar terms to the previous contract, or at all, has been difficult.

This resulted in the subsidiary being dispatched on diesel, which is not as favorable as being dispatched on natural gas. However, the Company is negotiating fuel agreements with other gas suppliers in order to execute future gas agreements. The lack of available natural gas in Campeche and the negative impact to the subsidiary is the subject of multiple disputes between Energía Campeche and Pemex, as well as Energía Campeche and Federal Electricity Commission (CFE, by its initials in Spanish) under the power purchase agreement. The Company is currently in an Arbitration Procedure ruled by the International Chamber of Commerce in order to claim and defend its position against the notification of the event of default made by the CFE on 2019 and 2018. Management expects this proceeding to be resolved during the 2nd quarter of 2020.

5.3 Capital Management:

The Company manages its capital to ensure that it will be able to continue as a going concern and comply with applicable regulations. The capital structure of the Company consists of capital stock contributions, related party long-term debt and long-term debt, See Note 16, *Debt*. Additionally, the Company is not subject to any externally imposed requirements for the Management of its capital.

Note 6 - Segment information:

6.1 Description of segments and principal activities.

CEO, CFO and FP&A (denominated as CODM under IFRS 8, *Operating Segments*), examine the Group's performance per type of revenues and has identified four (4) reportable-operating segments of its business. a) Electricity generation, b) Gas compression, c) Joint ventures and d) Corporate.

6.2 Performance of the reportable-operating segments.

The Company CODM primarily uses the operating profit to assess the performance of the reportable operating segments. However, the Management also receives information about the segments revenue and assets on a monthly basis.

6.3 Statements of financial position and statements of income on Management's report.

The statements of financial position at December 31, 2019 and 2018 and the statements of income on Management's report for the year ended as of December 31, 2019 and the period of nine-months ended at December 31, 2018 of the reportable-operating segments are as follows:

	2019				
	Electricity generation	Gas compression	Joint ventures	Corporate	Total
Statement of financial position:					
Property, plant and equipment	$ 775,639	$ 76,326	$	$ 2,313	$ 854,278
Investments accounted for using the equity method			197,275		197,275
Intangible assets	90,057	39,572			129,629
Goodwill	49,571	403	21,563		71,537
Other assets	152,402	28,502		35,194	216,098
Total assets [1]	$ 1,067,669	$ 144,803	$ 218,838	$ 37,507	$ 1,468,817
Debt	$	$	$	($ 817,717)	($ 817,717)
Other liabilities	(195,376)	(39,622)		(261,560)	(496,558)
Total liabilities [1]	($ 195,376)	($ 39,622)	$	($ 1,079,277)	($ 1,314,275)
Statement of income on Management's report:					
Revenues:					
Lease	$ 86,440	$ 45,611	$	$	$ 132,051
Deferred rent	(16,519)				(16,519)
Lease - Net	69,921	45,611			115,532
Electricity	495,402				495,402
Operating and maintenance	51,245				51,245
Other services and others	15,439				15,439
	632,007	45,611			677,618
Cost of sales and services	(537,868)	(7,188)		(17)	(545,073)
Gross profit	94,139	38,423		(17)	132,545
General and administrative expenses and other	(22,770)	(6,344)		(3,697)	(32,811)
Share of net profit of joint ventures			23,761		23,761
Operating profit	$ 71,369	$ 32,079	$ 23,761	$ (3,714)	$ 123,495

	2018				
	Electricity generation	Gas compression	Joint ventures	Corporate	Total
Statement of financial position:					
Property, plant and equipment	$ 788,492	$ 77,836	$	$ 3,091	$ 869,419
Investments accounted for using the equity method			192,062		192,062
Intangible assets	99,110	40,821			139,931
Goodwill	49,571	403	21,563		71,537
Other assets	203,505	27,233		20,376	251,114
Total assets [1]	$ 1,140,678	$ 146,293	$ 213,625	$ 23,467	$ 1,524,063
Debt	$	$	$	($ 832,423)	($ 832,423)
Other liabilities	(259,104)	(32,533)		(261,575)	(553,212)
Total liabilities [1]	($ 259,104)	($ 32,533)	$	($ 1,093,998)	($ 1,385,635)

	2018				
Statement of income on Management's report:					
Revenues:					
Lease	$ 58,617	$ 31,495	$	$	$ 90,112
Deferred rent	(11,225)				(11,225)
Lease - Net	47,392	31,495			78,887
Electricity	370,918				370,918
Operating and maintenance	30,504				30,504
Other services	321				321
	449,135	31,495			480,630
Cost of sales and services	(370,223)	(7,574)			(377,797)
Gross profit	78,912	23,921			102,833
General and administrative expenses and other	(14,636)	(4,793)		(2,216)	(21,645)
Share of net profit of joint ventures			14,175		14,175
Operating profit	$ 64,276	$ 19,128	$ 14,175	($ 2,216)	$ 95,363

(3) Segment assets, liabilities are measured in the same way as in the financial statements. These assets are allocated based on the operations of the segment.

Note 7 - Business combination:

7.1 Business combination background:

On April 26, 2018 (business combination date, or the transaction date), Cometa acquired 100% of Saavi Energia, B. V. Who owns the companies as mentioned in Note 1, *History, Company activities and relevant events*.

The acquisition is considered a business combination, and therefore, it has been recorded using the purchase price method. The acquisition has been recorded by distributing the total assets acquired, including intangible assets and assumed liabilities, based on the fair values determined at the date of acquisition. The excess of the acquisition cost over the net of the fair values of the assets acquired and liabilities assumed has been recorded as goodwill.

A goodwill of $71,537 was recognized at the business combination date. The goodwill associated with this business combination is not deductible for income tax purposes. The goodwill consists on the excess of the consideration transferred over the fair value of the net assets including: a) Fair value of property, plant and equipment; b) Fair value of Interests in joint ventures; c) identification of the implicit intangible asset within the costumer relationship, that represents future benefits, and d) deferred income tax of the fair value adjustments.

The fair value of the Trade and accounts receivable considered in the business combinations approximate their carrying value. The liabilities have been determined at fair value as of the date of the business combination.

7.2 Details of the consideration transferred on April 26, 2018 are:

	2018
Consideration paid	$ 877,404
Contingent consideration *	15,981
Total purchase consideration	$ 893,385

* Contingent consideration is recorded within Other long-term liabilities in the Balance Sheet.

7.3 The fair values of the assets and liabilities at April 26, 2018, the date of acquisition are as follows:

	2018
Cash and cash equivalents	$ 15,759
Restricted cash	45,303
Other current assets	126,507
Total current assets	187,569
Notes receivable from joint ventures	5,349
Property, plant and equipment	888,489
Investments accounted for using the equity method	171,903
Deferred income tax assets	3,771
Intangible assets	146,798
Deposits and other assets	1,701
Total assets	$1,405,580
Current liabilities	$ 158,817
Current portion of long-term debt	318,845
Deferred income tax	70,564
Other long-term liabilities	27,214
Pension and other post-retirement obligations	8,292
Total liabilities	583,732
Net assets	821,848
Goodwill	71,537
Implied net assets	$ 893,385

7.4 The fair values of the assets and liabilities at the date of acquisition was estimated in accordance with the following Methodology:

Property, plant and equipment. Actual replacement costs of an asset, less depreciation due to physical, functional and economic factors.

Investment in subsidiary. Present value of discounted cash flows.

Customer relationship. Multi-period excess earnings method under the income approach. Customer relationships are contract-based intangible assets product of the business combination of InterGen N. V., they are assumed identifiable regardless of whether the rights are transferrable or separable from the entity. In conducting its purchase price allocation, the acquirer had allocated value to the related customer relationships, assuming to have indefinite useful lives.

Long-term debt. Present value in accordance with the cancelation value.

Unfavorable terms of the contract. A property, plant and equipment decrease was recognized for operating lease arrangements, whose terms are favorable or unfavorable compared to current market terms, which is amortized to the end of the contract. See Note 13, *Property, plant and equipment, net*.

The projections used to apply the methodologies described above was based on the business plans approved by the Administration of the Company at the time of acquisition, which subsequently served as the basis for the analysis of deterioration made by the Administration at the date of the consolidated financial statements.

The goodwill recognized by the Company represents non-separable assets due to the growth potential and development opportunities of the Company.

7.5 Contingent consideration arisen from this acquisition

Contingent consideration arisen from the business acquisition, depends on the future performance and the cash flow projections related to the generation of electricity by Energía Campeche. This consideration may be payable semi-annually on the following 4 years to InterGen N. V., if certain conditions are met.

Note 8 - Financial assets and financial liabilities:

8.1 This note provides information about the Group's financial instruments, including:

- An overview of all financial instruments held by the Group.
- Specific information about each type of financial instrument.
- Accounting policies.
- Information about determining the fair value of the instruments, including judgements and estimation uncertainty involved.

8.2 We hold the following financial instruments as of December 31, 2019 and 2018:

	2019	2018
Accounts receivable	$ 51,944	$ 46,969
Accounts receivable from related parties	2,298	6,578
Financial assets	$ 54,242	$ 53,547
Accounts payable and accrued expenses	$ 178,170	$ 170,190
Accounts payable to related parties	484	815
Current portion of long-term debt	37,260	25,401
Current portion of related party long-term debt	1,765	48,938
Long-term debt	780,457	807,022
Related party long-term debt	162,512	195,733
Other long-term liabilities	19,635	35,192
Financial liabilities	$1,180,283	$1,283,291

The Group's exposure to various risks associated with the financial instruments is discussed in Note 5, *Financial risk Management*. The maximum exposure to credit risk at the end of the reporting period is the carrying amount of each class of financial assets mentioned above.

Note 9 - Cash and cash equivalents:

9.1 For purposes of the consolidated statements of cash flows, cash and cash equivalents include cash in banks and investments in money market instruments with maturities of less than 90 days and restricted cash. Cash and cash equivalents are integrated as follows:

	2019	2018
Cash at bank and in hand	$ 41,144	$ 62,537
Deposits at call	1,449	11,474
Restricted cash	3,915	3,586
Cash and cash equivalents	$ 46,508	$ 77,597

9.2 Restricted cash - As of December 31, 2019 and 2018, $3,915 and $3,586 of the cash balances are restricted to pay Operating and Maintenance costs of Green Energy Libramiento under its investment agreements.

Restricted cash is invested in highly liquid investments and is presented within the cash and cash equivalents in the consolidated statements of financial position and in the consolidated statements of cash flows.

Note 10 - Accounts receivable:

10.1 At December 31, 2019 and 2018 the components of accounts receivable were as follows:

	2019	2018
Trade	$ 14,065	$ 38,027
Other	37,879	8,942
Accounts receivable	$ 51,944	$ 46,969

10.2 At December 31, 2019 and 2018, there is no impairment of financial assets. Consequently, we have not recognized any allowance for doubtful accounts.

Note 11 - Related party balances and transactions:

11.1 Balances with related parties at December 31, 2019 and 2018 were as follows:

	2019	2018
Accounts receivable from unconsolidated joint ventures:		
Servicios Azteca VIII, S. de R. L. de C. V.	$ 938	$ 2,517
Energía Azteca VIII, S. de R. L. de C. V.	1,210	
Other unconsolidated joint ventures	150	902
Notes receivable from unconsolidated joint ventures:		
Energía Sierra Juárez, S. de R. L. de C. V.		3,159
Accounts receivable from related parties	$ 2,298	$ 6,578
Accounts payable to unconsolidated joint ventures:		
Other unconsolidated joint ventures	$ 484	$ 815
Debt to an indirect parent company:		
El Aguila Investments S. A. R. L. - Debt	$ 162,512	$ 230,667
Interest	1,765	14,004
Debt	164,277	244,671
Current portion of long-term debt	(1,765)	48,938
Long-term debt	162,512	$ 195,733

11.2 Transactions income/(expense) with related parties for year ended as of December 31, 2019 and the period of nine-months ended December 31, 2018 were as follows:

	2019	2018
General and administrative expenses:		
Others - (ultimate Holding)	($ 93)	$ 823
Financing income:		
Interest from Energía Sierra Juárez, S. de R. L. de C. V.	138	583
Financing cost:		
Interest to El Aguila Investments S. A. R. L.	(21,492)	(14,004)

11.3 Transactions with related parties are described as follows:

Administrative services provided by others, may also incur costs on behalf of the Company and its affiliates, which are then directly billed to each associated entity. These primarily include employee costs, as well as legal and other third-party costs related to the Company's operation.

We have recorded these costs as general and administrative expenses in the consolidated statements of income and comprehensive income, for the year ended as of December 31, 2019 and the period of nine-months ended December 31, 2018.

Energía Sierra Juarez, Debt-Project Loan: As part of the purchase of ESJ, the interest rate on the loan is calculated as LIBOR plus a margin of 6.375%; the interest rate was 8.72% as of December 31, 2018. Interest income is recorded in the interest expense- Net line of the consolidated statements of income and comprehensive income. The Loan was fully paid on February 14, 2019 See Note 23, *Analysis of the financing cost, net.*

El Aguila Investments: 3 Promissory notes amounting $230,667, bearing interest at market rate. Interest is payable in annual installments on April 20, of each year. Principal is payable on April 20, 2034.

11.4 The total amount of employee's benefits granted to key Management staff or directors of the entity, overall, grouped in each of the following categories is shown as follows:

	2019	2018
Wage and salaries	$ 1,610	$ 2,337
Short and long-term direct benefits	348	132
Other benefits	382	1,219

There are no loans granted by the Company to its key Management staff.

Note 12 - Inventories:

12.1 At December 31, 2019 and 2018 the inventories were as follows:

	2019	2018
Fuel	$ 7,019	$ 8,385
Emission allowances	4,671	3,516
Inventories	$11,690	$11,901

12.2 Emission allowances

In the United States at the Federal and California state levels, several legislative initiatives have been introduced to address climate change through the imposition of nationwide and state level regulatory limits on the emissions of greenhouse gases. On October 2011, the California Air Resources Board (ARB) adopted a "cap and trade" regulation. Companies subject to the regulation are required to submit allowances (each the equivalent of one ton of carbon dioxide) to cover their annual emissions. The regulation is divided into two phases: the first phase, which started in 2013, includes all major industrial sources and electricity utilities (including in-state power generators and importers of electricity from out-of-state) and the second phase, which started in 2015, includes distributors of transportation fuels and natural gases.

Energía de Baja California sold power on a merchant basis in the California market during 2019 and 2018. The plant sold 320 megawatts, which are not covered for allowances under the cap and trade regulation.

Note 13 - Property, plant and equipment, net:

13.1 At December 31, 2019 and 2018 the components of plant were as follows:

	March 6 2018	Acquired in the business combination	Acquisition	Depreciation	December 31, 2018	Acquisition	Depreciation	December 31, 2019
Power plants	$	$ 944,890	$ 2,424	$	$ 947,314	$ 16,877	$	$964,191
Depreciation				(27,615)	(27,615)		(41,367)	(68,982)
Power plant, net		944,890	2,424	(27,615)	919,699	16,877	(41,367)	895,209
Compression plants		107,408			107,408	57		107,465
Depreciation				(4,572)	(4,572)		(6,841)	(11,413)
Compression plant, net		107,408		(4,572)	102,836	57	(6,841)	96,052
Power and compression plants, net	$	$ 1,052,298	$ 2,424	($ 32,187)	$ 1,022,535	$ 16,934	($ 48,208)	$991,261

13.2 At December 31, 2019 and 2018 the components of property, plant and equipment were as follows:

	March 6 2018	Acquired in the business combination	Acquisition	Depreciation	December 31, 2018	Acquisition	Depreciation	December 31, 2019
Power and compression Plants, net	$	$ 1,052,298	$ 2,424	($ 32,187)	$ 1,022,535	$ 16,934	($ 48,208)	$991,261
Office equipment and others		3,492			3,492			3,492
Depreciation				(343)	(343)		(737)	(1,080)
Office equipment and others, net		3,492		(343)	3,149		(737)	2,412
Right-of-use assets		1,281			1,281	13		1,294
Depreciation				(252)	(252)		(392)	(644)
Right-of-use assets, net		1,281		(252)	1,029	13	(392)	650
Unfavorable term of the contract		(173,060)			(173,060)			(173,060)
Depreciation				11,506	11,506		17,249	28,755
Unfavorable term of the Contract, net		(173,060)		11,506	(161,554)		17,249	(144,305)
Land		4,260			4,260			4,260
Property, plant and equipment, net	$	$ 888,271	$ 2,424	($ 21,276)	$ 869,419	$ 16,947	($ 32,088)	$854,278

13.3 The table below presents our unfavorable terms of the contract, liabilities amount at December 31, 2019 and 2018, which are reflected in our consolidated statements of financial position.

Contract	End of contract	2019	2018
Energía Campeche	April- 28	$ 35,388	$ 39,634
Energía Chihuahua	Aug-28	17,687	19,708
Energía Azteca X	Jun-28	69,184	77,323
Green Energy Libramiento	Sep-27	22,046	24,889
		$144,305	$161,554

13.4 At December 31, 2019 and 2018, our property accounted for as operating lease were as follows:

	2019	2018
Plants	$741,207	$724,330
Depreciation	(65,102)	(26,041)
Plants accounted for as operating lease	676,105	698,289
Land	3,085	3,085
Property accounted for as operating lease	$679,190	$701,374

13.5 At December 31, 2019 and 2018, the consolidated statements of financial position shows the following amounts as a lessor:

	2019	2018
Within property, plant and equipment:		
Right-of-use assets	$ 1,294	$ 1,281
Depreciation	(644)	(252)
Total right-of-use assets	$ 650	$ 1,029
Within the following liabilities:		
Accounts payable and accrued expenses	$ 403	$ 396
Other long-term liabilities	284	649
Total lease liabilities	$ 687	$ 1,045

13.6 The consolidated statements of income and comprehensive income shows the following amounts relating to leases at December 31, 2019 and 2018:

	2019	2018
General and administrative expenses:		
Depreciation	$ 392	$ 252
Interest expense:		
Lease interest	26	23
Lease	$ 418	$ 275

Note 14 - Investments accounted for using the equity method:

The interests in joint ventures balances reflected in the consolidated statements of financial position include unrecognized gains (losses) from our share of AOCI- Net of applicable taxes, related to derivative instruments entered into by the joint ventures.

14.1 At December 31, 2019 and 2018 our interests in joint ventures accounted for under the equity method is as follows:

	Energía Sierra Juárez		Bajío		
	Equity Investment	Share of AOCI	Equity Investment	Share of AOCI	Total equity
March 6, 2018	$	$	$	$	$
Shareholders' transaction:					
Acquired on business combination	54,311	(6,479)	130,121	(6,050)	171,903
Other	779				779
Comprehensive income pro rata share accounted for using the equity method:					
Net profit	287		13,888		14,175
Interest rate swap amortization		50		5,155	5,205
December 31, 2018	55,377	(6,429)	144,009	(895)	192,062
Shareholders' transaction:					
Equity distribution	(1,954)				(1,954)
Dividends			(16,849)		(16,849)
Comprehensive income pro rata share accounted for using the equity method:					
Net profit	1,575		22,186		23,761
Interest rate swap amortization		223		32	255
December 31, 2019	$ 54,998	($6,206)	$ 149,346	($ 863)	$ 197,275

14.2 The statements of financial position as of December 31, 2019 and 2018 of our equity method investments are summarized below:

	2019		2018	
	Bajío [2][3]	ESJ	Bajío [2][3]	ESJ
Statement of financial position:				
Current assets	$123,878	$ 17,490	$ 93,889	$ 17,490
Noncurrent assets	283,615	268,482	302,658	260,275
Total assets	407,493	285,972	396,547	277,765
Current liabilities [3]	68,897	15,115	55,140	4,293
Debt, current and long-term [4]		206,231		208,496
Other noncurrent liabilities	180,645	7,156	221,531	7,505
Total liabilities	249,542	228,502	276,671	220,294
Total equity	$157,951	$ 57,470	$119,876	$ 57,471
Share of equity	51%	50%	51%	50%
Company's pro rata share of equity [1]	$ 80,555	$ 28,735	$ 61,137	$ 28,735

14.3 The results of operations for the year ended as of December 31, 2019 and the period of nine-months ended December 31, 2018, of our equity method investments are summarized below:

	2019		2018	
	Bajío	ESJ	Bajío	ESJ
Statement of income:				
Net revenues [3]	$ 291,931	$ 47,008	$ 268,988	$ 36,129
Net income	43,501	3,150	27,231	574
Company's pro rata share of net income	22,186	1,575	13,888	287

(1) The difference between our Interests in joint ventures balance and our pro rata share of equity is the fair value adjustment recognized as part of the business combination at the acquisition date.

(2) The statements of financial position and income statements for the Bajío Project represents the assets, liabilities, equity, revenue and costs of Energía Azteca VIII and Compresión Bajío.

(3) Within total revenues for the Energía Azteca VIII there is approximately $28,018 and $30,163 of intercompany revenues for the years ended December 31, 2019 and 2018 respectively. There are offsetting costs of revenues included within the operating profit line. These revenues and costs represent transactions between the Energía Azteca VIII and Compresión Bajío and are presented on a gross basis in the above summary. In addition, the associated intercompany accounts receivable and accounts payable as of December 31, 2019 and 2018 of approximately $3,643 and $3,432 are also presented on a gross basis within the current assets and current liabilities lines.

(4) The current portion of long-term debt of ESJ as of December 31, 2019 and 2018 is $11,493 and $10,822 respectively.

Note 15 - Goodwill and intangibles assets, net:

15.1 At December 31, 2019 and 2018 the components of customer relationship (customer) and goodwill were as follows:

	Acquired in March 6 2018	the business combination	Amortization	December 31, 2018	Amortization	December 31. 2019
Customer	$	$ 146,798	$	$ 146,798	$	$ 146,798
Amortization			(6,867)	(6,867)	(10,302)	(17,169)
Customer relationship, net	$	$ 146,798	($ 6,867)	$ 139,931	($ 10,302)	$ 129,629
Goodwill	$	$ 71,537	$	$ 71,537	$	$ 71,537

15.2 Estimated amortization expense for our finite-lived intangible assets is expected to approximate $10,302 for each of the next five years and thereafter. We will amortize the remaining balance of Customer relationship outstanding balance over the remaining weighted average life. See Note 3.18. *Intangible assets, net*.

15.3 In connection with the business acquisition, the Company determined a goodwill in accordance with Note 7, *Business combination,* as of the acquisition date.

15.4 We tests whether goodwill has suffered any impairment on annual basis determining for each Cash Generating Units (CGU), the recoverable amount using the higher between a) the fair value less costs of disposal and b) the value in use and then, comparing it to the carrying amount of the net assets excluding outflows associated with financing (interest-bearing debt, dividends and interest payable).

15.5 The fair value less costs of disposal require i) calculations of cash flow projections based on financial budgets approved by Management, including revenue and generation forecasts, projected capital and maintenance expenditures; ii) the time value of the money, applying the appropriate discount rate to those future cash flows. At December 31, 2019 and 2018 the discount rate determined was 8.1% and 10.1% respectively and no impairment was identified. The fair value analysis was based on the income approach using significant unobservable inputs (Level 3). The key assumptions used in the fair value less costs of disposal method was:

Discount rate: Reflects the specific risks related to the market rates of the industry in which we operate.

Revenue, operating costs of sales and services and general and administrative expenses: Was determined in accordance with our contractual agreement except for the fuel price which is determined in accordance with the expected market conditions.

Note 16 - Debt:

16.1 At December 31, 2019 and 2018 our consolidated long-term debt consisted of the following:

	Final maturity	2019 Current	2019 Long-term	2019 Total	2018 Current	2018 Long-term	2018 Total
Senior Secured Notes	Apr-35	$ 27,520	$ 805,820	$833,340	$ 15,480	$ 833,340	$ 848,820
Accrued interest		9,740		9,740	9,921		9,921
Deferred financing costs, net			(25,363)	(25,363)		(26,318)	(26,318)
		$ 37,260	$ 780,457	$817,717	$ 25,401	$ 807,022	$ 832,423

16.2 Senior Secured Notes offered by Cometa in U. S. dollars, bearing interest at 6.375%, through April 2035. Principal and interest are payable in semi-annual installments in accordance with the amortization schedule started on October 2018, through April 2035.

16.3 Amortization of deferred financing cost for the year ended as of December 31, 2019 and the period of nine-months ended December 31, 2018 was $955 and $677 respectively. See Note 23, *Analysis of the financing cost, net*.

16.4 The notes were issued in connection with the proposed acquisition of InterGen (International) B. V. (now Saavi Energia B. V.), its subsidiaries and joint ventures. Saavi Energia B. V. is a wholly-owned subsidiary of Cometa Energía, S. A. de C. V., this offering of notes was part of the financing for the consummation of the acquisition.

The Group used the proceeds from the issuance of the notes to: i) pay a substantial portion of the purchase price for the acquisition; ii) repay all amounts outstanding in respect of InterGen N. V. Mexico's Consolidated Subsidiaries Debt, and iii) pay transaction costs and expenses.

16.5 As of December 31st, 2019 and 2018, the market value of the Senior Secured Notes traded at 109.38 and 93.34, respectively. Senior Secured Notes are classified in level 1 on public stock exchanges for which quoted prices are readily available.

16.6 The Senior Secured Notes establish certain positive and negative covenants, which have been duly met by December 31, 2019 and 2018.

The following is a summary of the main covenants of the debt above mentioned:

- Limitations on capital investments.
- Permits.
- Know-Your-Customer's documentation.
- Restrictions on dividend payments.
- Restrictions on incurrence of debt.
- Insurance payments.
- Restrictions on sales, transfers or leases of properties.

- Not make any loans other than permitted ones.
- Not issue any equity interests or any other security convertible into any other equity interests in the borrower's capital to any person other than to the sponsor and the equity holder.
- Not make any restricted payments unless each of the applicable conditions are satisfied.
- Not enter into any agreement that modifies any finance document or creates any Lien

As of December 31, 2019, and 2018, the Group complied with the covenants mentioned above.

Note 17 - Deferred rent:

At December 31, 2019 and 2018, our Deferred rent liabilities reflected in our consolidated statements of financial position, and the timing of reversal are as follows.

Contract	Liability increase until	End of contract	2019	2018
Energía Campeche	Apr-22	Apr-28	$20,404	$ 8,570
Energía Chihuahua	Jan-23	Aug-28	9,742	3,053
Energía Azteca X		Jun-28	(2,402)	(398)
Deferred rent			$27,744	$11,225

Note 18 - Other long-term liabilities:

18.1 At December 31, 2019 and 2018, Other long-term liabilities were as follows:

	2019				2018			
	Current		Non-current		Current		Non-current	
	Principal	Interest	Principal	Interest	Principal	Interest	Principal	Interest
Energía San Luis de la Paz	$ 1,029	$ 27	$ 11,043	$ 6,499	$ 988	$ 23	$ 11,522	$ 7,074
Green Energy Libramiento			2,905	1,014			2,934	798
Other	403		284				431	184
Contingent consideration			1,809				15,981	
Total	$ 1,432	$ 27	$ 16,041	$ 7,513	$ 988	$ 23	$ 30,868	$ 8,056

18.2 Energía San Luis de la Paz acquired plant equipment that will be paid in accordance with the Equivalent Operating Hours (EOH) of our power plant until 2038 in accordance with our forecast, Interest was computed using a 5% discount rate.

18.3 The Maintenance fee of Green Energy Libramiento is deferred until a maintenance occurs, we do not expect to have a maintenance in the following year, therefore it is shown as part of the non-current liabilities. Interest was computed using a 5% discount rate.

Note 19 - Pension and post-retirement obligations:

19.1 Certain wholly owned subsidiaries as Saavi Operaciones México and GDD de Personal, maintain tax-qualified, non-contributory pension plans that cover all union employees. Saavi Operaciones México also has a post-retirement medical plan for eligible retirees. In addition, the two entities listed above, maintain the following:

- Termination Indemnity - legally required severance for all employees equivalent to three months of pay.

- Seniority Premium - legally required severance for all employees with fifteen or more years of employment who are dismissed, with or without cause, or who resign. This is equivalent to twelve days of pay for every year of service but cannot exceed two times an individual employee's annual salary.

All plans, as well as the termination indemnity and seniority premium liabilities, are denominated in Mexican pesos. The amounts in the following tables are all presented at the U.S. dollar to Mexican peso spot rate at December 31, 2019 and 2018.

19.2 The components of the Company's total periodic benefit costs for the year ended December 31, 2019 and 2018:

	December 31, 2019				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Service cost	$ 516	$ 42	$ 88	$ 66	$ 712
Interest cost	566	50	213	81	910
Expected return on plan assets	(52)				(52)
Net transition obligation amortization			12		12
Net prior service cost amortization	4			1	5
Net loss/(gain) amortization	16	(3)	2	(22)	(7)
Total periodic benefit cost	$1,050	$ 89	$315	$126	$ 1,580

	December 31, 2018				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Service cost	$ 548	$ 59	$123	$ 48	$ 778
Interest cost	566	57	127	45	795
Expected return on plan assets	(76)				(76)
Net transition obligation amortization			13		13
Net prior service cost amortization	4			1	5
Net loss/(gain) amortization		5	13	(8)	10
Total periodic benefit cost	$1,042	$121	$276	$ 86	$ 1,525

19.3 The projected benefit obligation at December 31, 2019 and 2018 which is reflected in the other long-term liabilities line in the consolidated statements of financial position, was as follows:

	December 31, 2019				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Projected benefit obligation at beginning of year	$ 9,086	$ 469	$ 2,303	$ 990	$ 12,848
Amount recognized in AOCI at beginning of year	(677)	(109)	(428)	200	(1,014)
Accrued benefit cost at beginning of year	8,409	360	1,875	1,190	11,834
Net periodic benefit cost	1,660	92	315	127	2,194
Benefits paid	(65)	(57)	(146)		(268)
Accrued benefit cost at end of year	10,004	395	2,044	1,317	13,760
Amount recognized in AOCI at end of year	284	146	302	(394)	338
Projected benefit obligation at end of year	$ 10,288	$ 541	$ 2,346	$ 923	$ 14,098

	December 31, 2018				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Projected benefit obligation at beginning of year	$ 8,050	$ 439	$ 2,135	$ 872	$ 11,496
Amount recognized in AOCI at beginning of year	(721)	(114)	(450)	198	(1,087)
Accrued benefit cost at beginning of year	7,329	325	1,685	1,070	10,409
Net periodic benefit cost	1,127	73	311	120	1,631
Benefits paid	(47)	(38)	(121)		(206)
Accrued benefit cost at end of year	8,409	360	1,875	1,190	11,834
Amount recognized in AOCI at end of year	677	109	428	(200)	1,014
Projected benefit obligation at end of year	$ 9,086	$ 469	$ 2,303	$ 990	$ 12,848

Only the Saavi Operaciones México pension plan has plan assets. These plan assets totaled approximately $632 and $600 at December 31, 2019 and 2018. The remaining plans remain unfunded.

19.4 Amounts related to these plans included in accumulated other comprehensive income as of December 31, 2019 and 2018 were as follows:

	December 31, 2019				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Net transition obligation	$ -	$ -	$ 12	$ -	$ 12
Net prior service cost	4	-	-	1	5
Net gain (loss)	16	-	2	(21)	(3)
Other	399	-	279	(399)	279
AOCI	$419	$ -	$ 293	($ 419)	$ 293

	December 31, 2018				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Net transition obligation	$ -	$ -	$ 10	$ -	$ 10
Net prior service cost	44	-	-	6	50
Net gain (loss)	-	5	12	(4)	13
AOCI	$ 44	$ 5	$ 22	$ 2	$ 73

19.5 The actuarial assumptions were as follows:

Weighted-average assumptions to determine benefit obligation at December 31, 2019 and 2018:

	2019 (%)	2018 (%)
Discount rate	9.50	9.50
Return on plan assets	9.50	9.50
Rate of compensation increase	4.50	4.50
Social security increase	3.50	3.50
Long-term inflation	3.50	3.50
Weighted-average assumptions to determine net periodic benefit cost for the years ended December 31, 2019 and 2018:		
Discount rate	8.75	8.25

Return on plan assets	9.25	9.00
Rate of compensation increase	4.50	4.50
Social security increase	3.50	3.50
Long-term inflation	3.50	3.50

19.6 Based on current assumptions, the Company expects to make the following benefit payments over the next ten years:

	2019 -Termination Post-Retirement				
	Pension plan	Seniority premium	Indemnity	Medical	Total
2019	$ 69	$ 63	$ 248	$ -	$ 380
2020	83	73	237	-	393
2021	94	78	230	-	402
2022	108	85	223	-	416
2023	123	93	218	-	434
2024-2028	3,399	505	1,651	-	5,555

	2018 - Termination Post-Retirement				
	Pension plan	Seniority premium	Indemnity	Medical	Total
2019	$ 47	$ 38	$ 121	$ -	$ 206
2020	57	49	126	-	232
2021	65	52	130	-	247
2022	77	62	134	-	273
2023	88	67	138	-	293
2024-2028	2,370	439	1,019	-	3,828

The Company is not expected to make contributions to any of the plans during 2020.

Note 20 - Stockholders' equity:

20.1 At an extraordinary Stockholders' Meeting held on March 6, 2018, the stockholders agreed to constitute the Company with 50,000 shares Class I of the capital stock of $3.

At an extraordinary Stockholders' Meeting held on March 20 and May 30, 2018, the stockholders increased 1,705,198,215 shares Class II of the capital stock by $92,707 by means of cash contributions.

20.2 After the previous increases, capital stock at December 31, 2019 and 2018, is composed as follows:

Shares	Description	Total
50,000	Class I: representing the fixed portion of equity without withdrawal rights	$ 3
1,705,198,215	Class II: representing the variable portion of equity with withdrawal rights	92,707
	Capital stock at December 31	$ 92,710

20.3 Class I shares have the following characteristics: grant voting rights at any Shareholders meeting to be held. Class II shares have the following characteristics: grant voting rights at any Shareholders meeting to be held.

20.4 Net income under Mexican Financial Reporting Standards of every subsidiary is subject to the legal requirement that at least 5% of the income for each year is intended to increase the legal reserve until it is equal to one fifth of the amount of the capital stock.

20.5 Dividends to be paid of the subsidiaries will be free from income tax if they come from Net Tax Profit Account (CUFIN, by its Spanish acronym). Any dividends paid in excess of CUFIN and Reinvested CUFIN will cause a tax equivalent to 42.86% if they are paid on 2020. The current tax is payable by the Company and may be credited against its income tax of the year or the following two years. Dividends paid coming from profit previously taxed by income tax are not subject to tax withholding or additional tax payment. The net contribution capital account (CUCA, by its Spanish acronym) represent the capital stock contributions free from income tax when its returned.

At December 31, 2019 and 2018, the CUFIN and CUCA is as follows:

	2019	2018
Net tax profit account	$	$
Net contribution capital account	96,816	94,161

Note 21 - Analysis of revenues:

21.1 An analysis of the revenues for the year ended December 31, 2019 and the period of nine-months ended December 31, 2018 is shown in the Note 6, *Segment information*.

21.2 Our electricity generation segment derives revenue from the transfer of goods (electricity) and ancillary services (maintenance and other) over time.

21.3 At December 31, 2019 and 2018 we recognized the following assets related to contracts:

	2018	Reverse	Post	2019
Operating and maintenance services	$ 4,335	($ 4,335)	$ 3,706	$ 3,706
Electricity sales	53,554	(53,554)	49,599	49,599
Noncurrent assets	441	(441)	1,349	1,349
Total assets	$58,330	($58,330)	$54,654	$54,654

21.4 Significant changes in contract assets - Contract assets are billed and collected in the following month period in all cases, the contract assets of the electricity sales are determined in accordance with the gas consumptions and electricity consumptions at the rates stipulated in our contracts. There are no liabilities unrecognized in relation to costs to fulfill our gas supply contracts.

21.5 The amount from operation and maintenance revenues, for the remaining performance obligations after December 31, 2019 and 2018 are shown below:

	2019	2018
2019	$	$ 46,705
2020	46,811	46,811
2021	46,687	46,687
2022	46,692	46,692
2023	46,692	46,692
2024	46,707	46,707
Thereafter	307,510	307,510
Total	$541,099	$ 587,804

21.6 Due to the characteristics of the power purchase contracts at the Energía Azteca X, Energía Campeche, Energía Chihuahua, Energía San Luis de La Paz, and Compression Services of Compresión Altamira and Green Energy Libramiento consolidated subsidiaries, the power capacity and compression services are represented under IFRS 16, *Leases*, as operating leases. Operating lease income includes minimum lease payments, such as capacity payments and contingent rentals, and was $115,532 and $78,887 for the year ended and of December 31, 2019 and for the nine-months period ended December 31, 2018.

21.7 Estimated minimum lease receivables, which do not include contingent rentals, to be received under operating leases subsequent to December 31, 2019 and 2018, are as follows:

	2019	2018
2019	$	$ 126,576
2020	111,456	110,954
2021	112,211	111,722
2022	101,311	100,866
2023	98,022	97,590
2024	97,461	97,031
Thereafter	695,898	733,483
	$1,216,359	$ 1,378,222

Note 22 - Analysis of cost of sales and general and administrative expenses:

An analysis of the nature of relevant costs and expenses classified by function in the consolidated statements of income and comprehensive income for the year ended and of December 31, 2019 and for the nine-months period ended December 31, 2018 is as follows:

	2019	2018
Fuel	$ 302,625	$ 277,392
Operation and maintenance	83,703	23,648
Interconnection	73,619	22,170
Fuel transportation	54,017	28,921
Depreciation	31,204	20,681
Pension plan and other	1,580	4,630
Currency exchange gains	(1,675)	
Other		355
Costs	545,073	377,797
Amortization of intangible assets	$ 10,302	$ 6,867
Wage, salaries and technology information	9,472	7,878
Management service and fee	5,339	2,525
Insurance	3,773	2,998
Duties and non-site property taxes	3,041	782
Depreciation	884	595
Expenses	32,811	21,645
Total	$ 577,884	$ 399,442

Note 23 - Analysis of the financing cost, net:

23.1 The financing income for the year ended and of December 31, 2019 and for the nine-months period ended December 31, 2018 is composed as follows:

	2019	2018
Banks deposits and others	$ 1,010	$ 2,297
Interest - Intercompany loans	135	236
Financing income	$ 1,145	$ 2,533

23.2 The financing cost for the year ended and of December 31, 2019 and for the nine-months period ended December 31, 2018 is composed as follows:

	2019	2018
Long-term debt	($ 53,721)	($ 37,333)
Related party	(21,492)	(14,004)
Other interest expense	(2,765)	(2,438)
Interest expense	(77,978)	(53,775)
Operating activities		(85)
Investment activities		(1)
Currency exchange loss		(86)
Other long-term debt fees		(610)
Letter of credit and fees	(4,145)	(1,889)
Amortization of deferred financing cost	(955)	(677)
Change in law financing expenses	(820)	(1,513)
Other financial expenses	(5,920)	(4,689)
Financing cost	($ 83,898)	($ 58,550)

Note 24 - Income tax:

24.1 For the year ended at December 31, 2019 and the period from March 6 to December 31, 2018, the income tax benefit (expense) are as follows:

	2019	2018
Current income tax	($ 23,315)	($ 2,460)
Deferred income tax	(1,861)	3,554
	($ 25,176)	$ 1,094

24.2 Mexico: Income tax of the year is calculated by applying a 30% rate on the taxable profit. The tax income differs from the accounting income, mainly in such items accumulated and deducted differently for accounting and tax purposes, by the recognition of inflation effects for tax purposes, as well as such items only affecting either the accounting or tax income.

Netherlands: The Dutch corporate income tax rate is 25% (19% for the first EUR 200,000) in 2019. However, this rate will be reduced in the coming years as follows:

	2019	2020	2021
Taxable amount up to €200,000	19.0%	16.5%	15.0%
Taxable amount exceeding €200,000	25.0%	22.5%	20.5%

UK Tax: The current rate of UK corporation tax rate is 19% (effective from 1 April 2017). However, from 1 April 2020 the rate of UK corporation tax will fall to 17%.

US Tax: On December 22, 2017, the President of the United States signed into law tax reform bill H.R. 1 (Act) which lowers the corporate tax rate for companies from 35 to 21%. In addition, the former 20 years loss carryover provision has been replaced and newly generated tax losses carryforward from 2018 onward may now be carried forward indefinitely, subject to certain limitations. Given the limited deferred taxes that the Company has related to the United States jurisdiction, the impact to the consolidated statements of financial position and consolidated statements of income and comprehensive income, for the year ended and of December 31, 2019 and for the nine-months period ended December 31, 2018 was not significant.

24.3 At December 31, 2019 and 2018, the main temporary differences on which the deferred income tax was recognized are analyzed as follows:

		Adjustment to the		
	2018	Statement of income	Equity	2019
Accrued expenses	$ 21,028	($ 3,551)	($ 37)	$ 17,440
Deferred rent	37,373	(29,257)		8,116
Property plant and equipment	(75,992)	19,909		(56,083)
Customer relationship	(41,979)	3,090		(38,889)
Prepaid expenses	(3,669)	1,283		(2,386)
Tax loss		6,665		6,665
Net deferred tax liability	($ 63,239)	($ 1,861)	($ 37)	($ 65,137)

24.4 As of December 31, 2019 and 2018, we had consolidated Tax losses carryforward that expire: a) Mexico in 10 years; b) Netherlands, 9 years; c) United Kingdom do not expire, and d) United States, 20 years. The Tax losses carryforwards are comprised as follows:

	2019			
Year of loss	Mexico	Netherlands	United Kingdom	United States
2014	$ 30,668	$ -	$ -	$ -
2015	30	-	-	-
2016	40,356	4,216	1	48
2017	18,570	1,237	7	161
2018	32,536	8,873	332	18,960
2019	4,535	2,827	66	10,136
Total	$ 126,695	$ 17,153	$ 406	$ 29,305

	2018			
Year of loss	Mexico	Netherlands	United Kingdom	United States
2009	$ 1,349	$ -	$ -	$ -
2010	5,195	-	-	-
2011	18	-	-	-
2012	-	-	-	-
2013	-	-	-	-
2014	30,276	-	-	-
2015	1,830	-	-	-
2016	48,910	4,216	1	48
2017	17,354	1,237	7	161
2018	31,621	8,873	332	18,960
Total	$ 136,553	$ 14,326	$ 340	$ 19,169

A tax losses carryforward of $118,192 and $170,388 was not included as of December 31, 2019 and 2018 in our deferred tax assets due to the low probability to be realized. Our assessment must cover all gross deferred tax assets, of which the largest asset relates to tax losses carryforward. Realization of a portion of our gross deferred tax assets is dependent on generating sufficient sources of future taxable income. Although realization is not assured, Management believes it is not probable that the net deferred tax asset will be realized in the foreseeable future, consequently the Group has not recorded deferred tax assets for these entities.

24.5 Taxing authorities routinely examine our tax returns. We are subject to different taxing jurisdictions, tax agreements and treaties. Management believes that the tax returns filed in the various tax jurisdictions may have positions that could be challenged by these tax authorities in the normal course of a tax audit.

If new information is identified in subsequent periods that would impact the Company's current position on certain tax matters, the Company will record the impact in the period when the new information is identified.

We had no unrecognized tax benefits and liabilities as of December 31, 2019 and 2018, related to uncertain tax positions.

24.6 The reconciliation of pre-tax income at our statutory rate to income tax expense presented in the consolidated statements of income and comprehensive income, for the year ended December 31, 2019 and for the nine-months period ended December 31, 2018 is as follows:

	2019	2018
Income before income tax	$ 40,742	$ 39,346
Effect of subsidiaries not subject to income tax	32,362	43,120
	77,104	82,466
Statutory tax rate applied to pre-tax income	30%	30%
Pre-tax income at the Mexican statutory rate	23,131	24,740
Decrease (increase) of tax expense resulting from statutory inclusions/exclusions from taxable income:		
Foreign income not taxed at statutory rate	(2,453)	9,109
Fluctuation exchange effect for tax purposes	1,008	(38,077)
Non-deductible expenses	771	387
Inflation adjustment for tax purposes	2,719	2,747
Total income tax expense (benefit)	$ 25,176	($ 1,094)

Note 25 - Consolidated statements of cash flows:

25.1 The reconciliation between the opening and closing balances in the statements of financial position for liabilities arising from financing activities, are shown below:

	2019		
	Related party	Long-term debt	Total
Balances at January 1	$ 244,671	$ 832,423	$ 1,077,094
Proceeds from issuance of long-term debt working capital		20,000	20,000
Repayment of long-term debt working capital		(20,000)	(20,000)
Repayment of debt	(68,155)	(15,480)	(83,635)
Amortization of deferred financing costs		955	955
Interest expense	21,492	53,721	75,213
Interest paid	(33,731)	(53,902)	(87,607)
Balances at December 31	164,277	817,717	982,020
Current portion of long-term debt	(1,765)	(37,260)	(39,025)
Debt	$ 162,512	$ 780,457	$ 942,995

	2018		
	Related party	Long-term debt	Total
Balances at March 6	$	$	$
Balances of the business combination		318,845	318,845
Payment and cancellation for original long-term debt		(318,845)	(318,845)
Proceeds from issuance of long-term debt working capital		67,500	67,500
Repayment of long-term debt working capital		(67,500)	(67,500)
Proceeds from issuance of debt	230,667	860,000	1,090,667
Repayment of debt		(11,180)	(11,180)
Deferred financing cost paid		(26,995)	(26,995)
Amortization of deferred financing costs		677	677
Interest expense	14,004	37,333	51,337
Interest paid		(27,412)	(27,412)
Balances at December 31	244,671	832,423	1,077,094
Current portion of long-term debt	(48,938)	(25,401)	(74,339)
Debt	$ 195,733	$ 807,022	$ 1,002,755

25.2 At December 31, 2019 there are not non-cash investing and financing activities, at December 31, 2018 the non-cash investing and financing activities is represented by the contingent consideration of $15,981 in the business acquisition.

Note 26 - Commitments and contingencies:

26.1 Power sales contract: Several of our power plants rely on power sales and gas compression contracts with one or a limited number of entities for the majority, and in some cases, all of the relevant plant's output over the term of the power sales contract. The minimum terms of power sales contracts for projects currently in operation expire between 2027 and 2035. The operations of these plants are dependent on the continued performance by customers of their obligations under the relevant power sales contracts, and in particular, on the credit quality of the purchasers. If a substantial portion of our long-term power sales contracts were modified or terminated, this could increase our exposure to market price volatility, and we could be adversely affected to the extent that we would be unable to find other customers at the same level of contract profitability. We have also contracted with various fuel suppliers and transportation providers to supply and transport fuel to our power plants.

26.2 Long term sales agreement: Certain of our subsidiaries have entered into gas turbine major maintenance LTSAs with the original equipment manufacturer of the particular gas turbines or other qualified third parties. These agreements provide for labor and supervision during scheduled inspections, repairs and overhauls of gas turbine equipment, including provisions for forced outage support. The agreements (with the exception of the agreement of Chihuahua) further allow for the supply of replacement, refurbished and critical capital spare parts required for the maintenance of the equipment in accordance with prudent industry practice.

These agreements have terms typically accommodating two or three major maintenance cycles which varies based on the equipment for each power subsidiary. These agreements may or may not contain termination provisions by us at our convenience, based on certain conditions in exchange for a fixed fee. Equivalent Operating Hours (EOH) accrued vary with output, plant cycling regimes, contractual guidelines and gas turbine events, such as trips and load shedding. The estimated annual fixed and variable amounts due under the LTSAs as of December 31, 2020 and 2021 is expected to total approximately $33,879 and $26,376 respectively. Due to the variable nature of these payments we only estimate two years of commitments.

26.3 Fuel purchase commitments: We have committed to purchase gas from different suppliers without a minimum volume of gas.

26.4 Letters of Credit (LOC): We are often required to provide guarantees and/or letters of credit to ensure contractual obligations with respect to bid performance, financing, construction and operations of our subsidiaries. We may issue guarantees in connection with obligations under our power purchase agreements, operations and maintenance contracts, management service agreements and obligations we have as determined in various purchase and sale agreements. Letters of credit relate primarily to debt service requirements, electricity sales agreements and trading requirements. The beneficiary of the guarantee and/or LOC has the ability to draw against the commitments to the extent that the contractual obligations, as defined in the related agreements, allow such draws to be made.

Cometa have maximum exposure under LOCs issued and outstanding at December 31, 2019 and 2018, are as follows:

	2019		2018	
Subsidiaries and Joint Ventures [1]	Amounts outstanding	Expirations date [2]	Amounts outstanding	Expirations date
Energía Azteca X	$ 23,047	2020	$ 22,991	2019
Energía Campeche	15,000	2020	15,000	2019
Energía Chihuahua	15,000	2020	15,000	2019
Energía San Luis de la Paz	12,904	2020	13,464	2019
Saavi Energy Solutions	11,182	2020	13,545	2019
Energía Azteca VIII	10,200	2020	10,200	2019
Compresión Altamira	7,240	2020	7,565	2019
Saavi Energía	6,982	2020	3,724	2019
Compresión Bajío	1,083	2020	2,051	2019
Energía de Baja California	838	2020	838	2019
	$103,476		$104,378	

[1]- Letters of credit outstanding related to these subsidiaries and joint ventures were issued under letter of credit provided for in Cometa Energía, S. A. de C. V.

[2]- Some letters of credit have a 2020 expiration date but automatically extend annually.

Cometa Energía, S. A. de C. V. pays LOC fees of 1.75% per annum.

Each account party pays LOC fees ranging from 2.63% to 2.75% per annum on outstanding LOCs.

26.5 Legal proceedings - We are involved in certain legal proceedings in the normal course of business. We are under the opinion that none of these proceedings will have a material adverse effect on our consolidated financial position or cash flows, individually or in the aggregate.

Note 27 - Subsequent events:

For the year ended December 31, 2019, subsequent events have been evaluated through April 28, 2020, the date which the consolidated financial statements were available to be issued.

27.1 The Company has evaluated non-recognized subsequent events. The COVID-19 outbreak is currently affecting many countries around the world, including Mexico and the United States. Due to the recent nature of these events, Management is unable to determine the financial impacts, that could range in significance, from related potential disruptions.

We continuously monitor our customers credit risks and use our judgement for modeling and understanding the implications of all scenarios on earnings as well as any other impact that this situation could bring to our business.

Fitch Ratings has recently downgraded Cometa Energía to BBB- (outlook stable, from BBB), and the international Foreign and Local Currency Long-Term ratings for Comisión Federal de Electricidad (CFE) to BBB-. CFE's rating downgrade reflect their direct linkage to Mexico's sovereign ratings.

Through April 28, 2020, we have not experienced an adverse result in our cash collections, and we have met all of our commitments. However, we continue to monitor this situation closely, and, we will be reflecting any impacts on the consolidated financial statements, if applicable, in accordance with IFRS.

27.2 In accordance with the Senior Secured Notes calendar on April 24, 2020, Cometa paid $16,340 of principal and $25,563 of interest.

Note 28 - Authorization of issuance of the consolidated financial statements:

The accompanying consolidated financial statements and notes were issued on April 28, 2020, by Mauricio del Valle (Chief Financial Officer) and Francisco Villalón (Controller).

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statement of Financial Position as of December 31, 2018 and Consolidated Statement of Income and Comprehensive Income, Change in Stockholders' Equity and Cash Flows for the nine-months period ended December 31, 2018

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Index

December 31, 2018

Contents | Page

Independent Auditor's Report ..... 1 to 3

Consolidated financial statements:

Consolidated statement of financial position 4

Consolidated statement of income and comprehensive income 5

Consolidated statement of changes in stockholders' equity 6

Consolidated statement of cash flows 7

Notes to the consolidated financial statements ..... 8 to 51



Independent Auditor´s Report

To the Board of Director and Stockholders of
Electricidad Firme de México Holdings, S. A. de C. V.:

Opinion

We have audited the consolidated financial statements of Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries (the Company), which comprise the consolidated statement of financial position as at December 31, 2018, and the related consolidated statements of income and comprehensive income, of changes in stockholders' equity and of cash flows for the year then ended and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2018, and its financial performance and its cash flows for the nine-month period ended as of December 31, 2018 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

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 Consolidated Financial Statements section of our report. We are independent of the Company in accordance with the Ethics Standards of Mexican Institute of Public Accountants together with other requirements applicable to our audit of the consolidated financial statements in Mexico. We have fulfilled our other ethical responsibilities in accordance with these requirements and standards. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRS and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated 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 Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company and subsidiaries to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the Company and subsidiaries audit. We remain solely responsible for our audit opinion.



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, S. C.

L.C.P.C. Patricia Soriano Solares
Audit Partner

Mexico City, March, 11 de 2020

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statement of Financial Position
December 31, 2018

Figures in thousands of U.S. Dollars

Assets	Notes	December 31, 2018	March 6, 2018
CURRENT ASSETS:			
Cash and cash equivalents	9	$ 77,597	$
Accounts receivable	10	46,969	3
Contract assets	21	58,330	
Accounts receivable from related parties	11	6,578	
Inventories	12	11,901	
Prepayments and other current assets	3.13	37,112	
Total current assets		238,487	3
Property, plant and equipment, net	13	869,419	
Investments accounted for using the equity method	14	192,062	
Intangible assets, net	15	139,931	
Goodwill	15	71,537	
Deferred income tax assets	24	11,300	
Other non-current assets		1,327	
Total assets		$ 1,524,063	$ 3
Liabilities and Equity			
CURRENT LIABILITIES:			
Accounts payable and accrued expenses	3.21	$ 170,190	$
Accounts payable to related parties	11	815	
Current portion of long-term debt	16	25,401	
Current portion of related party long-term debt	11	48,938	
Total current liabilities		245,344	
Long-term debt	16	807,022	
Related party long-term debt	11	195,733	
Deferred income tax liabilities	24	74,539	
Other long-term liabilities	18	38,924	
Pension and other post-retirement obligations	19	12,848	
Deferred rent	17	11,225	
Total liabilities		1,385,635	
Equity:			
Capital stock	20	92,710	3
Accumulated income		40,440	
Other comprehensive income		5,278	
Total equity		138,428	3
Total liabilities and equity		$ 1,524,063	$ 3

The accompanying notes are an integral part of these consolidated financial statements.

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statement of Income and Comprehensive Income
For the nine months period ended as of December 31, 2018

Figures in thousands of U.S. Dollars

	Notes	2018
Revenues	21	$ 480,630
Cost of sales and services	22	(377,797)
Gross profit		102,833
General and administrative expenses	22	(21,645)
Share of net profit of joint ventures accounted for using the equity method	14	14,175
Operating profit		95,363
Finance income	23	2,533
Finance cost	23	(58,550)
Finance cost - Net		(56,017)
Income before income tax		39,346
Income tax benefit	24	1,094
Net income		40,440
Comprehensive income:		
Items that will not be reclassified income:		
Remeasurement of pension and other post-retirement obligations - Consolidated entities	19	73
Items that may be reclassified to income:		
Interest rate swap in joint ventures	14	7,436
Income tax relating to these items	14	(2,231)
		5,205
Comprehensive income		$ 45,718

The accompanying notes are an integral part of these consolidated financial statements.

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statement of Changes in Stockholders' Equity
For the period of nine months ended as of December 31, 2018

Figures in thousands of U.S. Dollars

	Notes	Capital stock	Accumulated income	Other comprehensive income	Total
Balance at March 6, 2018	20	$ 3	$	$	$ 3
Shareholders' transaction:					
Capital stock increase	20	92,707			92,707
Comprehensive income:					
Net income			40,440		40,440
Items that will not be reclassified to income:					
Pension and other post-retirement obligations, net of tax - consolidated entities	19			73	73
Items that may be reclassified to income:					
Interest rate swap amortization in unconsolidated affiliates	14			5,205	5,205
			40,440	5,278	45,718
Balance at December 31, 2018		$ 92,710	$ 40,440	$ 5,278	$ 138,428

The accompanying notes are an integral part of these consolidated financial statements.

Electricidad Firme de México Holdings, S. A. de C. V. and subsidiaries

Consolidated Statement of Cash Flows
For the period of nine months ended as of December 31, 2018

Figures in thousands of U.S. Dollars

	Notes	2018
Cash flows from operating activities		
Income before income tax		$ 39,346
Adjustments for investing activities related items:		
Depreciation and amortization	13 & 15	28,143
Share of net profit of joint ventures accounted for using the equity method	14	(14,175)
Interest income	23	(236)
Adjustments for financing activities related items:		
Interest expense	25	51,337
Amortization of deferred financing costs	23 & 25	677
		105,092
Change in assets and liabilities resulting from operating activities:		
Accounts receivable		(20,367)
Accounts receivable from unconsolidated affiliates		3,001
Inventories		3,475
Prepayment and other current assets		(17,641)
Other non-current assets		374
Accounts payable and accrued expenses		22,966
Accounts payable to unconsolidated affiliates		(10,318)
Deferred rent		11,225
Other liabilities		(4,174)
Pension and other post-retirement obligations		4,630
Net cash provided by operating activities		98,263
Cash flows from investing activities		
Consideration paid for a business combination; net of cash acquired	7	(816,342)
Payments for property, plant and equipment	13	(2,424)
Proceeds from loan from related parties		2,223
Interest received		222
Net cash used in investing activities		(816,321)
Cash flows from financing activities		
Proceeds from issuance of long-term debt	25	860,000
Proceeds from issuance of long-term debt working capital	25	67,500
Proceeds from issuance of related party long-term debt	25	230,667
Repayment of long-term debt working capital	25	(67,500)
Repayment of long-term debt	25	(11,180)
Payment of deferred financing cost	25	(26,995)
Payment and cancellation for original long-term debt	25	(318,845)
Payment of derivative financial instrument		(3,290)
Capital stock contribution	20	92,710
Interest paid	23 and 25	(27,412)
Net cash provided by financing activities		795,655
Net increase in cash and cash equivalents		77,597
Cash and cash equivalents at beginning of period		
Cash and cash equivalents at end of period	9	$ 77,597
Non-cash financing and investing activities	25.3	

The accompanying notes are an integral part of these consolidated financial statements

Note 1 - History, Company activities and relevant events:

1.1 History and Company activities

Electricidad Firme de México Holdings, S. A. de C. V. (collectively with its subsidiaries, Electricidad Firme, we, our, us, Company or Group) is a direct subsidiary of El Aguila B. V. an indirect subsidiary on Actis LLP, and was incorporated on March 6, 2018 in Mexico City, with an indefinite duration.

Electricidad Firme indirectly owns Cometa Energía, S. A. de C. V. (Cometa) who owns, operates, acquires, and develops a diverse portfolio of electric generation facilities, gas compression facilities, and related infrastructure.

This portfolio includes subsidiaries that are consolidated and joint ventures accounted for under the equity method, See Note 3.1, *Principles of consolidation and equity accounting,* for further information that own and operate a natural gas-fired Combined Cycle Power Plant (CCPP) and Wind Farm (WF); Some other characteristics of the plant portfolio, such as the total megawatts, location, year of commercial operation, and characteristic of the permits to generate electric power in accordance with the Mexican Regulation such as: a) Independent Power Producer (IPP); b) External Producer (EP); c) Self Supply (SS); d) Electric Power Generation (EPG), and e) Electric Power Import (EPI) are as follows:

		Interest held by us	Year of commercial operation	Permits	Plant characteristics		
					Megawatts	Location	Type
Equity Method:							
Energía Azteca VIII	(1)	51.0	2002	IPP, SS	628	Guanajuato, Mexico	CCPP
Energía Sierra Juárez	(2)	50.0	2015	SS	156	Mexicali, Mexico	WF
Consolidated:							
Energía Campeche	(2)	100.0	2003	IPP	252	Campeche, Mexico	CCPP
Energía Chihuahua	(2)	100.0	2003	IPP, SS	271	Chihuahua, Mexico	CCPP
Energía Azteca X	(2)	100.0	2003	IPP, SS	780	Mexicali, Mexico	CCPP
Energía de Baja California	(1)	100.0	2003	EP, EPG	320	Mexicali, Mexico	CCPP
Energía San Luis de la Paz	(2)	100.0	2015	SS	214	Guanajuato, Mexico	CCPP

The portfolio also includes subsidiaries and a joint venture that own and operate Gas Compression plants; the permits of those plants were awarded by Centro Nacional de Gas. Their characteristics, such as the Million Cubic Feet (MCF) per day are as follows:

		Interest held by us	Year of commercial operation	Plant characteristics	
				MCF	Location
Equity Method:					
Compresión Bajío	(1)	51.0	2001	100.0	Querétaro, Mexico
Consolidated:					
Compresión Altamira	(2)	100.0	2014	1,300.0	Tamaulipas, Mexico
Green Energy Libramiento	(1)	100.0	2007	100.0	Querétaro, Mexico

Finally, our portfolio includes 2 subsidiaries, GDD de Personal [1] and Saavi Operaciones México [2], who provide personnel services to the companies mentioned above, as well as sub holding companies including 23 subsidiaries incorporated in the Netherlands and 3 subsidiaries incorporated in the United Kingdom.

[1] A limited liability company, S. de R. L. de C. V. with a $0.1 fixed portion of equity without withdrawal rights.

[2] A limited liability company, S. A. de C. V. with a $25 fixed portion of equity without withdrawal rights.

1.2 Relevant events

On April 26, 2018, Cometa purchased InterGen (International) B. V. (now Saavi Energia B. V.), its subsidiaries, and its joint ventures mentioned above from InterGen N. V.

The authorization of Federal Energy Regulatory Commission (FERC), the U. S. federal agency that regulates the transmission and wholesale sale of electricity and the authorization of Comisión Federal de Competencia Económica (COFECE) a Mexican organism, responsible for monitoring and guaranteeing free competition in the Mexican market, was received on March 5, 2018 and April 9, 2018, respectively.

Note 2 - Basis of preparation:

The accompanying consolidated financial statements of the Company have been prepared in accordance with International Financial Reporting Standards (IFRS) and interpretations issued by the IFRS Interpretations Committee applicable to companies reporting under IFRS. The financial statements comply with IFRS as issued by the International Accounting Standards Board (IASB).

Note 3 - Summary of significant accounting policies:

This note provides a list of the significant accounting policies adopted in the preparation of these consolidated financial statements. Our consolidated financial statements consist of Electricidad Firme de México Holdings, S. A. de C. V. and its subsidiaries.

3.1 Principles of consolidation and equity accounting

The consolidated financial statements include all the assets, liabilities, revenues, expenses and cash flows of the Company.

These consolidated financial statements include the accounts of the Company and all other entities in which we have a controlling financial interest and equity-method investments where we have significant influence. All material intercompany transactions and balances between consolidated entities have been eliminated. The net effect of the settlement of these intercompany transactions is reflected in net parent investment in the consolidated statement of financial position and in net distributions to parent in the financing activities section of the consolidated statement of cash flows.

Subsidiaries

Subsidiaries are all entities over which the Company has control, those entities are fully consolidated. The Company controls an entity when the Company is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power to direct the activities of the entity.

Intercompany transactions, balances and unrealized gains on transactions between Group companies are eliminated. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the transferred asset. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by us.

Joint arrangements

Under IFRS 11 Joint Arrangements investments in joint arrangements are classified as either joint operations or joint ventures. The classification depends on the contractual rights and obligations of each investor, rather than the legal structure of the joint arrangement. With regards to joint agreements, the Company only has joint ventures.

Joint ventures

Interests in joint ventures are accounted for using the equity method (see below), after initially being recognized at cost in the consolidated statement of financial position.

We do not consolidate the Energía Sierra Juárez, Energía Azteca VIII and Compresión Bajío because we have determined that control is shared between unrelated parties and that no one party has the power to direct the activities that most significantly impact the entities' economic performance. The partners must agree on all major decisions for each of the partnerships; as a result, we are not the primary beneficiary of them.

For total assets and liabilities of them refer to Note 14, *Investments accounted for using the equity method*.

The carrying amount of equity-accounted investments is tested for impairment in accordance with the policy adopted by us.

Equity method

Under the equity method of accounting, the investments are initially recognized at cost and adjusted thereafter to recognize the Company's share of the post-acquisition profits or losses of the investee in profit or loss, and the Company's share of movements in Other Comprehensive Income (OCI) of the investee in OCI. Dividends received or receivable from joint ventures are recognized as a reduction in the carrying amount of the investment.

When the Company's share of losses in an equity-accounted investment equals or exceeds its interest in the entity, including any other unsecured long-term receivables, the Company does not recognize further losses, unless it has incurred obligations or made payments on behalf of the other entity.

Unrealized gains on transactions between the Company and its joint ventures are eliminated to the extent of the Group's interest in these entities. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Accounting policies of equity accounted investees have been changed where necessary to ensure consistency with the policies adopted by us.

3.2 Segment reporting

Reportable-operating segments are reported in a manner consistent with the internal reporting provided to the board of Electricidad Firme. Chief Executive Officer (CEO), Chief Financial Officer (CFO) and the Finance Planning and Analysis Manager (FP&A) assesses the financial performance and position of the group and makes strategic decisions.

3.3 Business combination

The acquisition method of accounting is used to account for all business combinations, regardless of whether equity instruments or other assets are acquired. The consideration transferred for the acquisition of a subsidiary comprises the:

Fair values of the assets transferred.
Liabilities incurred to the former owners of the acquired business.
Equity interests issued by the group.
Fair value of any asset or liability resulting from contingent consideration arrangement.
Fair value of any pre-existing equity interest in the subsidiary.

Identifiable assets acquired and liabilities and contingent consideration assumed in a business combination are, with limited exceptions, measured initially at their fair values at the acquisition date.

Acquisition-related costs are expensed as incurred.

The excess of the: i) consideration transferred, and ii) acquisition-date fair value of any previous equity interest in the acquired entity, over the fair value of the net identifiable assets acquired is recorded as goodwill.

Where settlement of any part of cash consideration is deferred, the amounts payable in the future are discounted to their present value as at the date of exchange. The discount rate used is the entity's incremental borrowing rate, being the rate at which a similar borrowing could be obtained from an independent financier under comparable terms and conditions.

Contingent consideration is classified as financial liability and are subsequently remeasured to fair value with changes in fair value recognized in the consolidated statement of income and comprehensive income.

3.4 Financial instruments

The carrying amounts of cash and cash equivalents, restricted cash, receivables, accounts payable and accrued liabilities approximate fair value because of the short-term maturity of these instruments.

Classification

We classify the financial assets at amortized cost, both of the following criteria are met:

- The asset is held within a business model whose objective is to collect the contractual cash flows, and

- The contractual terms give rise to cash flows that are solely payments of principal and interest.

We reclassify debt investments classification when and only when its business model for managing those assets changes.

Recognition and derecognition

Regular way purchases and sales of financial assets are recognized on trade-date, the date on which the group commits to purchase or sell the asset. Financial assets are derecognized when the rights to receive cash flows from the financial assets have expired or have been transferred and we have transferred substantially all the risks and rewards of ownership.

Measurement

At initial recognition, we measure a financial asset at its fair value plus, transaction costs that are directly attributable to the acquisition of the financial asset.

Debt instruments

Subsequent measurement of debt instruments is represented under amortized cost methodology. These debt instruments are financial assets that are held for collection of contractual cash flows where those cash flows represent solely payments of principal and interest are measured at amortized cost. Interest income from these financial assets is included in finance income using the effective interest rate method.

Impairment

From March 6, 2018, we assess on a forward-looking basis the expected credit loss associated with its debt instruments carried at amortized cost. The impairment methodology applied depends on whether there has been a significant increase in credit risk.

For accounts receivables, the Group applies the simplified approach permitted by IFRS 9, which requires expected lifetime losses to be recognized from initial recognition of the receivables. See Note 3.11, *Accounts receivable* and Note 10, *Accounts receivable.*

3.5 Fair value measurements

Financial instruments recorded at fair value are classified by the valuation method used for each instrument, as follows:

- Level 1 - Quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2 - Information (inputs) other than budget prices included in level 1 that can be confirmed for the asset or liability, either directly (i.e., specific prices) or indirectly (i.e., derived from specific prices).
- Level 3 - Information (inputs) on the asset or liability not based on data that can be confirmed in active markets (i.e., financial models and unobservable information).

Level 2 - Interest rate swap of our Joint Venture of Energía Sierra Juárez.

The fair value measurements would incorporate various factors such as the credit standing of the counterparties involved, the nonperformance risk on the liabilities, the applicable exit market and specific risks inherent in the instrument. Credit standing and related credit discounting incorporates, as applicable and available, counterparty ratings from nationally recognized ratings agencies and credit default swap implied default probabilities as of the fair value measurement date.

Level 3 - Fair value measurements provisions in goodwill.

The starting point of the process for determining the non-recurring Level 3 fair value measurements used to recognize the impairments for goodwill are the cash flow projections based on each Cash Generating Units (CGU) business plan, including revenue and generation forecast and projected capital and maintenance expenditures. For periods not covered by contractual arrangements or that other market data is not available, these projections are dependent on the Company's views of revenue and generation forecasts, gas and carbon pricing, and projected capital and maintenance expenditures.

A financial asset or liability's classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

3.6 Foreign currency translation

Functional and presentation currency

Items included in the financial statements of each of the Company's subsidiaries are measured using the currency of the primary economic environment in which the entity operates ('the functional currency'). The consolidated financial statements are presented in US dollars, which is the Company's functional and presentation currency.

Transactions and balances

Foreign currency transactions are translated into the functional currency. We recognize in the consolidated statement of income and comprehensive income, foreign exchange gains and losses resulting from:

a) Settlement of the transactions using the exchange rates at the dates of the transactions.
b) Translation of monetary assets and liabilities denominated in foreign currencies using the exchange rate at year end.

Foreign exchange gains and losses related to borrowings are presented in the consolidated statement of income and comprehensive income, within finance costs. All other foreign exchange gains and losses (such as: accounts receivables and payables) are presented in the consolidated statement of income and comprehensive income on a net basis within Cost of sales and services or general and administrative expenses.

3.7 Revenue recognition

Revenues from the Company recognized in the statement of income and comprehensive income arise from: i) electricity sales, ii) other ancillary services and iii) power capacity and compression services. Due to the characteristics of the power capacity and compression services are represented under IFRS 16 as operating leases.

Identification of separate performance obligations

We evaluate separate performance obligations within a contract when it identifies a promise to transfer a good or service to the costumer that is distinct or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to the costumer. The Transaction price is allocated to each performance obligation based on the stand-alone selling prices. Where these are not directly observable, they are estimated based on expected cost-plus margin.

Contract assets or liabilities

We obtain rights to receive consideration from the customer and assume obligations to transfer goods or services to the customer (performance obligations) in certain contracts with a customer. The combination of those rights and performance obligations gives rise to an asset or a liability depending on the relationship between the remaining rights and the performance obligations. If the goods transferred or services rendered by us exceed the payment, a contract asset is recognized. If the payments exceed the goods transferred or services rendered, a contract liability is recognized. Customers are invoiced on a monthly basis and consideration is payable when invoiced. Unbilled sales or services are based and adjusted to the amount billed, therefore there are no significant changes to revenue amounts recognized. As of December 31, 2018, there are no contract liabilities.

Billing requirements to our customers generally result in a monthly basis billing in the following month of the good or service delivered. Once billed, payment is generally required within a month. Based on the terms of our agreements, payment is generally received at or shortly after delivery of the good or service. During the year ended December 31, 2018, there were no material credit or impairment losses recognized relating to accounts receivable balances associated with contracts with customers.

Financing components

The group does not expect to have any contracts where the period between the transfer of the promised goods or services to the customer and payment by the customer exceeds one year. As a consequence, the Group does not adjust any of the transaction prices for the time value of money.

Revenue from electricity

We recognize revenues from sales of electricity and gas since the incorporation date in accordance with IFRS 15. The analysis on revenue recognition shows that we record revenues from the sale of electricity and gas under long-term contracts based upon the output delivered provided at rates specified under the contract, unless the contract pricing terms are fixed, in this sense, revenue is recognized over time, when the client simultaneously receives and consumes the electricity and gas.

We applied the right to invoice practical expedient, when the right to consideration directly corresponds to the costumer value of our performance completed to date.

Revenues from the physical sale of electricity under short-term contracts or via the Mexican Wholesale Market (MEM) are at contractual or market rates based on the volumes delivered.

Sales are recognized when control of the products has transferred, being when the products are delivered to the client, the client has full discretion over the product and price to sell the products, and there is no unfulfilled obligation that could affect the client's acceptance of the products. Delivery occurs when the products have been delivered, and either the wholesaler has accepted the products in accordance with the sales contract, the acceptance provisions have lapsed, or the Group has objective evidence that all criteria for acceptance have been satisfied.

Revenue from these sales is recognized based on the price specified in the contract. A receivable is recognized when the products are delivered as this is the point in time that the consideration is unconditional because only the passage of time is required before the payment is due.

Other ancillary services

In addition to our generation activities, we manage as well as perform the operations and maintenance services under service contracts for certain subsidiaries in which we have an interest. Revenues from consolidated subsidiaries are eliminated in consolidation.

Revenue from providing services is recognized in the accounting period in which the services are rendered. For fixed-price contracts, revenue is recognized based on the actual service provided to the end of the reporting period as a proportion of the total services to be provided because the customer receives and uses the benefits simultaneously.

Power capacity and compression services

We analyzed power sales and compression services contracts and amendments to existing contracts in accordance with IFRS 16, "Leases". Currently, the power sales contracts and compression services contracts in place at the Energía Azteca X, Energía San Luis de la Paz, Energía Campeche, Energía Chihuahua and Energía Azteca VIII and Energía Sierra Juarez (equity method investee) power companies, as well as the Green Energy Libramiento and Compresión Altamira , meet the criteria for lease treatment. Accordingly, these power sales and compression services contracts are accounted for as operating leases. The non-contingent lease rental revenues reported under these contracts for the consolidated subsidiaries are included in lease rentals derived from power purchase and compression services agreements in the consolidated statement of income and comprehensive income.

Lease income from operating leases where the Group is a lessor is recognized in income on a straight-line basis over the lease term, See Note 3.8, *Deferred ren*t. Initial direct costs incurred in obtaining an operating lease are added to the carrying amount of the underlying asset and recognized as expense over the lease term on the same basis as lease income. The respective leased assets are included in the consolidated statement of financial position based on their nature. We did not need to make any adjustments to the accounting for assets held as lessor as a result of adopting the new leasing standard.

Finance income

Finance income from a financial asset is recognized when economic benefits will likely flow to the company and the amount of revenue can be measured reliably. The interest income is booked on a timely manner, in reference to the outstanding principal and the rate of applicable effective interest. Finance income is shown after the operating profit in the consolidated statement of income and comprehensive income.

3.8 Deferred rent

Revenues from leases are recognized on a straight-line basis (levelized) in the consolidated statement of income and comprehensive income, the difference between the lease payment and the income levelized are recognized in our consolidated statement of financial position as a Deferred rent.

In a business combination, we do not recognize the acquirer's deferred rent using the acquisition method because it does not meet the definition of an asset or liability. We recognize the liability related to deferred rent starting from the acquisition date. See Note 17, *Deferred rent*.

3.9 Insurance recoveries

We enter into insurance policies with various carriers to provide for reimbursement of incurred costs during unplanned outages as well as recovery of lost revenues. We consider "incurred costs" to be repair and maintenance costs and replacement power costs incurred in order to deliver power under a contracted position. Business interruption recoveries for lost revenues are those recoveries that relate to un-hedged positions or capacity revenues under a long-term power sales agreement.

When the insurance recovery relates to reimbursement of an incurred cost, the amount is recorded as a receivable from the insurance provider when collection is deemed probable by Management. The amount is recorded as an offset to the line item in the consolidated statement of income and comprehensive income where the incurred cost is recorded, or where the lost capacity revenue under the long-term power sales agreement would have been recorded.

For recovery of business interruption that is not directly calculable, it is our policy to recognize these recoveries only when the amount has been collected or when payment has been explicitly confirmed by the insurance provider(s), and therefore is assured of collection. The Company recognized nil of income for the proceeds received for business interruption in lease rentals - power purchase and compression services agreements in the consolidated statement of income and comprehensive income for the period from March 6 to December 31, 2018.

Insurance recoveries of nil have been recorded as a reduction to electric plant operating expenses in the consolidated statement of income and comprehensive income, for the period from March 6 to December 31, 2018. No insurance recoveries are recorded as a receivable on the consolidated statement of financial position as of December 31, 2018.

3.10 Cash and cash equivalents

We consider all highly liquid investments that are readily convertible to cash and have an original maturity when purchased of three months or less to be cash equivalents. Cash and cash equivalents held by certain consolidated subsidiaries are not restricted to specific uses within them; however, the terms of Green Energy Libramiento limit our ability to distribute those funds and use them for corporate purposes. See Note 9, *Cash and cash equivalents*, for further information on these balances.

3.11 Accounts receivable

Accounts receivable represent amounts due from customers and contracts assets and are generated by sales of goods or services provided in the normal course of the Company's operations. When collection is expected in a period of one year or less from the closing date (or in the normal operating cycle of the business if this cycle exceeds this period), they are presented as current assets. If this is not met, they are presented as non-current assets.

Other accounts receivable represent amounts arising from the Value Added Tax (VAT) in the normal course of Company's operations, which are expected to be collected over a period of one year or less from the closing date (or in the normal cycle of business operations in the event that this cycle exceeds this period), are presented as current asset. If the above is not met, they are presented as non-current assets.

Accounts receivable are recognized at fair value, less the allowance for un-collectability, when applicable. See Note 10, *Accounts receivable*.

3.12 Inventories

Inventories represents amounts of Liquid Fuel (Diesel) in certain power plants, to dispatch at the full capacity, 10 days of energy production approximately and Emission allowances inventory.

At December 31, 2018 inventories are expressed at their cost, determined through averaging. Values determined like this do not exceed their net realization value. The inventory is classified as current assets or non-current assets if it is expected to deliver said inventory within a period greater than one year from the date of consolidated statements of financial position. Cash inflows and outflows are classified as an operating activity in the consolidated statements of cash flows.

In each accounting period inventories are subject to impairment tests with the purpose of identifying obsolescence, damaged items or low market value. In the event that the amount of future economic benefits from inventory, i.e., its estimated net realization value, is lower than its net carrying amount, an impairment loss is recognized which is recorded in the cost of sales of the period presented. See Note 12, *Inventories*.

3.13 Prepayments

Prepayments represent such expenditures made by the Company where the risks and benefits inherent to the goods to be acquired or services to be received have not been transferred. Prepayments are recorded at their cost and presented in the consolidated statement of financial position as current or non-current assets, depending on the destination item. Prepayment of goods and/or services related to property, plant and equipment are included in this line. Advance payments in foreign currency are recognized at the exchange rate of the date of the transaction, without modification by subsequent exchange rate fluctuations between currencies.

Once goods and/or services related to prepayments are received, they should be recognized as an expense or an asset in the accounting period, according to their respective nature.

Prepayments are subject to impairment tests every accounting period, with the purpose of identifying if they have lost their ability to produce future benefits. In the event the amount of future economic benefits is lower than its carrying amount, an impairment loss is recognized, which is recorded in the consolidated statement of income and comprehensive income of the period it takes place.

3.14 Property, plant and equipment, net

Property, plant and equipment, which consists mainly of land, power and compression plants, capital spares and other equipment, is stated at historical cost less depreciation. Significant additions or improvements that increase cash flows or extend asset lives are capitalized while expenditures for maintenance and repairs to maintain facilities in operating condition are expensed as the work is incurred.

The cost of our property, plant and equipment is depreciated over the estimated useful life of the asset using the straight-line method less a residual value as follows:

	Useful life (years)
Power plants	15 - 40
Compression plants	20 - 40
Office equipment and other	3 - 10

Power plants and compression plants are integrated by different components that have different useful lives. The main individual components are depreciated over their individual useful life. Depreciation related to power plants and compression plants is recorded as a component of cost of sales and services in the consolidated statement of income and comprehensive income. Depreciation related to office equipment and other non-operating assets is recorded as a component of general and administrative expenses.

We evaluate the recoverability of our long-lived assets if events or changes in circumstances indicate the carrying value of these assets may not be fully recoverable. Such circumstances may include a significant decrease in the market price of a long-lived asset, a significant long-term adverse change in the manner the asset is being used or in its physical condition or a history of operating cash flow losses associated with the use of the asset. Under this guidance, impairment has occurred if an estimate of undiscounted future cash flows attributable to the long-lived assets is less than the carrying value of the assets. If impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the fair value of the assets and recording a loss only if the fair value is less than the carrying value. See Note 13, *Property, plant and equipment, net*.

Componentization requires each part of the property, plant and equipment with a cost that is significant in relation to the total cost of the items to be depreciated separately. The Company allocates the amount initially recognized in respect of an item of property, plant and equipment to its significant parts and depreciates separately each such part.

3.15 Unfavorable terms of contract

Unfavorable terms of the contract (UTC) represent a property, plant and equipment decrease, that were recognized, as part of the business combination, for operating lease arrangements, whose terms are unfavorable compared to current market terms, which is depreciated to the end of the contract using the straight-line method. See Note 13, *Property, plant and equipment, net*.

3.16 Leases

The Company has made the early adoption of IFRS 16 "Leases" as of March 6, 2018. On adoption of IFRS 16, we recognized lease liabilities measured at the present value of the remaining lease payments, discounted using the lessee's incremental borrowing rate. The weighted average lessee's incremental borrowing rate applied to the lease liabilities on April 26, 2018 was 3%. The associated right-of-use assets were measured at the amount equal to the lease liability.

The Company leases different right-to-use assets. Rental contracts are typically made for fixed periods but may have extension options. Contracts may contain both lease and non-lease components. The Company allocates the consideration in the contract to the lease and non-lease components based on their relative stand-alone prices. The right-of-use asset is depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis.

Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions.

The Right-of-use asset from the lease are recognized as property, plant and equipment and a corresponding liability at the date at which the leased asset is available for use by the Company. Each lease payment is allocated between the liability and finance cost. The finance cost is charged to consolidated statement of income over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period.

Assets and liabilities arising from a lease are initially measured on a present value basis. Lease liabilities include the net present value of the following lease payments:

- Fixed payments (including in-substance fixed payments), less any lease incentives receivable.
- Variable lease payments that are based on an index or a rate.
- Lease payments to be made under reasonably certain extension options are also included in the measurement of the liability.

The lease payments are discounted using the incremental borrowing rate, being the rate that the individual lessee would have to pay to borrow the funds necessary to obtain an asset of similar value to the right-of-use assets in a similar economic environment with similar terms, security and conditions.

To determine the incremental borrowing rate, the Company where possible, uses recent third-party financing received by the individual lessee as a starting point, adjusted to reflect changes in financing conditions since third party financing was received.

The Company is exposed to potential future increases in variable lease payments based on an index or rate, which are not included in the lease liability until they take effect. When adjustments to lease payments based on an index or rate take effect, the lease liability is reassessed and adjusted against the right-of-use assets.

Right-of-use assets are measured at cost comprising the following:

- The amount of the initial measurement of the lease liability.
- Any lease payments made at or before the commencement date less any lease incentives received.

3.17 Goodwill

The Company applies the following accounting guidelines to business acquisitions: i) purchase method is used only as a valuation rule, which requires the purchase price to be assigned to acquired assets and assumed liabilities based on their fair values at acquisition date; ii) acquired intangible assets are identified, valued and recognized, and iii) the non-assigned portion of the purchase price represents goodwill.

Goodwill is measured as described in Note 7, *Business combination*, and is included in the consolidated Statement of financial position. Goodwill is not amortized but it is tested for impairment annually, or more frequently if events or changes in circumstances indicate that it might be impaired and is carried at cost less accumulated impairment losses. Gains and losses on the disposal of an entity include the carrying amount of goodwill relating to the entity sold, See Note 15, *Goodwill and intangibles assets, net*.

3.18 Intangible assets, net

Customer-related intangible assets include, but are not limited to customer contracts and related customer relationships, acquired in a business combination, those customer relationships meet the definition of an intangible asset when legal rights are identified to protect customer relationships since it provides evidence that the entity is nonetheless able to control the expected future economic benefits flowing from the customer relationship, and are recognized at fair value at the acquisition date.

All intangible assets with finite useful lives are amortized over their useful lives (10 to 18 years). Intangible assets include the value of acquired power sales contracts. The value assigned to these contracts is being amortized on a straight-line basis over the term of the contracts. See Note 15, *Goodwill and intangibles assets, net*.

3.19 Impairment of assets

Goodwill and intangible assets that have an indefinite useful life are not subject to amortization and are tested annually for impairment, or more frequently if events or changes in circumstances indicate that they might be impaired. Other assets are tested for impairment whenever events or changes in 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. The recoverable amount is the higher of an asset's fair value less costs of disposal and value in use. Non-financial assets other than goodwill that suffered an impairment are reviewed for possible reversal of the impairment at the end of each reporting period.

3.20 Income taxes

The income tax expense or benefit for the period is the tax payable on the current period's taxable income based on the applicable income tax rate for each jurisdiction adjusted by changes in deferred tax assets and liabilities attributable to temporary differences and to unused tax losses.

The income tax expense or credit for the period is the tax payable on the current period's taxable income based on the applicable income tax rate for each jurisdiction adjusted by changes in deferred tax assets and liabilities attributable to temporary differences and to unused tax losses.

The current income tax charge is calculated on the basis of the tax laws enacted or substantively enacted at the end of the reporting period in the countries where the Company and its subsidiaries and associates operate and generate taxable income. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. It establishes provisions where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred income tax is provided in full, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements. However, deferred tax liabilities are not recognized if they arise from the initial recognition of goodwill. Deferred income tax is also 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 income or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the end of the reporting period and are expected to apply when the related deferred income tax asset is realized, or the deferred income tax liability is settled.

Deferred tax assets are recognized only if it is probable that future taxable amounts will be available to utilize those temporary differences and losses.

Deferred tax liabilities and assets are not recognized for temporary differences between the carrying amount and tax bases of investments in foreign operations where the company is able to control the timing of the reversal of the temporary differences and it is probable that the differences will not reverse in the foreseeable future.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the entity has a legally enforceable right to offset and intends either to settle on a net basis, or to realize the asset and settle the liability simultaneously.

Current and deferred tax is recognized in the consolidated statement of income and comprehensive income, except to the extent that it relates to items recognized in OCI or directly in equity. In this case, the tax is also recognized in OCI or directly in equity, respectively.

The Company has made the early adoption of IFRIC 23 "Uncertainty Tax Provision" as of March 6, 2018. On adoption of IFRIC 23, there were no impacts identified about tax provisions considered in tax calculations or tax events related to its transactions.

3.21 Accounts payable and accrued expenses

This item includes obligations with suppliers and other payables for purchases of goods or services acquired in the normal course of Company's operations as well as the VAT and other taxes different than the income tax. When collection is expected in a period of one year or less from the closing date, they are presented as current liabilities.

3.22 Derecognition of financial liabilities

We derecognize a financial liability only when it is extinguished either when the group:

- Discharges the liability by paying the creditor.
- Is legally released from primary responsibility for the liability.

When the Group makes an exchange with an existing lender of debt instruments with substantially different terms, the Group extinguishes the original financial liability and recognizes a new financial liability.

The terms are substantially different if the discounted present value of the cash flows under the new terms, including any deferred financing cost not amortized, is at least 10 per cent different from the discounted present value of the remaining cash flows of the original financial liability.

When the condition above is not met, the Group applies a qualitative assessment of the terms, based on the specific facts and circumstances in each case, for the derecognition of the financial liability.

Additionally, a substantial modification of the terms of an existing financial liability or a part of it is accounted for as an extinguishment of the original financial liability and the recognition of a new financial liability.

The difference between the carrying amount of an extinguished or transferred financial liability (or part of a financial liability) and the consideration paid, including any non-cash assets transferred or liabilities assumed, is recognized in the consolidated statement of income and comprehensive income.

3.23 Deferred financing cost

Incremental costs incurred that are directly attributable to the acquisition, issue or disposal of a financial asset or financial liability. These costs include fees and commissions paid to third parties but exclude debt premiums or discounts, financing costs or internal administrative or holding costs.

Deferred financing costs are those that would not have been incurred if the Group had not acquired, issued or disposed of the financial instrument.

When there is an exchange of debt instruments or modification of terms accounted for as an extinguishment, any costs or fees incurred are recognized as part of the gain or loss on the extinguishment. If the exchange or modification is accounted for as modification, costs or fees incurred adjust the carrying amount of the liability and are amortized over the remaining term of the modified liability.

Our debt issuance costs related to a recognized debt liability are presented as a direct deduction from the carrying amount of the related debt liability, which is consistent with the presentation of debt discounts. See Note 16, *Debt*.

Deferred financing cost is amortized using the effective interest rate of the associated financial liability. The amortization is presented as part of the financial cost in the consolidated statement of income and comprehensive income.

3.24 Other long-term liabilities

Energía San Luis de la Paz have liabilities related to plant equipment previously acquired that will be paid in accordance with the schedule of the Long-Term Service Agreement (LTSA). Deferred income in Green Energy Libramiento, will be incurred with future maintenance and are shown within accounts payable and other long-term liabilities in the consolidated statement of financial position. See Note 18, *Other long-term liabilities*.

3.25 Pension and other post-retirement obligations

Certain wholly owned subsidiaries of the Company maintain tax-qualified, non-contributory pension plans that cover all union employees, as well as a postretirement medical plan for eligible retirees. In addition, these subsidiaries also provide for legally required termination indemnity and seniority premiums. In applying these accounting policies, the Company has made estimates related to actuarial assumptions, including discount rates, health care cost trends and future compensation. See Note 19, *Pension and post-retirement obligation*.

Defined benefits

A benefit plan is considered to be an amount receivable by employees at retirement, usually depending on one or more factors such as age, years of service and compensation.

The liability recognized in the statement of financial position in relation to defined benefit plans is the present value of defined benefit obligations at the date of the statement of financial position, less the fair value of plan assets. Defined Benefit Obligations (DBO) are calculated annually by independent actuaries using the projected unit-cost method.

The present value of DBO is determined by discounting estimated future cash flows at the discount rates established in IAS 19, expressed in the currency in which the benefits are to be paid and with maturities approximating the terms of pension liabilities.

Actuarial gains and losses arising from adjustments and changes to actuarial assumptions are recorded directly in stockholders' equity under OCI in the year in which they accrue.

The Company determines its net financial expense (income) applying the discount rate to the net liability (asset) for defined benefits, net. Past service costs are recognized immediately in the statement of income.

Retirements benefits

Retirement benefits are paid when the employee reaches certain age and seniority conditions for the payments of these benefits.

The Company recognizes retirement benefits as a constructive obligation that will be paid to all employees once retirement ages have been reached.

Employees' Statutory Profit Sharing (ESPS) payable

The Company recognizes a liability and an expense for bonuses and ESPS, the latter based on a calculation that considers the current Tax Law. The Group recognizes a provision when it is contractually bound or when there is a past practice that gives rise to a constructive obligation.

Short-term benefits

The Company provides short-term employee benefits, which can include wages, salaries, annual bonuses and bonuses payable over the following 12 months. The Group recognizes a provision without discount, when is it contractually obligated or when the former practice has created an obligation.

Note 4 - Critical accounting estimates and judgments:

Estimates and judgments used in preparing the consolidated financial statements are constantly evaluated and are based on historical experience and other factors, including projections of future events considered to be reasonable in current circumstances.

4.1 Accounting estimations and critical assumptions

The Company prepares estimations and projections of future events to recognize certain items of its financial statements. The resulting accounting estimates recognized are likely to differ from actual results or events. The estimations and projections with a higher risk of material adjustment in the future are as follows:

Estimates of useful lives and residual values of property, plant and equipment

The Company estimates the useful lives of its property, plant and equipment based on Company's expertise, judgement and best practices in the industry. The useful life is the period over which an asset is expected to be available for use or the number of units expected to be obtained from the asset.

The residual value of the Company's property, plant and equipment is estimated based on the amount that the Company would currently obtain from their disposal, after deducting the estimated costs of disposal.

Estimated goodwill impairment

The Company tests whether goodwill has suffered any impairment on an annual basis or more frequently if events or changes in circumstances indicate that it might be impaired. For the impairment tests, the recoverable amount of the CGU is determined based on calculations that require the use of assumptions. The calculations use cash flow projections based on financial budgets.

4.2 Critical accounting judgments in applying the Company's accounting policies

Basis for consolidation and classification of joint arrangements

Evaluation of the existence of control in subsidiaries, joint control or significant influence over investments in joint ventures are explained in Note 3.1, *Principles of consolidation and equity accounting*.

Deferred income tax assets

The recognition of deferred tax assets is based upon whether it is more likely than not that there will be sufficient and suitable taxable profits against which to utilize the assets in the future. Judgment is required when determining probable future taxable profits, which are estimated using the budget of taxable income and deductible expenses that will result in taxable profits for futures years. Prior to recording deferred tax assets for tax losses, relevant tax law is considered to determine the availability of the losses to offset against the future taxable profits.

Note 5 - Financial risk management:

5.1 Financial risks

The Company's risk management is predominantly controlled by the finance department under policies approved by the board of directors. Company finance and treasury identifies, evaluates and hedges financial risks in close co-operation with the Company's operating units. The board provides written principles for overall risk management, as management defines policies covering specific areas, such as foreign exchange risk, interest rate risk, credit risk, use of derivative financial instruments and non-derivative financial instruments, and investment of excess liquidity.

Where all relevant criteria are met, hedge accounting would be applied to remove the accounting mismatch between the hedging instrument and the hedged item. This will effectively result in recognizing interest expense at a fixed interest rate for the hedged floating rate loans and inventory at the fixed foreign currency rate for the hedged purchases.

Credit risk
Financial instruments which potentially expose us to concentrations of credit risk consist primarily of cash, cash equivalents, restricted cash, accounts receivable and contract assets. We maintain a significant portion of our corporate cash and cash equivalent balances with several financial institutions thereby spreading the credit risk. Most of our accounts receivable are concentrated with entities engaged in the energy industry.

These industry concentrations may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, political, industry or other conditions. Receivables are generally collateralized, however the credit risk posed by industry concentration is offset by the diversification and creditworthiness of our customer base.
We are also exposed to credit risk as revenues are derived from a limited number of customers, in some cases, under long-term agreements. The prolonged failure of any of these customers to fulfill contractual obligations or make required payments could have a substantial negative impact on our consolidated results of operations and financial condition. However, management considers that the risk derived from the concentration of credit is minimal based on accounts receivables track record and since its major customers pay in a monthly basis.

The Group is responsible for managing and analyzing each of its new customer's credit risk prior to determining exposure and additional requirements. If clients are rated independently these ratings are used; otherwise we assess the quality credit of the customer based on their financial situation, past experience and other factors.

The allowance for doubtful accounts represents an estimate of the losses arising from customer inability to make required payments. Estimations are required in order to determine the allowance for doubtful accounts. The Group conducts evaluations of its customers and adjust: a) the credit limits based on payment history and b) current customer solvency information, aging of the accounts receivable portfolio, historic collection experience and legal situation.

Cash and cash equivalents are subject to limited credit risk because they are kept in financial institutions with high creditworthiness, with which the Group holds short-term investments locally rated: BBVA Bancomer (BBB+ to A-), Citibanamex (BBB+ to A-), Citibank (BBB+ to A), Intercam (A) and Invex (AA- to A+).

Liquidity risk

Cash flow projections are prepared by Management, who continually monitors cash flow projections and liquidity requirements to ensure enough cash levels. Projections consider the Company's financing plans and compliance with minimum internal liquidity ratios and legal or regulatory requirements.

The following table shows the Group's liabilities grouped per maturity date as of December 31, 2018. The amounts shown in the table are undiscounted contractual cash flows:

	Less than 1 years	Between 1 and 5 years	More than 5 years	Total
Accounts payable and accrued expenses	$ 170,152	$	$	$ 170,152
Related parties	815			815
Long-term debt	15,480	143,620	689,720	848,820
Interest of long-term debt	56,554	208,202	347,888	612,644
Related party long/term debt			195,733	195,733
Interest of related party long/term debt	20,045	69,856	187,370	277,271
Other long-term liabilities		16,566	22,294	38,860
Total	$ 263,046	$ 438,244	$ 1,443,005	$ 2,144,295

5.2 Additional risks; We own, operate, acquire and develop non-regulated electric generation and gas compression facilities that are subject to risks that could adversely affect our results of operations, financial condition and/or cash flows. Risks include, but are not limited to, items such as:

- Operations risks associated with operating the plants, including the breakdown or failure of power generation equipment, transmission lines, or other necessary equipment leading to unplanned outages or other operational issues, operator error, performance below expected output or efficiency levels, labor disputes, force majeure or other catastrophic events;
- Our marketing and trading activities of un-contracted capacity from some of our power companies do not fully remove the exposure to market risks;
- Transmission constraints within a number of our core regions;
- Our reliance on the joint venture partners, where we do not exercise day-to-day control;
- Our ability to obtain adequate insurance coverage for all losses we might incur in the event of loss or damage to a power subsidiary;

Contractual obligations and covenants (power purchase, gas compression and fuel supply agreements):

- Contractual covenants that require, among other things, project availability and generation minimums, maintenance of certain types and levels of insurance, compliance with obligations and scheduled payments and for the respective project entity to be financially viable. Should a project be out of compliance with one or more of its contractual obligations, the counterparty, if allowed under the agreement, may declare an event of default under the contract. If such an event of default were uncured it could, under certain circumstances, lead to the cancellation of the respective agreement.

- Disruption of fuel supply to the power subsidiaries or termination of fuel supply and transportation agreements.

- Campeche's fuel supply agreement. In accordance with the current Mexican energy reform, the fuel supply agreement originally provided by Pemex Gas y Petroquímica Básica (Pemex), was terminated in 2017. In consideration of the Energía Campeche's location and its natural gas infrastructure, executing a new fuel supply arrangement at similar terms to the previous contract, or at all, has been difficult.

  This resulted in the subsidiary being dispatched on diesel, which is not as favorable as being dispatched on natural gas. However, the Company is negotiating and executing fuel agreements with third parties as well as working with another gas suppliers in order to execute future gas agreements. The lack of available natural gas in Campeche and the negative impact to the subsidiary is the subject of multiple disputes between Energía Campeche and Pemex, as well as Energía Campeche and Federal Electricity Commission (CFE, by its initials in Spanish) under the power purchase agreement. The Company is currently in an Arbitration Procedure ruled by the International Chamber of Commerce in order to claim and defend its position against the notification of the event of default made by the CFE on 2018.

5.3 Capital management:

The Company manages its capital to ensure that it will be able to continue as a going concern and comply with applicable regulations. The capital structure of the Company consists of capital stock contributions, related party long-term debt and long-term debt, See Note 16, *Debt*. Additionally, the Company is not subject to any externally imposed requirements for the management of its capital.

Note 6 - Segment information:

6.1 Description of segments and principal activities.

CEO, CFO and FP&A (denominated as CODM under IFRS 8), examine the group's performance per type of revenues and has identified four (4) reportable-operating segments of its business. a) Electricity generation, b) Gas compression, c) Joint ventures and (d) Corporate.

6.2 Performance of the reportable-operating segments.

The Company CODM primarily uses the operating profit to assess the performance of the reportable-operating segments. However, the management also receives information about the segments' revenue and assets on a monthly basis.

	Electricity generation	Gas compression	Joint ventures	Corporate	Total
Statement of financial position:					
Property, plant and equipment	$ 788,492	$ 77,836	$	$ 3,091	$ 869,419
Goodwill	49,571	403	21,563		71,537
Investments accounted for using the equity method			192,062		192,062
Intangible assets	99,110	40,821			139,931
Other assets	204,044	27,233		19,837	251,114
Total assets [1]	$ 1,141,217	$ 146,293	$ 213,625	$ 22,928	$ 1,524,063
Long term debt	$	$	$	($ 832,423)	($ 832,423)
Other liabilities	(308,042)	(32,533)		(212,600)	(553,175)
Total liabilities [1]	($ 308,042)	($ 32,533)	$	($ 1,045,023)	($ 1,385,598)
Statement of income on management's report:					
Revenues:					
Lease	$ 47,392	$ 31,495	$	$	$ 78,887
Electricity	370,918				370,918
Operating and maintenance	30,504				30,504
Other services	321				321
	449,135	31,495			480,630
Cost of sales and services	(370,223)	(7,574)			(377,797)
Gross profit	78,912	23,921			102,833
General and administrative expenses and other	(14,636)	(4,793)		(2,216)	(21,645)
Share of net profit of joint ventures			14,175		14,175
Operating profit	$ 64,276	$ 19,128	$ 14,175	($ 2,216)	$ 95,363

[1] Segment assets, liabilities are measured in the same way as in the financial statements. These assets are allocated based on the operations of the segment.

Note 7 - Business combination:

7.1 Business combination background:

On April 26, 2018 (business combination date, or the transaction date), Cometa acquired 100% of Saavi Energia, B. V. who owns the companies as mentioned in Note 1, *History, Company activities and relevant events*.

The acquisition is considered a business combination, and therefore, it has been recorded using the purchase price method. The acquisition has been recorded by distributing the total assets acquired, including intangible assets and assumed liabilities, based on the fair values determined at the date of acquisition. The excess of the acquisition cost over the net of the fair values of the assets acquired and liabilities assumed has been recorded as goodwill.

A goodwill of $71,537 was recognized at the business combination date. The goodwill associated with this business combination is not deductible for income tax purposes. The goodwill consists on the excess of the consideration transferred over the fair value of the net assets including: a) Fair value of property, plant and equipment; b) Fair value of Interests in joint ventures; c) identification of the implicit intangible asset within the costumer relationship, that represents future benefits, and d) deferred income tax of the fair value adjustments.

The fair value of the Trade and accounts receivable considered in the business combinations approximate their carrying value. The liabilities have been determined at fair value as of the date of the business combination.

7.2 Details of the consideration transferred on April 26, 2018 are:

	2018
Consideration paid	$ 877,404
Contingent consideration [*]	15,981
Total purchase consideration	$ 893,385

* Contingent consideration is recorded within Other long-term liabilities in the Balance Sheet.

7.3 The fair values of the assets and liabilities at April 26, 2018, the date of acquisition are as follows:

	2018
Cash and cash equivalents	$ 15,759
Restricted cash	45,303
Other current assets	126,507
Total current assets	187,569
Notes receivable from joint ventures	5,349
Property, plant and equipment	888,489
Investments accounted for using the equity method	171,903
Deferred income tax assets	3,771
Intangible assets	146,798
Deposits and other assets	1,701
Total assets	1,405,580

	2018
Current liabilities	$ 158,817
Current portion of long-term debt	318,845
Deferred income tax	70,564
Other long-term liabilities	27,214
Pension and other post-retirement obligations	8,292
Total liabilities	583,732
Net assets	821,848
Goodwill	71,537
Implied net assets	$ 893,385

7.4 The fair values of the assets and liabilities at the date of acquisition was estimated in accordance with the following Methodology:

Property, plant and equipment. Actual replacement costs of an asset, less depreciation due to physical, functional and economic factors.

Investment in subsidiary. Present value of discounted cash flows.

Customer relationship. Multi-period excess earnings method under the income approach. Customer relationships are contract-based intangible assets product of the business combination of InterGen N. V., they are assumed identifiable regardless of whether the rights are transferrable or separable from the entity. In conducting its purchase price allocation, the acquirer had allocated value to the related customer relationships, assuming to have indefinite useful lives.

Long-term debt. Present value in accordance with the cancelation value.

Unfavorable terms of the contract. A property, plant and equipment decrease was recognized for operating lease arrangements, whose terms are favorable or unfavorable compared to current market terms, which is amortized to the end of the contract. See Note 13, *Property, plant and equipment, net*.

The projections used to apply the methodologies described above was based on the business plans approved by the Administration of the Company at the time of acquisition, which subsequently served as the basis for the analysis of deterioration made by the Administration at the date of the consolidated financial statements.

The goodwill recognized by the Company represents non-separable assets due to the growth potential and development opportunities of the Company.

7.5 Contingent consideration arisen from this acquisition

Contingent consideration arisen from the business acquisition, depends on the future performance and the cash flow projections related to the generation of electricity by Energía Campeche. This consideration may be payable semi-annual on the following 4 years to InterGen N. V., if the conditions are met.

Note 8 - Financial assets and financial liabilities:

8.1 This note provides information about the group's financial instruments, including:

- An overview of all financial instruments held by the Group.
- Specific information about each type of financial instrument.
- Accounting policies.
- Information about determining the fair value of the instruments, including judgements and estimation uncertainty involved.

8.2 We hold the following financial instruments as of December 31, 2018:

	2018
Accounts receivable	$ 46,969
Accounts receivable from related parties	6,578
Financial assets	$ 53,547
Accounts payable and accrued expenses	$ 170,719
Accounts payable to related parties	815
Current portion of long-term debt	25,401
Current portion of related party long-term debt	48,938
Long-term debt	807,022
Other long-term liabilities	35,192
Related party long-term debt	195,733
Financial liabilities	$ 1,283,820

The Group's exposure to various risks associated with the financial instruments is discussed in Note 5, *Financial risk management*. The maximum exposure to credit risk at the end of the reporting period is the carrying amount of each class of financial assets mentioned above.

Note 9 - Cash and cash equivalents:

9.1 For purposes of the statement of cash flows, cash and cash equivalents include cash in banks and investments in money market instruments with maturities of less than 90 days and restricted cash. Cash and cash equivalents are integrated as follows:

	2018
Cash at bank and in hand	$ 62,537
Deposits at call	11,474
Restricted cash	3,586
Cash and cash equivalents	$ 77,597

9.2 Restricted cash - As of December 31, 2018, $3,586 of the cash balances are restricted to pay Operating and Maintenance costs of Green Energy Libramiento under its investment agreements.

Restricted cash is invested in highly liquid investments and is presented within the cash and cash equivalents in the consolidated statement of financial position and in the consolidated statement of cash flows.

Note 10 - Accounts receivable:

10.1 At December 31, 2018 the components of accounts receivable were as follows:

	2018
Trade	$ 38,027
Other	8,942
Accounts receivable	$ 46,969

10.2 At December 31, 2018, there is no impairment of financial assets. Consequently, we have not recognized any allowance for doubtful accounts.

Note 11 - Related party balances and transactions:

11.1 Balances with related parties at December 31, 2018 were as follows:

	2018
Accounts receivable from unconsolidatedjoint ventures:	
Servicios Azteca VIII, S. de R. L. de C. V.	$ 2,517
Other unconsolidated joint ventures	902
Notes receivable from unconsolidatedjoint ventures:	
Energía Sierra Juárez, S. de R. L. de C. V.	3,159
Accounts receivable from related parties	$ 6,578
Accounts payable to unconsolidated joint ventures:	
Other unconsolidated joint ventures	$ 815
Debt to an indirect parent company:	
El Aguila Investments S. A. R. L. - Debt	$230,667
Interest	14,004
Debt	244,671
Current portion of long-term debt	48,938
Long-term debt	$195,733

11.2 Transactions [income/(expense)] with related parties for the period from March 6 to December 31, 2018 were as follows:

	2018
General and administrative expenses:	
Others – (Ultimate Holding)	$ 823
Finance income:	
Interest from Energía Sierra Juárez, S. de R. L. de C. V.	583
Financial cost:	
Interest to El Aguila Investments S. A. R. L.	(14,004)

11.3 Transactions with related parties are describes as follows:

Administrative services provided by others, may also incur costs on behalf of the Company and its affiliates, which are then directly billed to each associated entity. These primarily include employee costs, as well as legal and other third-party costs related to the Company's operation. We have recorded these costs as general and administrative expenses in the consolidated statement of income and comprehensive income, for the period from March 6 to December 31, 2018.

Energía Sierra Juarez, Debt-Project Loan - As part of the purchase of ESJ, the interest rate on the loan is calculated as LIBOR plus a margin of 6.375%; the interest rate was 8.72% as of December 31, 2018. Interest income is recorded in the interest expense, net line of the consolidated statement of income and comprehensive income. See Note 23, *Analysis of the finance cost, net*.

El Aguila Investments: 3 Promissory notes amounting $230,667, bearing interest at market rate. Interest is payable in annual installments on April 20, of each year. Principal is payable on April 20, 2034.

11.4 The total amount of employee's benefits granted to key management staff or directors of the entity, overall, grouped in each of the following categories is shown as follows:

	2018
Wage and salaries	2,337
Short and long-term direct benefits	132
Other benefits	1,219

There are no loans granted by the Company to its key management staff.

Note 12 - Inventories:

12.1 At December 31, 2018 the inventories were as follows

	2018
Fuel	$ 8,385
Emission allowances	3,516
Inventories	$11,901

12.2 Emission allowances

In the United States at the federal and California state levels, several legislative initiatives have been introduced to address climate change through the imposition of nationwide and state level regulatory limits on the emissions of greenhouse gases. In October 2011, the California Air Resources Board (ARB) adopted a "cap and trade" regulation. Companies subject to the regulation are required to submit allowances (each the equivalent of one ton of carbon dioxide) to cover their annual emissions.

The regulation is divided into two phases: the first phase, which started in 2013, includes all major industrial sources and electricity utilities (including in-state power generators and importers of electricity from out-of-state) and the second phase, which started in 2015, includes distributors of transportation fuels and natural gases.

Energía de Baja California sold power on a merchant basis in the California market during 2018. The plant sold 320 megawatts, which are not covered for allowances under the cap and trade regulation.

Note 13 - Property, plant and equipment, net:

13.1 At December 31, 2018 the components of plant were as follows:

	March 6 2018	Acquired in the business combination	Acquisition	Depreciation	December 31, 2018
Power plants	$	$ 944,890	$ 2,424	$	$ 947,314
Depreciation				(27,615)	(27,615)
Power plant, net		944,890	2,424	(27,615)	919,699
Compression plants		107,408			107,408
Depreciation				(4,572)	(4,572)
Compression plant, net		107,408		(4,572)	102,836
Power and compression plants, net	$	$ 1,052,298	$ 2,424	($ 32,187)	$ 1,022,535

13.2 At December 31, 2018 the components of property, plant and equipment were as follows:

	March 6 2018	Acquired in the business combination	Acquisition	Depreciation	December 31, 2018
Power and compression plants, net	$	$ 1,052,298	$ 2,424	($32,187)	$ 1,022,535
Office equipment and others		3,492			3,492
Depreciation				(343)	(343)
Office equipment and others, net		3,492		(343)	3,149
Right-of-use assets		1,281			1,281
Depreciation				(252)	(252)
Right-of-use assets, net		1,281		(252)	1,029
Unfavorable term of the contract		(173,060)			(173,060)
Depreciation				11,506	11,506
Unfavorable term of the contract, net		(173,060)		11,506	(161,554)
Land		4,260			4,260
Property, plant and equipment, net	$	$ 888,271	$ 2,424	($21,276)	$ 869,419

13.3 The table below presents our unfavorable terms of the contract, liabilities amount at December 31, 2018, which are reflected in our consolidated statement of financial position.

Contract	End of contract	2018
Energía Campeche	April- 28	$ 39,634
Energía Chihuahua	Aug-28	19,708
Energía Azteca X	Jun-28	77,323
Green Energy Libramiento	Sep-27	24,889
		$161,554

13.4 At December 31, 2018, our property accounted for as operating lease were as follows:

	2018
Plants	$ 724,330
Depreciation	(26,041)
Plants accounted for as operating lease	698,289
Land	3,085
Property accounted for as operating lease	$ 701,374

13.5 At December 31, 2018, the balance sheet shows the following amounts as a lessor:

	2018
Within property, plant and equipment:	
Right-of-use assets	$ 1,281
Depreciation	(252)
Total right-of-use assets	$ 1,029
Within the following liabilities:	
Accounts payable and accrued expenses	$ 396
Other long-term liabilities	649
Total lease liabilities	$ 1,045

13.5 The consolidated statement of income and comprehensive income shows the following amounts relating to leases at December 31, 2018:

	2018
General and administrative expenses:	
Depreciation	$ 252
Interest expense:	
Lease interest	23
Lease	$ 275

Note 14 - Investments accounted for using the equity method:

The interests in joint ventures balances reflected in the consolidated statement of financial position include unrecognized gains (losses) from our share of AOCI, net of applicable taxes, related to derivative instruments entered into by the joint ventures.

14.1 At December 31, 2018 our interests in joint ventures accounted for under the equity method is as follows:

	Equity Investment without AOCI	Share of AOCI	Total equity investment
Energía Azteca VIII	$ 144,009	($ 895)	$143,114
Energía Sierra Juárez	55,377	(6,429)	48,948
Investments accounted for using the equity method	$ 199,386	($ 7,324)	$192,062

Of the approximately $7,324 of unrealized losses reflected in AOCI at December 31, 2018, we expect that approximately $269 of losses (net of tax) will be transferred out of AOCI over the next twelve months as interest accrues and as settlement payments recorded in AOCI during construction are amortized. The actual impact on earnings may change as a result of fluctuations in future interest rates.

14.2 The net comprehensive income for the period from March 6 to December 31, 2018 is composed by interest rate swap amortization as follows:

	2018
Energía Sierra Juárez	$ 5,155
Energía Azteca VIII	50

14.3 The following details from March 6 to December 31, 2018 our share of earnings from joint ventures and net distributions from joint ventures:

	2018
Energía Azteca VIII and Compresión Bajío	$ 13,888
Energía Sierra Juárez	287
Share of earnings	$ 14,175

There are no distributions from Joint ventures for the period from March 6, 2018 to December 31, 2018.

14.4 The statement of financial position as of December 31, 2018 of our equity method investments are summarized below:

	Bajío Project [2]	ESJ [5]
Statement of financial position:		
Current assets	$ 93,889	$ 17,490
Noncurrent assets	302,658	260,275
Total assets	396,547	277,765
Current liabilities [3]	55,140	4,293
Debt, current and long-term [4]		208,496
Other noncurrent liabilities	221,531	7,505
Total liabilities	276,671	220,294
Total equity	$119,876	$ 57,471
Share of equity	*51%*	*50%*
Company's pro rata share of equity [I]	*$ 61,137*	*$ 28,735*

14.5 The results of operations for the period from March 6 to December 31, 2018 of our equity method investments are summarized below:

	Bajío Projects [2] [3]	ESJ [1]
Statement of income:		
Net revenues	$ 268,988	$ 36,129
Net income	27,231	574
Company's pro rata share of net income [1]	13,888	287

[1]- The difference between our Interests in joint ventures balance and our pro rata share of equity is the fair value adjustment recognized as part of the business combination at the acquisition date.

[2]- The statement of financial position and income statement for the Bajío Project represents the assets, liabilities, equity, revenue and costs of Energía Azteca VIII and Compresión Bajío.

[3]- Within total revenues for the Energía Azteca VIII there is approximately $30,163 of intercompany revenues for the years ended December 31, 2018. There are offsetting costs of revenues included within the operating profit line. These revenues and costs represent transactions between the Energía Azteca VIII and Compresión Bajío and are presented on a gross basis in the above summary. In addition, the associated intercompany accounts receivable and accounts payable as of December 31, 2018 of approximately $3,432 are also presented on a gross basis within the current assets and current liabilities lines.

[4]- The current portion of long-term debt of Compresión Bajío and ESJ is nil and $10,822 respectively as of December 31, 2018.

Note 15 - Goodwill and intangibles assets, net:

15.1 At December 31, 2018 the components of customer relationship (customer) and goodwill were as follows:

	March 6 2018	Acquired in the business combination	Amortization	December 31, 2018
Customer	$	$ 146,798	$	$ 146,798
Amortization			(6,867)	(6,867)
Customer relationship, net	$	$ 146,798	($ 6,867)	$ 139,931
Goodwill	$	$ 71,537	$	$ 71,537

15.2 Estimated amortization expense for our finite-lived intangible assets is expected to approximate $10,302 for each of the next five years and thereafter. We will amortize the remaining balance of Customer over the remaining weighted average life. See Note 3.18. *Intangible assets, net*.

15.3 In connection with the business acquisition, the Company determined a goodwill in accordance with the Note 7, *Business combination,* as of the acquisition date. At December 31, 2018 no impairment was identified. The fair value analysis was based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rate.

Note 16 - Debt:

16.1 At December 31, 2018 our consolidated long-term debt consisted of the following:

	Final maturity	Current	Long-term	Total
Senior Secured Notes	Apr-35	$15,480	$ 833,340	$ 848,820
Accrued interest		9,921		9,921
Deferred financing costs, net			(26,318)	(26,318)
		$25,401	$ 807,022	$ 832,423

16.2 Senior Secured Notes offered by the Group in U. S. dollars, bearing interest at 6.375%, through April 2035. Principal and interest are payable in semi-annual installments in accordance with the amortization schedule started on October 2018, through April 2035.

16.3 Amortization of deferred financing cost for the period from March 6 to December 31, 2018 was $677. See Note 23, *Analysis of the finance cost, net*.

16.4 The notes were issued in connection with the proposed acquisition of Saavi Energia B. V. and its subsidiaries and its equity investees or joint ventures (Saavi) by the issuer, an indirect, wholly-owned subsidiary of certain investment funds managed by Actis GP LLP (Actis) or Actis Guernsey GP Limited (An affiliate of Actis). This offering of notes is part of the financing for the consummation of the Acquisition.

The Group used the proceeds from the issuance of the notes to: i) pay a substantial portion of the purchase price for the acquisition; ii) repay all amounts outstanding in respect of InterGen N. V. Mexico's Consolidated Subsidiaries Debt, and iii) pay transaction costs and expenses.

16.5 At December 31, 2018 the fair value of the Senior Secured Notes is $803,334. The methodology used to determine the fair value is the discounted cash flows analysis.

16.6 The Senior Secured Notes establish certain positive and negative covenants, which have been duly met by December 31, 2018.

The following is a summary of the main covenants of the debt above mentioned:

- Limitations on capital investments.
- Permits.
- Know-Your-Customer's documentation.
- Restrictions on dividend payments.
- Restrictions on incurrence of debt.
- Insurance payments.
- Restrictions on sales, transfers or leases of properties.
- Not make any loans other than permitted ones.
- Not issue any equity interests or any other security convertible into any other equity interests in the borrower's capital to any person other than to the sponsor and the equity holder.
- Not make any restricted payments unless each of the applicable conditions are satisfied.
- Not enter into any agreement that modifies any finance document or creates any Lien

As of December 31, 2018, the Group complied with the covenants mentioned above.

Note 17 - Deferred rent:

At December 31, 2018, our Deferred rent liabilities reflected in our consolidated statement of financial position, and the timing of reversal for our power purchase agreements and the timing of reversal for our power purchase contracts.

Contract	Liability increase until	End of contract	2018
Energía Campeche	Apr-22	Apr-28	$ 8,570
Energía Chihuahua	Jan-23	Aug-28	3,053
Energía Azteca X		Jun-28	(398)
Deferred rent			$11,225

Note 18 - Other long-term liabilities:

18.1 At December 31, 2018, Other long-term liabilities were as follows:

		Current		Non-current	
		Principal	Interest	Principal	Interest
Energía San Luis de la Paz	18.2	$ 988	$ 23	$ 11,522	$ 7,074
Green Energy Libramiento	18.3			2,934	798
Other				16,412	184
Other long-term liabilities		$ 988	$ 23	$ 30,868	$ 8,056

18.2 Energía San Luis de la Paz acquired plant equipment that will be paid in accordance with the Equivalent Operating Hours (EOH) of our power plant until 2038 in accordance with our forecast, Interest was computed using a 5% of discounted rate.

18.3 The Maintenance fee of Green Energy Libramiento is deferred until a maintenance occurs, we do not expect to have a maintenance in the following year, therefore it is shown as part of the non-current liabilities. Interest was computed using a 5% of discounted rate.

Note 19 - Pension and post-retirement obligation:

19.1 Certain wholly owned subsidiaries as Saavi Operaciones México and GDD de Personal, maintain tax-qualified, non-contributory pension plans that cover all union employees. Saavi Operaciones México also has a post-retirement medical plan for eligible retirees. In addition, the two entities listed above, maintain the following:

- Termination Indemnity - legally required severance for all employees' equivalent to three months of pay.
- Seniority Premium - legally required severance for all employees with fifteen or more years of employment who are dismissed, with or without cause, or who resign. This is equivalent to twelve days of pay for every year of service but cannot exceed two times an individual employee's annual salary.

All plans, as well as the termination indemnity and seniority premium liabilities, are denominated in Mexican pesos. The amounts in the following tables are all presented at the U.S. dollar to Mexican peso spot rate at December 31, 2018.

19.2 The components of the Company's total periodic benefit costs for the year ended December 31, 2018:

	December 31, 2018				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Service cost	$ 548	$ 59	$ 123	$ 48	$ 778
Interest cost	566	57	127	45	795
Expected return on plan assets	(76)	-	-	-	(76)
Net transition obligation amortization	-	-	13	-	13
Net prior service cost amortization	4	-	-	1	5
Net loss/(gain) amortization	-	5	13	(8)	10
Net periodic benefit cost	1,042	121	276	86	1,525
Settlements	-	-	-	-	-
Reclassification of benefits	-	-	-	-	-
Total periodic benefit cost	$ 1,042	$ 121	$ 276	$ 86	$ 1,525

19.3 The projected benefit obligation at December 31, 2018 which is reflected in the other long-term liabilities line in the consolidated statement of financial position, was as follows:

	December 31, 2018				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Projected benefit obligation at beginning of year	$ 8,050	$ 439	$ 2,135	$ 872	$ 11,496
Amount recognized in AOCI at beginning of year	(721)	(114)	(450)	198	(1,087)
Accrued benefit cost at beginning of year	7,329	325	1,685	1,070	10,409
Net periodic benefit cost	1,127	73	311	120	1,631
Settlements					
Benefits paid	(47)	(38)	(121)		(206)
Reclassification of benefits					
Accrued benefit cost at end of year	8,409	360	1,875	1,190	11,834
Amount recognized in AOCI at end of year	677	109	428	(200)	1,014
Projected benefit obligation at end of year	$ 9,086	$ 469	$ 2,303	$ 990	$ 12,848

Only the Saavi Operaciones México pension plan has plan assets. These plan assets totaled approximately $600 at December 31, 2018. The remaining plans remain unfunded.

19.4 Amounts related to these plans included in accumulated other comprehensive income as of December 31, 2018 were as follows:

	December 31, 2018				
			Termination Post-Retirement		
	Pension plan	Seniority premium	Indemnity	Medical	Total
Net transition obligation	$ -	$ -	$ 10	$ -	$ 10
Net prior service cost	44	-	-	6	50
Net gain (loss)	-	5	12	(4)	13
AOCI	$ 44	$ 5	$ 22	$ 2	$ 73

19.5 The actuarial assumptions were as follows:

Weighted-average assumptions to determine benefit obligation at December 31, 2018:

	2018 (%)
Discount rate	9.50
Return on plan assets	9.50
Rate of compensation increase	4.50
Social security increase	3.50
Long-term inflation	3.50
Weighted-average assumptions to determine net periodic benefit cost for the years ended December 31, 2018:	
Discount rate	8.25
Return on plan assets	9.00
Rate of compensation increase	4.50
Social security increase	3.50
Long-term inflation	3.50

19.6 Based on current assumptions, the Company expects to make the following benefit payments over the next ten years:

	Termination Post-Retirement				
	Pension plan	Seniority premium	Indemnity	Medical	Total
2019	$ 47	$ 38	$ 121	$ -	$ 206
2020	57	49	126	-	232
2021	65	52	130	-	247
2022	77	62	134	-	273
2023	88	67	138	-	293
2024-2028	2,370	439	1,019	-	3,828

The Company is not expected to make contributions to any of the plans during 2019.

Note 20 - Stockholders' equity:

20.1 At an extraordinary Stockholders' Meeting held on March 6, 2018, the stockholders agreed to constitute the Company with a fix portion of the capital stock by $3.

At an extraordinary Stockholders' Meeting held on March 20 and May 30, 2018, the stockholders increased the variable portion of the capital stock by $92,745 by means of cash contributions.

20.2 After the previous increase, capital stock at December 31, 2018, is composed as follows:

Shares	Description	2018
50,000	Class I: representing the fixed portion of equity without withdrawal rights	$ 3
1,705,198,215	Class II: representing the variable portion of equity with withdrawal rights	92,707
	Capital stock at December 31, 2018	$92,710

20.3 Class I shares have the following characteristics: grant voting rights at any Shareholders meeting to be held. Class II shares have the following characteristics: grant voting rights at any Shareholders meeting to be held.

20.4 Net income under Mexican Financial Reporting Standards of every subsidiary is subject to the legal requirement that at least 5% of the income for each year is intended to increase the legal reserve until it is equal to one fifth of the amount of the capital stock.

20.5 Dividends to be paid of the subsidiaries will be free from income tax if they come from Net Tax Profit Account (CUFIN, by its Spanish acronym). Any dividends paid in excess of CUFIN and Reinvested CUFIN will cause a tax equivalent to 42.86% if they are paid on 2019. The current tax is payable by the Company and may be credited against its income tax of the year or the following two years. Dividends paid coming from profit previously taxed by income tax are not subject to tax withholding or additional tax payment.

Note 21 - Analysis of revenues:

21.1 An analysis of the revenues for the period from March 6 to December 31, 2018 is as follows:

	2018
Revenue from power capacity and compression services:	
Lease rentals	$ 78,887
Revenue from electricity:	
Electricity	370,918
Revenue from other ancillary services :	
Operating and maintenance services (O&M)	30,504
Other service contracts	321
Revenues	$480,630

21.2 Our electricity generation segment derives revenue from the transfer of goods (electricity) and ancillary services (maintenance and other) over the time.

21.3 At December 31, 2018 we recognized the following assets related to contracts:

	2018
Operating and maintenance services	$ 4,335
Electricity sales	53,554
Electricity sales with MEM	441
Contract assets	$ 58,330

21.4 Significant changes in contract assets - Contract assets are billed and collected in the following month period in all the cases, the contract assets of the electricity sales are determined in accordance with the gas consumptions and electricity consumptions at the rates stipulated in our contracts. There are no liabilities unrecognized in relation to costs to fulfill our gas supply contracts.

21.5 The amount of the transaction price allocated to the remaining performance obligations after December 31, 2018 correspond to the operation and maintenance income and is shown below:

2019	$ 46,705
2020	46,811
2021	46,687
2022	46,692
2023	46,692
Thereafter	354,217
Total	$587,804

21.6 Due to the characteristics of the power purchase contracts at the Energía Azteca X, Energía Campeche, Energía Chihuahua, Energía San Luis de La Paz, and Compression Services of Compresión Altamira and Green Energy Libramiento consolidated subsidiaries, the power capacity and compression services are represented under IFRS 16 as operating leases. Operating lease income includes minimum lease payments, such as capacity payments and contingent rentals, and was $78,887 for the period from March 6 to December 31, 2018.

21.7 Estimated minimum lease receivables, which do not include contingent rentals, to be received under operating leases subsequent to December 31, 2018, are as follows:

2019	$ 126,576
2020	110,954
2021	111,722
2022	100,866
2023	97,590
Thereafter	830,514
Total	$ 1,378,222

Note 22 - Analysis of cost of sales and general and administrative expenses:

An analysis of the nature of relevant costs and expenses classified by function in the consolidated statement of income and comprehensive income for the period from March 6 to December 31, 2018 is as follows:

	2018
Fuel	$ 277,392
Fuel transportation	28,921
Operation and maintenance	23,648
Interconnection	22,170
Depreciation	20,681
Pension plan and other	4,630
Others	355
Costs	377,797
Wage, salaries and technology information	7,878
Amortization of intangible assets	6,867
Insurance	2,998
Management service agreement fee	2,525
Duties and non-site property taxes	782
Depreciation	595
Expenses	21,645
Total	$ 399,442

Note 23 - Analysis of the finance cost, net:

23.1 The finance income for the period from March 6 to December 31, 2018 is composed as follows:

	2018
Banks deposits and others	$ 2,297
Intercompany loans	236
Finance income	$ 2,533

23.2 The finance cost for the period from March 6 to December 31, 2018 is composed as follows:

	2018
Long-term debt	($ 37,333)
Related party	(14,004)
Other interest expense	(2,438)
Interest expense	(53,775)
Operating activities	(85)
Investment activities	(1)
Currency exchange loss	(86)
Financing expenses and fees	(1,889)
Change in law financing expenses	(1,513)
Amortization of deferred financing cost	(677)
Long-term debt fees	(610)
Other financial expenses	(4,689)
Finance cost	($ 58,550)

Note 24 - Income tax:

24.1 For the period from March 6 to December 31, 2018, the income tax benefit (expense) are as follows:

	2018
Current income tax	($ 2,460)
Deferred income tax	3,554
	$ 1,094

24.2 Mexico: Income tax of the year is calculated by applying a 30% rate on the taxable profit. The tax income differs from the accounting income, mainly in such items accumulated and deducted differently for accounting and tax purposes, by the recognition of inflation effects for tax purposes, as well as such items only affecting either the accounting or tax income.

Netherlands: The Dutch corporate income tax rate is 25% (19% for the first EUR 200,000) in 2019. However, this rate will be reduced in the coming years as follows.

	2019	2020	2021
Taxable amount up to €200,000	19.0%	16.5%	15.0%
Taxable amount exceeding €200,000	25.0%	22.5%	20.5%

UK Tax: The current rate of UK corporation tax rate is 19% (effective from 1 April 2017). However, from 1 April 2020 the rate of UK corporation tax will fall to 17%.

US Tax: On December 22, 2017, the President of the United States signed into law tax reform bill H.R. 1 (Act) which lowers the corporate tax rate for companies from 35 to 21%. In addition, the former 20 years loss carryover provision has been replaced and newly generated tax losses carryforward from 2018 onward may now be carried forward indefinitely, subject to certain limitations. Given the limited deferred taxes that the Company has related to the United States jurisdiction, the impact to the consolidated statement of financial position and consolidated statement of income and comprehensive income, for the period from March to December 31, 2018 was not significant.

24.3 At December 31, 2018, the main temporary differences on which the deferred income tax was recognized are analyzed as follows:

	2018
Accrued expenses	$ 21,028
Deferred rent	37,373
Property plant and equipment	(75,992)
Customer relationship	(41,979)
Prepaid expenses	(3,669)
Net deferred tax liability	($ 63,239)

24.4 As of December 31, 2018, we had consolidated Tax losses carryforward that expire: a) Mexico in 10 years; b) Netherlands, 9 years; c) United Kingdom do not expire, and d) United States, 20 years. The Tax losses carryforwards are comprised as follows:

Year of loss	Mexico	Netherlands	United Kingdom	United States
2009	$ 1,349	$ -	$ -	$ -
2010	5,195	-	-	-
2011	18	-	-	-
2012	-	-	-	-
2013	-	-	-	-
2014	30,276	-	-	-
2015	1,830	-	-	-
2016	48,910	4,216	1	48
2017	17,354	1,237	7	161
2018	31,621	8,873	332	18,960
Total	$ 136,553	$ 14,326	$ 340	$ 19,169

A tax losses carryforward of $170,388 was not included as of December 31, 2018 in our deferred tax assets due to the low probability to be realized. Our assessment must cover all gross deferred tax assets, of which the largest asset relates to tax losses carryforward. Realization of a portion of our gross deferred tax assets is dependent on generating sufficient sources of future taxable income. Although realization is not assured, management believes it is not probable that the net deferred tax asset will be realized in the foreseeable future, consequently the group has not recorded deferred tax assets for these entities.

24.5 Taxing authorities routinely examine our tax returns. We are subject to different taxing jurisdictions, tax agreements and treaties. Management believes that the tax returns filed in the various tax jurisdictions may have positions that could be challenged by these tax authorities in the normal course of a tax audit.

If new information is identified in subsequent periods that would impact the Company's current position on certain tax matters, the Company will record the impact in the period when the new information is identified.

We had no unrecognized tax benefits and liabilities as of December 31, 2018, related to uncertain tax positions.

24.6 The reconciliation of pre-tax income at our statutory rate to income tax expense presented in the consolidated statement of income and comprehensive income, for the period from March 6 to December 31, 2018 is as follows:

	2018
Income before income tax	$ 39,346
Effect of subsidiaries not subject to income tax	43,120
	82,466
Statutory tax rate applied to pre-tax income	30%
Pre-tax income at the Mexican statutory rate	24,740
Decrease (increase) of tax expense resulting from statutory inclusions/exclusions from taxable income:	
Foreign income not taxed at statutory rate	9,109
Fluctuation exchange effect for tax purposes	(38,077)
Non-deductible expenses	387
Inflation adjustment for tax purposes	2,747
Total income tax benefit	($ 1,094)

Note 25 - Consolidated statement of cash flows:

25.1 The reconciliation between the opening and closing balances in the statement of financial position for liabilities arising from financing activities, are shown below:

	2018		
	Related party	Long-term debt	Total
Balances at March 6, 2018	$	$	$
Balances of the business combination		318,845	318,845
Payment and cancellation for original long-term debt		(318,845)	(318,845)
Proceeds from issuance of long-term debt working capital		67,500	67,500
Repayment of long-term debt working capital		(67,500)	(67,500)
Proceeds from issuance of debt	230,667	860,000	1,090,667
Repayment of debt		(11,180)	(11,180)
Deferred financing cost paid		(26,995)	(26,995)
Amortization of deferred financing costs		677	677
Interest expense	14,004	37,333	51,337
Interest paid		(27,412)	(27,412)
Balances at December 31, 2018	244,671	832,423	1,077,094
Current portion of long-term debt	(48,938)	(25,401)	(74,339)
Debt	$ 195,733	$ 807,022	$ 1,002,755

25.2 The cash paid for income taxes for the period from March 6 to December 31, 2018 was $17,498

25.3 The non-cash investing and financing activities is represented by the contingent consideration of $15,981 in the business acquisition.

Note 26 - Commitments and contingencies:

26.1 Power sales contract: Several of our power plants rely on power sales and gas compression contracts with one or a limited number of entities for the majority, and in some cases, all of the relevant plant's output over the term of the power sales contract. The minimum terms of power sales contracts for projects currently in operation expire between 2027 and 2035. The operations of these plants are dependent on the continued performance by customers of their obligations under the relevant power sales contracts, and in particular, on the credit quality of the purchasers. If a substantial portion of our long-term power sales contracts were modified or terminated, this could increase our exposure to market price volatility, and we could be adversely affected to the extent that we would be unable to find other customers at the same level of contract profitability. We have also contracted with various fuel suppliers and transportation providers to supply and transport fuel to our power plants.

26.2 Long term sales agreement: Certain of our subsidiaries have entered into gas turbine major maintenance LTSAs with the original equipment manufacturer of the particular gas turbines or other qualified third parties. These agreements provide for labor and supervision during scheduled inspections, repairs and overhauls of gas turbine equipment, including provisions for forced outage support. The agreements (with the exception of the agreement of Chihuahua) further allow for the supply of replacement, refurbished and critical capital spare parts required for the maintenance of the equipment in accordance with prudent industry practice.

These agreements have terms typically accommodating two or three major maintenance cycles which varies based on the equipment for each power subsidiary. These agreements may or may not contain termination provisions by us at our convenience, based on certain conditions in exchange for a fixed fee. Equivalent Operating Hours (EOH) accrued vary with output, plant cycling regimes, contractual guidelines and gas turbine events, such as trips and load shedding. The estimated annual fixed and variable amounts due under the LTSAs as of December 31, 2019, 2020 and 2021 is expected to total approximately $30,150 $33,879 and $26,376, respectively. Due to the variable nature of these payments we only estimate three years of commitments.

26.3 Fuel purchase commitments: We have committed to purchase gas from different suppliers without a minimum volume of gas.

26.4 Letters of Credit (LOC): We are often required to provide guarantees and/or letters of credit to ensure contractual obligations with respect to bid performance, financing, construction and operations of our subsidiaries. We may issue guarantees in connection with obligations under our power purchase agreements, operations and maintenance contracts, management service agreements and obligations we have as determined in various purchase and sale agreements. Letters of credit relate primarily to debt service requirements, electricity sales agreements and trading requirements. The beneficiary of the guarantee and/or LOC has the ability to draw against the commitments to the extent that the contractual obligations, as defined in the related agreements, allow such draws to be made.

Cometa have maximum exposure under LOCs issued and outstanding at December 31, 2018, as follows:

Subsidiaries and Joint Ventures [1]	Amounts outstanding	Expirations date [2]
Compresión Altamira	$ 7,565	2019
Compresión Bajío	2,051	2019
Energía Azteca VIII	10,200	2019
Energía Azteca X	22,991	2019
Energía Campeche	15,000	2019
Energía Chihuahua	15,000	2019
Energía de Baja California	838	2019
Energía San Luis de la Paz	13,464	2019
Saavi Energía	3,724	2019
Saavi Energy Solutions	13,545	2019
	$ 104,378	

[1]- Letters of credit outstanding related to these subsidiaries and joint ventures were issued under letter of credit provided for in Cometa Energía, S. A. de C. V.

[2]- Some letters of credit have a 2019 expiration date but automatically extend annually.

Cometa Energía, S. A. de C. V. pays LOC fees of 1.75% per annum.

Each account party pays LOC fees ranging from 2.63% to 2.75% per annum on outstanding LOCs.

26.5 Legal proceedings - We are involved in certain legal proceedings in the normal course of business. We are under the opinion that none of these proceedings will have a material adverse effect on our consolidated financial position or cash flows, individually or in the aggregate.

Note 27 - Subsequent events:

For the year ended December 31, 2018, subsequent events have been evaluated through December 13, 2019, the date which the consolidated financial statements were available to be issued.

On March 29, 2019, Jaime Tupper joined the Company as CEO.

In accordance with the Senior Secured Notes calendar on April 22, 2019, the Company paid $10,320 of principal and $27,056 of interest.

In accordance with El Aguila Investments Debt on June 4, 2019, the Company paid $32,905 of principal and $20,045 of interest.

In accordance with the Senior Secured Notes calendar on October 24, 2019, the Company paid $5,160 of principal and $26,727 of interest.

In accordance with El Aguila Investments Debt on November 15, 2019, the Company paid $35,250 of principal and $10,136 of interest.

Note 28 - Authorization of issuance of the financial statements:

The accompanying consolidated financial statements and notes were issued on February 20, 2020, by Mauricio del Valle (Chief Financial Officer) and Francisco Villalón (Controller).

ISSUER

Electricidad Firme de México Holdings, S.A. de C.V.
Paseo de la Reforma 115, 6th floor
Lomas de Chapultepec, 11000
Mexico City, Mexico

INDEPENDENT AUDITORS

PricewaterhouseCoopers S.C.
Mariano Escobedo 573
Col. Rincón del Bosque 11580
Mexico City, Mexico

TRUSTEE, REGISTRAR, PAYING AGENT AND TRANSFER AGENT

The Bank of New York Mellon
240 Greenwich Street, 7E
New York, New York 10286

LEGAL ADVISORS TO THE ISSUER

As to U.S. federal and New York law
Latham & Watkins LLP
1271 Avenue of the Americas
New York, New York 10020
United States

As to Mexican law
Creel, Garcia Cuellar, Aiza y Enriquez, S.C.
Pedregal 24, 24th Floor
Lomas de Chapultepec 11000
Mexico City, Mexico

LEGAL ADVISORS TO THE INITIAL PURCHASERS

As to U.S. federal and New York law
Shearman & Sterling LLP
599 Lexington Avenue
New York, New York 10022
United States

As to Mexican law
González Calvillo, S.C.
Montes Urales 632, 3rd Floor
Lomas de Chapultepec 11000
Mexico City, Mexico

US$350,000,000

Electricidad Firme de México Holdings, S.A. de C.V.

4.900% Senior Secured Notes due 2026

OFFERING MEMORANDUM

Joint Global Coordinators and Book-Runners

J.P. Morgan ***Mizuho Securities*** ***Scotiabank***

September 10, 2021