EB-2024-0063

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule. B);

AND IN THE MATTER OF a generic proceeding commenced by the Ontario Energy Board on its own motion to consider the cost of capital parameters and deemed capital structure to be used to set rates.

COMPENDIUM OF THE SCHOOL ENERGY COALITION
(Nexus Witness Panel)

Shepherd Rubenstein P.C.
2200 Yonge Street, Suite 1302
Toronto, Ontario M4S 2C6

Mark Rubenstein
Tel: 647-483-0113
Fax: 416-483-3305

Counsel for the School Energy Coalition

INDEX

M3-0-SEC-64

For each proceeding where the authors of the Nexus report have provided expert evidence on utility cost of capital, please provide the following information regarding those proceedings, as applicable:

i. Jurisdiction
ii. Date
iii. Docket Number
iv. Applicant
v. Client
vi. Existing equity ratio
vii. Author's recommended equity ratio
viii. Approved equity ratio
ix. Existing ROE
x. Author's recommended ROE
xi. Approved ROE
xii. A copy or web link to the authors written report/testimony
xiii. A copy or web link to the commission/regulatory decision

Response:

For the expert evidence that we have been able to compile, please see the attached Documents:

1. Puerto Rico Electric Power Authority revenue requirements panel testimony. Dr. Pampush was responsible for Section IV – PREPA Re-entry into the Capital Markets.

2. Jamaica Public Service Company, Ltd., proposed Criteria Response 2019-2024 Rate Review Process. Dr. Pampush developed the proposals for the cost of capital on page 16 in the column "2019-2024 JPS Proposal". Nexus Economics attempting to procure a copy of the order detailing the results for this case. It should be noted that this proceeding is a "consultation" with different procedural rules than those used in Canada or the United States and processes may differ.

3. A report prepared by Navigant Consulting for the Israeli electricity regulator, the Israel PUA. This report provided a rate review including a cost of capital for the Israel Electric Company prepared by Dr. Pampush. The director of this project was Mr. Zarumba.

Dr. Pampush also prepared testimony supporting the cost of capital for the Bermuda Electric Light Company. Testimony before the Bermuda Regulator is considered confidential. We are currently attempting to get permission to release this information.

M3-12-SEC-78

Please provide Nexus' views on the relative business and financial risk between electricity distributors, electricity transmitters, and natural gas utilities.

Response:

The Nexus Economics report specifically addressed electricity distributors. Nexus has no relevant views about electricity transmitters and natural gas utilities.

M3-10-SEC-77

[M3, p.81] Nexus states that "LEI presents information that focuses primarily on the perspective of debt holders. LEI says that it is "not aware" of OEB-regulated entities facing notable issues in attracting equity and debt capital since 2009". Have any of the EDA member utilities had notable issues attracting equity and debt capital? If so, please discuss.

Response:

We have not interviewed EDA members regarding notable issues attracting equity and debt capital since this was not necessary for our analysis or conclusions regarding the cost of equity. EDA has told us that it is unaware of such information, and that, in any event, it cannot reasonably determine the requested information within the proceeding timelines.

In any event, for guidance regarding the evaluation of capital attraction under the Fair Return Standard, we relied on the 2009 Board discussion (at page 20), which discusses the difficulty of ascertaining notable issues attracting capital. According to the Board (emphasis added):

> *[T]here was considerable discussion in the consultation about utility bond ratings.* ***The ability of a utility to issue debt capital and maintain a credit rating were generally put forth by stakeholders in the consultation as a sufficient basis upon which to demonstrate that a particular equity cost of capital and deemed utility capital structure meet the capital attraction and financial integrity requirements of the FRS. The Board is of the view that utility bond metrics do not speak to the issue of whether a ROE determination meets the requirements of the FRS.*** *The Board acknowledges that equity investors have, as the residual, net claimants of an enterprise, different requirements, and that bond ratings and bond credit metrics serve the explicit needs of bond investors and not necessarily those of equity investors.*
>
> *Finally,* ***the Board questions whether the FRS has been met, and in particular, the capital attraction standard, by the mere fact that a utility invests sufficient capital to meet service quality and reliability obligations. Rather, the Board is of the view that the capital attraction standard, indeed the FRS in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital.*** *As the Coalition of Large Distributors commented:*

[T]he fact that a utility continues to meet its regulatory obligations and is not driven to bankruptcy is not evidence that the capital attraction standard has been met. To the contrary, maintaining rates at a level that continues operation but is inadequate to attract new capital investment can be considered confiscatory. The capital attraction standard is universally held to be higher than a rate that is merely non-confiscatory. As the United States Supreme Court put it, 'The mere fact that a rate is non-confiscatory does not indicate that it must be deemed just and reasonable'. [footnote 14 omitted]

We interpret this to mean that <u>capital attraction (and the FRS in totality) is met based on the opportunity cost standard</u>. Hence, in our analysis, and we believe consistent with the Board's interpretation of the FRS, we focused our attention on opportunity cost as determined by the marginal investor -- and not on specific "notable issues" attracting equity and debt capital since there is no notable issues requirement under the Fair Return Standard.

M3-10-SEC-75

[M3, p.61] For each utility included in the Nexus ROE analysis, please provide: a) its credit ratings, b) its most recent credit rating report from each of S&P, DBRS, and Moody's, and c) a breakdown of annual revenue by business type (electricity distribution, electricity transmission, electricity generation, regulated natural gas, and other).

Response:

The requested analysis is extensive and involves considerable resources, and Nexus Economics is not in a position to perform it in the context of this proceeding and its abbreviated timelines.

M3-CCC-5

Ref: Ex. M3/p. 61

For each company in the proxy group listed in Exhibit M3 at page 61 (Table 6), please provide a table that includes the following information (if available and as applicable):

a) Company name
b) Credit rating
c) S&P business risk rating
d) S&P financial risk rating
e) Percentage of operating income from, as applicable, electricity distribution, electricity transmission, electricity generation, natural gas operations
f) Percentage of operating income, as applicable, by operating area (i.e., electricity distribution, transmission, generation or natural gas operations) that is regulated
g) Percentage of overall operating income that is regulated
h) Beta information:

> i. Raw beta
> ii. Beta used by expert in CAPM calculation

i) The regulatory agency that regulates the company (i.e., OEB, AUC, CPUC, etc.) and the applicable rating as set out in the "Utility Regulatory Jurisdiction Assessment performed by S&P Global" (see p. 129 of Exhibit M1 – LEI Expert Report)
j) Description of ratemaking approach applied to the company. As part of this response, please include information regarding:

> i. Most prevalent form of ratemaking (e.g., cost of service, cost of service plus IRM, etc.)
> ii. Application of a forward test year approach in cost of service ratemaking
> iii. Availability of Custom IR option (which, as applied in Ontario, allows for multi-year (typically 5 years) recovery of approved capital budgets as proposed by the utility)
> iv. Availability of mechanisms that allow the recovery of incremental capital between rebasing proceedings (and a description of how those mechanisms operate)
> v. Reliance on fixed vs. variable rates (by rate class)
> vi. Availability of deferral and variance accounts for non pass-through costs and revenues (and the types of accounts that are available)
> vii. Availability of Z-factor relief (and the types of relief available through this mechanism)
> viii. Availability of off-ramp provisions when actual ROE falls below a certain threshold

Response:

The analysis required to respond to this Interrogatory would require at least a week of full-time effort, which is not reasonable or feasible in the context of this proceeding and its abbreviated timelines, even assuming we have the data to address it, which we may not .

Nexus has provided its backup calculations for its ROE analysis in the Excel workbook M3-NAICS 2211 (as filed).xlsx, which any party may use to perform the requested analysis.

M3-10-CME-13

Ref: Exhibit M3, p. 38

At page 38, Nexus states “Our goal in this Chapter is to identify and quantify the opportunity cost of equity capital that can be applied to a risky asset, namely a distribution electric utility in Ontario.”

(a) Please confirm whether Nexus’ view is that a distribution electric utility in Ontario is a risky asset in comparison to other equity investments, such as private market businesses.

Response:

Yes, both Ontario electric utilities and private market businesses are risky assets. The appropriate peers for regulated energy utilities in Ontario are other regulated energy utilities in North America.

(b) If the answer to (a) is yes, please reconcile this opinion with the belief that utility stocks are less volatile and are recession resistant, as outlined in numerous articles (including one found here: WWhttps://www.investopedia.com/ask/answers/122314/what-kind-investors-buy-utility-stocks.asp

Response:

Ontario electric utilities experience risk that is higher than that of the risk-free asset, and therefore is considered a risky asset. Please see the response to (a). We have no response to the Investopedia reference, which appears to provide generic direction to investors. We concur with the statement in (b) that utility stocks are “less volatile and recession resistant” to the extent that their betas are less than 1.00.

Alaska Power & Telephone Company
and Subsidiaries
Consolidated Balance Sheets
December 31, 2023 and 2022

	2023	2022
ASSETS		
PROPERTY, PLANT, AND EQUIPMENT		
Electric	$ 149,256,644	$ 135,356,921
Telecommunications	143,998,715	135,753,605
Nonutility	10,729,546	10,258,996
	303,984,905	281,369,522
Less accumulated depreciation and amortization	166,526,538	154,148,259
	137,458,367	127,221,263
Utility plant under construction	10,900,863	9,268,661
Total property, plant, and equipment	148,359,230	136,489,924
OTHER ASSETS		
Investments	4,966,588	5,279,649
Goodwill, net of amortization	-	60,811
Rate stabilization asset	4,169,909	4,450,509
Operating lease right-of-use asset	2,360,678	2,333,807
Other assets	3,280,367	3,174,780
Total other assets	14,777,542	15,299,556
CURRENT ASSETS		
Cash and cash equivalents	5,127,569	3,128,132
Receivables, less allowance for doubtful accounts of $25,151 in 2023 and $26,728 in 2022	12,805,188	10,836,607
Inventory and other current assets	10,129,480	7,881,940
Income tax refunds receivable	-	329,665
Total current assets	28,062,237	22,176,344
Total assets	$ 191,199,009	$ 173,965,824

See accompanying notes.

Alaska Power & Telephone Company
and Subsidiaries
Consolidated Statements of Income
Years Ended December 31, 2023 and 2022

	2023	2022
REVENUE		
Electric	$ 28,230,884	$ 26,579,066
Telecommunications	35,095,929	34,368,321
Other	877,656	830,042
	64,204,469	61,777,429
EXPENSES		
Electric	21,259,834	18,044,254
Telecommunications	19,920,817	20,107,605
Other	43,003	107,927
Operations and maintenance expense	41,223,654	38,259,786
Depreciation and amortization expense	12,484,091	10,548,457
	53,707,745	48,808,243
Income from operations	10,496,724	12,969,186
OTHER INCOME (EXPENSE)		
Dividend income	1,083,303	990,207
Amortization of goodwill	(60,811)	(60,544)
Miscellaneous	(5,944)	304,454
Total other income	1,016,548	1,234,117
Interest income	5,202	26,223
Interest expense	(3,478,910)	(2,336,065)
Net interest expense	(3,473,708)	(2,309,842)
Income before income taxes	8,039,564	11,893,461
PROVISION FOR INCOME TAXES	(1,891,629)	(2,876,754)
Net income	$ 6,147,935	$ 9,016,707
BASIC AND DILUTED EARNINGS PER SHARE	$ 5.01	$ 7.23
WEIGHTED-AVERAGE BASIC AND DILUTED SHARES OUTSTANDING	1,227,985	1,246,438

See accompanying notes.

2023

OTTER TAIL CORPORATION

Annual Report

MANUFACTURING PLATFORM

BTD Manufacturing, Inc.
Metal fabricator
Headquarters: Detroit Lakes, MN
Acquired 1995
President, Paul Gintner
1,458 full-time employees
www.btdmfg.com

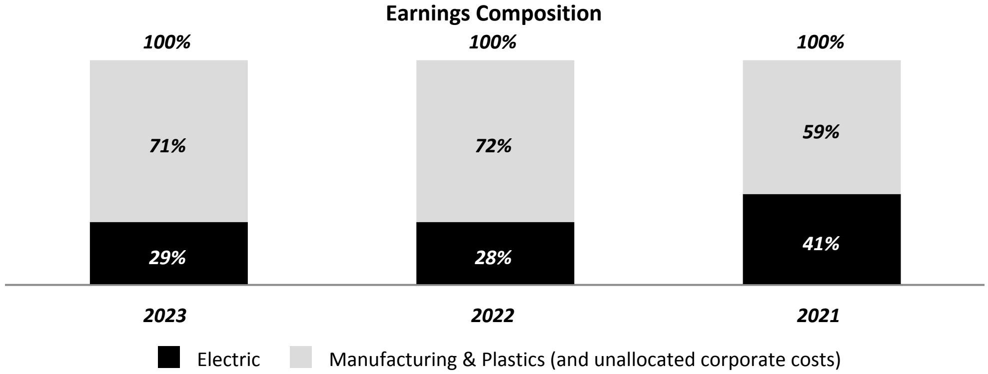
T.O. Plastics, Inc.
Custom plastic parts manufacturer
Headquarters: Clearwater, MN
Acquired 2001
President, Paul Meschke
192 full-time employees
www.toplastics.com

Northern Pipe Products, Inc.
PVC pipe manufacturer
Headquarters: Fargo, ND
Acquired 1995
President, Terry Mitzel
98 full-time employees
www.northernpipe.com

Vinyltech Corporation
PVC pipe manufacturer
Headquarters: Phoenix, AZ
Acquired 2000
President, Terry Mitzel
80 full-time employees
www.vtpipe.com

	2023	2022	PERCENT CHANGE
CONSOLIDATED OPERATIONS ($ in thousands, except per share amounts)			
Operating Revenues	**$ 1,349,166**	$ 1,460,209	(7.6)
Net Income	**$ 294,191**	$ 284,184	3.5
Diluted Earnings per Share	**$ 7.00**	$ 6.78	3.2
Dividends per Common Share	**$ 1.75**	$ 1.65	6.1
Return on Average Common Equity	**22.1%**	25.6%	(13.6)
Book Value per Common Share	**$ 34.60**	$ 29.24	18.3
Cash Flow from Operating Activities	**$ 404,499**	$ 389,309	3.9
Number of Common Shares Outstanding	**41,710,521**	41,631,113	0.2
Number of Common Shareholders	**10,650**	11,748	(9.3)
Closing Stock Price	**$ 84.97**	$ 58.71	44.7
Total Return (share price appreciation plus dividends)	**47.7%**	(15.5)%	n/m
Total Market Value of Common Stock	**$ 3,544,143**	$ 2,444,163	45.0
ELECTRIC PLATFORM ($ in thousands)			
Operating Revenues	**$ 528,359**	$ 549,699	(3.9)
Total Retail Electric Sales (MWH)	**5,772,215**	5,592,368	3.2
Operating Income	**$ 106,521**	$ 113,138	(5.8)
Net Income	**$ 84,424**	$ 79,974	5.6
Customers	**133,747**	133,414	0.2
Total Assets	**$ 2,533,831**	$ 2,351,961	7.7
Capital Expenditures	**$ 240,695**	$ 147,869	62.8
MANUFACTURING PLATFORM ($ in thousands)			
Operating Revenues	**$ 820,807**	$ 910,510	(9.9)
Operating Income	**$ 283,542**	$ 293,643	(3.4)
Net Income	**$ 209,202**	$ 216,324	(3.3)
Total Assets	**$ 415,522**	$ 372,187	11.6
Capital Expenditures	**$ 46,313**	$ 23,199	99.6

Our actual mix of earnings for the years ended December 31, 2023, 2022 and 2021 was as follows:



HUMAN CAPITAL

Our employees are a critical resource and an integral part of our success. We strive to provide an environment of opportunity and accountability where people are valued and empowered to do their best work. We are focused on the health and safety of our employees and creating a culture of inclusion, excellence and learning, and our executive annual incentive plan reflects those commitments. We monitor various metrics and objectives associated with i) employee safety, ii) workforce stability, iii) management and workforce demographics, including gender, racial and ethnic diversity, iv) leadership development and succession planning and v) productivity. We have established the following in furtherance of these efforts:

Safety - Safety is one of our core values. In managing our business, we focus on the safety of our employees and have implemented safety programs and management practices to promote a culture of safety. Safety is also a metric used and evaluated in determining annual incentive compensation. We continually monitor the Occupational Safety and Health Administration Total Recordable Incident Rate (number of work-related injuries per 100 employees for a one-year period) and Lost Time Incident Rate (number of employees who lost time due to work-related injuries per 100 employees for a one-year period). New cases are reported and evaluated for corrective action during monthly safety meetings attended by safety professionals at all locations. Our 2023 Total Recordable Incident Rate was 1.70, compared to 2.08 in 2022 and our Lost Time Incident Rate was 0.53 in 2023, compared to 0.49 in 2022.

Employee and Leadership Development, Succession Planning and Training Programs - We invest in training and professional development for various levels of employees, management and leaders throughout the Company to ensure all have the necessary training and skills to perform their work well, and to build enterprise-wide understanding of our culture, strategy and processes. Annual succession planning, individual development planning, mentoring, and supervisory and leadership development programs all play a role in ensuring a capable leadership team now and in the future. Our skill progression and technical training programs help to retain a stable and skilled workforce.

Workforce Stability - Recruiting, retaining and developing employees is an important factor in our continued success and growth. We regularly evaluate our recruiting programs, employee retention and turnover rates.

Employee Engagement - To enhance the effectiveness of our workforce and to help our companies continue to be places where our employees choose to work and thrive, we have undertaken a multi-year series of employee engagement surveys. We use the feedback to help shape the employee programs of our organization.

Human Rights - We are committed to the protection of our employee’s freedom of expression and freedom of organization and assembly.

Diversity, Equity, and Inclusion - We expect, and are committed to, diversity, equity and inclusion as part of who we are, what we value, and how we achieve individual, business and community success. We hold every employee accountable for their behavior in maintaining a workplace free of discrimination and harassment. We have implemented education initiatives for all employees, aimed at inclusive leadership and a respectful workplace, focused on identities and culture, unconscious bias, the power of diverse teams and culturally sensitive conversations. We have implemented initiatives to improve upon our demographic profile, including revised hiring processes and a commitment to diverse slates of interview candidates.

Code of Business Ethics - We require employees to complete training on several topics associated with our code of business ethics to reinforce our commitment to compliance with laws, regulations and values that guide who we are and how we do business.

2023 Integrated Report

Energizing the Future.

Description of the Business

TransAlta is a Canadian corporation and one of Canada's largest publicly traded power generators. Established in 1911, the Company now has over 112 years of operating experience in the development, production and sale of electricity. We own, operate and manage a geographically diversified portfolio of generation assets that include water, wind, solar, battery storage, natural gas and transition coal. We are one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta. We also have industry-leading energy marketing capabilities where we seek to maximize margins by securing and optimizing high-value products and markets for ourselves and our customers in dynamic market conditions. Our mix of merchant and contracted assets along with our energy marketing business provides resilient and growing cash flows that support our ability to pay dividends to our shareholders and reinvest in growth.

The Company's goal is to be a leading clean electricity company that is committed to a sustainable future and a responsible energy transition. Our strategic priorities include accelerating growth into customer-centred renewables and storage, selectively expanding flexible generation and reliability assets to support the transition, defining the next generation of power solutions and maintaining financial strength and capital allocation discipline. We are primarily focused on opportunities within our core markets of Canada, the US and Western Australia.

Our sustainability goals and our Clean Electricity Growth Plan remain the focus of our strategy, which includes our commitment to retire our last remaining operational coal facility at the end of 2025. We remain on track to achieve our 2026 greenhouse gas ("GHG") emissions reduction target of 75 per cent scope 1 and 2 GHG emissions reductions since 2015 and our carbon net-zero goal by 2045. Since 2005, we have reduced our scope 1 and 2 GHG emissions by 31 million tonnes ("MT") of CO_2e or a 74 per cent reduction, proudly representing approximately 10 per cent of Canada's Paris Agreement 2030 decarbonization target[1].

Portfolio of Assets

Our asset portfolio is geographically diversified with operations across Canada, the United States and Australia. The portfolio also generates power using a diverse set generation technologies and reliably supplies a broad cross section of counterparties.

Our Hydro, Wind and Solar, Gas and Energy Transition segments are responsible for operating and maintaining our electrical generation facilities. Our Energy Marketing segment is responsible for marketing and scheduling our merchant asset fleet in North America (excluding Alberta) along with the procurement of gas, transport and storage for our gas fleet, providing knowledge to support our growth team, and generating a stand-alone gross margin separate from our asset business through a leading North American energy marketing and trading platform.

Our highly diversified portfolio consists of both high-quality contracted assets and merchant assets. Approximately, 56 percent of our total installed capacity, including 81 per cent of our Wind and Solar fleet and 53 per cent of our Gas fleet, is contracted with investment-grade or creditworthy counterparties. The weighted-average contract life for these contracted facilities is 10 years.

Our merchant assets include our unique hydro merchant portfolio and our merchant legacy thermal portfolio and wind assets. Our merchant exposure is primarily in Alberta, where 53 per cent of our capacity is located and 75 per cent of our Alberta capacity is available to participate in the merchant market. The Alberta optimization team is responsible for marketing and scheduling our merchant asset fleet in Alberta.

A significant portion of the thermal generation capacity in the portfolio has been hedged to provide cash flow certainty. The Company's hedging strategy includes maintaining a significant base of commercial and industrial customers and is supplemented with financial hedges. In 2023, 78 per cent of our energy production in Alberta was sold under long term contracts or fixed price hedges. Refer to the 2024 Outlook section and the Optimization of the Alberta Portfolio of this MD&A for further details.

Our diversified fleet is a key success factor in our ability to deliver resilient cash flows while capturing higher risk-adjusted returns for our shareholders.

(1) In 2005, TransAlta's estimated scope 1 and 2 GHG emissions were 41.9 MT of CO_2e, which did not receive independent limited assurance. Canada's Paris Agreement 2030 decarbonization target assumed 293 MT of CO_2e or a 40 per cent reduction from a 2005 baseline of 732 MT of CO_2e.

The following table provides our consolidated ownership of our facilities across the regions in which we operate as of Dec. 31, 2023:

	Hydro		Wind & Solar		Gas		Energy Transition		Total	
Year ended Dec. 31, 2023	Gross Installed Capacity (MW)	Number of facilities	Gross Installed Capacity (MW)(1)	Number of facilities	Gross Installed Capacity (MW)(1)	Number of facilities	Gross Installed Capacity (MW)	Number of facilities	Gross Installed Capacity (MW)(1)	Number of facilities
Alberta	834	17	766	14	1,960	7	—	—	3,560	38
Canada, excluding Alberta	88	7	751	9	645	3	—	—	1,484	19
US	—	—	519	7	29	1	671	2	1,219	10
Australia	—	—	48	3	450	6	—	—	498	9
Total	**922**	**24**	**2,084**	**33**	**3,084**	**17**	**671**	**2**	**6,761**	**76**

(1) Gross installed capacity for consolidated reporting represents 100 per cent output of a facility. Capacity figures for the Wind and Solar segment includes 100 per cent of the Kent Hills wind facilities, and capacity figures for the Gas segment include 100 per cent of the Ottawa and Windsor facilities, 100 per cent of the Poplar Creek facility, 50 per cent of the Sheerness facility and 60 per cent of the Fort Saskatchewan facility.

Stable and Predictable Cash Flows

The following table provides our contracted capacity by MW and as a percentage of total gross installed capacity of our facilities across the regions in which we operate as of Dec. 31, 2023:

As at Dec. 31, 2023	Hydro	Wind & Solar	Gas	Energy Transition	Total
Alberta	—	374	511	—	885
Canada, excluding Alberta	88	751	645	—	1,484
US	—	519	29	381	929
Australia	—	48	450	—	498
Total contracted capacity (MW)	88	1,692	1,635	381	3,796
Contracted capacity as a % of total capacity (%)	10%	81%	53%	57%	56%

The weighted average contract life (years) of our facilities across the regions in which we operate as of Dec. 31, 2023 is:

As at Dec. 31, 2023	Hydro	Wind & Solar	Gas	Energy Transition	Total
Alberta(1)(2)	—	16	7	—	11
Canada, excluding Alberta(2)	10	10	8	—	9
US(2)	—	10	2	2	7
Australia(2)	—	15	15	—	15
Total weighted contract life (years)(2)	10	12	10	2	10

(1) The weighted-average remaining contract life in the Wind and Solar segment is related to the contract period for Garden Plain (130 MW), McBride Lake (38 MW), and Windrise (206 MW). The weighted-average remaining contract life in the Gas segment is related to the contract period for Poplar Creek (230 MW), Fort Saskatchewan (71 MW) and a capacity-contract that is not directly contracted with any one facility (210 MW).

(2) For power generated under long-term power purchase agreements ("PPAs") and other long-term contracts, the weighted-average remaining contract life is based on long-term average gross installed capacity.

The majority of TransAlta's long-term power purchase agreements are with investment-grade rated or creditworthy counterparties.

2023
Annual report

the future. We understand that the energy industry is changing rapidly, and aim to proactively seek solutions that will give us a continued competitive advantage. At the core of our innovation strategy is AES Next, our business and technology incubator. AES Next works to identify new and innovative technologies and business opportunities that provide or support leading-edge greener energy solutions.

2023 Strategic Highlights

- We signed 5.6 GW of renewables and energy storage under long-term PPAs.
- We completed the construction of 3.5 GW.
- Our backlog, which includes projects with signed contracts, but which are not yet operational, is now 12.3 GW, consisting of:
  - 5.1 GW under construction; and
  - 7.2 GW with signed PPAs, but that are not yet under construction.
- AES Indiana reached a unanimous settlement agreement for its first rate case since 2018, and expects to receive approval from the IURC by the middle of 2024.
- AES Ohio received approval from the PUCO for its Electric Security Plan (ESP4), providing the regulatory foundation necessary to enable future investments.
- We exited or announced the sale or closure of 2.1 GW of coal generation in Vietnam, the U.S., and Chile.
- We signed agreements for three-year extensions of 1.4 GW of gas generation at the Southland legacy units in Southern California. These extensions will help meet the State of California's grid reliability needs while supporting its decarbonization goals.
- Awarded up to $2.4 billion of grant funding by the U.S. Department of Energy for two green hydrogen hubs with AES participation.
- We secured $1.1 billion in asset sale proceeds, to accelerate our portfolio transformation, outpacing our target of $400 to $600 million.

Overview

Generation

We currently own and/or operate a generation portfolio of 34,596 MW, including generation from our integrated utility, AES Indiana. Our generation fleet is diversified by technologies and fuel type. See discussion below under *Fuel Costs*.

Performance drivers of our generation businesses include types of electricity sales agreements, plant reliability and flexibility, availability of generation capacity to meet contracted sales, fuel costs, seasonality, weather variations, economic activity, fixed-cost management, and competition. The financial performance of our renewables business is also impacted by our ability to complete construction projects and earn U.S. renewable tax credits.

Contract Sales — Most of our generation businesses sell electricity under medium- or long-term contracts in either regulated or competitive markets ("contract sales") or under short-term agreements in competitive markets ("short-term sales"). Our medium-term contract sales have terms of two to five years, while our long-term contracts have terms of more than five years.

Contracts requiring fuel to generate energy, such as natural gas or coal, are structured to recover variable costs, including fuel and variable O&M costs, either through direct or indexation-based contractual pass-throughs or tolling arrangements. When the contract does not include a fuel pass-through, we typically hedge fuel costs or enter into fuel or energy supply agreements for a similar contract period (see discussion below under *Fuel Costs*). These contracts also help us to fund a significant portion of the total capital cost of the project through long-term non-recourse project-level financing.

Certain contracts include capacity payments that cover projected fixed costs of the plant, including fixed O&M expenses, debt service, and a return on capital invested. In addition, most of our contracts require that the majority of the capacity payments be denominated in the currency matching our fixed costs. In some U.S. markets, the capacity payment is only for the resource adequacy or reliability benefits from the generating facility, allowing us to separately monetize the electricity produced by the facility through either contract sales or short-term sales.

Contracts that do not have significant fuel cost or do not contain a capacity payment are structured based on long-term prices and may also include negotiated pass-through costs, allowing us to recover expected fixed and variable costs as well as provide a return on investment.

Many of these contracts are intended to reduce exposure to the volatility of fuel and electricity prices by linking the business's revenues and costs. We generally structure our business to eliminate or reduce foreign exchange risk by matching the currency of revenue and expenses, including fixed costs and debt. Our project debt may consist of both fixed and floating rate debt for which we typically hedge a significant portion of our exposure. Some of our contracted businesses also receive a regulated market-based capacity payment, which is discussed in more detail in the *Short-Term Sales* section below.

Thus, these contracts, or other related commercial arrangements, significantly mitigate our exposure to changes in electricity and, as applicable, fuel prices, currency fluctuations and changes in interest rates. In addition, these contracts generally provide or account for a recovery of our fixed operating expenses and a return on our investment, as long as we operate the plant to the reliability, availability, and efficiency standards required in the contract or otherwise.

Short-Term Sales — Our generation businesses also sell power and ancillary services under short-term contracts with average terms of less than two years, including spot sales, directly in the short-term market or at regulated prices. The short-term markets are typically administered by a system operator to coordinate dispatch. Short-term markets generally operate on merit order dispatch, where the least expensive generation facilities, based upon variable cost or bid price, are dispatched first and the most expensive facilities are dispatched last. The short-term price is typically set at the marginal cost of energy or bid price (the cost of the last plant required to meet system demand). As a result, the cash flows and earnings associated with these businesses are more sensitive to fluctuations in the market price for electricity. In addition, many of these wholesale markets include markets for ancillary services to support the reliable operation of the transmission system. Across our portfolio, we provide a wide array of ancillary services, including voltage support, frequency regulation and spinning reserves.

Many of the short-term markets in which we operate include regulated capacity markets. These capacity markets are intended to provide additional revenue based upon availability without reliance on the energy margin from the merit order dispatch. Capacity markets are typically priced based on the cost of a new entrant and the system capacity relative to the desired level of reserve margin (generation available in excess of peak demand). Our generating facilities selling in the short-term markets typically receive capacity payments based on their availability in the market.

Plant Reliability and Flexibility — Our contract and short-term sales provide incentives to our generation plants to optimally manage availability, operating efficiency and flexibility. Capacity payments under contract sales are frequently tied to meeting minimum standards. In short-term sales and in certain contract sales, our plants must be reliable and flexible to capture peak market prices and to maximize market-based revenues. In addition, our flexibility allows us to capture ancillary service revenue while meeting local market needs.

Fuel Costs — For our thermal generation plants, fuel is a significant component of our total cost of generation. For contract sales, we often enter into fuel supply agreements to match the contract period, or we may financially hedge our fuel costs. Some of our contracts include indexation for fuels. In those cases, we seek to match our fuel supply agreements to the indexation. For certain projects, we have tolling arrangements where the power offtaker is responsible for the supply and cost of fuel to our plants.

In short-term sales, we sell power at market prices that are generally reflective of the market cost of fuel at the time, and thus procure fuel supply on a short-term basis, generally designed to match up with our market sales profile. Since fuel price is often the primary determinant for power prices, the economics of projects with short-term sales are often subject to volatility of relative fuel prices. For further information regarding commodity price risk please see Item 7A.—*Quantitative and Qualitative Disclosures about Market Risk* in this Form 10-K.

53% of the capacity of our generation plants are renewables, including hydro, solar, wind, energy storage, biomass and landfill gas, which do not have significant fuel costs.

27% of the capacity of our generation plants are fueled by natural gas. With the exception of our plants in the Dominican Republic and Panama, where we import LNG to utilize in the local market, we use gas from local suppliers in each market.

18% of the capacity of our generation fleet is coal-fired. In the U.S., most of our coal-fired plants are supplied from domestic coal. At our non-U.S. generation plants, and at our plant in Puerto Rico, we source coal from a mix of sources from the international market and in the local jurisdictions. To the extent possible, we utilize our global sourcing program to maximize the purchasing power of our fuel procurement.

2% of the capacity of our generation fleet utilizes pet coke or oil for fuel. We source oil and diesel locally at prices linked to international markets. We largely source pet coke from Mexico and the U.S.

Seasonality, Weather Variations and Economic Activity — Our generation businesses are affected by seasonal weather patterns and, therefore, operating margin is not generated evenly throughout the year. Additionally, weather variations, including temperature, solar and wind resources, and hydrological conditions, may also have an impact on generation output at our renewable generation facilities. In competitive markets for power, local economic activity can also have an impact on power demand and short-term prices for power.

Fixed-Cost Management — In our businesses with long-term contracts, the majority of the fixed O&M costs are recovered through the capacity payment or were otherwise factored in as a component of the long-term contract price. However, for all generation businesses, managing fixed costs and reducing them over time is a driver of business performance.

Competition — For our businesses with medium- or long-term contracts, there is limited market competition impacting prices during the term of the contract. For short-term sales, plant dispatch and the price of electricity are determined by market competition and local dispatch and reliability rules.

Utilities

Our utility businesses consist of AES Indiana and AES Ohio in the U.S., and four utilities in El Salvador. AES' six utility businesses distribute power to 2.6 million customers and AES' two utilities in the U.S. also include generation capacity totaling 3,500 MW.

AES Indiana, our fully integrated regulated utility, and AES Ohio, our transmission and distribution regulated utility, each operate as the sole distributors of electricity within their respective jurisdictions. AES Indiana owns and operates all of the facilities necessary to generate, transmit and distribute electricity. AES Ohio owns and operates all of the facilities necessary to transmit and distribute electricity. Our distribution business in El Salvador faces limited competition due to significant barriers to enter the market. According to El Salvador's regulation, large regulated customers have the option of becoming unregulated users and requesting service directly from generation or commercialization agents.

In general, our utilities sell electricity directly to end-users, such as homes and businesses, and bill customers directly. Key performance drivers for utilities include the regulated rate of return and tariff, seasonality, weather variations, economic activity and reliability of service. Revenue from utilities is classified as regulated on the Consolidated Statements of Operations.

Regulated Rate of Return and Tariff — In exchange for the right to sell or distribute electricity in a service territory, our utility businesses are subject to government regulation. This regulation sets the framework for the prices ("tariffs") that our utilities are allowed to charge customers for electricity and establishes service standards that we are required to meet.

Our utilities are generally permitted to earn a regulated rate of return on assets, determined by the regulator based on the utility's allowed regulatory asset base, capital structure and cost of capital. The asset base on which the utility is permitted a return is determined by the regulator, within the framework of applicable local laws, and is based on the amount of assets that are considered used and useful in serving customers. Both the allowed return and the asset base are important components of the utility's earning power. The allowed rate of return and operating expenses deemed reasonable by the regulator are recovered through the regulated tariff that the utility charges to its customers.

The tariff may be reviewed and reset by the regulator from time to time depending on local regulations, or the utility may seek a change in its tariffs. The tariff is generally based upon usage level and may include a pass-through of costs that are not controlled by the utility, such as the costs of fuel (in the case of integrated utilities) and/or the costs of purchased energy, to the customer. Components of the tariff that are directly passed through to the customer are usually adjusted through a summary regulatory process or an existing formula-based mechanism. In some regulatory regimes, customers with demand above an established level are unregulated and can choose to contract directly with the utility or with other retail energy suppliers and pay non-bypassable fees, which are fees to the distribution company for use of its distribution system.

The regulated tariff generally recognizes that our utility businesses should recover certain operating and fixed costs, as well as manage uncollectible amounts, quality of service and technical and non-technical losses. Utilities, therefore, need to manage costs to the levels reflected in the tariff, or risk non-recovery of costs or diminished returns.

Seasonality, Weather Variations, and Economic Activity — Our utility businesses are generally affected by seasonal weather patterns and, therefore, operating margin is not generated evenly throughout the year. Additionally, weather variations may also have an impact based on the number of customers, temperature variances from normal conditions, and customers' historic usage levels and patterns. Retail sales, after adjustments for weather variations, are also affected by changes in local economic activity, energy efficiency and distributed generation initiatives, as well as the number of retail customers.

Reliability of Service — Our utility businesses must meet certain reliability standards, such as duration and frequency of outages. Those standards may be explicit, with defined performance incentives or penalties, or implicit, where the utility must operate to meet customer and/or regulator expectations.

Development and Construction

We develop and construct new generation facilities. For our utility business, new plants may be built or existing plants retrofitted in response to customer needs or to comply with regulatory developments. The projects are developed subject to regulatory approval that permits recovery of our capital cost and a return on our investment. For our generation businesses, our priority for development is in key growth markets, where we can leverage our global scale and synergies with our existing businesses by adding renewable energy. We make the decision to invest in new projects by evaluating the strategic fit, financial profile, projected returns and risk for the investment and against alternative uses of capital, including corporate debt repayment.

In most cases, we enter into long-term contracts for output from new facilities prior to commencing construction. To limit required equity contributions from The AES Corporation, we also seek non-recourse project debt financing and other sources of capital, including partners, when it is commercially attractive. We typically contract with a third party to manage construction, although our construction management team supervises the construction work and tracks progress against the project's budget, schedule, and the required safety, efficiency and productivity standards.

Segments

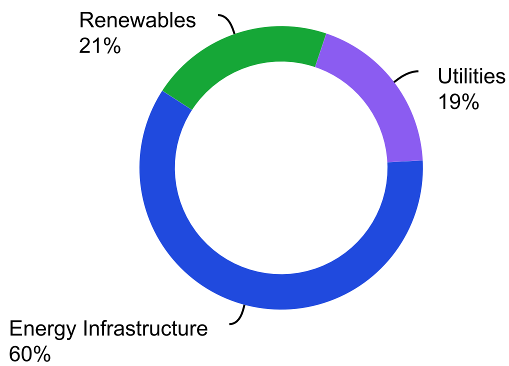
The segment reporting structure uses the Company's management reporting structure as its foundation to reflect how the Company manages the businesses internally and is mainly organized by technology.

We are organized into four technology-oriented SBUs: **Renewables** (solar, wind, energy storage, and hydro generation facilities); **Utilities** (AES Indiana, AES Ohio, and AES El Salvador regulated utilities and their generation facilities); **Energy Infrastructure** (natural gas, LNG, coal, pet coke, diesel, and oil generation facilities, and our businesses in Chile); and **New Energy Technologies** (green hydrogen initiatives and investments in Fluence, Uplight, and 5B) — which are led by our SBU Presidents.

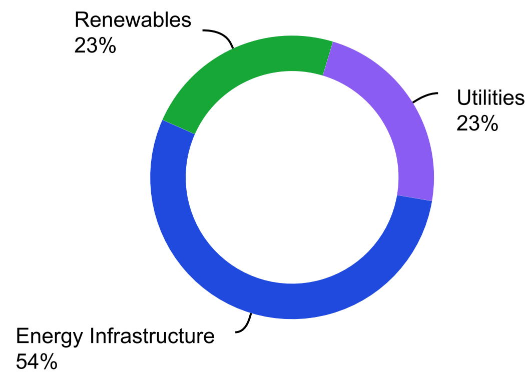
We have two lines of business: generation and utilities. Our Renewables, Utilities, and Energy Infrastructure SBUs participate in our first business line, generation, in which we own and/or operate power plants to generate and sell power to customers, such as utilities, industrial users, and other intermediaries. Our Utilities SBU participates in our second business line, utilities, in which we own and/or operate utilities to generate or purchase, distribute, transmit and sell electricity to end-user customers in the residential, commercial, industrial and governmental sectors within a defined service area. In certain circumstances, our utilities also generate and sell electricity on the wholesale market. Our New Energy Technologies SBU includes investments in new and innovative technologies to support leading-edge greener energy solutions.

We measure the operating performance of our SBUs using Adjusted EBITDA, a non-GAAP measure. The Adjusted EBITDA by SBU for the year ended December 31, 2023 is shown below. The percentages for Adjusted EBITDA are the contribution by each SBU to the gross metric, i.e., the total Adjusted EBITDA by SBU, before deductions for Corporate. Our New Energy Technologies SBU generated losses for the year ended December 31, 2023. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—SBU Performance Analysis* of this Form 10-K for reconciliation and definitions of Adjusted EBITDA.

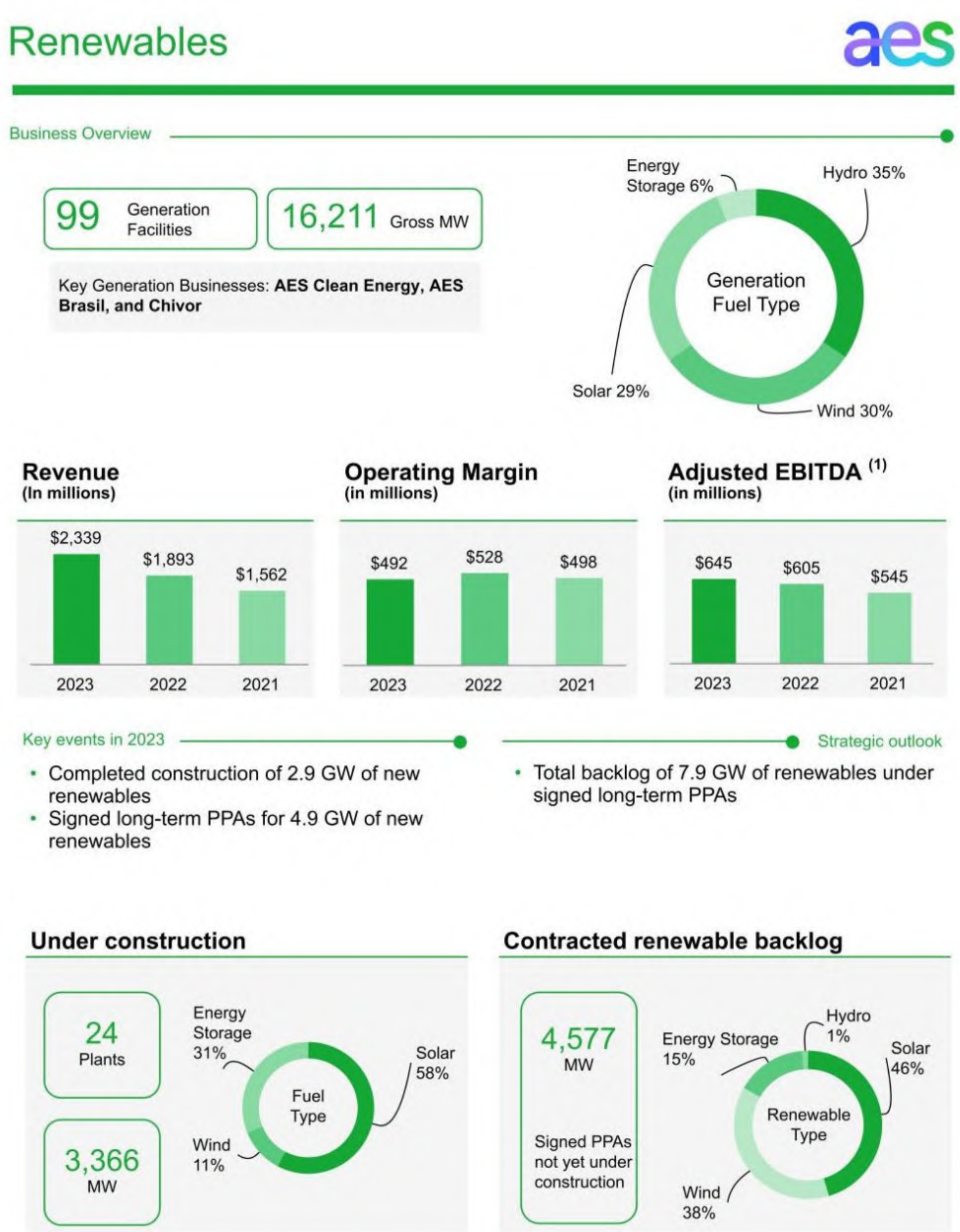
Operating Margin



Adjusted EBITDA



For financial reporting purposes, the Company's corporate activities are reported within "Corporate and Other" because they do not require separate disclosure. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations* and Note 18—*Segment and Geographic Information* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further discussion of the Company's segment structure.



(1) Non-GAAP measure. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—SBU Performance Analysis—Non-GAAP Measures* for reconciliation and definition.

Renewables

Our Renewables SBU is the highest growth segment for AES, adding 4.9 GW to our contracted backlog during 2023, including 1.2 GW with large technology companies.

Specifically, demand from data centers in the U.S. is expected to nearly double in the next three years as generative artificial intelligence use-cases expand. Our well-established relationships with these customers, combined with our proven track record of delivering our projects, positions us well to take advantage of this opportunity.

The Renewables SBU has generation facilities in ten countries — the United States, Brazil, Argentina, Colombia, Mexico, Panama, Bulgaria, the Dominican Republic, Jordan, and the Netherlands.

Generation — Total operating installed capacity of the Renewables SBU is 16,211 MW. The following table lists our Renewables SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
AES Brasil Operacoes (AES Tietê) (1)	Brazil	Hydro	2,658	47 %	1999	2032	Various
Alicura (9)	Argentina	Hydro	1,050	100 %	2000		
Chivor	Colombia	Hydro	1,000	99 %	2000	2024-2039	Various
OpCo A (2)	US-Various	Solar	967	26 %	2017-2019	2028-2046	Various
		Wind	140				
New York Wind (OpCo D) (3)	US-NY	Wind	612	75 %	2021		NYISO
AES Renewable Holdings (3)	US-Various	Solar	414	100 %	2015-2023	2029-2042	Utility, Municipality, Education, Non-Profit
		Energy Storage	90				
Spotsylvania Solar Energy Center (OpCo B) (2)	US-VA	Solar	485	26 %	2020-2021	2035	Apple, Akami, Etsy, Microsoft
Ventos do Araripe, Caetes & Cassino (Cubico II)	Brazil	Wind	456	47 %	2022	2034-2035	Various, CCEE
Alto Sertão II	Brazil	Wind	386	36 %	2017	2033-2035	Various, CCEE
Cajuina 1	Brazil	Wind	314	36%-47%	2023	2035-2043	Various
Mesa La Paz (2)	Mexico	Wind	306	50 %	2019	2045	Fuentes de Energia Peñoles
McFarland A (4)	US-AZ	Solar	200	75 %	2023	2038	BP
		Energy Storage	100				
Cajuina 2	Brazil	Wind	296	36%-47%	2023	2044	Various
OpCo B (2)	US-Various	Solar	260	26 %	2019	2039-2044	Various
Bayano	Panama	Hydro	260	49 %	1999	2030	ENSA, Edemet, Edechi, Other
Chevelon Butte (OpCo D) (3)	US-AZ	Wind	238	75 %	2023	2043	APS
Buffalo Gap II (3)	US-TX	Wind	233	100 %	2007		
Baldy Mesa (4)	US-CA	Solar	150	75 %	2023	2043	Amazon
		Energy Storage	75				
Changuinola	Panama	Hydro	223	90 %	2011	2030	AES Panama
Great Cove 1&2 (4)	US-PA	Solar	220	75 %	2023	2043	University of
Raceway 1	US-CA	Solar	125	50 %	2023	2043	Microsoft
		Energy Storage	80				
Prevailing Winds (OpCo B) (2)	US-SD	Wind	200	26 %	2020	2050	Prevailing Winds
Oak Ridge (4)	US-LA	Solar	200	75 %	2023	2043	Amazon
Ventus	Brazil	Wind	187	36 %	2020	2034	CCEE
Skipjack (OpCo D) (3)(4)	US-VA	Solar	175	75 %	2022	2036	Exelon Generation Company
Buffalo Gap III (3)	US-TX	Wind	170	100 %	2008		
Tucano Phase 2	Brazil	Wind	161	47 %	2023	2036	Anglo American
Mandacaru and Salinas	Brazil	Wind	159	47 %	2021	2033-2034	CCEE
St. Nikola	Bulgaria	Wind	156	89 %	2010	2025	Electricity Security Fund
Tucano Phase 1	Brazil	Wind	155	24 %	2022-2023	2042	Unipar
Guaimbê	Brazil	Solar	150	36 %	2018	2037	CCEE

Lancaster Area Battery (LAB) (3)(4)	US-CA	Energy Storage	127	75 %	2022	2037	PG&E
Buffalo Gap I (3)	US-TX	Wind	121	100 %	2006		
Chiriqui-Esti	Panama	Hydro	120	49 %	2003	2030	ENSA, Edemet, Edechi, Other
Cavalier (4)	US-VA	Solar	116	75 %	2023	2043	Dominion Energy
Delta (4)	US-MS	Wind	104	75 %	2023	2043	Amazon
Cabra Corral	Argentina	Hydro	102	100 %	1995		Various
Southland Energy—Alamitos Energy Center (5)	US-CA	Energy Storage	100	50 %	2021	2041	Southern California Edison
East Line Solar (OpCo B) (2)	US-AZ	Solar	100	26 %	2020	2045	Salt River Project
Central Line (OpCo B) (2)	US-AZ	Solar	100	26 %	2022	2039	Salt River Project Agricultural Improvement & Power District
West Line (OpCo B) (2)	US-AZ	Solar	100	26 %	2022	2047	Salt River Project Agricultural Improvement & Power District
Luna (3)	US-CA	Energy Storage	100	75 %	2022	2037	Clean Power Alliance of Southern California
Vientos Bonaerenses	Argentina	Wind	100	100 %	2020	2024-2040	Various
Vientos Neuquinos	Argentina	Wind	100	100 %	2020	2024-2040	Various
Laurel Mountain Repowering (OpCo D) (4)	US-WV	Wind	99	75 %	2022	2037	AES Solutions Management, LLC
McFarland B (4)	US-AZ	Solar	60	75 %	2023	2043	Amazon
		Energy Storage	30				
Estrella	US-CA	Solar	56	50 %	2023	2038	Southern California Edison
		Energy Storage	28				
Platteview (4)	US-NE	Solar	81	75 %	2023	2043	Omaha Public Power District
Clover Creek (OpCo B) (2)	US-UT	Solar	80	50 %	2021	2046	UMPA
Westwing 1 (4)	US-AZ	Energy Storage	77	75 %	2023	2043	APS
AGV Solar	Brazil	Solar	76	36 %	2019	2040	Various, CCEE
OpCo C (3)	US-Various	Solar	73	50 %	2021-2022	2041-2042	Various
Boa Hora	Brazil	Solar	69	47 %	2019	2038	CCEE
Mountain View Repowering (OpCo D) (3)(4)	US-CA	Wind	67	75 %	2022	2042	Southern California Edison
San Fernando	Colombia	Solar	61	99 %	2021	2036	Ecopetrol
Big Island Waikoloa (OpCo E) (3)(6)	US-HI	Solar	30	100 %	2022-2023	2047	HECO
		Energy Storage	30				
Penonome I	Panama	Wind	55	49 %	2020	2030	ENSA, Edemet, Edechi
Chiriqui-Los Valles	Panama	Hydro	54	49 %	1999	2030	ENSA, Edemet, Edechi, Other
Bayasol	Dominican Republic	Solar	50	65 %	2021	2036	Ede Sur
Agua Clara	Dominican Republic	Wind	50	65 %	2022	2039	Ede Norte
Santanasol	Dominican Republic	Solar	50	65 %	2022	2038	Ede Sur
Mountain View IV (OpCo E) (6)	US-CA	Wind	49	100 %	2012	2032	Southern California Edison
Chiriqui-La Estrella	Panama	Hydro	48	49 %	1999	2030	ENSA, Edemet, Edechi, Other
AM Solar (7)	Jordan	Solar	48	36 %	2019	2039	National Electric Power Company
Ullum	Argentina	Hydro	45	100 %	1996		Various
Lawa'i (3)(6)	US-HI	Solar	20	100 %	2018	2043	Kaua'i Island Utility Cooperative
		Energy Storage	20				
OpCo D (2)	US-Various	Solar	38	75 %	2022-2023	2042-2043	Various
		Energy Storage	2				

Kuihelni [4]	US-HI	Solar	14.5	100 %	2023	2048	HECO
		Energy Storage	14.5				
Kekaha [3][6]	US-HI	Solar	14	100 %	2019	2045	Kaua'i Island Utility Cooperative
		Energy Storage	14				
Brisas	Colombia	Solar	27	99 %	2022	2037	Ecopetrol
West Oahu Solar [6]	US-HI	Solar	12.5	100 %	2023	2048	HECO
		Energy Storage	12.5				
Na Pua Makani [6]	US-HI	Wind	24	100 %	2020	2040	HECO
Ilumina	US-PR	Solar	24	100 %	2012	2037	LUMA Energy
Castilla	Colombia	Solar	21	99 %	2019	2034	Ecopetrol
Tunjita	Colombia	Hydro	20	99 %	2016	2024-2039	Various
Laurel Mountain ES	US-WV	Energy Storage	16	100 %	2011		
Community Energy [4]	US-Various	Solar	14	75 %	2022	2024-2043	Various
Southland Energy—AES Gilbert (Salt River [5] [8]	US-AZ	Energy Storage	10	50 %	2019	2039	Salt River Project Agricultural Improvement & Power District
El Tunal	Argentina	Hydro	10	100 %	1995		Various
Andres ES	Dominican Republic	Energy Storage	10	65 %	2017		
Los Mina DPP ES	Dominican Republic	Energy Storage	10	65 %	2017		
Pesé Solar	Panama	Solar	10	49 %	2021	2030	ENSA, Edemet, Edechi, Other
Mayorca Solar	Panama	Solar	10	49 %	2021	2030	ENSA, Edemet, Edechi, Other
Cedro	Panama	Solar	10	49 %	2021	2030	ENSA, Edemet, Edechi, Other
Caoba	Panama	Solar	10	49 %	2021	2030	ENSA, Edemet, Edechi, Other
Netherlands ES	Netherlands	Energy Storage	10	100 %	2015		
Warrior Run ES	US-MD	Energy Storage	5	100 %	2016		
5B Costa Norte	Panama	Solar	1	100 %	2021	2051	Costa Norte LNG Terminal
			16,211				

(1) AES Tietê hydro plants: Água Vermelha (1,396 MW), Bariri (143 MW), Barra Bonita (141 MW), Caconde (80 MW), Euclides da Cunha (109 MW), Ibitinga (132 MW), Limoeiro (32 MW), Mog-Guaçu (7 MW), Nova Avanhandava (347 MW), Promissão (264 MW), Sao Joaquim (3 MW) and Sao Jose (4 MW).

(2) Unconsolidated entity, accounted for as an equity affiliate.

(3) AES owns these assets together with third-party tax equity investors with variable ownership interests. The tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes, that vary over the life of the projects. The proceeds from the issuance of tax equity are recorded as *Noncontrolling interest* or *Redeemable stock of subsidiaries* in the Company's Consolidated Balance Sheets, depending on the partnership rights of the specific project.

(4) Owned by ACED.

(5) On December 1, 2022, Southland Energy sold an additional 14.9% ownership interest in the Southland Energy assets. Following the sale, AES holds 50.1% of Southland Energy's interest and this business continues to be consolidated by AES.

(6) Owned by AES Renewable Holdings.

(7) Announced the sale of 26% of our interest in this business in November 2020.

(8) Facility experienced a fire event in April 2022 which rendered the asset currently inoperable.

(9) Operated by AES under a concession contract granted for a term of 30 years, which was set to expire on August 11, 2023. In accordance with the contract, the concession could be extended with a transitional period up to a maximum of 12 months. The Energy Secretariat has enacted several resolutions since the contractual expiration date extending it until March 18, 2024. Once its term expires, the ownership and possession of the power plant equipment will be transferred by full right to the National State in its capacity as grantor.

Under construction — The majority of projects under construction have executed long-term PPAs or, as applicable, have been assigned tariffs through a regulatory process. The following table lists our plants under construction in the Renewables SBU:

Business	Location	Fuel	Gross MW	AES Equity Interest	Expected Date of Commercial Operations
High Mesa [1]	US-CO	Solar	10	75 %	1H 2024
		Energy Storage	10		
Westwing 1 [1]	US-AZ	Energy Storage	3	75 %	
Delta [1]	US-MS	Wind	81	75 %	1H 2024
Chevelon Butte Phase II [1]	US-AZ	Wind	216	75 %	1H 2024
Kuihelni [2]	US-HI	Solar	45	100 %	1H 2024
		Energy Storage	45		
Cajuína 2	Brazil	Wind	74	47 %	1H 2024
Tucano Phase 2	Brazil	Wind	6	47 %	1H 2024
Mirasol 1&2	Dominican Republic	Solar	100	65 %	1H 2024
AES Clean Energy Development	US-Various	Solar	69	75 %	1H-2H 2024
		Energy Storage	7		
McFarland B [1]	US-AZ	Solar	240	75 %	2H 2024
		Energy Storage	120		
Cavalier [1]	US-VA	Solar	40	75 %	2H 2024
Alamitos 2	US-CA	Energy Storage	82	100 %	2H 2024
Cavalier Solar A2 [1]	US-VA	Solar	84	75 %	2H 2024
Waiwa Phase 2 [1]	US-HI	Solar	30	75 %	2H 2024
		Energy Storage	30		
Peravia I	Dominican Republic	Solar	70	65 %	2H 2024
Calhoun	US-MI	Solar	125	75 %	2H 2024
Mamm Creek	US-CO	Solar	10	75 %	2H 2024
		Energy Storage	10		
AGV VII	Brazil	Solar	33	47 %	2H 2024
Los Santos Solar	Panama	Solar	8	49 %	2H 2024
Corotu Solar	Panama	Solar	10	49 %	2H 2024
Esti Solar II	Panama	Solar	18	49 %	2H 2024
Rexford	US-CA	Solar	300	100 %	2H 2024-1H 2025
		Energy Storage	240		
Morris Solar	US-MO	Solar	250		1H 2025
Bellefield Phase 1 [1]	US-CA	Solar	500	75 %	2H 2025
		Energy Storage	500		
			3,366		

(1) Owned by ACED.

(2) Owned by AES Renewable Holdings.

AES Clean Energy

Business Description — AES' U.S. renewables portfolio, referred to as AES Clean Energy, is the leading U.S. renewables growth platform in serving large corporations with its 51 GW development pipeline. AES Clean Energy aims to solve customers' energy challenges by offering an expanded portfolio of innovative solutions based on cutting-edge technologies that are designed to accelerate customers' transitions to carbon-free energy. The generation capacity of the systems owned and/or operated under AES Clean Energy is 6,964 MW across the U.S., with another 3,121 MW under construction, including 1,725 MW of solar, 297 MW of wind, and 1,099 MW of energy storage. AES Clean Energy has a 6.1 GW backlog of projects, the majority of which are expected to come online through 2025. The adoption of the Inflation Reduction Act ("IRA") in 2022 and the expansion of data center needs related to the growing use of generative artificial intelligence are expected to be a significant accelerant to the growth of the U.S. renewables market and AES seeks to capture a significant portion of this market expansion.

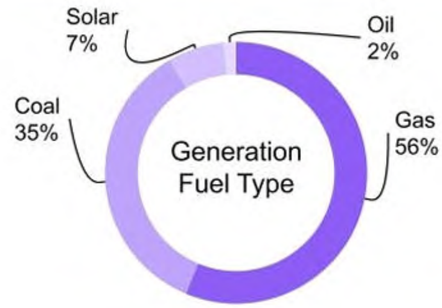
AES Clean Energy comprises AES Renewable Holdings, sPower, ACED, and other renewable assets, as part

Utilities

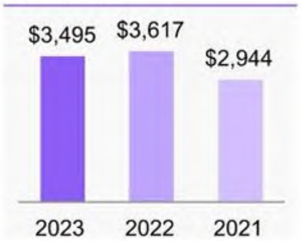
Business Overview

11 Generation Facilities	6 Utility Companies
3,500 Gross MW	31,725 GWH

Key Utilities: **AES Indiana, AES Ohio, and AES El Salvador**



Revenue
(In millions)



Operating Margin
(in millions)

Adjusted EBITDA [1]
(in millions)

Adjusted PTC [1]
(in millions)

Key events in 2023

- AES Indiana reached a settlement agreement for its first rate case since 2018
- AES Ohio received approval from the PUCO for its Electric Security Plan (ESP4)
- Retired 415 MW of coal at Petersburg Unit 2 at AES Indiana

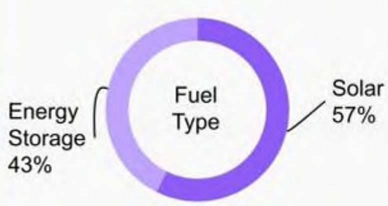
Strategic outlook

- AES Indiana expects to receive approval of its rate case from the IURC by the middle of 2024
- Total backlog of 0.7 GW of renewables under signed long-term PPAs
- Expect to convert remaining two coal units of Petersburg to natural gas

Under construction

3 Plants

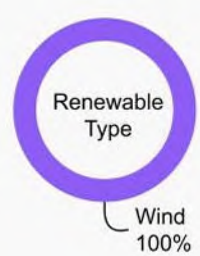
575 MW



Contracted renewable backlog

106 MW

Signed PPAs not yet under construction



(1) Non-GAAP measure. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—SBU Performance Analysis—Non-GAAP Measures* for reconciliation and definition.

Utilities

Our Utilities SBU is the second largest contributor to our future growth, particularly in the U.S., where we are targeting a combined 10% annual growth in rate base at our two utilities: AES Indiana and AES Ohio. In this segment, we also have four utilities in El Salvador and a portfolio of generation facilities, including at our integrated utility in Indiana, with installed operating capacity of 3,500 MW. IPALCO (AES Indiana's parent), AES Ohio, and DPL Inc. (AES Ohio's parent) are all SEC registrants, and as such, follow the public filing requirements of the Securities Exchange Act of 1934.

Utilities — The following table lists our utilities and their generation facilities:

Business	Location	Type	AES Equity Interest	Approximate Number of Customers Served as of 12/31/2023	Approximate GWh Sold in 2023	Fuel	Gross MW	Year Acquired or Began Operation
CAESS	El Salvador	Distribution	75 %	659,000	2,214			2000
CLESA	El Salvador	Distribution	80 %	475,000	1,143			1998
DEUSEM	El Salvador	Distribution	74 %	95,000	174			2000
EEO	El Salvador	Distribution	89 %	357,000	762			2000
El Salvador Subtotal				**1,586,000**	**4,293**			
AES Ohio [1]	US-OH	Transmission & Distribution	100 %	539,000	13,305			2011
AES Indiana [2]	US-IN	Integrated	70 %	523,000	14,127	Coal/Gas/ Oil/Solar/ Energy Storage	3,357	2001
United States Subtotal				**1,062,000**	**27,432**		**3,357**	
				2,648,000	**31,725**			

(1) AES Ohio's GWh sold in 2023 represent total transmission and distribution sales. AES Ohio's wholesale sales and SSO utility sales, which are sales to utility customers who use AES Ohio to source their electricity through a competitive bid process, were 3,183 GWh in 2023. AES Ohio owns a 4.9% equity ownership in OVEC, an electric generating company. OVEC has two plants in Cheshire, Ohio and Madison, Indiana with a combined generation capacity of approximately 2,109 MW. AES Ohio's share of this generation is approximately 103 MW.

(2) CDPQ owns direct and indirect interests in IPALCO (AES Indiana's parent) which total approximately 30%. AES owns 85% of AES US Investments and AES US Investments owns 82.35% of IPALCO. AES Indiana plants: Georgetown, Harding Street, Petersburg and Eagle Valley. 20 MW of AES Indiana total is considered a transmission asset. In December 2023, the first stage of construction for the 195 MW Hardy Hills solar project was completed and initial operations for over half of the project commenced. The remaining MW are expected to be placed in service in 2024.

Generation — The following table lists our Utilities SBU generation facilities. The energy produced by these generation facilities is fully contracted by AES' utilities in El Salvador.

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Bosforo [1]	El Salvador	Solar	100	50 %	2018-2019	2043-2044	CAESS, EEO, CLESA, DEUSEM
Metapan	El Salvador	Solar	15	100 %	2043-2048	2033	CLESA, Cemento Holcim de El Salvador
Cuscatlan Solar [1]	El Salvador	Solar	10	50 %	2021	2046	CLESA
AES Nejapa	El Salvador	Landfill Gas	6	100 %	2011	2035	CAESS
Meangura del Gofo	El Salvador	Solar	1	100 %	2023	2048	EEO
		Energy Storage	4				
Opico	El Salvador	Solar	4	100 %	2020	2040	CLESA
Moncagua	El Salvador	Solar	3	100 %	2015	2035	EEO
			143				

(1) Unconsolidated entity, accounted for as an equity affiliate.

Under construction — The following table lists our plants under construction in the Utilities SBU:

Business	Location	Fuel	Gross MW	AES Equity Interest	Expected Date of Commercial Operations
Hardy Hills Solar (AES Indiana) [(1)]	US-IN	Solar	80	70 %	1H 2024
Pike County (AES Indiana)	US-IN	Energy Storage	200	70 %	2024
Petersburg Energy Center (AES Indiana)	US-IN	Solar	250	70 %	2H 2025
		Energy Storage	45		
			575		

(1) In December 2023, the first stage of construction of this project was completed and initial operations for over half of the project commenced. The final stage of construction is expected to be completed during the first half of 2024.

AES Indiana

Business Description — IPALCO is a holding company whose principal subsidiary is AES Indiana. AES Indiana is an integrated utility that is engaged primarily in generating, transmitting, distributing, and selling electric energy to retail customers in the city of Indianapolis and neighboring areas within the state of Indiana and is subject to regulatory authority—see *Regulatory Framework and Market Structure* below. AES Indiana has an exclusive right to provide electric service to the customers in its service area, covering about 528 square miles with an estimated population of approximately 969,000 people.

AES Indiana owns and operates four generating stations, all within the state of Indiana. The first station, Petersburg, is coal-fired, and consists of four units. AES Indiana retired 230 MW Petersburg Unit 1 in May 2021 and 415 MW Petersburg Unit 2 in June 2023, which resulted in 630 MW of total retired economic capacity at this station. AES Indiana plans to convert the remaining two coal units at Petersburg to natural gas (see *Integrated Resource Plan* below). The second station, Harding Street, consists of three natural gas-fired boilers and steam turbines and uses natural gas and fuel oil to power five combustion turbines. In addition, AES Indiana operates a 20 MW battery-based energy storage unit at this location, which provides frequency response. The third station, Eagle Valley, is a CCGT natural gas plant. The fourth station, Georgetown, is a small peaking station that uses natural gas to power combustion turbines. In addition, AES Indiana helps meet its customers' energy needs with long-term contracts for the purchase of 300 MW of wind-generated electricity and 94 MW of solar-generated electricity.

In December 2021, AES Indiana completed the acquisition of Hardy Hills Solar Energy LLC, including the development of a 195 MW solar project (the "Hardy Hills solar project"). In December 2023, the first stage of construction for the Hardy Hills solar project was completed and initial operations for over half of the project commenced. The final stage of construction of the project is expected to be completed during the first half of 2024.

In August 2023, AES Indiana completed the acquisition of Petersburg Energy Center, LLC, including the development of a 250 MW solar and 45 MW (180 MWh) energy storage facility (the "Petersburg Energy Center project"). The Petersburg Energy Center project is expected to be completed in 2025.

In June 2023, AES Indiana executed an agreement for the construction of the 200 MW (800 MWh) Pike County BESS project to be developed at the AES Indiana Petersburg Plant site in Pike County, Indiana, subject to IURC approval, which was received in January 2024. The Pike County BESS project is expected to be completed in 2024.

In July 2023, AES Indiana executed a purchase agreement for the acquisition of the Hoosier Wind Project, which is an existing 106 MW wind facility located in Benton County, Indiana, subject to IURC approval, which was received in January 2024. The acquisition of the Hoosier Wind Project is expected to be completed in the first quarter of 2024.

Key Financial Drivers — AES Indiana's financial results are driven primarily by retail demand, weather, and maintenance costs. In addition, AES Indiana's financial results are likely to be driven by many other factors including, but not limited to:

- regulatory outcomes and impacts;
- the passage of new legislation, implementation of regulations, or other changes in regulation; and
- timely recovery of capital expenditures and operation and maintenance costs.

Regulatory Framework and Market Structure — AES Indiana is subject to comprehensive regulation by the IURC with respect to its services and facilities, retail rates and charges, the issuance of long-term securities, and certain other matters. The regulatory authority of the IURC over AES Indiana's business is typical of regulation generally imposed by state public utility commissions. The IURC sets tariff rates for electric service provided by AES Indiana. The IURC considers all allowable costs for ratemaking purposes, including a fair return on assets used and useful to providing service to customers.

AES Indiana's tariff rates for electric service to retail customers consist of basic rates and approved charges. In addition, AES Indiana's rates include various adjustment mechanisms, including, but not limited to: (i) a rider to reflect changes in fuel and purchased power costs to meet AES Indiana's retail load requirements, referred to as the Fuel Adjustment Charge, (ii) a rider for the timely recovery of costs incurred to comply with environmental laws and regulations, including a return, (iii) a rider to reflect changes in ongoing RTO costs, (iv) riders for passing through to customers wholesale sales margins and capacity sales above and below established annual benchmarks, (v) a rider for a return on, and of, investments for eligible TDSIC improvements, and (vi) a rider for cost recovery, lost margin recoveries and performance incentives from AES Indiana's demand side management energy efficiency programs. Each of these tariff rate components function somewhat independently of one another, but the overall structure of AES Indiana's rates is subject to review at the time of any review of AES Indiana's basic rates and charges. Additionally, AES Indiana's rider recoveries are reviewed through recurring filings.

AES Indiana filed a petition with the IURC on June 28, 2023, for authority to increase its basic rates and charges to cover the rising operational costs and needs associated with continuing to serve its customers safely and reliably. The factors leading to AES Indiana's first base rate increase request in five years include inflationary impacts on operations and maintenance expenses, investments in the transmission and distribution systems, and modernization of its customer systems. AES Indiana is also seeking recovery of increased costs to support its vegetation management plan, which covers the removal of overhang and tree trimming in its service territory. AES Indiana also seeks to better align depreciation expense with the period in which the generation plants provide service to customers and remove operational costs of the retired Petersburg units from rates. On November 22, 2023, AES Indiana entered into a unanimous stipulation and settlement agreement (the "settlement") with the OUCC and the intervening parties which, if approved by the IURC, would increase its annual revenue requirement by $73 million. AES Indiana expects to receive an order from the IURC and place new rates into effect by the end of the second quarter of 2024.

On October 31, 2018, the IURC issued an order approving an uncontested settlement agreement to increase AES Indiana's annual revenues by $44 million, or 3% (the "2018 Base Rate Order"), which are the base rates under which AES Indiana is currently operating. This revenue increase primarily includes recovery through rates of costs associated with the CCGT at Eagle Valley, completed in the first half of 2018, and other construction projects. New base rates and charges became effective on December 5, 2018.

AES Indiana is one of many transmission system owner members in MISO, an RTO which maintains functional control over the combined transmission systems of its members and manages one of the largest energy and ancillary services markets in the U.S. MISO dispatches generation assets in economic order considering transmission constraints and other reliability issues to meet the total demand in the MISO region. AES Indiana offers electricity in the MISO day-ahead and real-time markets.

Development Strategy — AES Indiana's construction program is composed of capital expenditures necessary for prudent utility operations and compliance with environmental regulations, along with discretionary investments designed to replace aging equipment or improve overall performance.

Senate Enrolled Act 560, the Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") statute, provides for cost recovery outside of a base rate proceeding for new or replacement electric and gas transmission, distribution, and storage projects that a public utility undertakes for the purposes of safety, reliability, system modernization, or economic development. Provisions of the TDSIC statute require that requests for recovery include a plan of at least five years and not more than seven for eligible investments. Once a plan is approved by the IURC, eighty percent of eligible costs can be recovered using a periodic rate adjustment mechanism, referred to as a TDSIC mechanism. Recoverable costs include a return on, and of, the investment, including AFUDC, post-in-service carrying charges, operation and maintenance expenses, depreciation, and property taxes. The remaining twenty percent of recoverable costs are deferred for future recovery in the public utility’s next base rate case. The TDSIC mechanism is capped at an annual increase of two percent of total retail revenues.

On March 4, 2020, the IURC issued an order approving the projects in AES Indiana's seven-year TDSIC Plan for eligible transmission, distribution, and storage system improvements totaling $1.2 billion from 2020 through 2026. Beginning in June 2020, AES Indiana files an annual TDSIC rate adjustment for a return on, and of, investments through March 31 with rates requested to be effective each November. Annual TDSIC plan update filings are required to be staggered by six months as ordered by the IURC and are filed each December. The total amount of AES Indiana’s equipment net of depreciation, including carrying cost, approved for TDSIC recovery as of December 31, 2023 was $400 million.

Integrated Resource Plan — In December 2022, AES Indiana filed its Integrated Resource Plan ("IRP"), which describes AES Indiana's Preferred Resource Portfolio for meeting generation capacity needs for serving AES Indiana's retail customers over the next several years. The Preferred Resource Portfolio is AES Indiana's reasonable least cost option and provides a cleaner and more diverse generation mix for customers. The 2022 IRP short-term action plan includes converting the two remaining coal units at Petersburg to natural gas. AES Indiana has not yet filed for the regulatory approvals from the IURC to convert Petersburg units 3 and 4, however, AES Indiana expects to do so at the appropriate time. Additionally, AES Indiana plans to add up to 1,300 MW of wind, solar, and battery energy storage by 2027. As new technologies, such as green hydrogen, small modular reactors, and carbon capture are developed and cost effective, we will evaluate them in the future planning processes.

AES Indiana expects to spend an estimated $3.2 billion on capital projects from 2024 through 2026, which includes AES Indiana's power generation and renewable energy projects discussed above, spending under AES Indiana's TDSIC Plan, as well as other new transmission and distribution projects.

In December 2021 and 2022, AES Indiana received equity capital contributions of $275 million and $253 million, respectively, from AES and CDPQ on a proportional share basis to be used for funding needs related to AES Indiana’s TDSIC and replacement generation projects.

AES Ohio

Business Description — DPL is a holding company whose principal subsidiary is AES Ohio. AES Ohio is a utility company that transmits and distributes electricity to approximately 539,000 retail customers in a 6,000 square mile area of West Central Ohio and is subject to regulatory authority—see *Regulatory Framework and Market Structure* below. AES Ohio has the exclusive right to provide transmission and distribution services to its customers, and procures retail standard service offer ("SSO") electric service on behalf of residential, commercial, industrial, and governmental customers through a competitive bid auction process.

Key Financial Drivers — AES Ohio's financial results are driven primarily by retail demand and weather. AES Ohio's financial results are likely to be driven by other factors as well, including, but not limited to:

- regulatory outcomes and impacts;
- the passage of new legislation, implementation of regulations, or other changes in regulations; and
- timely recovery of transmission and distribution expenditures.

Regulatory Framework and Market Structure — AES Ohio is regulated by the PUCO for its distribution services and facilities, retail rates and charges, reliability of service, compliance with renewable energy portfolio requirements, energy efficiency program requirements, and certain other matters. The PUCO maintains jurisdiction over the delivery of electricity, SSO, and other retail electric services.

Electric customers within Ohio are permitted to purchase power under contract from a Competitive Retail Electric Service ("CRES") provider or from their local utility under SSO rates. The SSO generation supply is provided by third parties through a competitive bid process. Ohio utilities have the exclusive right to provide transmission and distribution services in their state-certified territories. While Ohio allows customers to choose retail generation providers, AES Ohio is required to provide retail generation service at SSO rates to any customer that has not signed a contract with a CRES provider or as a provider of last resort in the event of a CRES provider default. SSO rates are subject to rules and regulations of the PUCO and are established through a competitive bid process for the supply of power to SSO customers.

AES Ohio's distribution rates are regulated by the PUCO and are established through a traditional cost-based rate-setting process. AES Ohio is permitted to recover its costs of providing distribution service as well as earn a regulated rate of return on assets, determined by the regulator, based on the utility's allowed regulated asset base, capital structure, and cost of capital. AES Ohio's retail rates include various adjustment mechanisms including, but not limited to, the timely recovery of costs incurred related to power purchased through the competitive bid process, participation in the PJM RTO, severe storm damage, and energy efficiency.

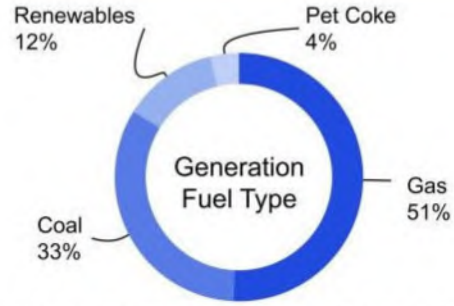
Energy Infrastructure

Business Overview

46 Generation Facilities

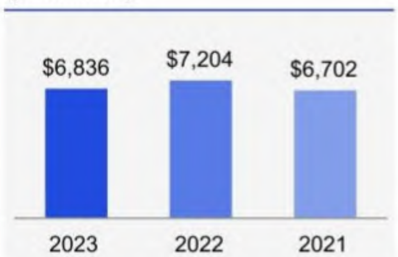
14,885 Gross MW

Key Generation Businesses: **AES Andes, Southland, AES Argentina, Mong Duong, Maritza, and Andres-Los Mina**

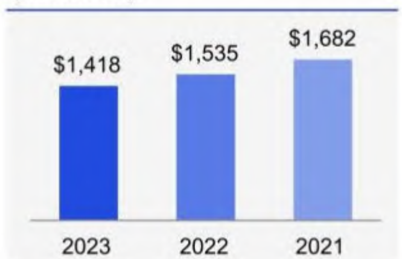


Note: All renewables in the Energy Infrastructure SBU are located in Chile.

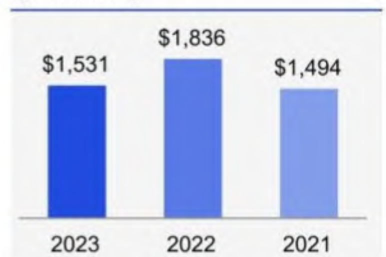
Revenue
(In millions)



Operating Margin
(in millions)



Adjusted EBITDA (1)
(in millions)



Key events in 2023

- Exited or announced the sale or closure of 1.7 GW of coal generation
- Signed agreements for three-year extensions of 1.4 GW of gas generation at the Southland legacy units in Southern California

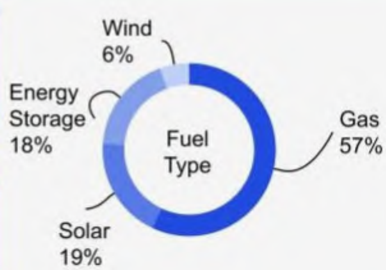
Strategic outlook

- Total backlog of 3.6 GW of renewables and gas under signed long-term PPAs, including 3 GW of renewables in Chile
- Intend to exit majority of coal businesses by year-end 2025[2]

Under construction

4 Plants

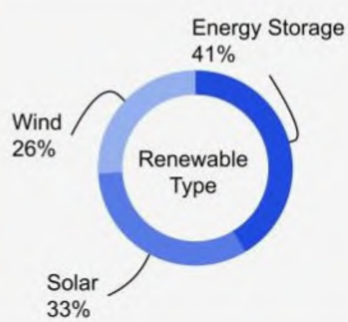
1,175 MW



Contracted renewable backlog

2,458 MW

Signed PPAs not yet under construction



(1) Non-GAAP measure. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—SBU Performance Analysis—Non-GAAP Measures* for reconciliation and definition.

(2) Through asset sales, fuel conversions and retirements, while maintaining reliability and affordability, and subject to necessary approvals. AES may delay the exit of a few select plants through 2027 to support continued electricity reliability.

Energy Infrastructure

Our Energy Infrastructure SBU aims to provide energy security to enable the integration of new renewables, maximize the value of our gas generation and LNG business through flexible operations that support the energy transition, and exit coal generation to achieve our decarbonization targets. This segment comprises generation facilities, using natural gas, LNG, coal, pet coke, diesel, and/or oil, in nine countries — Vietnam, the United States, Argentina, Chile, Bulgaria, Mexico, Jordan, Panama and the Dominican Republic. Although our businesses in Chile have a mix of generation sources, including renewables, the generation from all sources is pooled to service our existing PPAs. Consequently all of Chile's generation is included within the Energy Infrastructure SBU.

Generation — Operating installed capacity of our Energy Infrastructure segment totals 14,885 MW. The following table lists our Energy Infrastructure segment generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Mong Duong 2 [1]	Vietnam	Coal	1,242	51 %	2015	2040	EVN
Southland—Alamitos	US-CA	Gas	1,200	100 %	1998	2026	California Department of Water Resources
Paraná-GT	Argentina	Gas/Diesel	870	100 %	2001		
Southland Energy—Huntington Beach [3]	US-CA	Gas	694	50 %	2020	2040	Southern California Edison
Southland Energy—Alamitos [3]	US-CA	Gas	693	50 %	2020	2040	Southern California Edison
San Nicolás	Argentina	Coal/Gas/Oil/Energy Storage	691	100 %	1993		
Maritza	Bulgaria	Coal	690	100 %	2011	2026	National Electric Company (NEK)
TermoAndes [4]	Argentina	Gas/Diesel	643	99 %	2000	2024-2025	Various
Guillermo Brown [5]	Argentina	Gas/Diesel	576	— %	2016		
Angamos	Chile	Coal	558	99 %	2011		Various
Cochrane	Chile	Coal	550	57 %	2016	2030-2037	SQM, Sierra Gorda, Quebrada Blanca
Ventanas	Chile	Coal	537	99 %	2010, 2013		
Alto Maipo [2]	Chile	Hydro	531	99 %	2021	2040	Minera Los Pelambres
AES Puerto Rico	US-PR	Coal	524	100 %	2002	2027	LUMA Energy
Merida III	Mexico	Gas/Diesel	505	75 %	2000	2025	Comision Federal de Electricidad
Amman East [6]	Jordan	Gas	472	37 %	2009	2033	National Electric Power Company
Colon [7]	Panama	Gas	381	65 %	2018	2028	ENSA, Edemet, Edechi
DPP (Los Mina)	Dominican Republic	Gas	358	65 %	1996	2025	Ede Este, Ede Norte, Ede Sur, Non-Regulated Users
Andres [8]	Dominican Republic	Gas/Diesel	319	65 %	2003	2025	Ede Este, Ede Norte, Ede Sur, Non-Regulated Users
Andes 2b	Chile	Solar	180	99 %	2023		Various
		Energy Storage	112				
Norgener	Chile	Coal	276	99 %	2000	2028	Codelco
Termoelectrica del Golfo (TEG)	Mexico	Pet Coke	275	99 %	2007	2027	CEMEX
Termoelectrica del Penoles (TEP)	Mexico	Pet Coke	275	99 %	2007	2027	Peñoles
IPP4 [6]	Jordan	Gas	250	36 %	2014	2039	National Electric Power Company
Cordillera Hydro Complex [9]	Chile	Hydro	240	99 %	2000	2042	Various
Southland—Huntington Beach	US-CA	Gas	236	100 %	1998	2026	California Department of Water Resources
Warrior Run [10]	US-MD	Coal	205	100 %	2000	2024	Potomac Edison
Bolero	Chile	Solar	146	99 %	2023	2030	Various
Los Olmos	Chile	Wind	110	51 %	2022	2032	Google, Various
Los Cururos	Chile	Wind	109	51 %	2019		Various
Andes Solar 2a	Chile	Solar	81	51 %	2021		Google, Various

Mesamávida	Chile	Wind	68	51 %	2022	2038	Google, Various
Campo Lindo	Chile	Wind	65	51 %	2023		Various
Virtual Reservoir 2	Chile	Energy Storage	50	99 %	2023		
Sarmiento	Argentina	Gas/Diesel	33	100 %	1996		
Andes Solar 4	Chile	Solar	13	99 %	2023		Google, Various
		Energy Storage	13				
Andes Solar 1	Chile	Solar	22	99 %	2016	2036	Quebrada Blanca
Cochrane ES	Chile	Energy Storage	20	57 %	2016		
Angamos ES	Chile	Energy Storage	20	99 %	2011		
San Matias	Chile	Wind	17	99 %	2023	2038	Microsoft
Laja	Chile	Biomass	13	99 %	2000	2023	CMPC
Andes	Chile	Energy Storage	12	99 %	2009		
Alfalfal Virtual Reservoir	Chile	Energy Storage	10	99 %	2020		
PFV Kaufmann	Chile	Solar	1	99 %	2021	2040	Kaufmann
			14,885				

(1) In November 2023, agreed to sell this business to Sev.en Global Investments Pty Ltd. Following approvals by the Government of Vietnam and the Ministry of Industry and Trade, the anticipated close for this transaction is in line with AES' intent to exit the majority of its coal assets by the end of 2025.

(2) In November 2021, Alto Maipo SpA filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code. After Chapter 11 filing, the Company no longer has control over Alto Maipo and therefore deconsolidated the business. In May 2022, Alto Maipo emerged from bankruptcy. The restructured business is considered a VIE and the Company continues to account for the business as a deconsolidated entity.

(3) On December 1, 2022, Southland Energy sold an additional 14.9% ownership interest in the Southland Energy assets. Following the sale, AES holds 50.1% of Southland Energy's interest and this business continues to be consolidated by AES.

(4) TermoAndes is located in Argentina, but is connected to both the SING in Chile and the SADI in Argentina.

(5) AES operates this facility through management or O&M agreements and to date owns no equity interest in the business.

(6) Entered into an agreement to sell 26% interest in these businesses in November 2020.

(7) Plant also includes an adjacent regasification facility, as well as an 80 TBTU LNG storage tank, or an operating capacity of 180,000 m^3.

(8) Plant also includes an adjacent regasification facility, as well as two LNG storage tanks: Andres with 70 TBTU, or an operating capacity of 160,000 m^3 and Enadom with 50 TBTU, or an operating capacity of 120,000 m^3.

(9) Includes: Alfalfal, Queltehues and Volcan.

(10) On June 29, 2023, Warrior Run terminated its PPA with Potomac Edison. As part of the agreement, Warrior Run stopped selling its electricity to Potomac Edison, but will continue to provide capacity to Potomac Edison through May 31, 2024. The previous expiration for the PPA was 2030.

Under construction — The majority of projects under construction have executed mid- to long-term PPAs. The following table lists our plants under construction in the Energy Infrastructure SBU[1]:

Business	Location	Fuel	Gross MW	AES Equity Interest	Expected Date of Commercial Operations
San Matias	Chile	Wind	65	99 %	1H 2024
Andes Solar 4	Chile	Solar	225	99 %	2H 2024
		Energy Storage	135		
Gatun	Panama	Gas	670	24 %	2H 2024
Andes Solar 2a	Chile	Energy Storage	80	51 %	1H 2025
			1,175		

AES Chile

Business Description — In Chile, through AES Andes, we are engaged in the generation and supply of electricity (energy and capacity) in the SEN—see *International Energy Markets and Regulatory Environment* below. AES Andes is a publicly traded company in Chile and has applied to be de-listed. AES Andes owns all of our assets in Chile. AES has a 99.5% ownership interest in AES Andes, the third largest generation operator in Chile in terms of installed capacity with 3,516 MW, excluding energy storage, and has a market share of approximately 11% as of December 31, 2023. In addition, AES Andes has 237 MW of energy storage systems in operation.

AES Andes owns a diversified generation portfolio in Chile in terms of geography, technology, customers, and energy resources. AES Andes' generation plants are located near the principal electricity consumption centers, including Santiago, Valparaiso, and Antofagasta. AES Andes' diverse generation portfolio provides flexibility for the management of contractual obligations with regulated and unregulated customers, provides backup energy to the spot market and facilitates operations under a variety of market and hydrological conditions.

FitchRatings

ENTITY - ULTIMATE PARENT

Hawaiian Electric Industries, Inc.

Corporate Finance / Utilities and Power/Global / North America/United States

EU Endorsed, UK Endorsed; Solicited by or on behalf of the issuer (sell side)

ESG RELEVANCE

1	2	3	4	5

01 Ratings

RATING	ACTION	DATE	TYPE
B	Rating Watch Maintained	08-Mar-2024	Long Term Issuer Default Rating
B	Rating Watch Maintained	08-Mar-2024	Short Term Issuer Default Rating

Ratings Key	Outlook	Watch
POSITIVE		
NEGATIVE		
EVOLVING		
STABLE		

* Ratings displayed in orange denotes EU or UK Unsolicited and Non-Participatory Ratings

Where there was a review with no rating action (Review – No Action), please refer to the "Latest Rating Action Commentary" for an explanation of key rating drivers

*Premium Content is displayed in Fitch Red

RATING HISTORY

LONG TERM ISSUER DEFAULT RATING

SHORT TERM ISSUER DEFAULT RATING

DATE :	08-Mar-2024	21-Aug-2023	28-Jul-2023	17-Aug-2022	27-Jun-2022	18-Oct-2021	25-Jun-2021	15-Oct-2020	20-
RATING :	B	B	BBB+	BBB	BBB	BBB	BBB	BBB	BB
ACTION :	Rating Watch Maintained	Downgrade	Upgrade	Review - No Action	Affirmed	Review - No Action	Affirmed	Review - No Action	Aff

02 Rating Actions

RATING ACTION COMMENTARY / FRI 08 MAR, 2024

Fitch Maintains Hawaiian Electric Industries and HECO on Rating Watch Negative

RATING ACTION COMMENTARY / MON 21 AUG, 2023

Fitch Downgrades HEI and HECO to 'B'; On Rating Watch Negative

RATING ACTION COMMENTARY / FRI 28 JUL, 2023

Fitch Upgrades HEI to 'BBB+' and HECO to 'A-'; Outlook is Stable

RATING ACT

Fitch 'BBB' Outlo

ENTITY - ULTIMATE PARENT

PG&E Corporation

Corporate Finance / Utilities and Power / Corporate Finance: Leveraged Finance/Global / North America/United States

EU Endorsed, UK Endorsed; Solicited by or on behalf of the issuer (sell side)

ESG RELEVANCE

1	2	3	4	5

01 Ratings

RATING	ACTION	DATE	TYPE
BB+	Affirmed	12-Apr-2024	Long Term Issuer Default Rating
WD	Withdrawn	14-Mar-2019	Short Term Issuer Default Rating

Ratings Key	Outlook	Watch
POSITIVE		
NEGATIVE		
EVOLVING		
STABLE		

* Ratings displayed in orange denotes EU or UK Unsolicited and Non-Participatory Ratings

Where there was a review with no rating action (Review – No Action), please refer to the "Latest Rating Action Commentary" for an explanation of key rating drivers

*Premium Content is displayed in Fitch Red

RATING HISTORY

LONG TERM ISSUER DEFAULT RATING

SHORT TERM ISSUER DEFAULT RATING

DATE :	12-Apr-2024	18-Dec-2023	20-Mar-2023	02-Jun-2022	09-Mar-2022	07-Oct-2021	21-May-2021	09-Apr-2021	15-C
RATING :	BB+	BB+	BB+	BB	BB	BB	BB	BB	BB
ACTION :	Affirmed	Review - No Action	Upgrade	Affirmed	Review - No Action	Affirmed	Affirmed	Under Criteria Observation	Revi

02 Rating Actions

RATING ACTION COMMENTARY / MON 09 SEP, 2024

Fitch Rates PG&E Corporation's Jr. Sub Notes 'BB-'/'RR6'

RATING ACTION COMMENTARY / FRI 12 APR, 2024

Fitch Revises PG&E Corp.'s & Pacific Gas and Electric's Outlooks to Positive; Ratings Affirmed

RATING ACTION COMMENTARY / MON 20 MAR, 2023

Fitch Upgrades PG&E Corp.'s and Pacific Gas and Electric's IDRs to 'BB+'; Outlook Stable

RATING ACT

Fitch and E Affir

FitchRatings

RATING ACTION COMMENTARY

Fitch Affirms Alectra's IDR at 'A-'; Outlook Stable

Tue 23 Jul, 2024 - 2:36 PM ET

Fitch Ratings - Toronto - 23 Jul 2024: Fitch Ratings has affirmed Alectra Inc.'s Long-Term Issuer Default Rating (IDR) at 'A-'. The Rating Outlook is Stable. Fitch has also affirmed the company's senior unsecured debt at 'A'.

The affirmation reflects Fitch's continued expectation that a constructive rebasing outcome in 2027 would lead to improvement of Alectra's elevated FFO leverage to 5.4x in 2028. The company's rating are also supported by its large-scale regulated electric distribution operations under a highly constructive regulator in high growth areas of Ontario. Fitch rates Alectra based on its standalone credit profile with no direct uplift related to municipal ownership.

KEY RATING DRIVERS

Regulated Business Remains Predominant: Fitch expects Alectra's predominantly low-risk, regulated business mix to continue with 87%-90% of EBITDA from regulated activities through 2028. Fitch expects Alectra to dedicate over 90% of its $1.7 billion capex through 2028 to regulated operations. Recent unregulated projects and investments include gas generation facilities, energy storage facilities, and the acquisition of a power restoration business. No single segment contributes more than 2% to Alectra's total EBITDA per Fitch estimates.

Fitch expects Alectra's non-regulated businesses will maintain low capital intensity with minimal debt requirements and support its consolidated cash flows. Any material changes in business mix or debt-funded acquisitions resulting in a sustained leverage increase could lead to negative rating actions.

Continued Expectation of Deleveraging: Alectra's 'A-' IDR continues to be premised upon a constructive outcome in the 2027 rebasing and the resulting subsequent improvement in credit metrics. Fitch anticipates that Alectra's FFO leverage would remain elevated during the ongoing 10-year rebasing deferral period and then improve to 5.4x in 2028, which would be within Fitch's thresholds.

Fitch expects disposition of over-collected regulatory assets in 2027 will push the expected deleveraging by a year. In the interim, Fitch anticipates Alectra's leverage to remain elevated as earned ROEs continue to lag due to higher capex, the expiry of the Incremental Capital Module recovery mechanism in 2024, and higher operational costs. Nevertheless, constructive rebasing, customer growth, and continuing synergies should improve leverage post-rebasing. Fitch believes the regulatory support and lack of sectoral bankruptcies in Canada offset higher leverage relative to U.S. peers due to lower allowed equity thickness.

Constructive Regulatory Environment: Fitch expects the regulatory environment for Alectra under the Ontario Energy Board (OEB) to remain constructive. Alectra currently operates under the Price Cap performance-based rate-setting option and benefits from forward-looking test years in base rate cases, multi-year formulaic rate plans, revenue decoupling, and annual tariff adjustments tracking inflation and productivity savings.

Fitch believes the various annual rate riders, like those for power cost recoveries, allowed under OEB are also a credit positive. The OEB's 2023 acceleration of rate application parameters for some of the riders ahead of normal timelines has helped reduce regulatory lag and demonstrates OEB's credit-supportive stature. Alectra's allowed ROE of 8.95% and equity capitalization of 40% are lower than U.S. averages. However, Fitch believes these are sufficiently offset by the OEB's track record of predictable regulatory support.

Continuing Service Territory Growth: Alectra services over one million customers in the Greater Golden Horseshoe Area of Ontario, which has historically experienced high population and economic growth. Fitch expects customer growth of around 0.7% annually during the forecast period, supported by a strong regional economy and federal immigration targets.

Ontario Favorably Positioned for Decarbonization: Ontario derived only 13% of its electricity from fossil fuels in 2023, significantly lower than the U.S. and most Canadian provinces. The province has demonstrated support for nuclear generation, which is a zero-carbon electricity source, with plant refurbishments and investments in small modular reactors. Fitch views the cost pressures from energy transition to be more manageable for Ontario.

Shareholder Relationship: Alectra is a private corporation owned by seven municipalities of Ontario: Mississauga (26.6%), Hamilton (17.3%), Vaughan (20.5%), Markham (15%), Barrie (8.4%), Guelph (4.6%), and St. Catharines (4.6%) and by the Ontario Municipal Employees' Retirement System (OMERS) (3%). Fitch considers Alectra a Government-Related Entity (GRE). The shareholders elect Alectra's board of directors, allowing them to collectively exercise legal control over the company. However, no single shareholder has explicit control or special voting rights and, as such, is not involved in general decision-making or oversight.

After an initial investment at the time of the amalgamation in 2017, shareholders have no precedence of support to Alectra. Fitch believes a default by Alectra would have a limited impact on the continued provision of a key public service and the preservation of its government policy role. Fitch also believes Alectra's small relative contribution to the cities' operating budgets and a lack of guarantees limits contagion risk from a default by the company. Fitch has virtually no expectations of support for Alectra and rates the company based on its standalone credit profile with no direct uplift related to the municipal ownership.

Financing Structure: There are no limitations on debt issuance at the subsidiaries in the lender agreements or regulatory orders. However, Alectra's instrument rating benefits from the standard one-notch uplift applicable to the utilities sector, given management's express policy of raising debt solely at the parent. The uplift assumes that Alectra's business mix will remain predominantly regulated. Material changes to the financing policy or business mix would likely result in removal of the uplift.

DERIVATION SUMMARY

Alectra's Long-Term IDR is well positioned relative to Canadian peer parent holding companies Enmax Corporation (BBB/Stable) and ATCO Limited (BBB+/Stable). While Alectra operates an electric distribution only in Ontario, Enmax operates T&D utilities in Alberta and Maine, and ATCO operates T&D utilities in Alberta through its purely regulated subsidiary CU, Inc. (A-/Stable).

Fitch views the regulatory environment in Maine (just over 20% of the forecasted EBITDA for Enmax) as restrictive compared to Ontario while the regulatory construct in Ontario is comparable to Alberta (roughly 45% of forecasted EBITDA for Enmax and 80%-85% for ATCO). Both employ a performance-based rate setting approach for distributors, but Enmax has slightly higher allowed ROE and equity thickness. The construct in Ontario has been somewhat tempered by the regulatory lag in the recent past, although this is expected to improve.

Regulatory lag coupled with deferred rebasing for Alectra is expected to remain elevated in the near term and improve to below its 5.5x sensitivity threshold in 2028 post the rate rebasing. Enmax's leverage is forecast to remain lower in the 4.6x-5.0x range through 2026 while ATCO's leverage is also expected to be in the 5.1x to 5.5x range over the period.

However, Alectra's proportion of consolidated EBITDA from regulated utility operations is forecast to remain in the 87%-90% range, higher than Enmax's 60%-70% and comparable to ATCO's 80%-85%. This offers more predictability in cash flows for Alectra compared to Enmax, which has a sizeable exposure to competitive non-regulated businesses.

ATCO's non-regulated businesses include cyclical segments like infrastructure, transport and logistics. Additionally, it owns commodity exposed segments like generation and retail in higher risk geographies such as Latin America. Compared to these peers, Alectra's non-regulated businesses are mainly Ontario-based energy services, which are lower risk due to low capital intensity and higher margins.

KEY ASSUMPTIONS

--Continuation of the multi-year Incentive-Rate Setting framework for distribution rates;

--Constructive rebasing outcomes in 2027 in line with recent outcomes for other utilities in the province;

--Annual Adjustment Mechanisms to continue in line with the existing Price IR model;

--Regulated EBITDA to form 87%-90% of the total through 2028;

--Shareholder dividends consistent with the current policy of targeting 60% of the net income (MIFRS) excluding the Ring Fenced Solar Partnership income and targeting 80% of the solar net FCF while maintaining the regulated capital structure of 40% equity capitalization;

--Consolidated Alectra capex of $1.7 billion through 2028 with over 90% towards utility operations;

--Annual customer growth of around 0.7%

RATING SENSITIVITIES

Factors that could, individually or collectively, lead to positive rating action/upgrade:

-- FFO leverage below 4.8x for the period 2023-2027 on a sustained basis with regulated utility EBITDA continuing to form over 85% of the total on a sustained basis;

--Constructive rebasing outcome providing for an FFO leverage below 4.5x for 2028 and beyond on a sustainable basis;

--Further improvement in regulatory outcomes in Ontario providing for timely cost recoveries and earning of allowed ROE.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--FFO leverage expected to exceed 5.8x on a sustained basis till 2027 and 5.5x following the rebasing in 2027;

--Debt financed acquisition or amalgamations with no clear path to deleveraging over the forecast period;

--Expansion into unregulated businesses leading to less than 85% EBITDA contribution on a sustained basis from regulated operations;

--Adverse regulatory outcomes especially for the next rebasing application;

--As it pertains to the debt ratings, any changes in Alectra's financial policy of raising debt solely at the parent level or introduction of any structural subordination to the debt structure or expansion into unregulated businesses leading to less than 85% EBITDA contribution on a sustained basis from regulated operations

LIQUIDITY AND DEBT STRUCTURE

Fitch considers Alectra's liquidity adequate. It is primarily supported by the company's $700 million CP program backstopped by a $700 million committed unsecured revolving credit facility (RCF), maturing in 2027. Additionally, Alectra has a $100 million uncommitted credit facility (overdraft facility) and another $200 million credit facility to support its LCs.

At March 31, 2024, the company had $410 million of CP issued. Including a March 31, 2024 cash balance of around $14 million and excluding availability under the company's uncommitted facilities, total Alectra liquidity was approximately $304 million.

Alectra's debt maturities are manageable with the near-term maturities being private debentures of $150 million in late 2024 and private debentures of $675 million in 2027. Fitch expects Alectra to have continued access to capital markets to refinance the private debt as it comes due. Fitch also expects the company to manage its debt in accordance with the regulated capital structure.

ISSUER PROFILE

Alectra Inc. was formed in 2017 by amalgamation of three Ontario, Canada electric distributor utilities: PowerStream, Inc., Enersource Hydro Mississauga, Inc., and Horizon Utilities Corporation. Alectra subsequently acquired Hydro One Brampton Networks, Inc. in 2017 and amalgamated with Guelph Hydro Electric System, Inc. in 2019.

REFERENCES FOR SUBSTANTIALLY MATERIAL SOURCE CITED AS KEY DRIVER OF RATING

The principal sources of information used in the analysis are described in the Applicable Criteria.

ESG CONSIDERATIONS

The highest level of ESG credit relevance is a score of '3', unless otherwise disclosed in this section. A score of '3' means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. Fitch's ESG Relevance Scores are not inputs in the rating process; they are an observation on the relevance and materiality of ESG factors in the rating decision. For more information on Fitch's ESG Relevance Scores, visit https://www.fitchratings.com/topics/esg/products#esg-relevance-scores.

RATING ACTIONS

ENTITY / DEBT	RATING	PRIOR

Alectra Inc.	LT IDR	A- Rating Outlook Stable Affirmed		A- Rating Outlook Stable
senior unsecured	LT	A	Affirmed	A

VIEW ADDITIONAL RATING DETAILS

FITCH RATINGS ANALYSTS

Simar Jolly
Associate Director
Primary Rating Analyst
+1 647 556 8268
simar.jolly@fitchratings.com
Fitch Ratings, Inc., Canada Subsidiary: Fitch Ratings Canada, Inc.
22 Adelaide Street West Suite 2810 Toronto

Barbara Chapman, CFA
Senior Director
Secondary Rating Analyst
+1 646 582 4886
barbara.chapman@fitchratings.com

Shalini Mahajan, CFA
Managing Director
Committee Chairperson
+1 212 908 0351
shalini.mahajan@fitchratings.com

MEDIA CONTACTS

Eleis Brennan
New York
+1 646 582 3666
eleis.brennan@thefitchgroup.com

Additional information is available on www.fitchratings.com

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APPLICABLE CRITERIA

Corporates Recovery Ratings and Instrument Ratings Criteria (pub. 13 Oct 2023) (including rating assumption sensitivity)

Corporate Rating Criteria (pub. 03 Nov 2023) (including rating assumption sensitivity)

Sector Navigators – Addendum to the Corporate Rating Criteria (pub. 21 Jun 2024)

Government-Related Entities Rating Criteria (pub. 09 Jul 2024)

APPLICABLE MODELS

Numbers in parentheses accompanying applicable model(s) contain hyperlinks to criteria providing description of model(s).

Corporate Monitoring & Forecasting Model (COMFORT Model), v8.1.0 (1)

ADDITIONAL DISCLOSURES

Dodd-Frank Rating Information Disclosure Form

Solicitation Status

Endorsement Policy

ENDORSEMENT STATUS

Alectra Inc.	EU Endorsed, UK Endorsed

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Research Update:

GrandBridge Energy Inc. Outlook Revised To Stable From Negative; Ratings Affirmed

March 20, 2024

PRIMARY CREDIT ANALYST

Mayur Deval
Toronto
(1) 416-507-3271
mayur.deval
@spglobal.com

SECONDARY CONTACT

Matthew L O'Neill
New York
+ 1 (212) 438 4295
matthew.oneill
@spglobal.com

Rating Action Overview

- We concluded our review on Ontario's regulatory construct and maintained our assessment as most credit supportive.
- Our assessment reflects that the Ontario Energy Board (OEB) has proactively addressed regulatory lag, and we now believe that its utilities, including GrandBridge Energy Inc. (GBE), will maintain consistent financial measures sufficient for the current ratings.
- We therefore affirmed our ratings on GBE, including our 'A' issuer credit rating and senior unsecured rating, and revised the outlook to stable from negative.
- The stable outlook on GBE reflects our expectation that its financial measures will remain consistent, such that funds from operations (FFO) to debt is greater than 15%. The stable outlook also reflects our expectation that the regulated utility business will consistently contribute about 95% of consolidated EBITDA. Under our base case, we expect consolidated FFO to debt of 17%-18% through 2026.

Rating Action Rationale

Our assessment of Ontario's regulatory environment remains unchanged as most credit supportive. During 2023, the OEB proactively addressed regulatory lag, particularly related to the timely recovery of rising transmission-related costs. Previously, the local distribution companies (LDCs) in Ontario experienced regulatory lag of about 24 months in recovering the transmission costs increases. Regulatory lag is the timing difference between when costs are incurred by the LDCs and when they ultimately recover such costs from ratepayers. Because of inflation and rising transmission capital spending, transmission costs were significantly increasing, and the regulatory lag was materially weakening the financial measures of most of Ontario's LDCs.

However, beginning in 2024, the OEB allowed the LDCs to implement new preliminary transmission rates at about the same time that the OEB authorizes such rates for the transmission companies, materially reducing the regulatory lag. Overall, we view the OEB's proactiveness to quickly address this regulatory lag as constructive and consistent with our view of Ontario's regulatory construct as most credit supportive. As such, we expect GBE's financial measures will be more consistent and reflect FFO to debt of 17%-18% through 2026.

We continue to assess GBE's business risk profile as excellent. This reflects the company's lower-risk regulated LDC operations, operating under Ontario's constructive regulatory framework, and service territories that benefit from above-average economic growth. Partially offsetting GBE's key credit strengths are the company's below-average size, serving only about 113,000 customers, and lack of geographic diversity.

Our assessment also considers parent, Grandbridge Corp.'s (GBC's) nonutility exposure (about 5% of consolidated EBITDA). These businesses include solar assets, telecommunication services, street lighting, and home comfort products. We view these businesses as having more risk than regulated utilities. However, we expect the company will not materially grow these businesses in relation to the overall consolidated company.

We assess GBE's financial risk profile as intermediate. This reflects our expectation that GBE will maintain FFO to debt of about 17%-18% throughout our forecast period. Our forecast assumes capital spending of about C$35 million-C$38 million annually and annual dividends averaging about C$8 million. We assess the financial risk profile using our low-volatility financial benchmark table, which reflects its mostly lower-risk regulated electric distribution operations and effective management of regulatory risk. Our assessment further reflects GBC and GBE's generally steady cash flow and rate-regulated utility operations with highly supportive cost recovery.

Outlook

The stable outlook on GBE reflects our expectation for predictable and stable cash flows from the utility's low-risk, regulated distribution business over the next two years. In our base-case scenario, we expect GBE's consolidated FFO to debt to be about 17%-18% throughout the forecast period.

Downside scenario

We could lower our rating on GBE over the next 24 months if:

- GBE's financial measures weaken such that FFO to debt consistently weakens to less than 15%;
- GBE experiences a material adverse regulatory ruling; or
- GBE's nonutility business increases to greater than 10% of consolidated EBITDA.

Upside scenario

We could raise our rating on GBE over the next 24 months if:

- GBE improves its financial measures, such that FFO to debt is consistently above 21% without increasing business risk.

Company Description

Grandbridge Energy Inc. (GBE) is a midsize Ontario LDC located in Southeastern Ontario. Almost all cash flows come from its regulated electricity distribution business. GBE delivers electricity to 113,000 customers through a fully owned extensive network of overhead and underground lines.

Liquidity

We assess GBE's liquidity as adequate and expect its sources to be 1.1x over its uses for the next 12 months. In addition, we anticipate its net sources would remain positive even if its forecast consolidated EBITDA declines 10%. We believe the company's generally predictable regulatory framework provides manageable cash flow stability, even in times of economic stress, which supports our use of slightly lower thresholds to assess its liquidity. In addition, we believe GBE could absorb high-impact, low-probability events, reflecting about C$70 million of committed loan facilities through 2027 and our view that the company can reduce its capital spending (averaging about C$38 million annually through 2026) during stressful periods. This indicates that it would have a limited need for refinancing under such conditions. Furthermore, our assessment reflects GBE's generally prudent risk management practices. Overall, we believe the company would likely be able to withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations.

Principal liquidity sources

- Cash FFO of about C$36 million; and
- Committed loan facility availability of C$63 million.

Principal liquidity uses

- Debt maturities of C$5.8 million;
- Capital expenditures of about C$38 million; and
- Dividend payments of about C$8 million.

Capital structure

GBE's capital structure comprises about C$105 million of senior unsecured debt, a term facility of about C$22 million and a balance outstanding under its revolving credit facility of about C$5 million.

Analytical conclusions

We rate GBE's senior unsecured debt 'A', the same as our long-term issuer credit rating, because it is the debt of a qualifying investment-grade utility.

Ratings Score Snapshot

Issuer Credit Rating: A/Stable/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Strong

Financial risk: Intermediate

- Cash flow/leverage: Intermediate

Anchor: a

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Neutral (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a

Group credit profile: a

Related Criteria

- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013

- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

Ratings Affirmed; Outlook Action

	To	From
GrandBridge Energy Inc.		
Issuer Credit Rating	A/Stable/--	A/Negative/--
Issue-Level Ratings Affirmed		
GrandBridge Energy Inc.		
Senior Unsecured	A	

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.spglobal.com/ratings for further information. Complete ratings information is available to RatingsDirect subscribers at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.spglobal.com/ratings.

M3-2-SEC-66

[M3, p.9-10] With respect to the Reference and Net Zero Scenario:

a. Footnote 7 says that "[t]he Reference and Net-Zero Scenarios were developed by the EDA based upon load forecasts developed by the IESO." Please provide a copy of the EDA scenarios, including all calculations, assumptions, and sources of data.
b. Figure 4 shows 'Projected Annual Infrastructure Investment by Ontario Distributors' for each scenario. Please provide all calculations, assumptions, and sources of data of the annual infrastructure investments.

Response:

(a) Please see the attached Excel Workbook M3-2-SEC-66.

(b) Please see (a).

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M1, p.63]

Question(s):

LEI has outlined a number of OEB regulatory/policy changes since 2006. Appendix A to these interrogatories outlines a number of additional OEB regulatory/policy changes since 2011. For each, please provide Concentric's view on how each would impact utility business and financial risk.

Response:

In the table below, Concentric summarizes the regulatory/policy changes outlined in the LEI report, as well as the additional regulatory/policy changes in SEC's Appendix A. Concentric's overall assessment is that these regulatory and policy changes have somewhat reduced certain utility cost recovery risks on an absolute basis, but notes that regulatory/policy changes can be in reaction to factors that can increase utility risk (e.g., distributed resources). Further, the existence of a regulatory/policy change does not necessarily mean the utilities benefit from them (e.g., when ICM requests are denied).

Further, these changes, either individually or as a package, have not appeared to materially change investors' perceptions of regulatory risk in Ontario. For example, UBS, which evaluates "mechanisms that reduce regulatory lag" in its ranking of North American jurisdictions, ranks Ontario in its third tier out of five. In addition, as described in Concentric's report, it is necessary to compare overall regulatory risk in Ontario to regulatory risk in peer jurisdictions when assessing the cost of capital. In Concentric's analysis (see pages 125-127 of Concentric's report), we found the aggregate business risk profiles of the North American proxy groups reflect similar risk as the Ontario electric and gas utilities, other than OPG. These Ontario utilities are closely aligned with the North American proxy groups in terms of commodity price risk and the use of infrastructure recovery mechanisms such as riders and capital trackers. We also find a comparable level of regulatory protection for mitigating regulatory lag through the use of deferral accounts.

Regulatory/Policy Change	Description	Risk Impact
Electricity distributors' DVA review initiative (EB-2008-0046; OEB report issued in July 2009)	Provides a systematic approach to the review and disposition of DVAs.	Modest reduction (clarifies timing and classification of DVAs).
Renewed regulatory framework for electricity (EB-2010-0377, EB-2010-0378 and EB-2010-0379; OEB report issued in October 2012)	Updates the regulatory framework for electricity distributors.	Neutral impact (clarifies the framework, but incentive regulation increases cost recovery risks).
Rate design for electricity distributors (EB-2012-0410; OEB report issued in April 2015)	Adopts a new policy under which electricity distributors will structure residential rates so that all the costs for distribution service are collected through a fixed monthly charge.	Reduction in volumetric risk related to residential sales for electricity distributors.
Rate design for commercial and industrial customers (EB-2015-0043; OEB Staff report issued in February 2019)	OEB Staff Report to the OEB that provides OEB staff's recommendations and proposals for proposed commercial and industrial rate design changes.	N.A. (no OEB decision was issued).
Framework for energy innovation: distributed resources and utility incentives (EB-2021- 0118; OEB report issued in January 2023).	Framework that establishes OEB expectations, a benefit cost analysis framework, and the ability for electric distribution utilities to seek a new deferral account and incentives related to distributed energy resource integration.	Neutral to higher risk (this initiative reflects an expectation that utilities begin to seek 3rd party solutions for traditional poles and wires, which means having to seek counterparties, taking on operational/contractual risks, and new solutions could result in capacity or reliability issues; offsetting this is a modest cost recovery risk reduction via the ability to seek deferral accounting for certain costs).
Introduction of Advanced Capital Module (ACM). See Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (September 18, 2014)	Revises the capital module policy by adopting the Advanced Capital Module ("ACM") framework.	Modest risk reduction due to the acceleration of the timing of review.

Regulatory/Policy Change	Description	Risk Impact
MAAD transaction deferred rebasing lengthened from 5 to up to 10 years, at discretion of utility. See Report of the Board Rate-Making Associated with Distributor Consolidation (March 26, 2015)	Sets OEB policies on the duration of the deferral period for rebasing following the closing of a MAADs transaction and establishes mechanism for adjusting rates to reflect incremental capital investments during the deferred rebasing period.	Risk neutral (reduces certain capital-related risks; longer deferred rebasing introduces new risks related to performance and maintenance of financial integrity during the rebasing period).
OEB requiring residential customers to be billed on a monthly basis (previously many were bimonthly). See Distribution System Code (DSC) Amendments (April 15, 2015). Related, reduced billing lag as demonstrated by OEB's reduction in default working capital from 13% to 7.5%. See OEB Letter, Allowance for Working Capital for Electricity Distribution Rate Applications, June 3, 2015)	<u>Monthly Billing</u> The OEB amended the DSC related to billing frequency. <u>Reduced Billing Lag</u> The OEB determined that the default value for working capital allowance for electricity distributors will be 7.5% of the sum of the cost of power and OM&A.	<u>Monthly Billing</u> Modest risk reduction (incremental costs associated with monthly billing incurred by distributors can be mitigated by more frequent and lower bills, which can improve collection costs and bad debts). <u>Reduced Billing Lag</u> Modest risk increase due to reduced cash flows.
Reduction of ACM/ICM deadband from 20% to 10%. See Supplemental Report: New Policy Options for the Funding of Capital Investments (Jan 22, 2016).	The OEB reduced the dead band from 20% to 10%, citing that adjusting the level of the dead band is a practical decision to balance proposals for necessary incremental capital funding versus marginal applications.	Reduction in risk related to capital recovery as the reduction to the dead band in the materiality threshold calculation for the ACM and ICM makes those mechanisms more accessible to distributors.
Expansion of eligibility for ICM for utilities on deferred rebasing period. See OEB Letter Re: Incremental Capital Modules During Extended Deferred Rebasing Periods (Feb 10, 2022).	The OEB provided flexibility for electricity distributors considering consolidation by allowing them to apply for incremental capital funding for an annual capital program during the extended rebasing period if they meet certain criteria.	Risk neutral (reduces certain capital-related risks; longer deferred rebasing introduces new risks related to performance and maintenance of financial integrity during the rebasing period).
Annual update to LV Rates through IRM/rate adjustment process, whereas previously only updated at rebasing. See Updated Filing	The OEB allowed embedded or partially embedded distributors to update the Low Voltage Service Rates on an annual basis as part of each	Modest reduction in risk (the update may reduce the variance between the low voltage costs charged by a host distributor to an

Regulatory/Policy Change	Description	Risk Impact
Requirements for Electricity Distribution Rate Applications, Chapter 3 (June 15, 2023).	distributor's incentive-rate setting application.	embedded distributor and low voltage revenues collected through low voltage service rates that the embedded distributor charges its customers).
UTRs issued earlier in year allowing for more up to date RTSRs included in annual rate adjustments applications. See OEB Letter, 2024 Preliminary Uniform Transmission Rates and Hydro One Sub Transmission Rates (September 28, 2023).	Previously, Uniform Transmission Rates ("UTRs") were issued on a final basis in December or January. Typically, distributors with rate years beginning January 1 would not be able to use new UTRs in the Retail Transmission Service Rate ("RTSR") calculations until the following year. Now the OEB issues preliminary UTRs which allows for the UTR data to be integrated into the rate applications.	Modest reduction in risk (the OEB decision is expected to decrease amounts accumulated in retail transmission variance accounts).
Introduction of OEB NWS Guidelines which provides opportunities for utilities during IRM (or even in circumstances existing Custom IR plan) to seek additional funding opportunities for non-wires solutions. See Non-Wires Solutions Guidelines for Electricity Distributors (March 28, 2025)	The OEB granted the option to file a request for funding for non-wires solutions outside of rebasing to distributors using any rate-setting methodology.	Risk neutral (the application process allows the OEB to assess the proposed non-wires solutions and funding requests as they relate to the system needs outlined in distribution system plans; the OEB can better understand forecasted impacts of non-wires solutions on the distributor's revenue requirement and load forecast).

Staff Interrogatories on Parties' Expert Evidence

M3-2-OEB Staff-31

Note this interrogatory has been asked by LEI

Ref: Nexus Report, p. 8

Nexus stated the following:

While there are several risks facing Ontario utilities, there can be none more fundamental[3] than the imminent energy transition, sometimes also referred to as 'electrification'.

a) In your opinion, is energy transition a significant opportunity for electricity distributors to significantly increase the size of their rate base (thereby increasing the $ ROE earned)? If not, please explain.

Response

a) We are unable to confirm the use of the qualifiers "significant" and "significantly." However, we agree that energy transition may provide distributors with the opportunity to increase their rate bases.

An increase in rate base does not imply that the energy providers will earn a greater return (in percentage terms) or that it will mitigate risk.

Moreover, many of the investments that will be required by the energy transition are sunk and irreversible. Once made, sunk and irreversible investments have no value in alternative use. They are essentially valueless if expected demand does not materialize during the expected timeframe.

These investments therefore are accompanied by risk about the possible changes in the trajectory of investment (e.g., over-investment, under-investment, incorrect investment) or even the location of new demand.

Issues such as the "used and useful" criteria [see reference to Phillips below] could arise if the infrastructure is constructed and the load for which it is constructed does not materialize, occurs later than anticipated, or occurs in a different place than was anticipated. Distributors could be subjected to risk to profitability if the load materializes in advance of expectations, leading to reliability challenges.

The regulatory mechanisms currently used in Ontario were developed for an environment that did not anticipate the growth associated with the current era of electrification. Distributors may be negatively impacted by this growth if regulatory mechanisms are not updated.

b) Have any major credit rating agencies (such as S&P Global, DBRS Morningstar, and/or Moody's) expressed concerns that Ontario utilities may be unable to recover the capital or operating costs over the next 5 years? If yes, please provide examples.

Response:

Nexus Economics is unaware of any reported expressions of concern.

c) Please provide examples of disallowances of actual costs incurred from energy transition.

Response:

Please see our Response to M3-3-OEB-33, subpart b).

Examples of prudency disallowances which have historically occurred are discussed by Charles F. Phillips, Jr. in The Regulation of Public Utilities (1993), p. 340-1, p. 366, and p. 409.

The examples cited by Dr. Phillips are from a previous energy transition when nuclear generation was adopted in the 1960-70s. The concept of "used and useful" was adopted in some jurisdictions to disallow costs for nuclear power generation, which was unneeded due to load growth that did not materialize.

M3-2-OEB Staff-32

Note this interrogatory has been asked by LEI

Ref: Nexus Report, p. 25

Nexus stated the following:

LEI has identified business and financial risks in its report. However, given the changes in industry structure occurring due to decarbonization and electrification efforts, Nexus Economics has also identified a category of risk that LEI ignores: strategic risk.

a) What specific business decisions face "strategic risk"?

Response

Some non-exhaustive examples of strategic risk include:

- Distributors are required to move into business lines and operations that they traditionally have not operated in, such as non-wires alternatives.
- Uncertainties regarding load growth can trigger mismatches with infrastructure investment.
- Regulatory lag associated with the IRM. The existing IRM mechanism was developed for an environment of relatively flat load per customer. In contrast, the energy transition would expect to trigger increasing load per customer.

b) Please explain how 'strategic risk' is not evaluated as part of 'business risks' and 'financial risks' as assessed by OEB as well as major rating agencies (such as S&P Global, DBRS Morningstar, and/or Moody's).

Response:

Strategic risk is associated with changes in the industry structure whereas business risk is associated with risk associated with the ongoing operations of a business in a static environment.

c) Please confirm that LEI's recommendation for Issue 2 explicitly mentions that utilities should be allowed to highlight additional risk categories in their rate applications if they consider them material.

Response:

Confirmed.

M3-2-CME-2

Ref: Exhibit M3, p. 26

At page 26, Nexus states "The electric power industry is undergoing a significant transition which is exposing the distributors to not only the normal risk associated with utility operations, but uncertainty regarding the future of the electric distribution business model." It also states that the adoption of mainly fixed charges is an impediment to revenue growth for distributors.

(a) Please confirm that Ontario distributors' move to mainly fixed charges mitigates the uncertainty about the future of the electric distribution business model.

Response:

Please see the response to M3-CCC-2.

(b) To the extent that a) is not confirmed, please explain why not.

Response:

Please see the response to M3-CCC-2.

(c) If the Board were, in the future, to move electricity distributors back to more volumetric charges, thereby increasing revenue growth, please describe the impact of such a decision on Nexus' conclusions regarding business risk and cost of capital.

Response:

This response requires an investigation by the Board and a response would be premature at this time. Existing policies were developed in an environment of flat or declining load growth that may not be expected to exist in the future, thus requiring a reinvestigation of policies.

M3-CCC-2

Ref: Ex. M3/pp. 8, 11, 26, 28, 32

(Page 8) Capital spending is expected to increase markedly, triggered by significant load growth, grid hardening, and cyber-security investments.

(Page 26) Prior policies adopted by the OEB to facilitate policy goals and reduce the risk faced by distributors have become obstacles to adopting new goals. For example, in the past several years, the OEB adopted residential fixed distribution charges (i.e., no volumetric component of the tariff) to address the declining residential average usage problem and facilitate the adoption of DERs. However, the adoption of electrification policies would presumably reverse the trend of decreasing average usage and thus limit revenue growth to distributors.

(Page 28) Other jurisdictions embracing carbon reduction and electrification policies have amended their regulatory mechanisms recognizing that the trajectory of capital spending may be uncertain. The absence of these policy changes in Ontario increases the risk to which distributors are exposed.

a) (Page 8) In the context that regulated distributors are allowed to recover prudently incurred capital costs, please explain why increased spending in response to climate change/electrification is a risk to distributors.

Response:

a) Please see Chapter 1, Section E of the Nexus Economics report.

b) (Page 8) In the context of electricity distributors, please provide Nexus' view on the impact on risk of longer-term significant growth in approved rate base, which provides for larger returns on an absolute basis. Does growth in the capital asset base reduce risk overall once the costs are approved for recovery?

Response:

We do not agree that growth in the capital asset necessarily reduces risk overall for distributors. The current IRM mechanism was designed based on an assumption of a relatively flat load on a per customer basis. The current regulatory mechanisms in Ontario may or may not be appropriate to address the changes required for the energy transition.

See Response to M3-2-OEB Staff-31.

c) (Page 11) Does Nexus agree that the regulatory framework applied to electricity distributors is an important consideration in determining the appropriate cost of capital?

Response:

The phrase “regulatory framework” is overly broad. Regulatory changes (or even lack thereof) and uncertainty may affect risk in a way that affects the cost of capital. In situations such as the energy transition, regulatory mechanisms which do not reflect the dynamic nature of the industry can introduce risk over and above that of the industry as a whole.

In addition, if regulation precludes a utility from earning its cost of capital, investors may shy away from that utility and invest elsewhere.

d) (Page 26) In the context of the ability for a distributor to reset its rates at rebasing (including increases to fixed charges to reflect changes to costs), please explain how the adoption of electrification policies would limit revenue growth to distributors.

Response:

Under electrification, growth per customer would be expected to increase between rebasings. The existing fixed charge mechanism would, however, hold revenues constant on a per-customer basis. Hence, distributors would not be allowed to recover costs until rates are rebased.

e) (Page 26) Please advise whether Nexus believes that fully fixed rates or fully variable rates are riskier for a distributor.

Response:

The question of the level of risk associated with fixed or volumetric rates is influenced by the cost structure of the utility, the regulatory mechanism and the trajectory and capital investments and O&M Expenses. The existing mechanics of fixed distribution charges is predicated upon flat usage per customer.

f) (Page 28) Please describe the regulatory or ratemaking mechanisms that are not available to Ontario distributors that would address Nexus’ concerns regarding the trajectory of capital spending?

Response:

Nexus does not recommend a specific mechanism(s). However, other jurisdictions with similar policy goals have embarked upon these investigations. Nexus suggests that the OEB open a proceeding to investigate changes in the IRM and review these jurisdictions' approaches in that context.

g) (Page 32) What mechanism(s) is Nexus referring to that are currently unavailable in Ontario, or are provided on a more limited basis, that operate to increase Ontario LDC risks relative to its peers?

Response:

See Response to M3-3-CME-3. Nexus is simply responding to LEI's suggestion that Ontario is a less risky jurisdiction than its comparables, which is not the case.

h) Please advise whether NEXUS is aware of any LDC in Ontario having difficulty attracting capital (either debt or equity).

Response:

Please see our response to M3-10-SEC-77.

M3-CCC-3

Ref: Ex. M3/p. 30

a) Please explain why Nexus believes that the k-bar methodology is "superior" to the ICM approach. As part of this response, please provide Nexus' views on which approach provides more incremental capital funding (i.e., incremental capital provided based on historical capital with a growth factor through the k-bar or forecast incremental capital based on best available information provided through the ICM). Please also discuss whether Alberta and Massachusetts offer the availability of a Custom IR, which as applied in Ontario, allows for multi-year (typically 5 year) recovery of approved capital budgets as proposed by the utility.

Response:

Nexus Economics offered the k-bar as an example of a potential alternative regulatory mechanism with certain benefits given the changes in the energy markets in Ontario. The board has different options that it may pursue which could introduce another dimension of risk.

Reply to PEG Framework Report

Submitted On Behalf Of

Toronto Hydro-Electric System Limited

d/b/a Toronto Hydro

May 24, 2024

Smart. Focused. Done Right.®

scottmadden

MANAGEMENT CONSULTANTS

Toronto Hydro
Reply to PEG Framework Report

Introduction

On May 2, 2024, OEB Staff filed a copy of the Pacific Economics Group Research LLC ("PEG") report titled 'CIR 2.0 for Toronto Hydro-Electric System Limited' ("Framework Report"). The Framework Report raises various issues or concerns related to the jurisdictional review conducted by ScottMadden Management Consultants ("ScottMadden"). ScottMadden has reviewed the PEG Framework Report and provides the following reply comments in response to PEG's new issues and concerns.

Reply Comments

ScottMadden's jurisdictional review and findings were independent and unbiased as ScottMadden did not have any prior knowledge of Toronto Hydro's proposed Custom IR framework.

1. PEG has raised an issue as to whether ScottMadden's report has biased scope and emphasis. Specifically, PEG states: "Precedents that support the Company's proposal are highlighted while precedents that don't are either not mentioned in the direct evidence or not emphasized".

2. PEG has misunderstood the scope of ScottMadden's jurisdictional review. As stated in its response to JT5.25, ScottMadden selected examples of ratemaking frameworks based on 1) jurisdictions that have passed mandates regarding climate/ clean energy goals; 2) jurisdictions that have implemented elements of performance-based regulation; and 3) utilities that have proposed or implemented performance-based regulation in the context of meeting mandates regarding climate/ clean energy goals.

3. After completing this review, ScottMadden evaluated the proposed Toronto Hydro custom IR plan for relative consistency with ratemaking frameworks it identified. ScottMadden did not have any prior knowledge of Toronto Hydro's proposed Custom IR framework when conducting the jurisdictional review.

4. As an example of "biased scope", PEG states that ScottMadden reviewed Alberta's PBR1 plan, but not the PBR2 and PBR3 plans. However, ScottMadden presented Alberta's PBR 1 plan as an example where a separate funding mechanism was approved for certain capital investments (ScottMadden Jurisdictional Review, page 21). A similar mechanism was approved in all three iterations of Alberta's PBR plan, recognizing that the criteria for qualifying investments changed. It is important to note that Alberta's PBR3 plan was approved in October 2023, whereas ScottMadden's review was conducted in August 2023.

ScottMadden did not conduct a jurisdiction-by-jurisdiction scan of rate plans nor a trend analysis. The presence of varying mechanisms in other jurisdictions does not disprove ScottMadden's findings that there are certain modernized rate mechanisms currently approved for utilities that are facing challenges associated with energy transition.

5. PEG has misunderstood the nature of ScottMadden's review. In its criticism, PEG has cited and raised other jurisdictions where there are other types of rate mechanisms currently implemented. ScottMadden agrees there are other types of rate mechanisms approved in jurisdictions across North America.

6. However, PEG misses the point. Presence of other types of rate mechanisms in other jurisdictions does not disprove ScottMadden's findings of the rate mechanisms currently approved for utilities that are facing challenges associated with the energy transition, such as in UK, New York, and Hawaii.

7. As an example, PEG cites Alberta's k-bar mechanism which sets capital revenues based on historical forecasts. ScottMadden agrees that historical costs can be the basis for capital revenues. However, such an approach does not necessarily address the needs of the unprecedented change and transformation related to the energy transition.

8. In fact, the AUC recognized the k-bar was unsuitable for expenditures related to achieving net-zero objectives. Specifically, AUC noted: "The Commission agrees that there is the potential for net-zero objectives to drive the need for additional expenditures during the PBR3 term, and that the level of uncertainty and risk associated with the need for and timing of net-zero objectives makes capital investments required to respond to any such objectives unsuitable for funding through the Type 2 K-bar mechanism."[1]

PEG raises an issue that various ScottMadden findings are "misleading statements". However, PEG mischaracterizes ScottMadden's review, and in some cases, does not provide support on how the findings are misleading.

9. **First**, PEG has mischaracterized ScottMadden's findings on Indexed ARMs. PEG implies that ScottMadden has presented a "misleading statement" that there is a trend in ARM design to move away from indexing.

10. ScottMadden did not present any such finding. As mentioned earlier, ScottMadden did not conduct an industry trend analysis.

11. Rather, PEG presents a trends analysis stating that there is strong continuing interest on indexing in North America but provides only limited examples where these are recently approved. Jurisdictions cited by PEG have shown either 'keen interest' (e.g., Connecticut), or in proposal stage (e.g., British Columbia, Massachusetts). PEG also cited Indiana where the legislation requires the Commission to conduct a comprehensive study of PBR mechanisms, including index-driven revenue formulas.[2] Based on the examples provided, ScottMadden

[1] AUC Decision 27388-D01-2023 (October 4, 2023), page 62
[2] IN Code § 8-1-2.5-6.5 (2023)

does not see indication of continuing interest of utilities or regulator on indexing, as PEG claims.

12. **Second**, PEG has mischaracterized ScottMadden's findings on New York and UK rate mechanisms, particularly related to forecasted revenues.

13. For example, PEG states that: "In Great Britain, Ofgem's "building block" approach to ARM design places heavy weight on its own independent view of required future costs." ScottMadden did not state any finding contrary to what PEG has stated, and thus did not "mislead" in its report. Rather, PEG is putting emphasis on Ofgem's role, ignoring the fact that the foundation of forecasted revenue requirements that Ofgem reviews is utilities' capital and O&M forecasts.

14. Similarly, PEG states that: "Most multiyear rate plans in New York are the outcome of settlements and feature only three-year plan terms." Again, ScottMadden did not state any finding contrary to what PEG has stated, and thus did not "mislead" in its report. Rather, PEG is putting emphasis on New York's rate plans being settlements, ignoring the fact that the foundation of forecasted revenue requirements in these settlements is utilities' capital and O&M forecasts.

15. **Third**, PEG has misunderstood ScottMadden's findings on cost trackers. PEG states that "Most American utilities don't have multiyear rate plans" and that "under these circumstances, cost trackers can materially reduce the frequency of general rate cases without requiring sweeping changes in ratemaking systems".

16. PEG does not recognize that even without future test years, cost trackers are important since they address uncertainty in costs. By addressing this uncertainty, cost trackers can result in fewer rate cases.

17. **Fourth**, PEG mischaracterizes ScottMadden's findings on modernized PBRs balancing financial integrity and public policy goals. ScottMadden provided an example that in Hawaii, the PBR framework ensures the financial integrity of utility aligns with consumer interests. Utility financial integrity was one of the three guiding principles approved by the Commission during the PBR proceeding. The Commission noted, "The PBR Framework approved in this D&O has been carefully designed to include multiple safeguards and review opportunities to protect the Companies' financial health from extreme hardship".[3]

18. In its criticism, PEG states that: *"PEG was a witness for the Hawaiian Electric Company in this proceeding. Based on our experience, we can say that the HECO plans are not that favorable to the companies."*

19. PEG's statement seems inconsistent with the Commission's guiding principle of financial integrity as established in its PBR framework.[4] In addition, PEG's statement seems

[3] Docket No. 2018-0088, Decision and Order No. 37507 Instituting a Proceeding to Investigate a Performance-Based Regulation, Hawaii Public Utilities Commission, p. 210

[4] Docket No. 2018-0088, Decision and Order No.36326, Hawaii Public Utilities Commission, May 23, 2019, p. 6

inconsistent with HECO's May 2023 investor presentation in which is stated that its new regulatory framework "enhances opportunity for steady earnings growth" and "aligns utility long term goals with stakeholder interests".[5]

[5] HEI, Investor Presentation, May 2023 (page 5)

M3-3-CME-3

Ref: Exhibit M3, p. 30

At page 30, Nexus states “Nexus Economics does not agree with LEI that the regulatory environment offered in Ontario is significantly safer than its peers and, therefore, should be provided with a lower ROE.” Nexus provides several reasons why distributors still are subject to high risk.

(a) How many of the peers in Nexus’ peer group operate in jurisdictions where adjustments can be made to the deemed return once rebasing is established.

Response:

This question is inapplicable since few of the referenced jurisdictions have adopted a deemed return, as has the OEB. Instead, rates of return are applicable to an individual company. Further, each of these peers operate under varied regulatory mechanisms adopting a multi-year rate plan.

(b) Nexus states that 2 peers in the peer group have K-Bar mechanisms. How many of the peers in Nexus’ peer group have an ICM mechanism or comparable mechanism? How many of the peers in Nexus’ peer group have a “C” Factor or related capital true up mechanism. How many of the peers in Nexus’ peer group do not have access to any incremental capital mechanism of any kind?

Response:

Other jurisdictions have mechanisms that address incremental capital challenges in different ways. The capital mechanisms adopted in these jurisdictions differ than Ontario, and in some cases, replaced “Ontario-like” mechanisms with new mechanisms adapted to address the energy transition. Capital mechanisms include kbar, multi-year projections with true-ups, and similar processes. Given the design of these mechanisms, an “ICM” may not be required.

(c) How does Nexus view the availability of custom IR mechanisms, whereby utilities can craft their own mechanisms such as the custom capital factor used by Hydro One in terms of Ontario’s utilities level of risk?

Response:

Nexus Economics believes that widespread adoption of custom IRs is unrealistic and not a substitute for an updated deemed ROE. First, if all distributors requested custom IRs, the OEB resources may not be able to process that volume of requests. Second, the ability for small distributors to prepare a custom IR is questionable due to cost.

M3-10-SEC-74

[Exhibit M3, p.5, 40] Nexus recommended that the ROE formula include 50 basis points for transaction costs. For EDA member utilities owned by municipalities (directly or indirectly), what type of equity transaction costs do they incur? Please provide cost data to assess the reasonableness of 50 basis points added to reflect transaction costs.

Response:

Please see M3-10-OEB Staff-38.

As for municipal utilities, the Board correctly noted in its 2009 Report that capital is a cost that does not change depending upon who owns the asset. (See 2009 Board Report, pp. 25-26:

> *It follows that the opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities regardless of ownership. The Board sees no compelling reason to adopt different methods of determining the cost of capital based on ownership.*

M3-10-OEB Staff-38

Note this interrogatory has been asked by LEI

Ref: Nexus Report, p. 5

Nexus stated the following:

This result includes 50 basis points for transaction costs associated with acquiring the equity, which is a continuation of existing OEB policy.

a) Other than the fact that this would be a continuation of existing OEB policy, please provide the empirical basis for recommending 50 basis points for transaction costs associated with acquiring equity.

Response:

Please see our Report at pp. 36-37 for the explanation of why it is important to continue the 50 basis point transactions costs.

Also, in 2009 the Board appeared to convene a panel of capital market experts that provided evidence to support the 50 basis point equity flotation cost. Such a panel has not been convened in this proceeding. Therefore, we have taken it that the Board is satisfied that no such evidence is required and transaction costs have not changed since 2009.

M3-12-SEC-80

[M3, p.84] Nexus says that "British Columbia and Alberta have Deemed Debt Ratios of 55 percent." Please provide the source of this information.

Response:

This was an error. Please see the corrected Figure 1. The calculations are included in response to M3-10-AMPCO/IGUA-26 (c).

M3-19-SEC-81

If Nexus' ROE recommendations were implemented for the 2025 rate year, for all electricity distributors, please provide an estimate in the increase of costs that would be recovered from customers. Please provide all assumptions and underlying calculations.

Response:

The requested analysis is extensive and involves considerable resources, and Nexus is not in a position to perform it in the context of this proceeding and its abbreviated timelines. Our interpretation of the request suggests we would be required to recalculate the distribution revenue requirement for each distributor. Further, we would be required to (1) estimate allocation of costs across customer type; (2) prepare rate design; and (3) estimate usage parameters for each customer.