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
(Concentric Witness Panel)

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Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

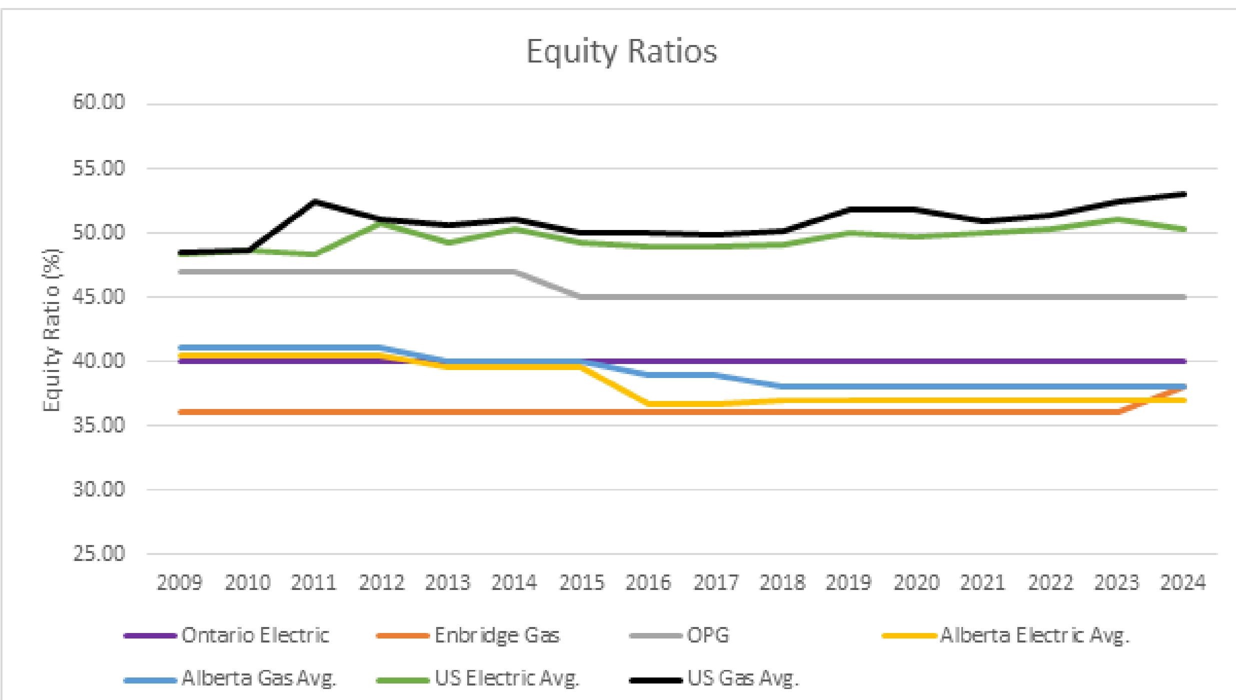
[M2, p.135]

Question(s):

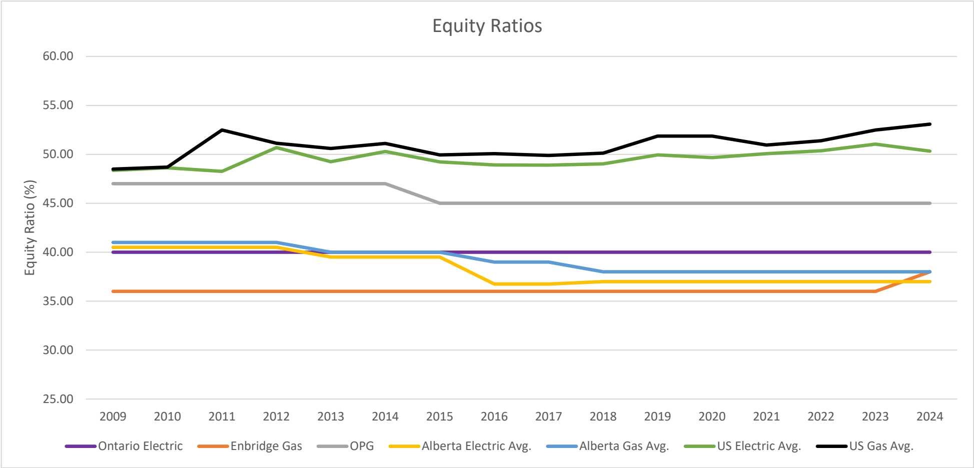
Please provide a revised version of Figure 35 that shows Alberta deemed equity ratio.

Response:

Please see the revised version of Figure 35 and N-M2-12-SEC-54, Attachment 1 for additional data.



	Ontario Electric	Enbridge Gas	OPG	Alberta Electric Avg.	Alberta Gas Avg.	US Electric Avg.	US Gas Avg.
2009	40.00	36.00	47.00	40.50	41.00	48.36	48.49
2010	40.00	36.00	47.00	40.50	41.00	48.63	48.70
2011	40.00	36.00	47.00	40.50	41.00	48.26	52.49
2012	40.00	36.00	47.00	40.50	41.00	50.69	51.13
2013	40.00	36.00	47.00	39.50	40.00	49.25	50.60
2014	40.00	36.00	47.00	39.50	40.00	50.28	51.11
2015	40.00	36.00	45.00	39.50	40.00	49.23	49.93
2016	40.00	36.00	45.00	36.75	39.00	48.91	50.06
2017	40.00	36.00	45.00	36.75	39.00	48.90	49.88
2018	40.00	36.00	45.00	37.00	38.00	49.02	50.12
2019	40.00	36.00	45.00	37.00	38.00	49.94	51.86
2020	40.00	36.00	45.00	37.00	38.00	49.67	51.87
2021	40.00	36.00	45.00	37.00	38.00	50.06	50.94
2022	40.00	36.00	45.00	37.00	38.00	50.36	51.38
2023	40.00	36.00	45.00	37.00	38.00	51.04	52.49
2024	40.00	38.00	45.00	37.00	38.00	50.32	53.08



Ontario Energy Association (OEA)

Answer to Interrogatory from
Ontario Energy Board Staff (OEB Staff)

INTERROGATORY

Reference:

Concentric Report, p. 7

Question(s):

Note this interrogatory has been asked by LEI

Concentric stated the following:

Concentric's recommendations fall short of parity between Ontario and U.S. utilities but would advance the ability of Ontario's utilities to compete for investment capital on a comparable basis with their North American peers.

a) Please elaborate on the above statement.

b) Please provide real-world examples of Ontario utilities being unable to compete for investment capital on a comparable basis with their North American peers.

Response:

a) As stated in Concentric's report, Exhibit M2, at 136, "Ideally, the Ontario utilities should have a deemed equity ratio at parity with their U.S. counterparts, which is approximately 50-51 percent for electric utilities and 52 percent for gas distributors." Concentric's recommended minimum equity ratio of 45% is approximately halfway between current equity ratios for Ontario distributors and transmitters and their U.S. comparators, and thus falls short of parity.

b) Concentric's view is not that Ontario utilities have been unable to compete for investment capital with North American peers, but rather that the level of equity thicknesses in Ontario does not currently meet the comparable return standard of the Fair Return Standard and is thus not providing investors a comparable risk-adjusted return. With the strengthening of the Energy Transition and the significant level of capital that will be deployed, lower risk-adjusted returns will prevent

Ontario's utilities from competing for investment capital on a comparable basis with North American peers with stronger balance sheets.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.23]

Question(s):

Concentric states: "Consequently, the Energy Transition has already increased both business and policy-related risks for all Ontario utilities and is inevitably going to continue to do so." For each of the following types of Ontario utilities, please separately explain, in detail, the impacts of the energy transition on both business and financial risk: i) electricity distribution, ii) electricity transmission, iii) regulated OPG, and iv) natural gas distribution, transmission, and storage.

Response:

Please refer to Appendix B in Exhibit M2 for further description of the impacts of the energy transition on each of the Ontario utilities covered in Concentric's report in the proceeding.

i) & ii) Electricity distribution and transmission

The electricity distribution infrastructure is particularly vulnerable to climate change. This is because it has the most linear Infrastructure above-ground that is directly exposed to climate hazards. As well, for cost-effectiveness reasons, the distribution system is built to lower engineering thresholds than the core transmission system.[1]

Electricity distributors and transmitters will need to invest in assets as interconnectivity from energy sources to the customer becomes fundamental in supplying increased loads to meet demand. With higher reliance on electricity resulting from the transition

[1] Ontario Ministry of Energy, Governance, Strategy and Analytics Branch, "Vulnerability Assessment for Ontario's Electricity Distribution Sector:
Report on Anticipated Climate Change Impacts and Considerations for Adaptation and Resilience," May 2024, p. 1.

away from natural gas, electricity distributors and transmitters have increased financial risk to invest in infrastructure.

iii) Regulated OPG

Energy Transition requires OPG, as a generator, to take on multiple new projects to support the system's future needs. While the suite of risks faced by OPG as a result will continue to evolve and new risks emerge as the Energy Transition unfolds, these projects are expected to have heightened risks including labour force, supply chain and financing risks. There are also construction risks, particularly for first-of-a-kind or first-in-a-while technologies that carry higher cost and schedule risks (refer to VECC 16.3). All of these risks are additionally elevated as utility companies, both locally and globally, are responding to the Energy Transition in parallel and thus seeking to access the same pools of labour, supply chain and financial resources, as further discussed below.

In particular, there are large competing projects in Ontario to OPG's projects, such as Bruce Power refurbishing 6,550 MW of nuclear capacity and plans to build up to 4,800 MW of large new nuclear at the Bruce site. In parallel, OPG is planning to refurbish four units at the Pickering Nuclear Generating Station ("PNGS") and build North America's first fleet of SMRs at the Darlington New Nuclear site. With the IESO's Pathways to Decarbonization Report setting out a scenario that would require almost 18,000 MW of additional nuclear capacity to be added by 2050, there is a possibility of further competing nuclear projects. OPG is also refurbishing two of Ontario's largest hydro stations – the Sir Adam Beck Complex and R.H. Saunders Generating Station – representing up to 2,745 MW of hydroelectric capacity.

The labour challenges associated with the increased project buildout include:

- Immediate need for specialized skilled trades, project managers and engineers, which are in high demand across the energy sector.
- The pool of graduates entering the nuclear field had been decreasing for some time. With the shift towards a buildout of the nuclear sector, the labour force needs to be expanded, relying on public institutions to train and immigration flows to meet this demand.
- Given SMRs are different from the large CANDU reactors OPG currently operates, OPG will need to compete to secure different technical experts.

The project delivery risks associated with competition for supply chain capacity spans beyond Ontario given the often global nature of the supply chains, and include:

- Nuclear supply chains are specialized.
- There are limited vendors with the expertise to make critical components such as steam and hydro turbines, power transformers and construction services.
- The geopolitical, social and economic conditions of the markets where raw materials and components are produced influence access, such as disruptions by trade barriers, sanctions, or political instability.
- Reliance on certain key suppliers can drive up supply costs, reduce market competition, create demand and supply imbalance and affect project delivery schedules.

From a financial perspective, Energy Transition related risks are to the ability to fund increased capital investment requirements and to managing credit rating pressures:

- Capital market availability risks due to a significant rise in demand for Energy Transition related investment around the world.
- Investor requirements for higher returns due to perceived higher risk of new generation project construction, particularly for nuclear development.
- Regulatory lag of cost recovery for longer duration projects, and the inability of investors to recover the full cost of financing during construction under the current policy (Concentric Report, Section IX).
- Credit rating agencies' views on project execution risk and availability of supportive and timely cost recovery mechanisms

iv) Natural gas distribution, transmission, and storage

In EB-2022-0200, the OEB found: "Considering both a decrease in business risk due to amalgamation, and an increase in business risk due to the energy transition, which is partially mitigated by this Decision and Order, the OEB concludes that there is a net increase in business risk that justifies a modest increase in the deemed equity thickness."[2]

Furthermore, gas utilities will need to continue to invest in their assets to ensure safety and reliability for the remaining customers on the gas distribution system. As more customers shift away from natural gas, gas distributors will face higher risks in recovering costs. Increased business risks arise from the implementation of alternative fuels, such as hydrogen and renewable natural gas, into the existing gas distribution system. Natural gas distributors will also face increased business risk as higher

[2] OEB Decision and Order in EB-2022-0200, December 21, 2023, p. 68.

stranded asset risk is balanced with the necessity to maintain their assets for continued operation.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.126]

Question(s):

With respect to Volume Risk:

a) Concentric states that: “Approximately 62 percent of the operating utilities held by the North American proxy groups are protected from market (or demand) risk by full or partial revenue decoupling mechanisms.” For each North American proxy group companies, please specify which utility is protected from “market (or demand) risk by full or partial revenue decoupling mechanisms” and the details of the specific mechanism.

b) Concentric states: “The majority of Ontario’s electric distribution utilities also have a regulatory mechanism to mitigate volumetric risk.” Which Ontario electricity distribution utilities do not have a regulatory mechanism to mitigate volumetric risk?

c) Please confirm that all Ontario electricity distributors are protected against residential customer volumetric risk as a result of full fixed residential distribution rates.

d) Do any non-Ontario electric utilities in the North American proxy group companies have full fixed distribution rates for residential or any other rate class? If so, please provide details.

Response:

a) Please see N-M2-10-SEC-51(a), Attachment 1 for the requested information for the operating utilities held by the North American proxy group companies. Concentric has not researched the details of the specific revenue decoupling mechanisms for each of the 132 operating companies.

b) Concentric's understanding is that all of Ontario's electric distribution utilities have a regulatory mechanism to mitigate volumetric risk.

c) Confirmed.

d) Concentric has not researched each of the specific revenue decoupling mechanisms for the 132 operating companies and so Concentric is not aware of any electric utilities in the North American proxy group that have full fixed distribution rates. As shown in SEC-51(a), Attachment 1, there are eight electric operating utilities that have full revenue decoupling (not including Hydro One).

North American Combined Proxy Group - Decoupling Mechanisms

Company	Ticker	Operating Subsidiary	Service Type	Jurisdiction	[1] Full Decoupling	[1] Partial Decoupling
Canadian Proxy Group						
AltaGas Limited	ALA	ENSTAR Natural Gas Company	Natural Gas	AK		
		Washington Gas Light Company	Natural Gas	DC		
		Washington Gas Light Company	Natural Gas	MD		✓
		SEMCO Energy, Inc.	Natural Gas	MI		
		Washington Gas Light Company	Natural Gas	VA		✓
Canadian Utilities Limited	CU	ATCO Electric	Electric	Alberta		
		ATCO Gas	Natural Gas	Alberta		✓
Emera Inc.	EMA	Tampa Electric Company	Electric	FL		
		Peoples Gas System	Natural Gas	FL		
		New Mexico Gas Company, Inc.	Natural Gas	NM		✓
		Nova Scotia Power Inc.	Electric	Nova Scotia		✓
Enbridge	ENB	Enbridge Gas	Natural Gas	Ontario		✓
		Gazifere	Natural Gas	Quebec		
Fortis Inc.	FTS	Central Hudson Gas & Electric Corp.	Electric	NY	✓	
		Central Hudson Gas & Electric Corp.	Natural Gas	NY	✓	
		Tucson Electric Power Company	Electric	AZ		✓
		UNS Electric, Inc.	Electric	AZ		✓
		UNS Gas, Inc.	Natural Gas	AZ		✓
		FortisAlberta	Electric	Alberta		
		FortisBC	Electric	British Columbia	✓	
		FortisBC Energy	Natural Gas	British Columbia	✓	
		Newfoundland Power Inc	Electric	Newfoundland & Labrador		✓
		Maritime Electric Company Ltd.	Electric	Prince Edward Island		✓
HydroOne Inc.	H	Hydro One Inc.	Electric	Ontario	✓	

Company	Ticker	Operating Subsidiary	Service Type	Jurisdiction	Full Decoupling	Partial Decoupling
U.S. Electric Proxy Group						
Alliant Energy Corporation	LNT	Interstate Power and Light Company	Electric	IA		
		Interstate Power and Light Company	Natural Gas	IA		
		Wisconsin Power and Light Company	Electric	WI		
		Wisconsin Power and Light Company	Natural Gas	WI		
Ameren Corporation	AEE	Ameren Illinois Company	Electric	IL		✓
		Ameren Illinois Company	Natural Gas	IL		✓
		Union Electric Company	Electric	MO		✓
		Union Electric Company	Natural Gas	MO		✓
American Electric Power Company, Inc.	AEP	Southwestern Electric Power Company	Electric	AR		✓
		Indiana Michigan Power Company	Electric	IN		✓
		Kentucky Power Company	Electric	KY		✓
		Southwestern Electric Power Company	Electric	LA		✓
		Indiana Michigan Power Company	Electric	MI		✓
		Ohio Power Company	Electric	OH		✓
		Public Service Company of Oklahoma	Electric	OK		✓
		Kingsport Power Company	Electric	TN		
		AEP Texas Inc.	Electric	TX		
		Southwestern Electric Power Company	Electric	TX		
		Appalachian Power Company	Electric	VA		
		Wheeling Power Company	Electric	WV		
Duke Energy Corporation	DUK	Duke Energy Florida, LLC	Electric	FL		
		Duke Energy Indiana, LLC	Electric	IN		✓
		Duke Energy Kentucky, Inc.	Electric	KY		✓
		Duke Energy Kentucky, Inc.	Natural Gas	KY		✓
		Duke Energy Carolinas, LLC	Electric	NC		
		Duke Energy Progress, LLC	Electric	NC		
		Piedmont Natural Gas Company, Inc.	Natural Gas	NC	✓	
		Duke Energy Ohio, Inc.	Electric	OH		✓
		Duke Energy Ohio, Inc.	Natural Gas	OH		
		Duke Energy Progress, LLC	Electric	SC		
		Duke Energy Carolinas, LLC	Electric	SC		
		Piedmont Natural Gas Company, Inc.	Natural Gas	SC		✓
		Piedmont Natural Gas Company, Inc.	Natural Gas	TN		✓

Company	Ticker	Operating Subsidiary	Service Type	Jurisdiction	Full Decoupling	Partial Decoupling
Entergy Corporation	ETR	Entergy Arkansas, LLC	Electric	AR		✓
		Entergy New Orleans, LLC	Electric	LA		
		Entergy New Orleans, LLC	Natural Gas	LA		
		Entergy Louisiana, LLC	Electric	LA		✓
		Entergy Mississippi, LLC	Electric	MS		✓
		Entergy Texas, Inc.	Electric	TX		
Eversource Energy	ES	The Connecticut Light and Power Company	Electric	CT	✓	
		Yankee Gas Services Company	Natural Gas	CT	✓	
		Eversource Gas Company of Massachusetts	Natural Gas	MA	✓	
		NSTAR Electric Company	Electric	MA	✓	
		NSTAR Gas Company	Natural Gas	MA	✓	
		Public Service Company of New Hampshire	Electric	NH		✓
Evergy, Inc.	EVRG	Evergy Kansas Central, Inc.	Electric	KS		✓
		Evergy Kansas South, Inc.	Electric	KS		✓
		Evergy Metro, Inc.	Electric	KS		
		Evergy Metro, Inc.	Electric	MO		✓
		Evergy Missouri West, Inc.	Electric	MO		✓
Exelon Corporation	EXC	Delmarva Power & Light Company	Electric	DE		
		Delmarva Power & Light Company	Natural Gas	DE		
		Potomac Electric Power Company	Electric	DC		✓
		Commonwealth Edison Company	Electric	IL		
		Baltimore Gas and Electric Company	Electric	MD	✓	
		Baltimore Gas and Electric Company	Natural Gas	MD	✓	
		Delmarva Power & Light Company	Electric	MD	✓	
		Potomac Electric Power Company	Electric	MD	✓	
		Atlantic City Electric Company	Electric	NJ		✓
		PECO Energy Company	Electric	PA		
		PECO Energy Company	Natural Gas	PA		
NextEra Energy, Inc.	NEE	Florida Power & Light Company	Electric	FL		
		Pivotal Utility Holdings, Inc.	Natural Gas	FL		
		Lone Star Transmission, LLC	Electric	TX		

Company	Ticker	Operating Subsidiary	Service Type	Jurisdiction	Full Decoupling	Partial Decoupling
OGE Energy Corporation	OGE	Oklahoma Gas and Electric Company	Electric	AR		✓
		Oklahoma Gas and Electric Company	Electric	OK		✓
Pinnacle West Capital Corporation	PNW	Arizona Public Service Company	Electric	AZ		✓
PPL Corporation	PPL	Kentucky Utilities Company	Electric	KY		✓
		Louisville Gas and Electric Company	Electric	KY		✓
		Louisville Gas and Electric Company	Natural Gas	KY		✓
		PPL Electric Utilities Corporation	Electric	PA		
		The Narragansett Electric Company	Electric	RI	✓	
		The Narragansett Electric Company	Natural Gas	RI	✓	
		Kentucky Utilities Company	Electric	VA		
Portland General Electric Company	POR	Portland General Electric Company	Electric	OR		
Southern Company	SO	Alabama Power Company	Electric	AL		
		Atlanta Gas Light Company	Natural Gas	GA		
		Georgia Power Company	Electric	GA		
		Northern Illinois Gas Company	Natural Gas	IL		✓
		Mississippi Power Company	Electric	MS		✓
		Chattanooga Gas Company	Natural Gas	TN	✓	
		Virginia Natural Gas, Inc.	Natural Gas	VA		✓
Xcel Energy Inc.	XEL	Public Service Company of Colorado	Electric	CO		✓
		Public Service Company of Colorado	Natural Gas	CO		✓
		Northern States Power Company	Electric	MN		✓
		Northern States Power Company	Natural Gas	MN		
		Southwestern Public Service Company	Electric	NM		
		Northern States Power Company	Electric	ND		
		Northern States Power Company	Natural Gas	ND		
		Northern States Power Company	Electric	SD		✓
		Southwestern Public Service Company	Electric	TX		
		Northern States Power Company	Electric	WI		
		Northern States Power Company	Natural Gas	WI		

Company	Ticker	Operating Subsidiary	Service Type	Jurisdiction	Full Decoupling	Partial Decoupling
US Gas Proxy Group						
Atmos Energy Corp	ATO	Atmos Energy Corporation	Natural Gas	CO		
		Atmos Energy Corporation	Natural Gas	KS		✓
		Atmos Energy Corporation	Natural Gas	KY		✓
		Atmos Energy Corporation	Natural Gas	LA		✓
		Atmos Energy Corporation	Natural Gas	MS		✓
		Atmos Energy Corporation	Natural Gas	TN		✓
		Atmos Energy Corporation	Natural Gas	TX		✓
Northwest Natural Holding Company	NWN	Northwest Natural Gas Company	Natural Gas	OR		✓
		Northwest Natural Gas Company	Natural Gas	WA		
ONE Gas, Inc.	OGS	Kansas Gas Service Company, Inc.	Natural Gas	KS		✓
		Oklahoma Natural Gas Company	Natural Gas	OK		✓
		Texas Gas Service Company, Inc.	Natural Gas	TX		✓
Spire, Inc.	SR	Spire Missouri Inc.	Natural Gas	MO		✓
		Spire Alabama Inc.	Natural Gas	AL		✓
		Spire Gulf Inc.	Natural Gas	AL		✓

Proxy Group Results	**Total:**		
	132	18	64
		14%	48%

Notes:

[1] Source: US companies are based on Regulatory Research Associates, "Adjustment Clauses: A State by State Overview", July 18, 2022. Canadian companies are from Annual Repo

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.133]

Question(s):

Please reconcile Concentric's recommendation for an equity thickness of 42% for Enbridge Gas in EB-2022-0200, with its recommendation for an equity thickness of 45% for all utilities (which include Enbridge Gas).

Response:

In EB-2022-0200, Concentric recommended that Enbridge Gas, Inc.'s equity ratio be set between 40% and 45%, and, within that range, recommended the OEB authorize a common equity ratio of 42% for the Company. Concentric also recognized that, at the time, OPG's equity ratio of 45% likely set a ceiling for the OEB on the appropriate authorized equity ratio for Enbridge Gas, and was of the view that the equity ratio for electric distributors of 40% was a floor for Enbridge Gas, Inc.'s equity ratio. Lastly, Concentric recognized that, based on its risk assessment in EB-2022-0200, its recommendation was conservative (see, page 121 of Concentric's evidence in EB-2022-0200, where we stated "[g]iven the risk factors noted above, we ***conservatively*** recommend that Enbridge Gas' authorized equity thickness fall within the range of 40% to 45%."

In this generic proceeding, where the OEB is evaluating equity thicknesses for all industry segments, the floor and ceiling concepts discussed above are now being considered in a comprehensive process by the Board. With regard to equity thickness, Concentric's primary finding within the context of this generic cost of capital proceeding is that Ontario equity ratios across all industry segments are lower than North American industry peers and fail to meet the comparable return standard component of the Fair Return Standard. While we continue to support the use of equity thickness to distinguish risk profiles among Ontario utilities, we have not recommended individual changes to each utility's equity thickness. Rather, we recommend that the deemed equity ratio be set at a minimum of 45.0% for all Ontario utilities, but that each utility have the option to retain its current equity ratio and/or propose differences from the "generic" equity thickness in its rates application. Concentric's recommendation of a minimum equity thickness of 45.0% reflects approximately the midpoint between the current deemed equity ratios in Ontario, which are generally consistent with the Canadian average deemed equity ratio for investor-owned utilities, and the authorized equity ratios for U.S. electric and gas utilities.

ONTARIO POWER GENERATION COMMON EQUITY RATIO STUDY

DECEMBER 31, 2020

CEADVISORS.COM

SECTION 8:
PROXY GROUP COMPARATIVE ANALYSIS

1. Overview

In addition to assessing changes to OPG's business and financial risk profile since EB-2016-0152, Concentric also analyzed the equity ratios of other North American utilities screened for risk characteristics similar to OPG's. To identify companies with risk characteristics similar to OPG, Concentric selected publicly-traded investor-owned utility companies that passed a series of screening criteria based on OPG's operational profile. Concentric reviewed three separate measures of the equity ratios of those similarly-situated regulated utilities: (1) the historical equity ratios maintained by comparable publicly-traded holding companies; (2) the historical equity ratios maintained by the operating subsidiaries of those holding companies; and (3) the equity ratios authorized by the regulators of those operating subsidiaries. Those measures provide context for where, within a reasonable range, OPG's equity ratio should be set by the OEB, with the regulated operating company equity ratios being most relevant for purposes of assessing OPG's regulated equity thickness. Concentric also analyzed two different proxy groups. The first proxy group (the "Concentric Proxy Group") was a broader group of companies that met the screening criteria described herein. The second proxy group (the "Moody's Peer Group") included the companies identified as OPG's peers by Moody's.[101] The results for those two proxy groups are provided in the Figure 14 and Figure 15 below.

Figure 14: Summary of Comparative Analysis Results (Concentric Proxy Group)

Analytical Approach	Mean Equity Ratio	Median Equity Ratio
Holding Company Equity Ratios: 5-Year Avg.	45.7%	47.4%
Operating Company Equity Ratios: 5-Year Avg.	52.8%	53.0%
Operating Company Equity Ratios: Authorized	49.5%	49.6%

[101] Moody's Credit Opinion, Ontario Power Generation Inc., December 21, 2020, at 9.

Figure 15: Summary of Comparative Analysis Results (Moody's Peer Group)

Analytical Approach	Mean Equity Ratio	Median Equity Ratio
Holding Company Equity Ratios: 5-Year Avg.	50.6%	49.1%
Operating Company Equity Ratios: 5-Year Avg.	55.9%	53.6%
Operating Company Equity Ratios: Authorized	50.7%	50.1%

Our analysis of comparable regulated utilities with significant regulated generation assets indicates that OPG's current deemed equity thickness is low relative to comparable companies, despite OPG falling towards the upper end of the spectrum of risk profiles established by the proxy companies. Taken together, the analyses support an equity ratio of no less than 50% for OPG.

2. Use of Proxy Company Analysis for Cost of Capital Determinations

Analyses of comparable, or "proxy," companies is a common and well-accepted approach used in the determination of the cost of capital for regulated utilities and for benchmarking business and financial risks. Proxy groups are used for the following main reasons in cost of capital determinations: (1) adherence to the comparable investment standard; (2) since the cost of capital is a market-based concept, and given that OPG is not a publicly-traded entity, it is necessary to establish a group of companies that is both publicly-traded and comparable to OPG in certain fundamental business and financial respects to serve as its "proxy" for purposes of the cost of capital evaluation process; and (3) even if OPG's regulated operations were held by a stand-alone publicly-traded entity, it is possible that transitory events could bias its market-determined cost of capital in one way or another over a given period of time. A significant benefit of using a proxy group is its ability to mitigate the effects of anomalous events that may be associated with any one company.

Regulatory commissions and cost of capital analysts generally apply a set of screening criteria in order to define a risk-appropriate group of comparable companies. For instance, the Federal Energy Regulatory Commission ("FERC") provides the following summary of its practice for selection of a proxy group for electric transmission companies:

> *Composition of the Proxy Group: In this section we address the following issues concerning the proper methodology for developing a proxy group and calculating the zone of reasonableness: (1) the use of a national group of companies considered electric utilities by Value Line; (2) the inclusion of companies with credit ratings no more than one notch above or below the utility or utilities whose rate is at issue; (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut*

> *during the six-month study period; (4) the inclusion of companies with no major merger activity during the six-month study period; and (5) companies whose DCF results pass threshold tests of economic logic.*[102]

While the individual screens require modification based on the subject company to which proxy companies are being compared,[103] the goal of screening companies based on their risk characteristics increases both the comparability of the group and the confidence that the analyst (or regulator) can have in drawing conclusions based on analyses of the proxy group. Therefore, for consistency with the above considerations, Concentric relied on a screening process similar to that we typically apply in cost of capital analyses to narrow the list of potential companies in order to establish a proxy group of North American electric utility companies that are risk appropriate for comparison to OPG.

Given the unique characteristics of OPG, and, in particular, the fact that its regulated operations consist of 100% generating assets, it is not possible to find proxy companies that are perfectly comparable from a risk perspective. At issue, then, is how to determine an appropriate equity ratio in the context of that range. That determination must be based on an assessment of OPG-specific risks relative to the proxy group and informed judgment. For example, the National Energy Board (predecessor to the Canada Energy Regulator), in discussing the cost of capital for the TransCanada Mainline, stated, "[t]o the greatest extent possible, comparable companies have to face similar business risk as the Mainline. If they do not, judgment needs to be applied to the cost of capital estimates to reflect business risk differences."[104] In other words, whereas a subject company of average risk relative to the proxy group potentially would warrant an equity ratio equal to the average or median result of the proxy group, a company of greater risk potentially would warrant an equity ratio above the mean or median result, and a company of lower risk potentially would warrant an equity ratio below the mean or median result.

In summary, the use of comparable companies to benchmark business and financial risks in the context of cost of capital determinations is a common practice among North American regulatory jurisdictions, and it is a method Concentric has applied to our evaluation of OPG's capital structure. In the discussion that follows, we present Concentric's analysis of OPG's level of business and

102 Opinion No. 531, Order on Initial Decision, 147 FERC ¶ 61,234 (June 19, 2014), at 44-45
103 For instance, the FERC applies a screen for the inclusion of master limited partnerships ("MLPs") in natural gas pipeline proxy groups that the MLPs derive at least 50% of operating income from, or have 50% of their assets devoted to, interstate operations (see, Opinion No. 510, Portland Natural Gas Transmission System, 134 FERC ¶ 61,129 (February 17, 2011), at 62.
104 National Energy Board RH-003-2011 Reasons for Decision, TransCanada PipeLines Ltd, NOVA Gas Transmission Ltd., and Foothills Pipe Lines Ltd., March 2013, at 165.

financial risk relative to a proxy group of electric utilities, as well as our review of equity ratios authorized for the proxy group to provide context for where, within a reasonable range, OPG's equity ratio should be set by the OEB.

3. Selection of Proxy Companies

As discussed above, Concentric studied data derived from two separate proxy groups, the Concentric Proxy Group and the Moody's Peer Group.

As a starting point for our screening process for the Concentric Proxy Group, Concentric reviewed data related to both Canadian and U.S. utilities, including the following Canadian utilities: Algonquin Power & Utilities Corp ("Algonquin"), Canadian Utilities Limited, Emera Inc. ("Emera"), Enbridge Inc., Fortis Inc. ("Fortis"), and TC Energy Corporation, and the 37 U.S. companies that Value Line classifies as "Electric Utilities."[105]

From that group, Concentric screened for companies that:

- **<u>Own regulated generation assets that are included in rate base</u>**. As it relates to the rate setting process, OPG's assets represent 100% rate-regulated generation. As such, it is important to exclude companies from the proxy group that bear no risks related to regulated generation. The reason for this is the generation function is generally regarded by investors as being higher risk than electric transmission or distribution. As stated by Moody's in its 2017 ratings methodology for regulated electric and gas utilities, "[g]eneration utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays;" [106]

[105] Precedent for the consideration of U.S. proxy companies in Canadian cost of equity analyses is discussed in Appendix C.
[106] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, at 21.

- **Own regulated nuclear and/or hydroelectric generation**.[107] As noted earlier, OPG's rate regulated facilities consist of the Pickering and Darlington nuclear stations, as well as 54 hydroelectric generating stations. In addition, as previously noted, the OEB has recognized that nuclear assets are higher in risk than hydroelectric assets. Therefore, it is important to compare OPG against a group of companies that also own regulated nuclear and/or hydroelectric generation facilities;

- **Have regulated revenue and regulated net income that make up greater than 60% of total revenue and total income for the consolidated company**. This screen, in combination with the screen below regarding electricity revenue and net income, serves to exclude companies that do not derive a significant portion of their financial results from regulated electric operations. While rates in this proceeding are being set for OPG's 100% rate-regulated nuclear operations, these two screens are set at levels below 100% so that the resulting proxy group is not unduly small. Including only those companies that derive more than 60% of their revenues and net income from regulated operations ensures that the proxy companies are protected by regulation rather than being subject to substantial merchant or market-related risks. While 60% is not a "bright line" percentage for separating regulated from non-regulated companies, in Concentric's experience, using a screening criteria of around 60% increases the comparability of the proxy group to the regulated utility without unduly limiting the size of the group

- **Have regulated electricity revenue and net income that make up greater than 80% of revenue and income for the consolidated company's regulated operations**. Including only those companies that derive more than 80% of their regulated revenue and net income from regulated electricity operations ensures that the proxy companies, like OPG, derive the predominant share of their financial results from regulated electricity segments. Similar to the regulated revenue and net income screen, the 80% regulated electric revenue and net income screen is not a "bright line," but rather is intended to balance the comparability of the proxy group with its overall size; and

[107] Excludes utilities with only a minimal (*i.e.*, less than 5% of their total generation portfolio) amount of nuclear or hydroelectric generation.

- **<u>Have an investment grade credit rating similar to that of OPG</u>**. As noted earlier, OPG has an "A (low)" issuer and unsecured debt rating from DBRS, a "BBB+" corporate and unsecured debt credit rating from S&P, and an "A3" senior unsecured debt rating from Moody's. As also noted earlier, S&P and Moody's rate OPG as "BB+" and "baa3" (*i.e.*, three notches below its corporate credit rating) on a stand-alone basis, before consideration of support by the Province. As credit ratings are based on the utility's business risk profile (including an assessment of its regulatory environment) and financial risk profile, companies with similar credit ratings have been determined by the rating agency to have similar levels of business and financial risk. This concept has been adopted by regulatory agencies, including the FERC, which has found that "it is reasonable to use the proxy companies' corporate credit rating as a good measure of investment risk, since this rating considers both financial and business risk."[108] Concentric's credit rating screen selects electric utility companies with investment-grade credit ratings (an S&P credit rating of BBB- or above or a Moody's credit rating of Baa3 and above), which reduces the need to adjust the results to account for any perceived differences in business or financial risk compared to OPG. Further, selecting proxy companies that, like OPG, have an investment grade credit rating ensures that the proxy companies are generally in sound financial condition. Because credit ratings consider business and financial risks, the ratings provide a broad measure of investment risk that is widely referenced by investors.[109]

4. Proxy Group Summary

None of the publicly traded Canadian companies that Concentric reviewed met all of our screening criteria. Emera, however, only failed the screen that each utility should have more than a minimal amount of regulated hydroelectric and/or nuclear generation.[110] Fortis only failed the screens that each utility should have regulated electricity revenue and net income that make up greater than 80% of the consolidated company's regulated operations and that each utility should have more than a minimal amount of regulated hydroelectric and/or nuclear generation.[111] Algonquin failed the screens that each utility should own more than a minimal amount of regulated nuclear and/or

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108 See, for example, Potomac-Appalachian Transmission Highline, LLC, 122 FERC ¶ 61,188 (2008), at 97.

109 The only utility removed from the proxy group due to this screening criterion is PG&E Corporation, which has a sub-investment grade credit rating due to its recent bankruptcy.

110 Specifically, Emera currently owns no regulated hydroelectric or nuclear generation.

111 Fortis has 76% regulated electricity revenue and regulated net income, while only owning a minimal amount of regulated hydroelectric generation (and no nuclear generation).

hydroelectric generation and that each utility should derive greater than 80% of consolidated regulated revenue from regulated electricity operations.[112]

In order to broaden the proxy group to include at least a minimal number of Canadian utilities, Concentric included Emera, Fortis, and Algonquin in the proxy group, as they otherwise meet our screening criteria. Figure 16 presents the sixteen U.S. companies that met our screening criteria, along with OPG and the three Canadian companies noted above. In addition to the company name, Concentric also provides the S&P rating, as well as S&P's business risk and financial risk rating summary for each company. Exhibit 1 details how each proxy company meets the screening criteria above.

[112] Algonquin owns just 16 MW of hydroelectric generation according to S&P Global Market Intelligence and has 49% regulated electricity revenue.

Figure 16: Concentric Proxy Group and OPG

Company	Ticker	S&P Summary: Credit Rating / Outlook	S&P Summary: Business Risk	S&P Summary: Financial risk
OPG	n/a	BBB+/Stable	Strong	Significant
ALLETE, Inc.	ALE	BBB/Stable	Strong	Significant
Ameren Corporation	AEE	BBB+/Stable	Excellent	Significant
American Electric Power Co., Inc.	AEP	A-/Stable	Excellent	Significant
Avista Corporation	AVA	BBB/Stable	Strong	Significant
Duke Energy Corporation	DUK	A-/Stable	Excellent	Significant
Edison International	EIX	BBB/Negative	Strong	Significant
El Paso Electric Company[113]	EE	Not Rated	Not Rated	Not Rated
Entergy Corporation	ETR	BBB+/Stable	Strong	Significant
FirstEnergy Corporation	FE	BBB/Negative	Excellent	Aggressive
Evergy, Inc.	EVRG	A-/Stable	Excellent	Significant
IDACORP, Inc.	IDA	BBB/Stable	Strong	Significant
NextEra Energy, Inc.	NEE	A-/Stable	Excellent	Intermediate
Pinnacle West Capital Corporation	PNW	A-/Stable	Excellent	Significant
PNM Resources, Inc.	PNM	BBB/Stable	Strong	Significant
Portland General Electric Company	POR	BBB+/Negative	Excellent	Significant
Southern Company	SO	A-/Negative	Excellent	Significant
Xcel Energy, Inc.	XEL	A-/Stable	Excellent	Significant
Algonquin Power & Utilities Corp	AQN	BBB/Stable	Strong	Significant
Emera, Inc.	EMA	BBB/Stable	Excellent	Aggressive
Fortis Inc.	FTS	A-/Negative	Excellent	Significant

As described above, Concentric also considered the Moody's Peer Group, which is a proxy group composed of companies identified by Moody's as OPG's peers.[114] Figure 17 presents those three companies along with OPG. Again, Concentric also provides the S&P rating, as well as S&P's business risk and financial risk rating summary for each Moody's peer.

113 S&P withdrew its ratings on El Paso Electric Co. ("El Paso") on September 18, 2020, due to a lack of sufficient information. Previously, El Paso was rated BBB with a negative outlook, with "Strong" business risk and "Significant" financial risk.

114 Moody's Credit Opinion, Ontario Power Generation Inc., December 21, 2020, at 9.

Figure 17: Moody's Proxy Group and OPG

Company	Ticker	S&P Summary: Credit Rating / Outlook	S&P Summary: Business Risk	S&P Summary: Financial risk
OPG	n/a	BBB+/Stable	Strong	Significant
Public Service Enterprise Group, Inc	PEG	BBB+/Stable	Strong	Significant
NextEra Energy, Inc.	NEE	A-/Stable	Excellent	Intermediate
Exelon Corporation	EXC	BBB+/Negative	Strong	Significant

5. Proxy Group Business Risk Analysis

In order to further evaluate the comparability of the proxy group companies, Concentric examined the business risks of each operating company relative to those of OPG. The purpose of this evaluation was to determine the extent to which the companies in the proxy group have similar risk profiles to OPG (indicating that OPG is of average risk, compared to the proxy group), or are more or less risky than OPG (indicating a need to potentially establish a proxy-based capital structure for OPG that is above or below the mean and median of the group).

Concentric focused on two primary business risk characteristics – operational profile, and generation percentage and mix.

a. Operational profile

Concentric examined the operations of each of the companies in the two proxy groups. Exhibits 5.1 and 5.2 provide summaries of several relevant indicators for the operating subsidiaries of the Concentric Proxy Group and the Moody's Peer Group, respectively, including: (1) the province or state in which the utility provides service; (2) the ratemaking mechanisms available to the utility (*e.g.*, fuel cost recovery, revenue decoupling, capital cost recovery, etc.); and (3) whether the jurisdiction relies on historical or forecast test years for ratemaking purposes.

In reviewing the comparability of the ratemaking mechanisms available to proxy group companies, Concentric specifically considered the OEB's statement in EB-2016-0152 that "in OPG's specific circumstances, there are a number of factors that substantially mitigate that risk [*i.e.*, higher business risks associated with nuclear generation]. These include the various protections provided by O. Reg. 53/05 and the variance and deferral accounts that allow OPG the opportunity to recover substantially all their unexpected or unforeseen costs."[115]

[115] EB-2016-0152, Decision and Order, December 28, 2017, at 102. Clarification added.

ENBRIDGE GAS INC.
COMMON EQUITY RATIO STUDY

OCTOBER 17, 2022

CEADVISORS.COM

SECTION 4(a):
ENERGY TRANSITION

Introduction

In EB-2011-0354, EGD stated that it faced increased business risk due to environmental policies and laws such as Ontario's Green Energy Act (2009). EGD further submitted that there "is a clear long-term risk that demand for natural gas will decline, as new technologies and energy saving practices take further hold."[22] However, the OEB concluded in 2013 that "Enbridge has not experienced a significant increase in risk since 2007 relating to environmental and technological advancement."[23] Specifically, the OEB found:

> *The evidence does not demonstrate a tangible risk that new environmental policy and laws in relation to gas distribution will be implemented over the near term, or if implemented, will be likely to have a detrimental effect on Enbridge in terms of volume over the near term. The Board agrees with intervenors that, to the contrary, the policy commitment to cease all coal-fired electricity generation in Ontario is likely to result in more gas-fired electricity generation, which is a benefit to Enbridge. In addition, as discussed under Volumetric Demand Profile, to the extent that DSM initiatives decrease Enbridge's volume, this risk is addressed by the LRAM account. Also, as discussed above, increasing energy efficiency has the effect of strengthening the ongoing competitive position of gas compared to other fuels.*[24]

The situation today is starkly different than at the time of the OEB's above-quoted findings. Within the last five years, and accelerating within the past year, the global energy sector has embarked on a broad-scale transformation, referred to generally as the "Energy Transition," from a primary reliance on fossil fuels to an increased emphasis on more renewable fuel sources.[25] As a result, the risk profile of natural gas distribution utilities such as Enbridge Gas has fundamentally changed.

The subsections that follow discuss the evidence that the Energy Transition is already underway, the steps the Company has taken in response to the Energy Transition, and the effects of the Energy Transition on the Company's current risk profile.

22 EB-2011-0354, Ontario Energy Board Decision on Equity Ratio and Order, February 7, 2013, at 14.
23 *Id.*, at 15.
24 *Ibid*.
25 S&P Global, "What is Energy Transition," February 24, 2020, https://www.spglobal.com/en/research-insights/articles/what-is-energy-transition.

1. Evidence of the Energy Transition

a) Government Policy

Protecting the environment is an increasing area of focus for federal, provincial, and local governments in both Canada and the U.S. At the federal level, the Trudeau administration pledged to reduce greenhouse gas ("GHG") emissions by 40 to 45 percent (relative to 2005 levels) by 2030,[26] and to achieve net zero emissions by 2050, consistent with the Paris Accord that was signed in 2015.[27] In June 2021, the federal government formalized Mr. Trudeau's pledge by passing the Canadian Net-Zero Emissions Accountability Act, setting into law the commitment to achieve net-zero carbon emissions by 2050. The federal act also mandates the setting of intermediary targets at five-year intervals (2030, 2035, 2040, and 2045) at least a decade in advance of each target, and requires the development of emissions reduction plans for these targets. Further, Prime Minister Trudeau's recent re-election makes it likely that these environmental policies will continue.[28]

Additionally, the Canadian federal government adopted a carbon tax in 2019. The tax is approximately $50 per metric tonne in 2022 and, as summarized in Figure 2, is expected to reach $170 per metric tonne by 2030. All else equal, the increase in the carbon tax means that delivered natural gas prices to Enbridge Gas' customers will also increase, thereby eroding the price advantage of natural gas relative to electricity.

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26 CBC News, "Trudeau Pledges to Slash Greenhouse Gas Emissions By At Least 40% by 2030," April 22, 2021, https://www.cbc.ca/news/politics/trudeau-climate-emissions-40-per-cent-1.5997613.

27 S&P Global Market Intelligence, "Biden, Trudeau Agree to Pursue Goal of Net-Zero Emissions by 2050," February 24, 2021, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/biden-trudeau-agree-to-pursue-goal-of-net-zero-emissions-by-2050-62841040.

28 The Conversation, "Canada's Federal Election Made Big Strides for Climate and the Environment," September 30, 2021, https://theconversation.com/canadas-federal-election-made-big-strides-for-climate-and-the-environment-168918.

Figure 2: Canadian Carbon Tax Projections[29]

Year	Carbon Tax ($/tonne)	Cents / Cubic Meter of Natural Gas
2023	$65	12.39
2024	$80	15.25
2025	$95	18.11
2026	$110	20.97
2027	$125	23.83
2028	$140	26.69
2029	$155	29.54
2030	$170	32.40

At the local level, at least 48 municipalities in Ontario have declared climate emergencies, as illustrated in Figure 3.

Figure 3: Municipalities in Ontario with Declared Climate Emergencies

Aurora	Essex	London	Sarnia
Barrie	Goderich	Meaford	St. Catharines
Bracebridge	Greater Sudbury	Middlesex Centre	Stratford
Brampton	Grey Highlands	Milton	Thunder Bay
Brantford	Guelph	Mississauga	Toronto
Burlington	Halton Hills	Niagara-on-the-Lake	Vaughan
Caledon	Halton	Oakville	Waterloo
Cambridge	Hamilton	Ottawa	Waterloo
Chatham-Kent	Kenora	Peel	West Grey
Cobourg	King	Petawawa	Wilmot
Collingwood	Kingston	Peterborough	Windsor
Durham	Kitchener	Prince Edward	Woolwich

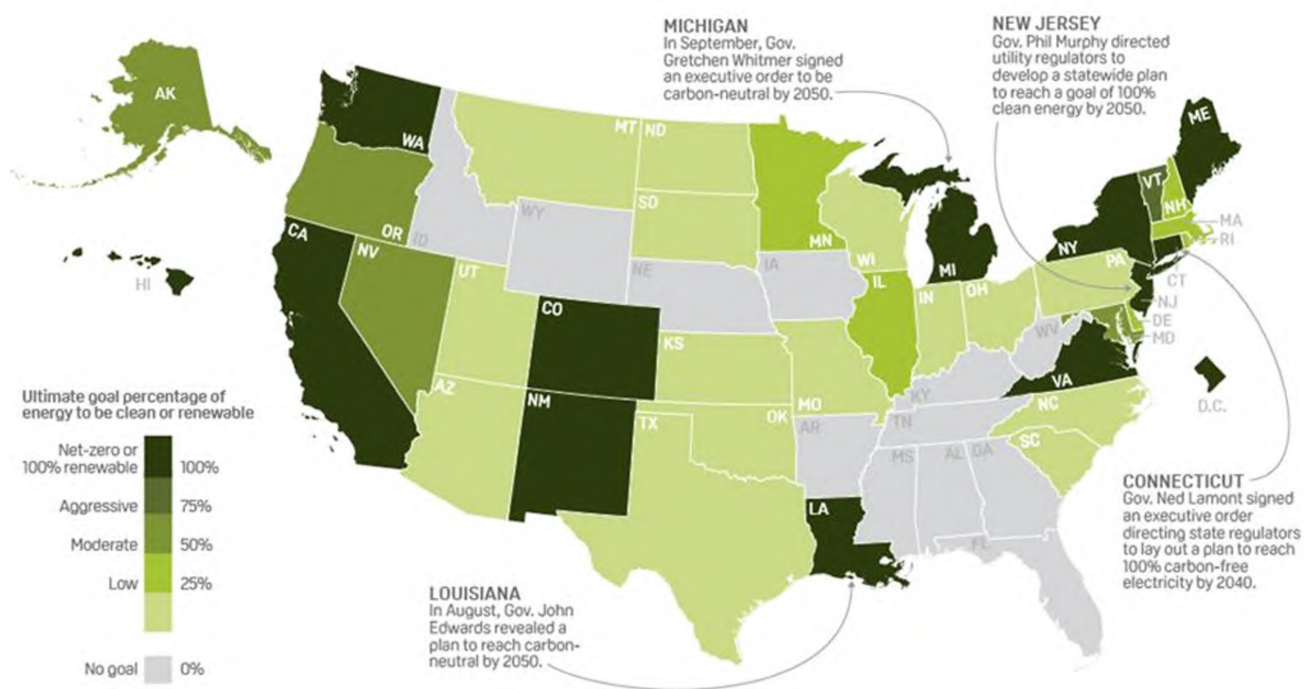
The Energy Transition is accelerating rapidly in the United States as well. President Joe Biden's administration is targeting a 50 percent reduction in GHG emissions relative to 2005 by 2030, and net zero emissions economy-wide by 2050.[30] This effort was reinforced by the August 2022 climate change legislation that was included in the Inflation Reduction Act ("IRA") signed by President Biden.

[29] Government of Canada, "Fuel Charge Rates for Listed Provinces and Territories for 2023 to 2030" (https://www.canada.ca/en/department-finance/news/2021/12/fuel-charge-rates-for-listed-provinces-and-territories-for-2023-to-2030.html; accessed September 29, 2022).

[30] White House Fact Sheet: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies, April 22, 2021, https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/.

The legislation provides approximately $370 billion in new spending over the next ten years to promote research on low-carbon technologies and new agricultural programs, to provide incentives for electric heat pumps, and to provide tax credits for electric vehicles, among other things. According to analysts, the IRA will result in a 41 percent reduction in U.S. emissions by 2030, compared to 2005 levels. Without the new legislation, emission reductions were only projected at 27 percent by 2030, as compared to the Biden administration's commitment to reduce emissions by 50 percent from 2005 levels by 2030.[31] In addition, as shown in Figure 4, at least a dozen U.S. states have committed to net zero or 100 percent renewable power targets by 2050 or earlier.

Figure 4: United States Renewable Targets[32]



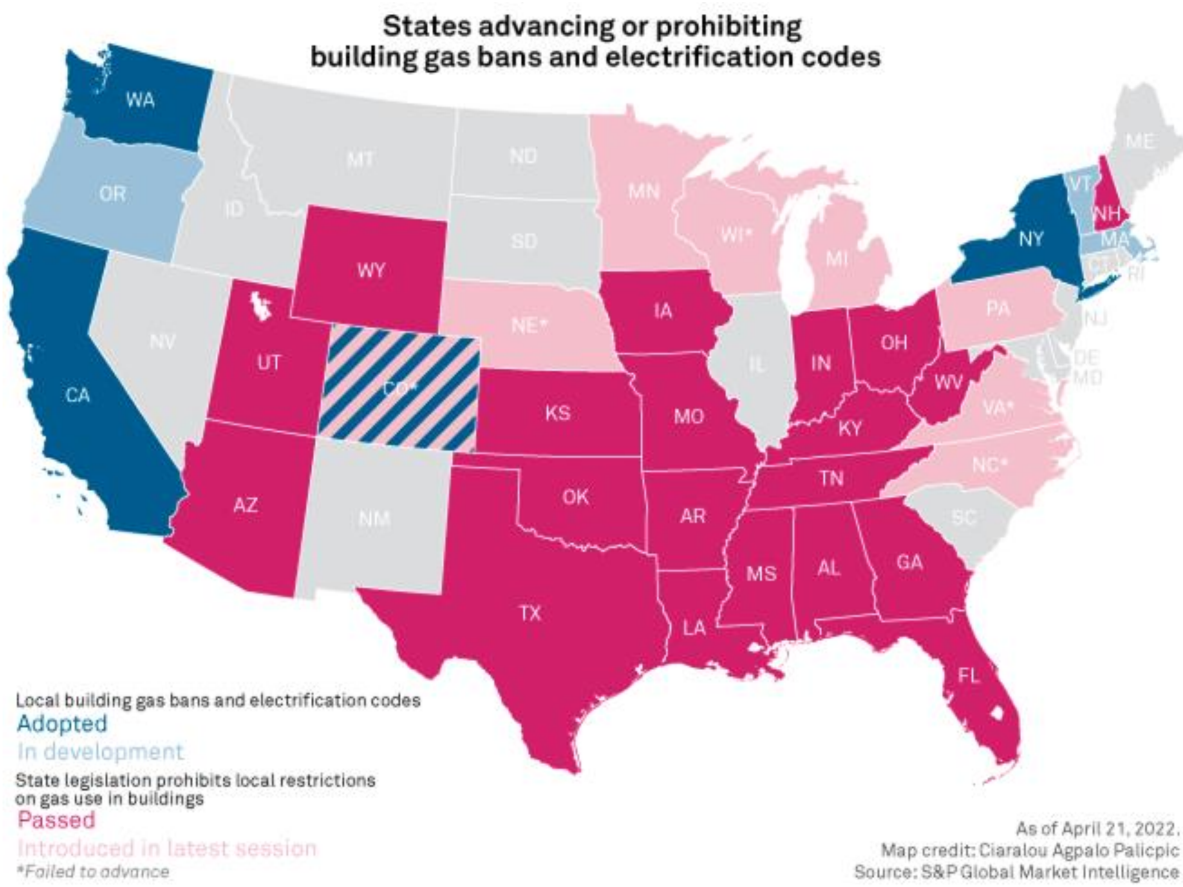
Additionally, restrictions on gas use in buildings have advanced at the state or local level in at least six U.S. states that collectively represent approximately one quarter of gas use in the U.S. These restrictions threaten natural gas customer growth because they generally apply to new buildings, but in some cases, such as Washington and New York, state policymakers have also proposed plans that

31 Council on Foreign Relations, "What the Historic U.S. Climate Change Bill Gets Right and Gets Wrong," August 17, 2022.

32 S&P Global Platts, "Commodities 2021: States Racing to Set Goals Towards Net-Zero Emission, 100% Renewable Electricity," December 24, 2020.

would phase gas use out of existing buildings.[33] In juxtaposition to these developments, at least 20 other states have passed laws prohibiting gas bans at the local level. Figure 5 summarizes the various legislative developments regarding building gas bans in the U.S.

Figure 5: Status of Building Gas Bans by State[34]



While the prohibitions on building gas bans in many U.S. states are a positive near-term development for natural gas distribution utilities in some jurisdictions, declining costs and government support for alternatives to gas space heating continue to pressure natural gas' long-term economic viability. As the consultancy the Brattle Group ("Brattle") recently observed:

> *Traditional gas utility business models face increasing risks as more states and locales challenge the long-run role natural gas could play in meeting climate and energy policy goals. Even though certain states are moving against this trend and enacting prohibitions on bans on new gas connections, cost declines related to technology innovation and federal, state, and municipal policy support will increase the deployment*

33 S&P Capital IQ Pro, "Natural Gas in Transition: High-Stakes Battles Over Gas Use Take Shape," June 7, 2021.
34 S&P Capital IQ Pro (formerly S&P Global Market Intelligence), "Gas Ban Monitor: Building Electrification Evolves as 19 States Prohibit Bans," July 20, 2021.

> *of lower-carbon alternatives to natural gas, as happened with renewables in the electricity sector. The transition is already underway: at the current rate, the number of homes with electric space heating could exceed the number of homes with gas space heating by 2032.*[35]

Concentric is not aware of any building gas bans, or prohibitions on such bans, in Ontario. However, as discussed previously, 48 municipalities have already declared climate emergencies in Ontario. Twenty one Ontario communities, including the City of Toronto, are urging the Ontario government to phase out the use of gas-fired electricity generation.[36] In December 2021, the Toronto City Council adopted an ambitious strategy to reduce community wide GHG emission in Toronto to net zero by 2040 – ten years earlier than initially proposed. Toronto's net zero by 2040 target is one of the most ambitious in North America. To reach its targets, the City will use its influence to regulate, advocate and facilitate transformation in five key areas:

- Demonstrate carbon accountability locally and globally, by establishing a carbon budget for its own operations and the community as a whole.
- Accelerate a rapid and significant reduction in natural gas use.
- Establish performance targets for existing buildings across Toronto.
- Increase access to low-carbon transportation options, including walking, biking, public transit and electric vehicles.
- Increase local renewable energy to contribute to a resilient, carbon-free grid.[37]

Further, while not enacted, the provincial government has previously drafted climate change action plans that include the phase-out of gas for home heating by 2030.[38] Additionally, the current Minister of Energy, Todd Smith, requested in 2021 that the Independent Electricity System Operator ("IESO") (1) "evaluate a moratorium on the procurement of new natural gas generating stations in Ontario," and (2) "develop an achievable pathway to phase-out natural gas generation and achieve zero emissions in the electricity system."[39] Then, in August 2022, Mr. Smith accelerated the timeline for an interim report from the IESO, stating that he "asked the IESO to speed up that report back to us so

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35 The Brattle Group, "The Future of Gas Utilities Series: Transition Gas Utilities to A Decarbonized Future," Part 1 of 3, August 2021, at 9.

36 The Energy Mix, "Toronto City Council Calls for Ontario Gas Phaseout," March 12, 2021, https://www.theenergymix.com/2021/03/12/toronto-city-council-calls-for-ontario-gas-phaseout/.

37 https://www.toronto.ca/news/net-zero-by-2040-city-council-adopts-ambitious-climate-strategy/

38 CBC News, "Ontario Government Not Denying Report on Sweeping Climate Change Plan," March 12, 2021, https://www.theenergymix.com/2021/03/12/toronto-city-council-calls-for-ontario-gas-phaseout/.

39 Letter from the Honourable Todd Smith, Minister of Energy, to Lesley Gallinger, President and Chief Executive Officer of the Independent Electricity System Operator, October 7, 2021.

that we can get the information from them as to what the results would be for our grid here in Ontario and whether or not we actually need more natural gas… I don't believe that we do."[40]

b) Investor Actions

In addition to the governmental developments discussed above, an increasing number of investors have instigated a "capital transition" and are prioritizing environmental, social and governance ("ESG") considerations when making investment decisions. S&P and Moody's have incorporated ESG criteria into their credit rating analyses, while other investment firms and pension funds have adopted restrictions that prohibit them from owning equity or debt in companies seen as contributing to climate change. For example, in January 2020, investment manager BlackRock sent a letter to its clients announcing a number of initiatives to place sustainability at the center of its investment approach, including: making sustainability integral to its portfolio management; exiting investments that present a high sustainability-related risk, and strengthening its commitment to sustainability and transparency in investment stewardship activities.[41] BlackRock joins investors on a global basis that collectively represent more than $60 trillion in assets under management, including asset managers such as J.P. Morgan, Santander, and Goldman Sachs.[42] Those investors are now pushing utilities to decarbonize by 2035.[43] Six of Canada's largest banks, including the Bank of Montreal, the Canadian Imperial Bank of Commerce, the National Bank of Canada, the Royal Bank of Canada, Scotiabank, and Toronto-Dominion Bank, recently signed on to the Net-Zero Banking Alliance, thereby committing to establishing a variety of sustainability-linked emissions targets.[44] These banks are the primary debt capital providers for EGI. In Ontario specifically, Ontario Teachers' Pension Plan is targeting a 45% reduction in "portfolio" emissions intensity by 2025, a two-thirds decrease by 2030, and net zero by 2050.[45]

[40] The Canadian Press, "Ontario energy minister asks for early report exploring a halt to natural gas power generation," August 23, 2022.

[41] BlackRock Letter to CEOs, "A Fundamental Reshaping of Finance," January 20, 2020.

[42] Climate Action 100+, Investor Signatories, https://www.climateaction100.org/whos-involved/investors/. See also MarketWatch, "World's Largest Asset Manager BlackRock Joins $41 Trillion Climate-Change Investing Pact," January 14, 2020, https://www.marketwatch.com/story/worlds-largest-asset-manager-blackrock-joins-41-trillion-climate-change-investing-pact-2020-01-09.

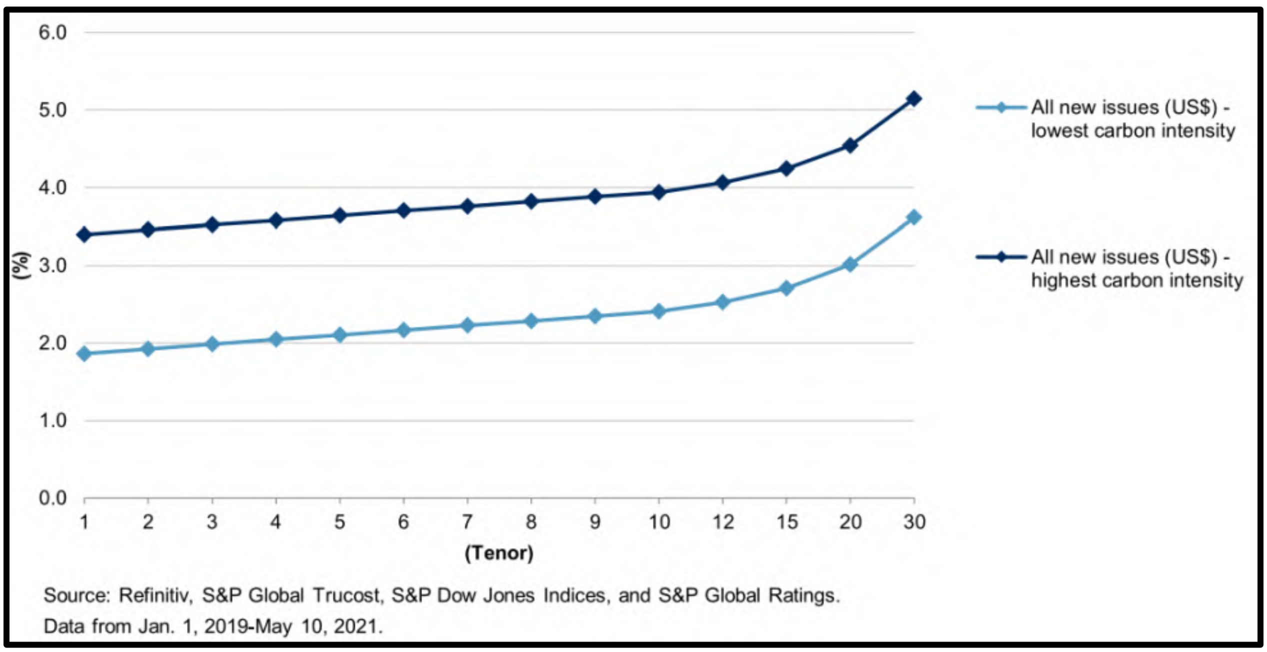
[43] S&P Capital IQ Pro, "Investors With $60 Trillion in Assets Call on Utilities to Decarbonize by 2035," October 20, 2021.

[44] https://mcmillan.ca/insights/major-canadian-banks-join-net-zero-banking-alliance-nzba-unpacking-the-initiative-and-net-zero-commitments/.

[45] Ontario Teachers' Pension Plan, "Ontario Teachers' Releases Ambitious Interim Net-Zero Targets," September 16, 2021, https://www.otpp.com/news/article/a/ontario-teachers-releases-ambitious-interim-net-zero-targets.

Investor ESG concerns are already affecting capital markets, as illustrated by S&P's analysis of the financing costs of North American oil and gas companies relative to their environmental impact. Specifically, S&P grouped North American energy companies into quartiles based on the carbon intensity of their revenue as measured by the annual metric tons of carbon emissions per million dollars of annual revenue. S&P concluded that it saw "evidence that issuers with lower carbon intensity were able to issue longer-dated debt at lower financing costs than their more carbon-intense peers."[46] Figure 6 provides the yield curves that S&P developed for new debt issuances from the companies in the highest and lowest quartiles of carbon intensity. As shown, issuers in the highest carbon intensity quartile tend to have materially more expensive debt than issuers in the lowest carbon intensity quartile. S&P estimated that differences in debt yields between the highest and lowest carbon intensity issuers exceeded 150 basis points for 10+ year issuances over the period studied.

Figure 6: S&P Estimated North American Energy New Issues Yield Curve: 2019-2021[47]



[46] S&P Global Ratings, "The Energy Transition: ESG Concerns Are Starting to Present Capital Market Challenges to North American Energy Companies," June 14, 2021, at 4.

[47] *Id.*, at 5.

c) Utility Commitments

Dozens of North American electric and gas utilities that collectively represent hundreds of billions of dollars in market capitalization have established "net-zero" targets of 2050 or earlier, with many interim emission reduction targets announced as well.

Figure 7 summarizes many of the most prominent emissions related commitments by utilities in both the U.S. and Canada.

Figure 7: North American Utility Emissions Commitments[48]

Company	Ticker	Market Cap ($B)	Goal
Duke Energy Corp.	DUK	$81	Net-zero methane from gas utility by 2030; Companywide by 2050
Enbridge, Inc.	ENB	$79	Net-zero GHG emissions by 2050; 35% intensity reduction by 2030
Southern Co.	SO	$69	Net-zero carbon emissions by 2050; 50% by 2030
Dominion Energy Inc.	D	$62	Net-zero for gas operations by 2040; Companywide by 2050
TC Energy Crop	TRP	$58	Net zero GHG emissions by 2050; 30% by 2030
National Grid	NG	$47	Net zero GHG emissions by 2050
Sempra Energy	SRE	$42	SDG&E targeting zero-carbon power by 2045
Xcel Energy Inc.	XEL	$37	100% carbon-free by 2050; 80% carbon-free by 2030
Public Service Enterprise Group Inc.	PEG	$32	Net-zero carbon emissions from power generation by 2050
Eversource Energy	ES	$31	Carbon-neutral companywide by 2030
WEC Energy Group Inc.	WEC	$30	Net-carbon neutral electric generation fleet by 2050
Ontario Power Generation [1]	N/A	$30	Net zero by 2040
Consolidated Edison Inc.	ED	$27	100% clean electricity by 2040
DTE Energy Co.	DTE	$23	Net-zero companywide by 2050
Entergy Corp.	ETR	$22	Net-zero emissions by 2050
Ameren Corp.	AEE	$22	Net-zero carbon emissions across its operations by 2050
Edison International	EIX	$22	Supports state goal of carbon neutrality by 2045
FirstEnergy Corp.	FE	$21	Carbon neutral by 2050
PG&E Corp.	PCG	$21	Commited to meeting California goal of carbon neutrality by 2045
Avangrid Inc.	AGR	$20	Carbon neutral by 2035; Working to reduce methane from gas
CMS Energy Corp.	CMS	$18	Net-zero methane from gas utility by 2030; Electricity by 2040
AES Corp.	AES	$16	Net-zero emissions by 2050
Hydro One	H	$15	Net-zero GHG emissions by 2050; 30% decrease by 2030
Algonquin Power and Utilities	AQN	$12	Net-zero by 2050; 75% renewable generation by 2023
Emera Inc.	EMA	$12	Net-zero CO2 emissions by 2050; 55% decrease by 2025
NRG Energy Inc.	NRG	$10	Net-zero GHG emissions by 2050
Vistra Corp.	VST	$9	Net-zero carbon emissions by 2050
Pinnacle West Capital Corp	PNW	$9	100% carbon-free electricity by 2050
AltaGas Inc.	ALA	$6	Supports DC's goal of carbon neutrality by 2050
Spire, Inc.	SR	$4	Carbon neutral by 2050; 53% methane reduction by 2025
South Jersey Industries, Inc.	SJI	$3	Carbon neutrality by 2040; 70% reduction by 2030
Chesapeake Utilities Corp	CPK	$2	Net-zero direct GHG emissions by 2035
Northwest Natural Gas Company	NWN	$2	Carbon neutral by 2050

A recent update to this survey by S&P Global characterizes the state of the industry as follows:

> Over the past five years, virtually all leading U.S. utilities have gone from business as usual to setting greenhouse gas emissions reduction targets to making net-zero announcements. Twenty-five of the country's 30 largest power and natural gas companies by market cap have

48 S&P Global Market Intelligence, "Path to Net Zero: 70% of Biggest US Utilities Have Deep Decarbonization Targets," December 9, 2020. Supplemented with Concentric research.
[1] Ontario Power Generation is not publicly-traded; therefore, its market capitalization reflects the value of its net property, plant, and equipment as of June 30, 2021.

> set interim carbon reduction milestones, a new survey by S&P Global Commodity Insights shows. Two of those companies, Public Service Enterprise Group Inc. and Eversource Energy, have promised to phase out all their greenhouse gas emissions by 2030, rendering an interim target superfluous.
>
> .....
>
> Three of the nation's 30 largest utilities — CMS Energy, Dominion Energy Inc. and Duke Energy Corp. — this year expanded their climate targets to include all emissions connected with natural gas, including hard-to-measure Scope 3 emissions. Their moves came after pressure from shareholder groups, which insist that U.S. utilities must step up their game to help the world combat climate change."[49]

The utilities industry is responding to both public policy mandates and pressures from shareholders to take aggressive actions to reduce greenhouse gas emissions. Also, according to S&P, "[m]ore than half of global assets under management are now committed to net zero by 2050 through the Net Zero Asset Managers initiative which is part of the Glasgow Financial Alliance for Net Zero (GFANZ)."[50] So even where public policy measures do not require emission reductions, investors are pressuring companies to alter their business profiles.

[49] S&P Global, "Path to net-zero: Utility execs insist 'we can'," June 9, 2022, (https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/path-to-net-zero-utility-execs-insist-we-can-69901885).

[50] S&P Dow Jones Indices, "S&P Dow Jones Indices and S&P Global Sustainable1 Launch S&P Net Zero 2050 Carbon Budget Index Series," September 8, 2022, (https://www.prnewswire.com/news-releases/sp-dow-jones-indices-and-sp-global-sustainable1-launch-sp-net-zero-2050-carbon-budget-index-series-301620184.html).

d) Regulatory Response

In response to these developments, multiple regulators in the U.S. have opened dockets investigating the role that local gas distribution companies ("LDCs") will play during and after the Energy Transition. For example, in Massachusetts, the Office of the Attorney General ("AGO") petitioned the Department of Public Utilities ("DPU") in June 2020 to "initiate an investigation to assess the future of LDC operations and planning in light of the Commonwealth's legally binding statewide limit of net-zero greenhouse gas ('GHG') emissions by 2050."[51] The AGO acknowledged that "climate policy requirements will have profound impacts on gas distribution system management, operations, and rates. This will require the LDCs to make significant changes to their planning processes and business model."[52] Noting that as "electrification and decarbonization of heating increases, the Commonwealth's natural gas demand and usage from thermal heating requirements will decline substantially and could be near zero by 2050,"[53] the AGO raised several questions, including:

- "Should shareholders pay for the diversification and expansion of the LDC's business operations to meet GHG emission limits?"[54]
- "How much additional LDC investment is prudent in the next 30 years to ensure a safe and reliable gas distribution system, while statewide gas demand declines?"[55]
- "Should the Department [i.e., the DPU,] adjust GSEP [Gas System Enhancement Plan] planning and cost recovery to mitigate against potentially stranded infrastructure investment, as well as operations and maintenance expenses as a result of declining gas demand? Should accelerated depreciation or retirement of older leak prone infrastructure alternatives be considered?"[56]
- "Can the LDCs sustain their current business model as the Commonwealth takes affirmative action to electrify and decarbonize the heating sector? What does the LDC look like in 2030? 2040? 2050?"[57]

Additionally, the Public Utilities Commission of the State of Colorado ("Colorado PUC") opened a proceeding in 2020 to "serve as a repository for presentations, comments, and other materials

[51] Massachusetts Docket D.P.U. 20-80, Petition of the Office of the Attorney General, June 4, 2020, at 1.
[52] *Id.*, at 2.
[53] *Id.*, at 7.
[54] *Id.*, at 12.
[55] *Id.*, at 13.
[56] *Id.*, at 14.
[57] *Id.*, at 15-16.

relating to the Commission's general investigation of retail natural gas industry greenhouse gas emissions in light of the statewide greenhouse gas emission reduction goals."[58] The Colorado PUC specifically noted that:

> *Potential changes to the business model or scale of usage are of great consequence to the Commission in ensuring effective regulation of the natural gas sector. The Commission is responsible for regulation of several aspects of the retail natural gas industry in Colorado including rate setting, system safety and integrity riders, demand-side management programs, reliability of service, and gas pipeline safety. This market uncertainty and the relatively short timeline to make significant progress on the statutory greenhouse gas emission reduction goals makes it important for the Commission to obtain more information about potential impacts to utility systems and how those impacts may affect utility investments and the rates utilities charge Colorado customers.*[59]

Regulators in California opened a similar proceeding in January 2020, finding:

> *With respect to past events, several operational issues in Southern California prompt the Commission to reconsider the reliability and compliance standards for gas public utilities. Over the next 25 years, state and municipal laws concerning greenhouse gas emissions will result in the replacement of gas-fueled technologies and, in turn, reduce the demand for natural gas.*
>
> *Thus, in order to ensure safe and reliable natural gas service at just and reasonable rates in California, the Commission will (1) develop and adopt updated reliability standards that reflect the current and prospective operational challenges to gas system operators; (2) determine the regulatory changes necessary to improve the coordination between gas utilities and gas-fired electric generators; and (3) implement a long-term planning strategy to manage the state's transition away from natural gas-fueled technologies to meet California's decarbonization goals.*[60]

The New York Public Service Commission echoed these sentiments in March 2020, stating:

> *Recent developments have challenged conventional approaches to gas system planning. These developments include, but are not limited to, recent and current instances of supply/demand imbalance, the emergence of viable, less-traditional and increasingly*

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58 Colorado Proceeding No. 20M-0439G, Decision No. C20-0770, "Decision Opening Repository Proceeding; Scheduling Commissioners' Information Meeting; and Designating Hearing Commissioner," Adopted October 7, 2020, at 1.

59 *Id.*, at 2-3.

60 California Docket R.20-01-007, "Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning," January 16, 2020.

> *cleaner alternative solutions for demand and supply, the controversy and uncertainty associated with major gas infrastructure decisions, and the CLCPA's establishment of state policy directions. All the while, continued investment in gas infrastructure has significant long term financial implications for customers. The current approach to gas system planning poses risks of incomplete alignment with CLCPA, sub-optimal consideration of alternatives and timeframe, increased risk and cost to consumers, and unsatisfactory provision of service and solutions for those same consumers. To align with these policies and to recognize the emergence of potentially viable alternatives to gas infrastructure, gas planning must explicitly take account of the likely useful life of all alternatives, and of the resulting cost and risk implications.*[61]

Of course, the OEB is not bound by the findings of utility regulators in Massachusetts, Colorado, California, or New York. However, these proceedings illuminate the degree to which the operating environment for gas distribution utilities has changed. Within the last two years, multiple regulators have determined that it is necessary to examine the future of gas utilities. Further, these proceedings illustrate the degree to which the Energy Transition affects gas utilities' business risks today, as investors must consider that the long-term prospects of the industry have changed. Even if these impacts take years to unfold, investors take these factors into account today. One sign of this development is the significant upward shift in betas for gas utilities (electrics are also affected), as discussed in a subsequent section.

2. Enbridge Developments

EGI, as a natural gas distributor, has been and will continue to be affected by the Energy Transition. In fact, the Company has already taken a variety of steps to position itself in response to ESG-focused government policies and investors. For example, in November 2020, EGI's parent company, Enbridge Inc. ("Enbridge") committed to achieving net zero GHG emissions by 2050, with an interim target of reducing the intensity of its GHG emissions by 35% relative to 2018 levels by 2030.[62] Beginning in 2021, Enbridge's executive and staff compensation is tied to the Company's progress towards its emissions targets.[63]

Further, the Company's access to capital is becoming increasingly intertwined with its ability to meet ESG goals. In February 2021, Enbridge entered a three-year syndicated Sustainability Linked Credit Facility for $1.0 billion, which allows Enbridge to reduce its borrowing costs if it achieves certain ESG

61 New York Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, Order Instituting Proceeding, March 19, 2020, at 6-7.
62 Enbridge Inc., "Net Zero by 2050: Pathways to Reducing Our Emissions," at 2.
63 *Id.*, at 11.

goals.[64] Enbridge was also among the first companies in North America to issue a Sustainability-Linked Bond ("SLB") with a $1.0 billion, 12-year term 2.50% issuance in June 2021.[65] Enbridge estimated that this bond issuance received a 5-basis point "greenium" (i.e., discount relative to the estimated interest rate of a regular debt issuance from Enbridge at that time) because the interest rate was linked to Enbridge's ability to achieve certain emissions and inclusion targets.[66] However, Concentric notes that this SLB issuance includes asymmetrical risks and rewards. While Enbridge benefits from the estimated 5-basis point "greenium," the SLB issuance also includes a 50-basis point penalty if Enbridge fails to meet the GHG emission reduction milestones.[67]

Enbridge issued a second SLB in September 2021 and estimated that the "greenium" doubled to 10-basis points.[68] Bond analysts have noted that such premiums are increasingly common among green bond issuances as investor demand far outpaces supply.[69] Average oversubscription on green bonds issued in U.S. dollars was 4.7x in the first half of 2021, as compared to just 2.5x for equivalent non-green debt issuances.[70]

Equity investors have taken note of Enbridge's ESG efforts. For example, one CIBC analyst noted that the Company's efforts may reduce the "ESG discount" on its stock:

> *While it will take some time to develop, we think meaningful participation in energy transition projects could be a key catalyst to reducing the ESG discount in energy infrastructure share valuations. To this end the company announced an MOU for a carbon capture development partnership, Cross Carbon Ventures (CCV), with Svante Inc, Cross River Infrastructure Partners and OTS Ltd to explore carbon capture projects. This is one of many areas the company is looking at in order to invest in the energy transition, in addition to the existing renewable energy business, and RNG. It is also continuing the development of the solar self-power program in both Liquids Pipelines and Gas Transmission, with three facilities in operation and four more under construction.*[71]

In July 2021, the OEB issued an order on the Company's Integrated Resource Planning ("IRP") proposal. Generally, the IRP provides a planning process that enables the Company to evaluate,

64 Enbridge Inc., "Enbridge Reports Strong 2020 Financial Results," February 12, 2021, https://www.enbridge.com/media-center/news/details?id=123663.
65 S&P Capital IQ Pro, "Enbridge Closes $1B Sustainability-Linked Bond Financing," June 29, 2021.
66 Bloomberg News, "Enbridge Doubles 'Greenium' with Canadian SLB Sale," September 17, 2021.
67 Enbridge Inc., Form 424B5 Prospectus Supplement, June 24, 2021, at 2.
68 Bloomberg News, "Enbridge Doubles 'Greenium' with Canadian SLB Sale," September 17, 2021.
69 S&P Capital IQ Pro, "Green Bond 'Greenium' is Evident Globally, Especially Strong for US Dollar Debt," September 15, 2021.
70 *Ibid*.
71 CIBC Equity Research, "Enbridge Inc: Solid Quarter and Capital Outlook Building," August 2, 2021.

compare and implement supply-side (e.g., compressed natural gas, renewable natural gas, peaking supply) and demand-side (e.g., energy efficiency and demand response) options for meeting system energy needs. However, the OEB also identified three specific risks that accompany the first-generation IRP framework it approved:

- Plan Accuracy: The OEB noted that the IRP assessment process "should result in more prudent and effective integrated resource system planning,"[72] which should reduce the risk that it does not accurately identify superior alternatives to facility projects. However, the OEB also noted that it "retains the authority to deny recovery of costs if it determines that Enbridge Gas was not prudent in considering alternatives, and Enbridge Gas acknowledged this possibility."[73]

- Success of IRP Plan Implementation: The OEB indicated that Enbridge Gas "may be at risk for recovery of some portion of IRP investments that are deemed imprudent," and that "there may be a greater degree of performance and cost risk associated with IRPAs [IRP alternatives] and IRP Plans in comparison with facility projects" because the Company has "less experience in addressing system constraints using IRPAs like geotargeted DSM or demand response, and these IRPAs depend on consumer behaviour for success."[74]

- Stranded Assets: The OEB found that the "risk of stranded assets is a concern for both infrastructure builds and for IRPAs. The OEB has limited experience with the treatment of stranded assets. The examination of the treatment of stranding of assets in other jurisdictions and the findings of the Technical Working Group on this topic might help provide a better understanding of stranded assets and options to allocate the costs between Enbridge Gas and its customers."[75]

Absent the Energy Transition, EGI would not be subject to these same risks, which are only partly mitigated by the OEB's approval of the Company's plans.

3. Viability of Alternatives

Achieving net zero GHG emissions by any date is a tremendous challenge for any natural gas distribution utility, Enbridge Gas included. There are two commonly identified fuel alternatives for gas distribution utilities to comply with net zero targets: hydrogen and renewable natural gas

[72] EB-2020-0091, Decision and Order, July 22, 2021, at 61.
[73] *Ibid*.
[74] *Ibid*.
[75] *Id*., at 62.

("RNG"). However, pursuing those pathways carries risk from an investor's perspective. This section discusses the various operational, technical, and financial concerns that investors have noted with large-scale moves towards hydrogen and RNG.

a) Hydrogen

The Company recently proposed, and the OEB recently approved, a pilot project involving the injection of a controlled quantity of hydrogen into an isolated portion of its distribution system in Markham, Ontario. Enbridge Gas undertook the project, referred to as the Low Carbon Energy Project ("LCEP"), as a first step in gaining experience with hydrogen injection. Successful implementation of the LCEP will allow the Company to pursue additional, larger scale hydrogen blending in other portions of its system.[76] Three cost categories were identified in the LCEP proceeding:

- Consumption Impact: The heating value of hydrogen is approximately one third that of natural gas. Therefore, customers receiving blended gas under the LCEP pilot program would consume more gas than if they received natural gas, all else equal.[77] The Company bills volumetrically; therefore, increased consumption would result in increased bills for customers.
- Facilities Impact: The Company incurred costs isolating a portion of its distribution system and constructing a hydrogen blending station.[78]
- Commodity Impact: The price of hydrogen may differ from the price of traditional natural gas. In the case of the LCEP pilot program, the Company acquired hydrogen from 2562961 Ontario Ltd for a price that tracked the market price of traditional natural gas.[79]

As a pilot program, the LCEP is in its early stages, and the Company is providing updates regarding its experience with the project as part of this rebasing application. The Company has also committed to following up with the OEB and other interested parties after five years of actual experience regarding several aspects of the project, including its costs, stakeholder communications, and recommended next steps.[80] Therefore, it is premature to draw conclusions regarding the viability of

[76] EB-2019-0294, Leave to Construct Application: Low Carbon Energy Project, December 20, 2019, at 1-4.
[77] EB-2019-0294, Decision and Order, October 29, 2020, at 21.
[78] *Ibid*.
[79] *Ibid*.
[80] *Id.*, at 12-14.

hydrogen in the Company's system on a broader scale at this time because the results of the LCEP pilot program are currently uncertain.

However, it is precisely that uncertainty that creates risk for investors. Further, it is an uncertainty that was not as meaningful at the time of the Company's previous equity thickness proceedings (i.e., 2012). At that time, whether natural gas distribution utilities could remake their systems to support hydrogen was not a topic of question. In contrast, today, analysts such as Wells Fargo are noting:

> *Even with the steps being taken to decarbonize, it is yet to be seen whether the LDC decarbonization story will ultimately resonate with ESG-minded investors. We expect the answer will be influenced by (1) the pace at which LDCs clean-up the gas molecules and reduce overall emissions, which likely requires technological advancements to drive down the costs of RNG and hydrogen and (2) the level of local policy support.*[81]

Credit rating agencies are cautious regarding the near-term prospects for hydrogen. For example, S&P noted that hydrogen "faces many hurdles" and that a "truly hydrogen-based economy, in which hydrogen, not gas, is used to heat buildings and balance the power grid, for example, therefore appears out of reach, at least before 2030."[82] S&P elaborated:

> *S&P Global Ratings believes hydrogen can push the energy transition forward, but this would require coordinated policy, lower hydrogen production costs, and massive growth of renewables. Energy transitions typically take decades. A Hydrogen Council report suggests that hydrogen could account for 15% of global primary energy supply by 2050. Yet the huge cost of producing it is a potential stumbling block. It's more likely that hydrogen developments this decade will be for the production of commercial transport vehicles, assuming fuel-cell costs decline.*[83]

S&P continued:

> *Hydrogen-based heating in buildings, if supported by policy, may likely only be realized well past 2030. Hydrogen boilers or fuel cells can be a cost-competitive low-carbon fuel alternative to heat pumps, at an all-in cost of $4/kg-$5/kg. However, we currently see many hurdles. First, electric heat pumps are already an available cost-competitive option, and are easier to install, not least for new buildings. Second, switching to hydrogen-based boilers requires a major overhaul of the gas network infrastructure. Upgrading grids to allow for hydrogen distribution would require a concurrent rollout of hydrogen boilers (or fuel cells) to all consumers affected by the switch from gas. A prerequisite is a new hydrogen transmission network to which to connect, since many*

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81 Wells Fargo Securities, "Gas Utility 2021 Outlook," January 6, 2021, at 4.
82 S&P Global Ratings, "How Hydrogen Can Fuel The Energy Transition," November 19, 2020, at 1 and 3.
83 *Id.*, at 1.

> *applications would still rely on gas for decades to come. Affordability is a key consideration because both hydrogen and fuel cells are 1.5x-2.5x more expensive than conventional gas-based household heating, at least in Northern Europe according to a Hydrogen Council report (January 2020).*[84]

Further, panelists convened by Columbia University's Center on Global Energy Policy noted that modifying gas pipelines to carry hydrogen has "generated concern among climate activists" due to fears that hydrogen will prolong fossil fuel use.[85] The panelists indicated that these concerns may mean that operators "seeking to build or adapt infrastructure to carry hydrogen and other low-carbon fuels may face challenges accessing capital."[86]

Therefore, we conclude that while hydrogen may offer a potential pathway for the Company through the Energy Transition, investors perceive significant risk to that pathway because of its operational, technical, and financial challenges.

b) Renewable Natural Gas

Like hydrogen, RNG may offer Enbridge Gas a pathway through the Energy Transition. Another large Canadian natural gas distribution utility, FortisBC Energy Inc. ("FEI"), recently proposed providing all new residential customers with 100 percent RNG in an effort to comply with strict municipal building codes.[87] As part of its application, FEI noted that "federal, provincial and municipal regulations and policies focused on reducing GHG emissions threaten the long-term viability of the gas delivery system."[88]

Concentric is unable to draw conclusions regarding the long-term viability of RNG at this time. However, academics have noted a variety of financial, technical, and other barriers to widespread adoption of RNG. For example, one California study found that "relatively inexpensive RNG (for example, biomethane from landfills and wastes) is limited and cannot alone reduce the GHG intensity of pipeline gas enough."[89] The study went on to conclude that, after factoring in the more expensive forms of gas, "the commodity cost of blended pipeline gas is more than four to seven times that of

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84 S&P Global Ratings, "How Hydrogen Can Fuel The Energy Transition," November 19, 2020, at 10.
85 S&P Capital IQ Pro, "Financing of Hydrogen, Low-Carbon Fuel Pipelines Faces Hurdles in ESG Era," October 4, 2021.
86 *Ibid*.
87 British Columbia Utilities Commission, Biomethane Energy Recovery Charge Rate Methodology and Comprehensive Review of a Revised Renewable Gas Program, Exhibit B-11, filed December 17, 2021, at 1-2.
88 *Id*., at 1.
89 California Energy Commission, Energy Research and Development Division, "The Challenge of Retail Gas in California's Low-Carbon Future," April 2020, at 69.

natural gas today."[90] Another California study noted that "RNG faces large technical obstacles."[91] A study conducted by Washington State University's Energy Program indicated that "adequate opportunities exist for RNG production equivalent to 3 percent to 5 percent of current natural gas consumption."[92] Oregon's Department of Energy identified 13 barriers to using RNG to reduce GHG emissions, including financial barriers (i.e., difficulties attracting capital), information barriers (i.e., due to unfamiliarity with the technology), market barriers (i.e., lack of vehicles and infrastructure), and policy barriers (i.e., Oregon-specific rules and statutes impeding RNG development).[93]

These preliminary studies regarding the viability of RNG do not necessarily mean that RNG is not a viable long-term solution. However, from an investor's perspective, pursuing such an uncertain pathway intrinsically carries risk. Further, as with the hydrogen discussion above, it is a risk that was not as meaningful at the time of the Company's previous equity thickness proceedings (i.e., 2012).

4. Risk Implications

The Energy Transition substantially affects nearly every aspect of the Company's business, from its growth prospects, to the capital projects it pursues, to its fundamental ability to offer investors the opportunity to earn a fair return on, and of, invested capital. Even though the Energy Transition will play out over many decades, it is now underway and it is materially increasing the Company's risk profile because of the long expected lives of most natural gas utility investments. For example, as Brattle recently noted:

> *The transition will affect gas companies' growth opportunities, cost recovery, and capital attraction. In the past decade, gas utility capital expenditures have grown by around double the rate of water and electric utilities' spending, largely driven by safety and reliability. Utilities will need to recover their costs from a changing – and possibly shrinking – customer base. With energy and environmental policy targets rapidly approaching, gas utilities need to decide today how best to invest capital in long-lived assets and avoid stranded asset risks. Heightened perceptions of business risk are increasing financing costs for gas utilities.*[94]

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90 *Ibid*.
91 *Id*., at 33.
92 Washington State University Energy Program, "Promoting Renewable Natural Gas in Washington State: A Report to the Washington State Legislature," December 2018, at 1.
93 Oregon Department of Energy, "Biogas and Renewable Natural Gas Inventory SB334 (2017): 2018 Report to the Oregon Legislature," September 2018, at 43-45.
94 The Brattle Group, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 9.

Similarly, Moody's observed:

> *Although natural gas transportation and distribution companies continue to provide generally safe, reliable service while reducing emissions, there are ESG reputational risks associated with any hydrocarbon-based business, including financial governance policy risks around a higher cost of capital and lower asset returns over a multi-decade time horizon. Events like the August 2020 Baltimore explosion exact heavy social costs related to customer relations and public health and safety. Financial risks also stem from the likelihood of construction delays and greenfield project budget overruns, potential cancellations, regulatory fines and penalties for accidents, increasing debt obligations associated with gas infrastructure expansion and potential write-offs of stranded assets as the carbon transition progresses.*[95]

McKinsey examined the future for gas utilities under four alternative scenarios, and concluded:

> *These four scenarios, then, envision a wide range of outcomes. What's notable is that in three of them, natural-gas demand declines substantially. The only scenario with stable demand is the one in which renewable natural gas is developed—and this is by no means a sure thing. Clearly, gas LDCs need to prepare.*[96]

The sub-sections below discuss several specific ways in which the Company's risk profile has changed because of the Energy Transition.

a) Volumetric Risk

The opposition to natural gas threatens the Company's sales volumes through franchise renewal challenges, potential net-zero mandates, and increasingly stringent building codes or bans on new gas hook-ups. The Company has deferral and variance accounts that provide a degree of short-term insulation from this risk (insulation that will improve if the Company's SFV rate design proposal is adopted). However, in the long-term, investors are concerned that increasing costs recovered over declining volumes may create a "death spiral" scenario. As Brattle notes:

> *As states pursue degasification policies and homes convert to electric heating, utilities risk losing customers and load. Nationally, electric heating is outpacing gas heating adoption. Technology mandates and policy further accelerate the problem. Utilities will likely continue investing in their existing system for safety and reliability but need to*

95 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 2.

96 McKinsey & Company, "Are US gas utilities nearing the end of their golden age?" September 2018, (https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/are-us-gas-utilities-nearing-the-end-of-their-golden-age).

> *recover those costs from a shrinking customer base. This puts remaining customers at risk, a "death spiral" trend pushing more customers to electrification. Up to $150–180 billion of gas distribution assets could be underrecovered as a result of the transition. This spiral will increase customer costs and increase energy burdens, especially for low-income and vulnerable populations.*[97]

Brattle also observes that the "transition will not occur at the same pace or magnitude across customer classes, which compounds cost recovery risks."[98]

Therefore, as discussed more fully in the volumetric risk section below, we conclude that the Energy Transition increases the Company's volumetric risk.

b) Operational Risk

Increasing opposition to natural gas makes it more difficult, costly, and time-intensive for natural gas distribution utilities such as the Company to construct and permit new facilities. Depending on the extent of this opposition, shareholders may bear increasing amounts of operational risks or cost overruns as critical infrastructure projects are delayed. As Moody's notes:

> *Long-term challenges to natural gas infrastructure are increasing. Natural gas is increasingly being called into question over environmental and greenhouse gas (GHG) emissions. Permitting difficulties related to new pipelines, local government mandates favoring electrification and state carbon reduction commitments raise operating risks and cost of capital.*[99]

This increasing opposition represents a marked change from the operating environment in 2012 (i.e., the Company's previous equity thickness proceedings). In 2020, the New York Times noted that oil and gas pipelines are "being challenged as never before as protests spread, economics shift, environmentalists mount increasingly sophisticated legal attacks and more states seek to reduce their use of fossil fuels to address climate change."[100] Setbacks experienced by the Atlantic Coast Pipeline, the Dakota Access Pipeline, and the Keystone XL oil pipeline were specifically cited as evidence that heightened opposition "represents a break from the past decade, when energy companies laid down tens of thousands of miles of new pipelines."[101] It was further noted that, even

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97 Brattle, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 11.

98 *Id*., at 15.

99 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.

100 New York Times, "Is This the End of New Pipelines?" July 8, 2020, https://www.nytimes.com/2020/07/08/climate/dakota-access-keystone-atlantic-pipelines.html.

101 *Ibid*.

when projects are successful, the increased opposition results in costly delays. In 2009, gas pipelines took an average of 386 days to receive federal approval to commence construction. That increased to 587 days in 2018.[102] Joan Dreskin, chief counsel to the Interstate Natural Gas Association of America, added that "[b]uilding energy infrastructure today is certainly more challenging that it was five, 10, or 15 years ago."[103] Brandon Barnes, an analyst at Bloomberg Intelligence, opined that the "Dakota Access and Atlantic Coast pipes encapsulate the last few years of a trend we've watched: the dramatic expansion of using regulatory obligations to hurt infrastructure projects in the courts."[104]

While the New York Times specifically highlighted difficulties faced by the Atlantic Coast Pipeline, the Dakota Access Pipeline, and the Keystone XL oil pipeline, Moody's identified four additional examples (for a total of seven) of legal challenges to pipeline development in 2020, as summarized in Figure 8.

102 *Ibid*.
103 Reuters, "End Of An Era? Series of U.S. Setbacks Bodes Ill For Big Oil, Gas Pipeline Projects," July 8, 2020, https://www.reuters.com/article/us-usa-pipelines/end-of-an-era-series-of-u-s-setbacks-bodes-ill-for-big-oil-gas-pipeline-projects-idUSKBN2491M5
104 *Ibid*.

Figure 8: Moody's List of Recently Derailed or At-Risk Pipeline Investments[105]

Pipeline	Date	Description of Event
PennEast Pipeline	2/20/2020 (*At Risk*)	PennEast filed an appeal with the Supreme Court of the US, challenging a lower-court ruling that prevents the project from condemning New Jersey state land for pipeline construction.
Constitution Project	2/24/2020 (*Cancelled*)	Williams Companies, Inc. (Baa3 stable) and partners halted investment in the proposed pipeline, citing risk adjusted return prospects no longer supported development.
Frontier Oil Sands Project	2/24/2020 (*Cancelled*)	Teck Resources Limited (Baa3 stable) withdrew its regulatory application for the Frontier oil sands project in Alberta, Canada due to the broader Canadian national discussion on energy development, indigenous reconciliation and climate change. This resulted in a C$1.1 billion write down for Teck.
Keystone XL	3/31/2020 (*At Risk*)	Negative outlook for TransCanada Pipelines Limited (Baa1 negative) reflects the very high level of execution risk related to environmental, social and governance factors associated with the Keystone XL pipeline project, which parent TC Energy Corporation (Baa2 negative) has decided to move forward on.
Northeast Supply Enhancement Project	5/14/2020 (*Withdrawn*)	The New York State Department of Environmental Conservation denies authorization of a water permit to Williams Companies, Inc.'s (Baa3 stable) NESE natural gas pipeline, due to the project's failure to meet water quality standards.
Atlantic Coast Pipeline	7/5/2020 (*Cancelled*)	Atlantic Coast Pipeline canceled, resulting in an approximate $4.8 billion write-off for Dominion Energy Inc. (Baa2 stable) and Duke Energy Corporation (Baa1 stable).
Mountain Valley Pipeline	9/2020 (*At Risk*)	Received re-authorizations for two environmental permits (i.e., stream crossing and biological opinion). MVP is seeking additional federal approval to restart construction that has been halted for about one year. We estimate that the pipeline is nearly three years behind schedule and is roughly $2.0 billion over-budget.

Further, subsequent to the Moody's report, the U.S Circuit Court of Appeals for the D.C District of Columbia vacated a permit order for the 65-mile Spire STL Pipeline. The Court ruled that the Federal Energy Regulatory Commission ("FERC") did not seriously consider arguments that challenged the

[105] Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 3.

need for the project. FERC had authorized the interstate pipeline in 2018 and construction began in 2019.[106]

While the increase in regulatory and permitting challenges is most pronounced for natural gas and oil pipelines, natural gas distribution utilities are affected as well. For example, National Grid, one of the largest LDCs in the Northeast, recently noted:

> *Despite the steps taken by National Grid to implement the Distributed Infrastructure Solution, the solution faces risks to successful implementation. The distributed infrastructure projects face permitting delays and the risk of not obtaining needed regulatory approvals. The incremental demand-side programs face implementation risks in terms of uncertainty of regulatory approval and funding and uncertainty of meeting targets given the ambitious levels of these programs' demand reduction targets, and the unpredictable nature of customer participation.*
>
> *In particular, while only a few permits remain for the LNG Vaporization Project, the Company has experienced substantial delays in obtaining those permits and the LNG Vaporization Project is key to being able to solve for the Demand-Supply Gap in the near future. Similarly, the ExC project, which Iroquois submitted to FERC in January 2020, is still awaiting approval after a year and a half, and Iroquois is now not expected to ascertain whether it will receive all necessary permits and approvals until 2022. With the implementation lags and other risks inherent in achieving the savings under the DSM programs and the still evolving external work around Net Zero, it is critically important that these distributed infrastructure projects move forward as quickly as possible to meet the growing demands of Downstate NY.*[107]

Enbridge Gas has not been immune to the industry-wide trend of increased opposition to and scrutiny of natural gas distribution projects. For example:

- On November 1, 2019, the Company filed a leave to construct application to construct approximately 10.2 kilometers of natural gas transmission pipeline and associated facilities in the City of Hamilton.[108] While Enbridge Gas ultimately withdrew its application, over a dozen parties intervened in the proceeding, issuing the Company over 800 interrogatories.
- On March 2, 2021, the Company filed a leave to construct application to replace approximately 19.8 kilometers of natural gas pipeline and associated facilities in the City of

106 S&P Capital IQ, "DC Circuit Knock down FERC certificate for Spire STL gas pipeline," June 22, 2021.
107 National Grid, "Natural Gas Long-Term Capacity – Second Supplemental Report for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY")," June 2021, at 18.
108 EB-2019-0159, Decision on Issues List, March 6, 2020.

Ottawa to address integrity issues.[109] Energy Probe Research Foundation, Environmental Defence Canada Inc., Federation of Rental Housing Providers of Ontario, Industrial Gas Users Association, Pollution Probe, School Energy Coalition, and the City of Ottawa were granted intervenor status. Many of these intervenors recommended that the OEB reject EGI's application. For example, the City of Ottawa noted that, in "the current state of flux," rejecting EGI's proposal "would avoid a large investment which may not be required as events around the energy transition unfold."[110] Pollution Probe was even more definitive, stating "[e]very time a new pipeline is built it increases the likelihood for stranded assets and the time to consider those issue [sic] and risk are during this Leave to Construct proceeding. It is no longer acceptable for excess pipelines to be built with the thought that they will eventually be used by future customers and load growth. Those days are gone under a Net Zero future."[111] In May 2022, the OEB rejected the application, citing concerns that EGI had not demonstrated that replacement of this segment of pipeline was necessary or whether other alternatives might be more economical and cost effective. The OEB's decision specifically highlighted the City of Ottawa's position that "… provided that integrity issues are not an immediate significant concern," the proposed St. Laurent replacement project is not consistent with the overall strategic direction the City is taking in its Energy Evolution policy.[112]

- On September 10, 2021, the Company filed a leave to construct application to construct a natural gas pipeline and associated facilities in the Municipality of Greenstone (the "Greenstone Pipeline Project").[113] While the Company estimated the costs of the Greenstone Pipeline Project to be approximately $25.8 million, offsetting those costs was a contribution in aid of construction of approximately $20.3 million from Greenstone Gold Mine LP.[114] Nonetheless, the Greenstone Pipeline Project faced significant opposition from intervenors such as Pollution Probe and Environmental Defence Canada.
- On March 21, 2022 and June 10, 2022, Enbridge Gas filed leave to construct applications for the Dawn – Corunna Replacement Project[115] and the Panhandle Regional Expansion

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109 EB-2020-0293, Staff Submission, March 24, 2022, at 1.
110 EB-2020-0293, City of Ottawa Letter Summation, March 24, 2022, at 3.
111 EB-2020-0293, Pollution Probe Argument, March 24, 2022, at 3.
112 EB-2020-0293, Decision and Order, May 3, 2022, at 13.
113 EB-2021-0205, Decision and Order, March 17, 2022, at 1.
114 *Id.*, at 8.
115 EB-2022-0086.

Project,[116] respectively. Intervenors have challenged those projects, in part, on concerns about long-lived assets becoming stranded because of the declining use of fossil fuels, including natural gas.[117]

The above-referenced leave to construct applications are individual data points and do not represent a comprehensive review of all of the Company's filings since 2012. However, they do serve as case studies illustrating that the Company's experience is consistent with the broader natural gas industry. Thus, we conclude that the Energy Transition has significantly increased the Company's operational risk by increasing the possibility that it will face challenges and delays in siting, permitting, and constructing facilities.

c) Stranded Asset Risk

Another risk of the Energy Transition is that a significant portion of the Company's gas plant investments could become stranded. Generally, the term "stranded asset" refers to an investment that becomes no longer used or useful in the provision of service to customers before the end of its depreciable life. At that point in time, the undepreciated value of the asset (i.e., its net book value) is "stranded" with costs to be borne by either investors or customers. Gas distribution utilities such as the Company generally depreciate capital invested in their systems over the expected useful life of the underlying physical property, which is often many decades. Therefore, the Energy Transition creates stranded asset risk for the Company by introducing the possibility that significant portions of the Company's property will cease being used or useful before it is fully depreciated. In fact, the OEB recently acknowledged the risk of stranded assets when evaluating the Company's IRP proposal.[118]

The potential for stranded assets was not a material concern for the Company in 2012 (i.e., the time of its previous equity thickness proceedings). As S&P notes, "[s]tranded costs have not up until now been an issue for gas local distribution companies."[119] S&P observes, however, that concerns about stranded assets have spiked recently:

> *While new pipelines have faced fierce opposition from environmental activists and local communities since the initial shale gas development boom and the pace of new projects*

[116] EB-2022-0157.
[117] See, e.g., EB-2022-0088, Pollution Probe Submission, September 23, 2022, at 4; and Environmental Defence Submission, at 2-3. See also, e.g., EB-2022-0157, Interrogatories of Environmental Defence (September 1, 2022), at 4-6.
[118] EB-2020-0091, Decision and Order, July 22, 2021, at 62.
[119] S&P Global Market Intelligence, "RRA Regulatory Focus: 2021 Energy Utility Regulatory Focus," February 11, 2021, at 10.

> *has declined in recent years, the specter of stranded assets did not really emerge for existing gas pipelines and the gas LDCs until recently when the zero-carbon movement picked up steam.*[120]

S&P concludes that "[c]hallenges with respect to addressing stranded costs arising from the latest energy transition are likely to continue and intensify in 2021 and beyond." [121]

Investors are acutely aware of the increase in stranded asset risk and expect utilities to work with their regulators to mitigate this risk. For example, as Moody's notes:

> *Supportive regulation likely to help companies avoid stranded asset risk. State regulators and utilities will likely collaborate to avoid stranded asset risk as exposure to such risks increases. Adjusting the useful life of assets, accelerating depreciation rates of existing assets and securitizing the asset value of at-risk property, plant and equipment help ensure full investment recovery and support long term utility credit quality.*[122]

Like Moody's, Concentric expects that the OEB will approve measures to mitigate the Company's stranded asset risk, up to and potentially including the acceleration of depreciation rates as appropriate. However, we note that this is a "downside-only" area for the Company. In other words, while regulatory changes (e.g., the acceleration of depreciation rates) may improve the Company's prospects of recovering its investment, there remains a chance that investors are not able to earn a full "return of" their invested capital. There is no scenario under which investors face less risk than before the advent of the Energy Transition. Further, all else equal, accelerating depreciation rates will increase rate pressure for customers, rendering natural gas less competitive against alternative energy sources, mainly electricity. Therefore, while we expect the OEB and the Company will work together to mitigate stranded asset risks, we conclude that stranded asset risks have increased since 2012.

d) *Going Concern*

Depending on the specific pathways ultimately taken by the Canadian federal government and the province of Ontario, the Company may no longer be able to engage in the provision of its main business enterprise: the distribution of natural gas.

120 *Ibid*.
121 *Id*., at 11.
122 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.

Consultants for the Attorney General of Rhode Island, in recommending that the State of Rhode Island Division of Public Utilities and Carriers condition the sale of Narragansett Electric (the largest electric and gas LDC in Rhode Island) on the limitation of capital expenditures, summarized the "going concern" issue as follows:

> *[L]egal and societal pressures are building to substantially reduce fossil fuel consumption. Moreover, policymakers are becoming increasingly concerned about methane emission in both gas production and distribution activities. In addition, the costs associated with replacing obsolescent natural gas distribution systems have increased substantially over the past decade, as many distribution utilities have accelerated their system replacement efforts. Finally, electric alternatives to natural gas heating (e.g., "mini-splits") are becoming more efficient and cost competitive. The economic risks to gas distribution service are both environmental and economic. Having a monopoly on natural gas distribution service does not insulate the utility from competition with alternative energy sources.* ***In that context, it is not clear that natural gas distribution systems serving residential and smaller commercial customers have a long-term future****.*[123]

The future for the gas distribution business is far from certain, and the Company is taking a variety of steps to position itself in response to the Energy Transition. As noted above, the Energy Transition creates both risks and opportunities for gas utilities such Enbridge Gas. For example, the Company's previously-discussed IRP may provide rate base IRPAs. However, there remains substantial risk from an investor's perspective. For example, Wells Fargo stated:

> *We had many conversations with investors this year regarding gas utilities place (or lack thereof) in a decarbonizing world and, from a similar but different angle, how the LDCs fit into the ESG picture. This conversation started in 2019, which saw the advent of the local ban on new gas hookups. The discussion heated up in the throes of the pandemic as (1) the LDC underperformance itself led investors to seek out explanations as to why with terminal value concerns coming up as one potential reason and (2) the green theme gained momentum with clean energy plays, such as NEE and ORSTED, topping the performance charts.*[124]

Wells Fargo's position has been echoed by a variety of equity and debt investors and industry participants. For example, Moody's noted that "[l]ong-term challenges to natural gas infrastructure

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123 Direct Testimony and Exhibits of Mark Ewen and Robert Knecht, Docket No. 21-09, November 8, 2021, at 23. ***Emphasis added***.

124 Wells Fargo Securities, "Gas Utility 2021 Outlook," January 6, 2021, at 3.

are increasing," which raises "operating risks and cost of capital."[125] As noted above, Brattle has stated that "gas utility business models face increasing risks as more states and locales challenge the long-run role natural gas could play in meeting climate and energy policy goals."[126] Additionally, as discussed in more detail below, S&P has observed that the "'electrification' movements in states like California, Massachusetts, New York and Washington are raising questions about the future of gas utilities in the U.S."[127]

From an investor's perspective, both short-term and long-term risk is important. If the Company's ability to operate as a going concern over the long-term is impeded because of changes in policy or investor sentiment, it will be difficult, if not impossible, for regulation to fully mitigate that risk for investors.

5. The European Case Study

Generally, the pace and status of the Energy Transition differs by region. Regions that are further along in the Energy Transition can serve as instructive examples of what is to come for regions that are further behind. Therefore, we have examined Europe's gas utilities, which operate in a region that is ahead of many others in the Energy Transition, as a case study in the future of Canadian gas utilities if the Energy Transition continues.

S&P observes that "Europe is ahead of many regions in energy transition, which increases longer-term business risks for the gas industry."[128] Specifically, S&P states:

> *Demand for natural gas in Europe is extremely unlikely to expand over the next decade. S&P Global Platts Analytics expects accumulated demand decline of 11.5 billion cubic metres (bcm) in 2020-2030. Although carbon dioxide emissions from gas are about 50% lower than those from coal, this is not enough to make gas compatible with Europe's decarbonization targets and with the EU Green Taxonomy.*[129]

125 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.

126 Brattle, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 9.

127 S&P Global Market Intelligence, "RRA Regulatory Focus: 2021 Energy Utility Regulatory Focus," February 11, 2021, at 10.

128 S&P Global Ratings, "As Europe's Gas Markets Slowly Stall, Gas Producers' and Utilities' Business Risks May Rise," November 16, 2020, at 1. We note that S&P's comments pre-date the war in Ukraine, which has increased the focus on European energy supply.

129 *Ibid*.

S&P further notes that, considering these limitations on growth, Europe's gas utilities will need to "reduce their financial leverage" (i.e., increase the equity ratio) to maintain their credit ratings despite "supportive and very predictable regulations." Specifically, S&P concludes:

> *At present, regulated gas transmission and distribution companies still benefit from supportive and very predictable regulations, which underpin their resilience. Despite this, we anticipate that they will need to reduce their financial leverage if they are to maintain ratings at the current level. There are limited growth prospects for gas infrastructure, and alternative growth paths, like diversifying into hydrogen, carry technological and regulatory uncertainties.*[130]

The path for Enbridge and other North American utilities may deviate from those in Europe, but the trends are likely to be comparable. As discussed in more detail in the next section, the Company has experienced, and is projected to continue experiencing, declining use per customer and declines in the number of new customers per year. Therefore, while the Company's present situation does not precisely mimic that of Europe's gas utilities, those utilities nonetheless serve as an instructive case study.

6. Conclusions

The Energy Transition represents a radical transformation of the long-term risk environment for Enbridge Gas relative to 2012 (i.e., the time of OEB's last equity thickness assessments for the Company). Since 2012, both the Canadian federal government and the U.S. federal government committed to achieving net zero greenhouse gas emissions by 2050. The Trudeau administration imposed a carbon tax that is projected to hit $170 per metric tonne by 2030. Utilities with a collective market capitalization of several hundred billion dollars have similarly committed to achieving net zero emissions by 2050 or earlier. Investors collectively managing trillions of dollars of assets are also pursuing aggressive emission reduction targets. Dozens of municipalities in the Company's service territory have declared climate emergencies, and there have been several calls for the phase-out of gas in Ontario from home heating and electric generation.

Enbridge and Enbridge Gas are taking steps to actively position the companies in response to the Energy Transition. These steps include issuing SLBs that tie its cost of debt to its ability to achieve ESG goals; committing to net-zero emissions by 2050; and for Enbridge Gas investing in pilot projects for hydrogen, RNG, hybrid heating, IRPAs, and demand-side management more broadly. While these measures provide future growth pathways for the Company, they do not eliminate the substantial

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130 *Id.*, at 2.

increase in uncertainty created by the Energy Transition. Further, in the case of the SLB issuances, these measures directly link the cost of capital to the ability to achieve ESG goals.

Investors are increasingly recognizing the effect of the Energy Transition on gas LDCs. For example, Moody's has opined that "[l]ong-term challenges to natural gas infrastructure are increasing" and that "carbon reduction commitments raise operating risks and cost of capital."[131] Brattle noted that "gas utility business models face increasing risks as more states and locales challenge the long-run role natural gas could play in meeting climate and energy policy goals."[132] Wells Fargo observed that this represents "a stark change from 5+ years ago when LDCs were considered to offer more sustainable growth at a lower risk profile."[133]

We have identified a number of discrete ways in which the Energy Transition affects Enbridge Gas's business risk profile, including increasing the Company's volumetric risk and operational risk, creating transition risk and stranded asset risk, and even jeopardizing the Company's ability to continue operating as a going concern. We expect regulation to partially mitigate, but not eliminate, these risks. For example, accelerating depreciation rates and approving SFV rate design may reduce the Company's stranded asset risk and volumetric risk, respectively. However, in the context of the Energy Transition, these measures are defensive in nature. From an investor's perspective, there is still the risk that they may not work. In other words, there is no scenario under which the Company is less risky today than it was in 2012.

Finally, the Energy Transition affects the Company's business risk today despite its multi-decade time horizon because utility assets are long-lived. That is why utility regulators in Massachusetts, New York, California, and California opened dockets investigating the future of natural gas utilities. As Moody's recently observed:

> *Energy companies are pursuing emission reduction goals by emphasizing efficiencies, demand-side management and electrification – that is, the process of converting services and products that historically relied on fossil fuels (such as cooking stoves, heating systems and powertrains) to electric power. Occasional gas explosions in residential neighborhoods only heighten the political and social scrutiny on the sector and on the fuel's role in providing energy. These concerns increase risks for gas investments made today, given the long-lived nature of the assets and related environmental, social and governance (ESG) considerations, such as emissions levels,*

131 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.
132 Brattle, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 15.
133 Wells Fargo Securities, "Gas Utility 2021 Outlook," January 6, 2021, at 3.

public health and safety, corporate reputational risk, financial policies and the cost of capital over a multi-decade time horizon.[134]

[134] Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 2.

SECTION 4(b):
VOLUMETRIC RISK

Introduction

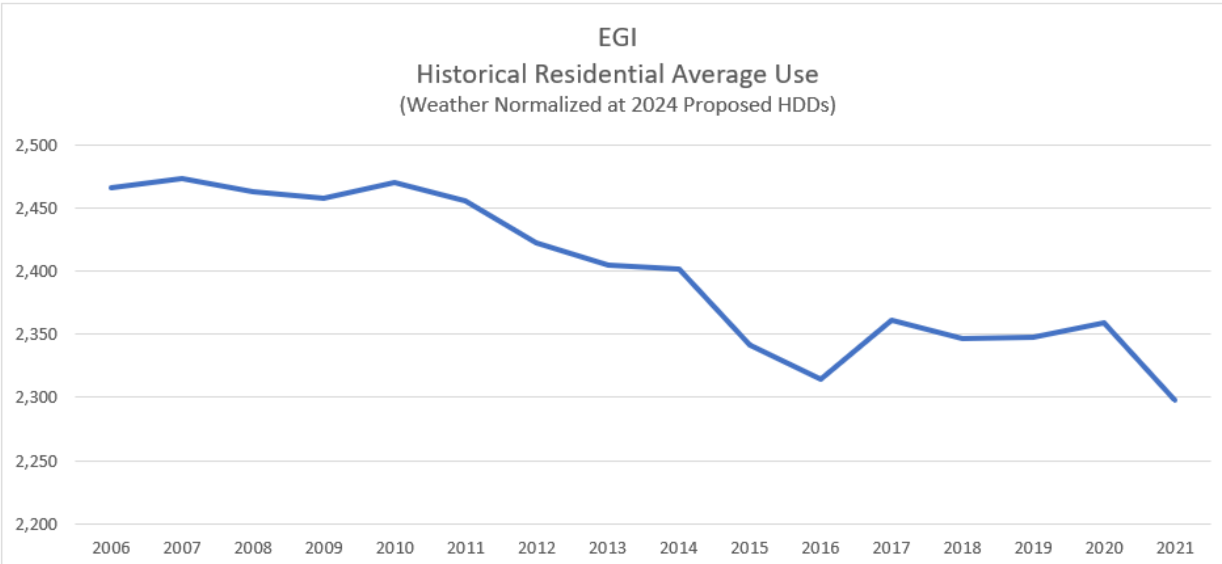
In EB-2011-0354, the OEB found that there was "no dispute that average use has declined and continues to do so."[135] However, the OEB determined that this development did not increase the Company's risk relative to 2007 (i.e., the period in which the OEB had previously examined the Company's equity thickness) for several reasons, including:

- Declines in use per customer are mitigated by customer additions.[136]
- Shale gas strengthens the competitive position of natural gas relative to alternative fuel sources such as oil and electricity.[137]
- Regulatory mechanisms such as rate design and deferral and variance accounts protect the Company's revenues from declines in its sales volumes.[138]
- A "death spiral" is unlikely from declines in average use per customer because declining usage also decreases commodity costs.[139]

Figure 9 presents the normalized average use of natural gas by the Company's residential customers from 2006 to 2021. This figure shows that normalized residential average use has declined even further from 2012 levels. In fact, for the period 2006 to 2012, the average annual growth rate in residential average use was -0.30%. For the period 2013 to 2021, the average annual growth rate decreased to -0.57%.

135 EB-2011-0354, Ontario Energy Board Decision on Equity Ratio and Order, February 7, 2013, at 9.
136 *Ibid*.
137 *Id*., at 9-10.
138 *Id*., at 10-11.
139 *Id*., at 11.

Figure 9: Annual Average Use Per Residential Customer (2006 – 2021)



Considering the Energy Transition risks discussed above, we conclude that the Company's growth prospects today are weaker than they were at the time of the Company's previous equity thickness proceeding (i.e., 2012). Further, Figure 10 compares a variety of long-term economic growth projections from 2012 to comparable projections today. As shown, long-term economic growth prospects in Ontario, Canada overall, and the U.S. are weaker today than they were in 2012, diminishing the Company's growth prospects relative to 2012 even absent Energy Transition risks.

Figure 10: Comparison of Economic Growth Projections (2012 and Current)

Projection Source	2012	Current	Conclusion
Conference Board of Canada (Ontario Projections)	While the near term will be challenging for Ontario, the long-term prospects are brighter. With a large deficit to bring under control, provincial government spending on goods and services will post only limited gains until 2017-18. Strong population growth, combined with an improving economy south of the border, will offset the weakness in Ontario's public sector.[140]	Population aging is bad news for the Ontario government, which was running huge deficits and a massive debt even before the pandemic. Both exploded during COVID-19 and will linger well into the long term.[141]	**Worse** Current Outlook
Consensus Economics (Canada Projections)	Projected Real GDP Growth:[142] Year 3: 2.3% Year 4: 2.5% Year 5: 2.3% Year 6: 2.1% Years 7-10: 2.0%	Projected Real GDP Growth:[143] Year 3: 2.1% Year 4: 2.0% Year 5: 1.8% Year 6: 1.8% Years 7-10: 1.8%	**Worse** Current Outlook
Consensus Economics (US Projections)	Projected Real GDP Growth:[144] Year 3: 2.8% Year 4: 3.1% Year 5: 2.8% Year 6: 2.7% Years 7-10: 2.5%	Projected Real GDP Growth:[145] Year 3: 1.8% Year 4: 2.2% Year 5: 2.0% Year 6: 1.9% Years 7-10: 1.9%	**Worse** Current Outlook
Blue Chip Financial Forecasts (US Projections)	Projected Real GDP Growth:[146] First Five Years: 2.9% Next Five Years: 2.5%	Projected Real GDP Growth:[147] First Five Years: 2.1% Next Five Years: 2.0%	**Worse** Current Outlook

We are cognizant of the OEB's findings in EB-2011-0354 that "the issue in this proceeding is not whether average use has declined; it is whether the declining average use presents a larger risk than

[140] The Conference Board of Canada, Provincial Outlook 2012: Long-Term Economic Forecast – Executive Summary, at ii.
[141] The Conference Board of Canada, Provincial Outlook to 2041, updated October 13, 2021.
[142] Consensus Forecasts by Consensus Economics Inc., Survey Date October 8, 2012, at 28.
[143] Consensus Forecasts by Consensus Economics Inc., Survey Date April 11, 2022, at 28.
[144] Consensus Forecasts by Consensus Economics Inc., Survey Date October 8, 2012, at 3.
[145] Consensus Forecasts by Consensus Economics Inc., Survey Date April 11, 2022, at 3.
[146] Blue Chip Financial Forecasts, Vol. 31, No. 12, December 1, 2012, at 14.
[147] Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, at 14.

in"[148] the Company's previous equity thickness proceeding. Therefore, the sections that follow discuss the factors previously identified by the OEB as mitigating the risk created by declines in average use per customer.

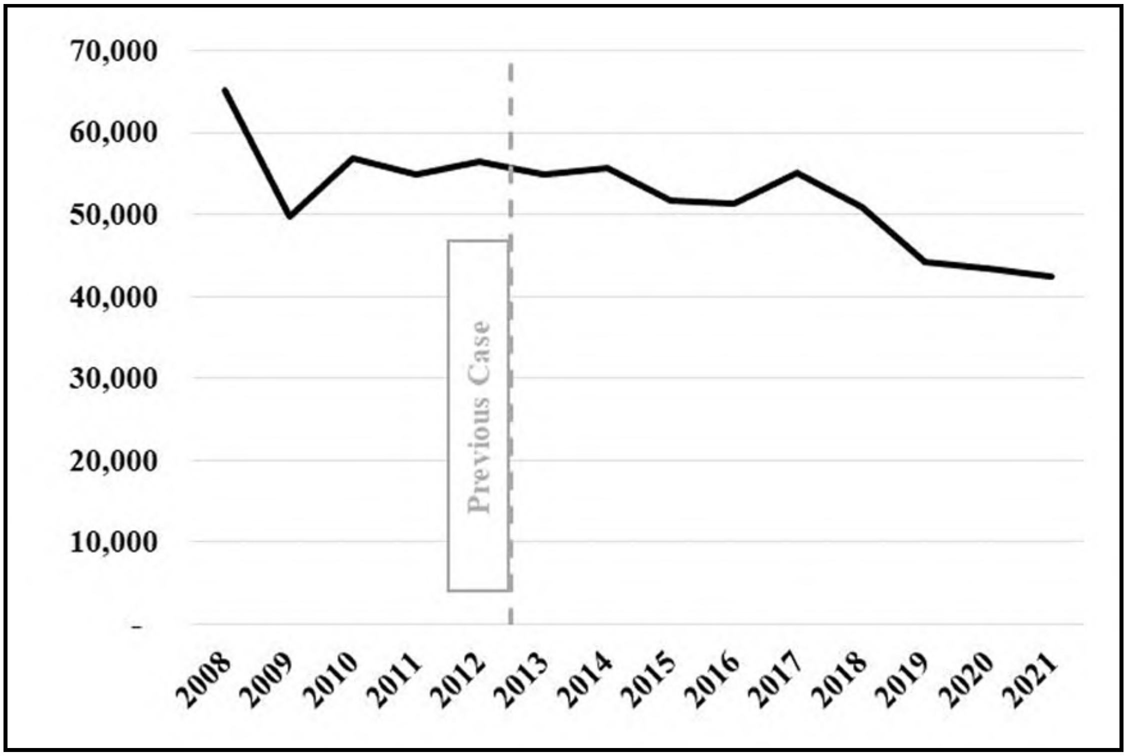
Customer Additions

In EB-2011-0354, the OEB noted that intervenors "submitted that an increase in the number of Enbridge customers mitigates the impact of declining average use."[149] While the OEB did not find explicitly that this mitigated the effects of declining average use per customer, the OEB did state that "Enbridge has added customers each year since 2007, an overall increase of 11% from 2007 to its forecast for 2013. The OEB notes that although Enbridge has expressed concern about the fact that most new customers are weather-sensitive, its evidence indicates that weather risk has not increased since 2007."[150]

The Company's rate of customer additions has continued declining since 2012, as shown in Figure 11. Specifically, the Company added approximately 56,500 on average from 2008 to 2012. In contrast, the Company added approximately 50,000 customers on average from 2013 to 2021, a 12 percent decrease from the 2008 to 2012 period. The Company added 42,500 customers in 2021, which represented the lowest amount of customer additions over the entire period from 2008 to 2021. As such, while the Company continues to add customers, it has steadily added fewer and fewer over time, a trend that has accelerated since about 2017.

148 EB-2011-0354, Ontario Energy Board Decision on Equity Ratio and Order, February 7, 2013, at 9.
149 *Id.*, at 8.
150 *Id.*, at 9.

Figure 11: Annual Customer Additions (2008 – 2021)



Further, we expect the number of customer additions each year to continue declining for three reasons: (1) the Energy Transition, (2) a weaker economic growth outlook, and (3) the OEB's generic proceeding on community expansion. The Energy Transition and economic growth outlook were both discussed previously, and the OEB's generic proceeding on community expansion is discussed below.

In EB-2016-0004, the OEB indicated that qualified parties may compete for the right to serve areas that do not currently receive gas distribution service, even if one utility already holds a franchise agreement or certificate with that municipality.[151] The OEB's decision allows utilities to charge "stand-alone" rates to new expansion communities that are higher than the rates charged to the rest of the utility's customers.[152] This shift in the competitive landscape has already affected expansion projects in several communities, including South Bruce (where EPCOR was selected to provide service instead of Enbridge Gas),[153] Fenelon Falls (where Enbridge Gas was selected),[154] Bobcaygeon (Enbridge Gas paused this project after initially not being awarded a government grant; the project

151 EB-2016-0004, Ontario Energy Board Generic Proceeding on Community Expansion, Decision with Reasons, November 17, 2016.
152 *Id.*, at 18.
153 *Ibid.*
154 EB-2017-0147, Ontario Energy Board Decision and Order, March 1, 2018.

The Future of Gas Utilities Series

TRANSITIONING GAS UTILITIES TO A DECARBONIZED FUTURE

Part 1 of 3

AUGUST 2021

Brattle

Filed: 2023-03-08, EB-2022-0200, Exhibit I.5.3-ED-146, Attachment 1, Page 2 of 31

Agenda

A. Risk and opportunities for transition
B. Regulatory and financial expectations
C. Heating electrification
D. Investor reactions
E. Equity and energy justice

SERIES INTRODUCTION

Energy Sector's Changing Landscape Threatens Natural Gas Utilities

Sources: S&P Market Intelligence; American Gas Association; EIA 2015 Residential Energy Consumption Survey.

Impact Will Differ for Pure-Play, Combination, and Electric Utilities

The natural gas transition will impact all three types of utilities:

- **Combination utilities** may be better positioned to transition business from gas to electricity investment and sales. Gas sale declines presents downside risk, but electrification can present upside potential.
- Electrification serves as a boon to **electric utilities**, which can increase electricity investments and sales.
- **Pure-play gas utilities** face the most downside risk, and will need to be innovative and proactive to grow business.

Regulation will fundamentally answer the question of "who pays" for the transition, highlighting the need for well-designed regulatory strategy.

Who pays?

- Gas, electric, or combination utilities
- Shareholders or utility customers
- Gas or electric customers
- Current or future customers
- Advantaged vs. vulnerable populations

This series provides commentary on these issues and aims to help gas and combination utilities navigate the transition in a fiscally and socially responsible way.

Waiting Passively Is Not a Sustainable Option for Utilities or Customers

If gas utilities defer building a long-term strategy, they risk not having a voice in the policy, planning, and regulation process.

Gas demand reduction and bill increases for remaining customers will come with or without utility involvement. However, the needed change is likely to be delayed or inefficient without utility involvement.

The scale of the transition is massive: displacing natural gas in the US would involve replacing nearly 150 million heating and cooking appliances, in addition to the gas distribution system infrastructure.

Proactive implementation of suitable solutions affords utilities the following benefits:

- Allows utilities to build a diversified and tailored strategy ahead of regulatory mandates
- Finding substitute capital deployments makes gas utilities part of the solution, not an obstacle
- Satisfy customers, reduce costs, and head off or offset probable customer defection
- Address investor concerns

The transition process will play out over many years, **but the planning must start now**.

The Transition Presents Significant Growth Opportunities

Natural gas utilities can create new business opportunities as an enabler of the energy transition, through proactive and innovative approaches.

- Utilities' access to capital, capabilities in large-scale planning and execution, and experience in working with regulatory authorities make them uniquely positioned to help plan and implement large infrastructure transitions.
- Clean fuels, such as renewable natural gas (RNG) and hydrogen, can provide growth opportunities while re-utilizing gas utilities' existing infrastructure or right-of-ways.

Gas utilities have options to create and capture value and reduce customer costs.

- Utilities' pathways will depend on their characteristics (pure-play versus combination), location, customer base, and regulatory environment.

Natural gas utilities will need to work closely with legislators, regulators, and stakeholders to **design and pursue enabling regulatory mechanisms and policies** to navigate this transition.

Building Blocks for a Successful Energy Transition

1

Is it a real risk? How big is it, and how immediate?

2

What strategies will enable solutions?
- Regulatory framework for transition
- New technologies and infrastructure
- Securing life of existing assets

3

What steps can be taken to get there?
- Performance-based regulation
- Multi-year rate plan
- New programs

Filed: 2023-03-08, EB-2022-0200, Exhibit I.5.3-ED-146, Attachment 1, Page 8 of 31

The Brattle Group's Future of Gas Utilities Presentation Series

The Brattle Group's Future of Gas Utilities building blocks will be presented in a series of three presentations to be released in the summer and fall of 2021.

The Brattle Group's Future of Gas Utilities Series will culminate in a **Symposium**, where industry and Brattle experts will convene to debate key challenges and opportunities facing the gas industry.

The remainder of this slide deck will cover the first building block: **Assessing Risk**.

Part 1: Assessing Risk

The Future of Gas Utilities Series

ASSESSING RISK

Risks and Opportunities of the Transition

- Even though certain states are moving against this trend and enacting prohibitions on bans on new gas connections, cost declines related to technology innovation and federal, state, and municipal policy support will increase the deployment of lower-carbon alternatives to natural gas, as happened with renewables in the electricity sector.
- The transition is already underway: at the current rate, the number of homes with electric space heating could exceed the number of homes with gas space heating by 2032.
- In the past decade, gas utility capital expenditures have grown by around double the rate of water and electric utilities' spending, largely driven by safety and reliability.
- Utilities will need to recover their costs from a changing – and possibly shrinking – customer base.
- With energy and environmental policy targets rapidly approaching, gas utilities need to decide today how best to invest capital in long-lived assets and avoid stranded asset risks.
- Heightened perceptions of business risk are increasing financing costs for gas utilities. In early 2021, gas utilities traded at a ~20% discount relative to electric utilities.

Any strategic plan (including electrification and alternative gas technologies) must address equity and energy justice by considering financial, health, and economic impacts to vulnerable communities.

The Debate on the Future of Natural Gas Is Widespread

The **landscape for natural gas has shifted dramatically**, as states and cities across the country have passed natural gas bans and electrification mandates.

States are also launching proceedings on the role gas utilities will play in meeting the state's greenhouse gas (GHG) emissions and clean energy goals.

Proposed approaches include "electrify everything" or leveraging alternative gas technologies such as RNG, hydrogen, etc.

The outcomes being debated vary widely: while some states have banned the use of gas in new buildings, **others have prohibited the enactment of such bans**.

STATES ENACTING GAS BANS | AS OF JULY 21, 2021

	STATE-WIDE	CITY			
	Proceeding on Future Role of Natural Gas	Proposed Gas Bans	Enacted Gas Bans	Implemented Moratoriums	Electrification "Reach" Codes
California	✓		✓		✓
Oregon	✓	✓			
Washington	✓	✓	✓		
New York	✓	✓		✓ PARTIALLY LIFTED	✓
Massachusetts	✓	✓	✓		
Colorado	✓	✓			✓
Washington, DC	✓				
Vermont					✓

Proposed Prohibition on Gas Bans	CO, MI, MN, NC, PA
Enacted Prohibition on Gas Bans	AL, AR, AZ, FL, GA, IA, IN, KS, KY, LA, MO, MS, OH, OK, TN, TX, UT, WV, WY

Gas Utilities Can Participate in a Decarbonized Future to Mitigate a Potential Death Spiral and Control Customer Costs

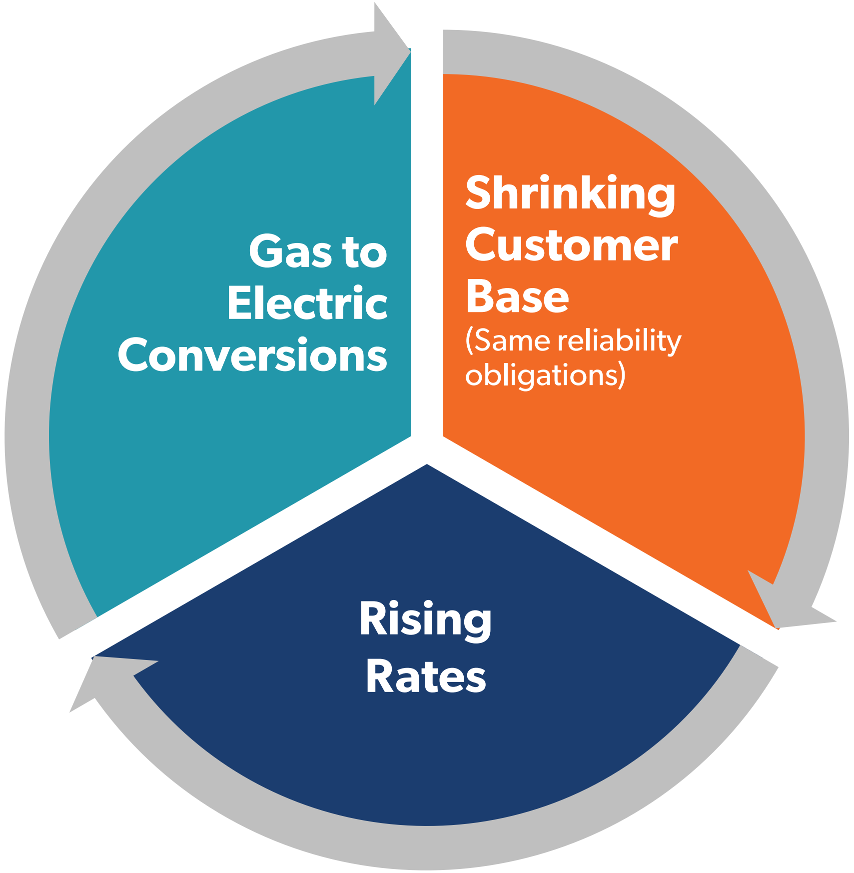
As states pursue degasification policies and homes convert to electric heating, **utilities risk losing customers and load.**

- Nationally, electric heating is outpacing gas heating adoption.
- Technology mandates and policy further accelerate the problem.

Utilities will likely **continue investing in their existing system for safety and reliability but need to recover those costs from a shrinking customer base.**

- This puts remaining customers at risk, a "death spiral" trend pushing more customers to electrification.
- Up to $150–180 billion of gas distribution assets could be under-recovered as a result of the transition.

This spiral will increase customer costs and increase energy burdens, especially for low-income and vulnerable populations.



Gas utilities may reverse this problem if they quickly become part of the solution to a decarbonized future.

Gas Utilities' Risks and Opportunities with Decarbonization

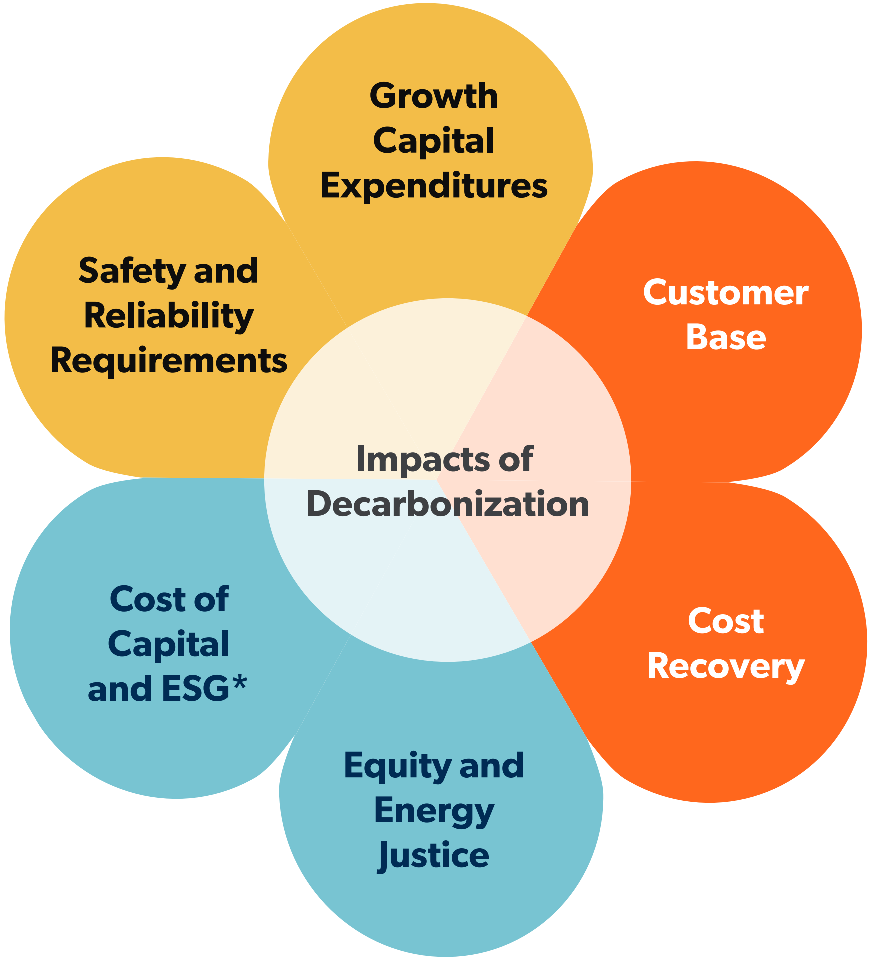
Proposed decarbonization pathways generally emphasize electrification, challenging the traditional business model of natural gas utilities.

Without proactive adjustments, utilities face increasing **cost recovery risks from capital investments** to grow the gas system or to maintain safety and reliability requirements.

There are **offsetting opportunities**, such as:

- Alternative fuels (RNG, hydrogen) are a viable alternative for end-uses that lack cost-effective electrification options.
- Long-run deep degasification may be expensive to achieve, requiring utilities to invest in clean performance of existing assets.
- Utilities could own and rate base gas replacement infrastructure, earning a return on these decarbonization assets.

The transition will take time and depends on factors such as costs, regulatory and legislative mandates, and customer adoption.



*ESG stands for Environmental, Social, Governance investing

Filed: 2023-03-08, EB-2022-0200, Exhibit I.5.3-ED-146, Attachment 1, Page 14 of 31

Traditional Planning Faces Conflicting Regulatory and Financial Expectations

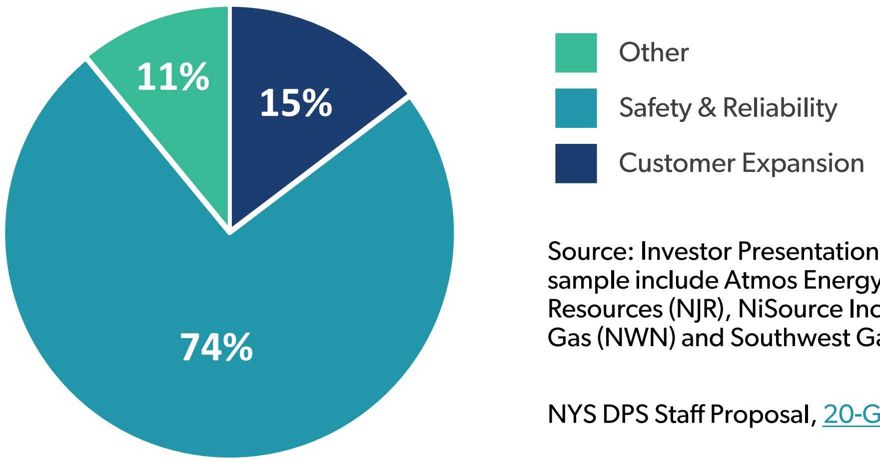
New gas assets placed into service today have a useful life of ~40 years – well beyond target dates for many decarbonization goals, creating cost-recovery risk.

- Gas utility capital expenditures have grown by around double the rate of water and electric utilities' capital expenditures.

Regulators are requiring gas utilities to develop gas long-range capital investment plans that conform to state climate and energy policy goals. Gas utilities and regulators need to decide today how best to deploy capital and avoid cost recovery risks due to the transition.

- **Alternative depreciation schedules** may be required to fully recover traditional gas investments before policy target dates.
- **Diversifying into gas decarbonization technologies** can limit exposure to lost growth opportunities and reduce stranded asset risk.

FORECASTED CAPITAL EXPENDITURES



Source: Investor Presentations, 2020. Utilities in the sample include Atmos Energy (ATO), New Jersey Resources (NJR), NiSource Inc. (NI), Northwest Natural Gas (NWN) and Southwest Gas (SWX).

NYS DPS Staff Proposal, 20-G-0131, February 12, 2021.

NY GAS PLANNING PROCEEDING | STAFF PROPOSAL

Utilities must incorporate demand-side solutions into their long-term planning to **reduce gas demand and the need for gas infrastructure investments.**

LDCs must **identify opportunities to avoid replacing leak prone pipe** and instead deploy "Non-Pipeline Alternative" investments.

Safety and Reliability Investments Will Remain a Priority

Utilities are under increasing pressure and are making **significant investments to meet new and existing safety and reliability requirements**.

- PHMSA's Mega Rule went into effect in 2020, mandating confirmation of Maximum Allowed Operating Pressures (MAOP), more frequent and regular pipeline integrity assessments, and new repair and leak detection requirements, amongst other requirements.
- This will require material investments, but increases the risk of obsolescence before the end of normal asset life (~40 years).

Utilities are also focused on replacing **leak-prone pipe,** which reduces methane emissions and helps meet state and corporate GHG emission targets.

- 32 natural gas utilities have pledged to reduce methane intensity to 1% by 2025.
- New York is asking utilities to identify opportunities to retire leak prone pipe and instead deploy non-pipeline alternatives, such as electrification of heating.
- Methane is a more potent GHG than CO_2 even though it is short-lived. Its 20-year warming potential is 80x – and its 100-year warming power is 25x – that of CO_2, per ton emitted.

Enabling regulatory mechanisms will need to be designed and implemented to recover safety and reliability costs from a changing and/or declining customer base.

Shifts in Customer Base Increase Cost Recovery Risks

The transition **will not occur at the same pace or magnitude across customer classes**, which compounds cost recovery risks (cost allocation, appropriate tariff designs, equity and energy justice).

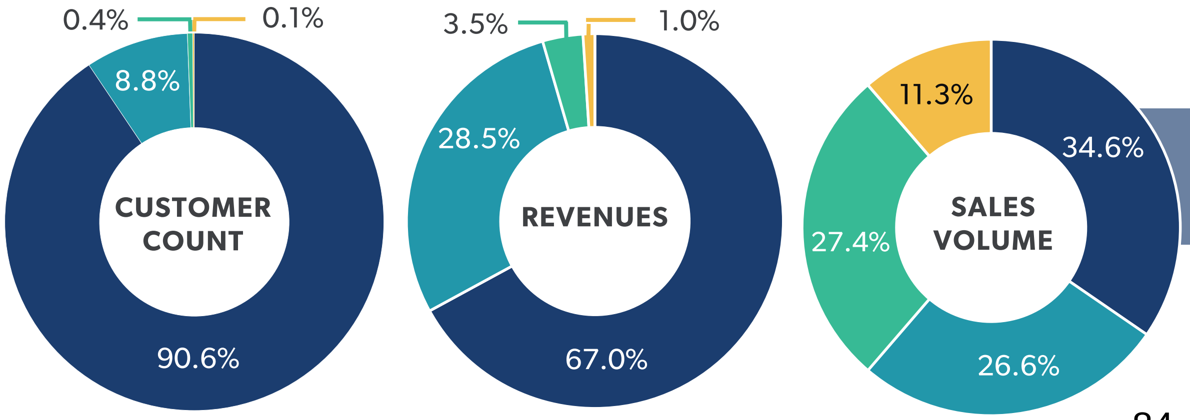
- Residential customers, who are more likely to convert to electric alternatives, comprise 90% of total natural gas utility customers and 67% of revenues, but they account for only one-third of total system volumes.
- Harder to electrify industrial customers are a small portion of total customers but about 27% of total sales volumes.
- Differences in customer transition trends will impact the pace and feasibility of achieving state GHG emission targets.

Gas utilities can mitigate this risk by focusing on degasification solutions for commercial and industrial customers, which could most effectively help meet state and corporate decarbonization goals.

Declines in customer base, starting with easy-to-electrify customers, will raise costs for remaining customers, such as for low-income and other vulnerable customer populations.

Gas Utility Customer Base

Industrial | Commercial | Residential | Other



68M total customers | **$67B** total revenues | **29.7B** MMBtu*

Source: S&P Market Intelligence, data as of year-end 2019.
Note: Other revenues and sales volumes reflect electric power revenues and sales.
*American Gas Association summary statistics

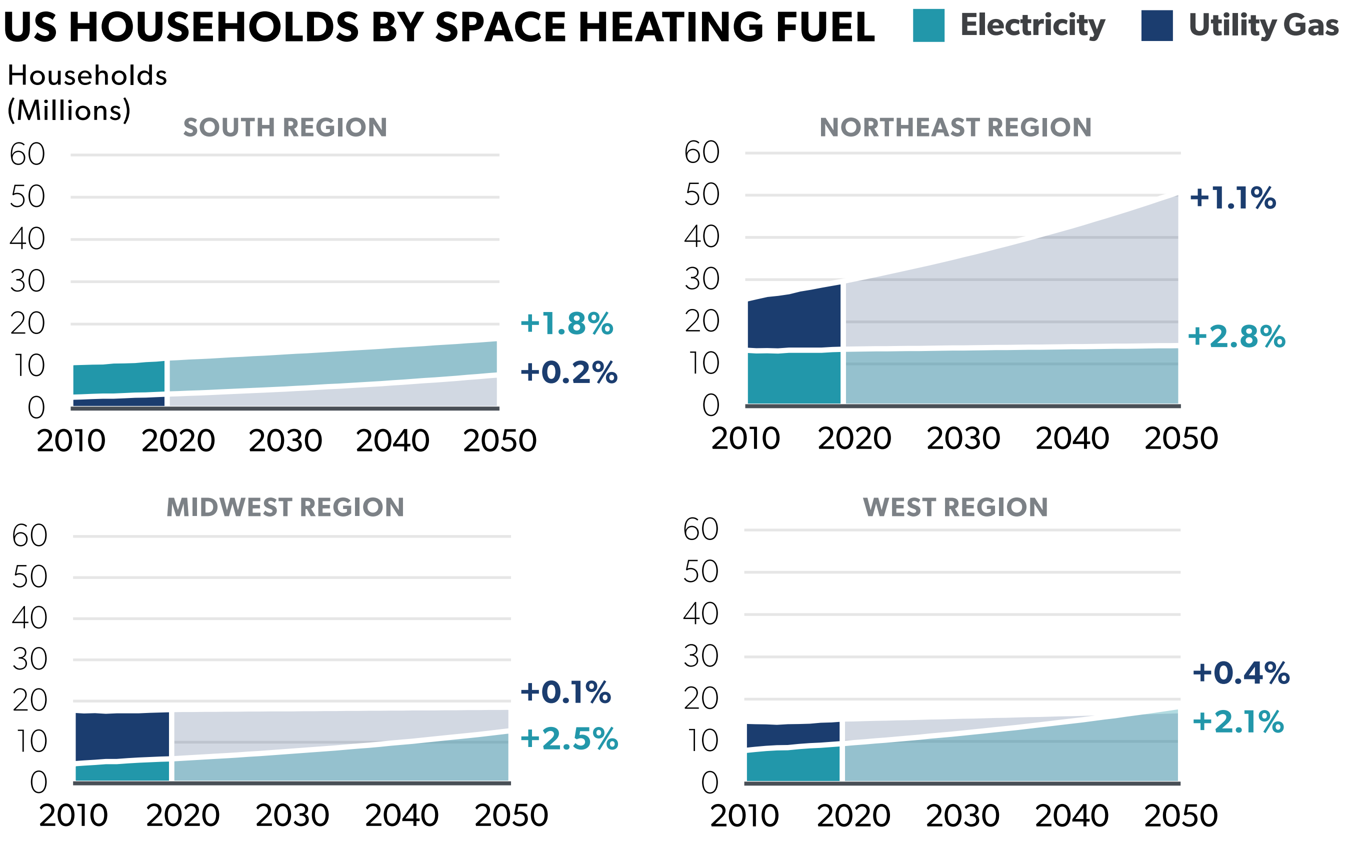
Filed: 2023-03-08, EB-2022-0200, Exhibit I.5.3-ED-146, Attachment 1, Page 17 of 31

Heating Electrification Will Accelerate Declines in Gas Customer Base

Heating electrification is outpacing gas growth in some parts of the country. At the current pace, the number of homes with electric space heating could surpass homes with gas space heating by 2032.

- Heat pumps remain more expensive than gas furnaces, but could become more competitive with technological improvements and financial incentives.
- Economics of heat pump water heaters (HPWH) can be more appealing because of lower upfront costs relative to heat pumps. HPWH also has a higher efficiency than its gas counterpart.

Electric utilities are promoting rebates for heat pumps and HPWHs to accelerate adoption. As heat pumps and other decarbonization technologies become more popular, **gas utilities need to think strategically about how to participate in this transition in order to remain viable.**



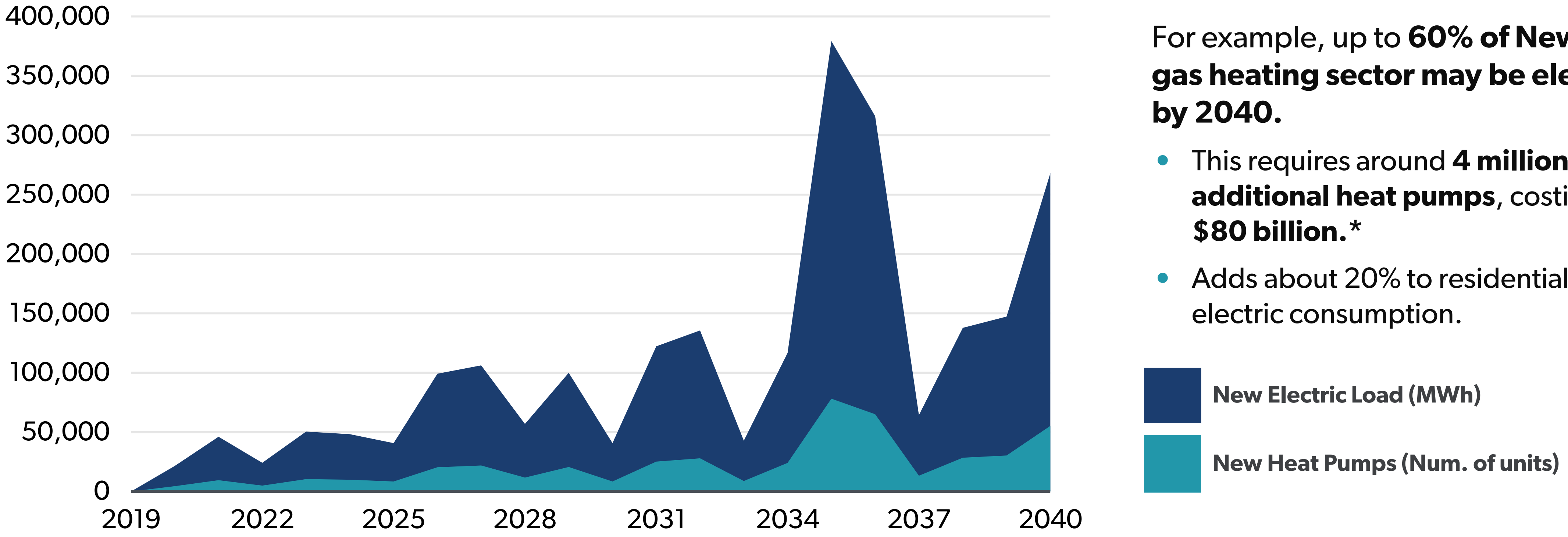
Source: US Census Data, 2019. | Note: Electricity includes both heat pumps and electric resistance heating.

At current rates, homes with electric heating could surpass homes with gas heating by 2032 nationally.

Death Spiral for Gas Utilities: An Illustrative Example

ELECTRIFICATION OF HEATING SECTOR CASE STUDY: NEW YORK GENERIC UTILITY

Forecasted Newly Electrified Load



Source: CCIS NYISO forecast.
*Assumed forecast of new heat pumps from CCIS forecast, calculated new load and related costs. We assume AHSP at $12,800 and GHSP at $35,700 in real dollars. Capital cost assumptions come from New Efficiency NY Analysis of Residential Heat Pumps.

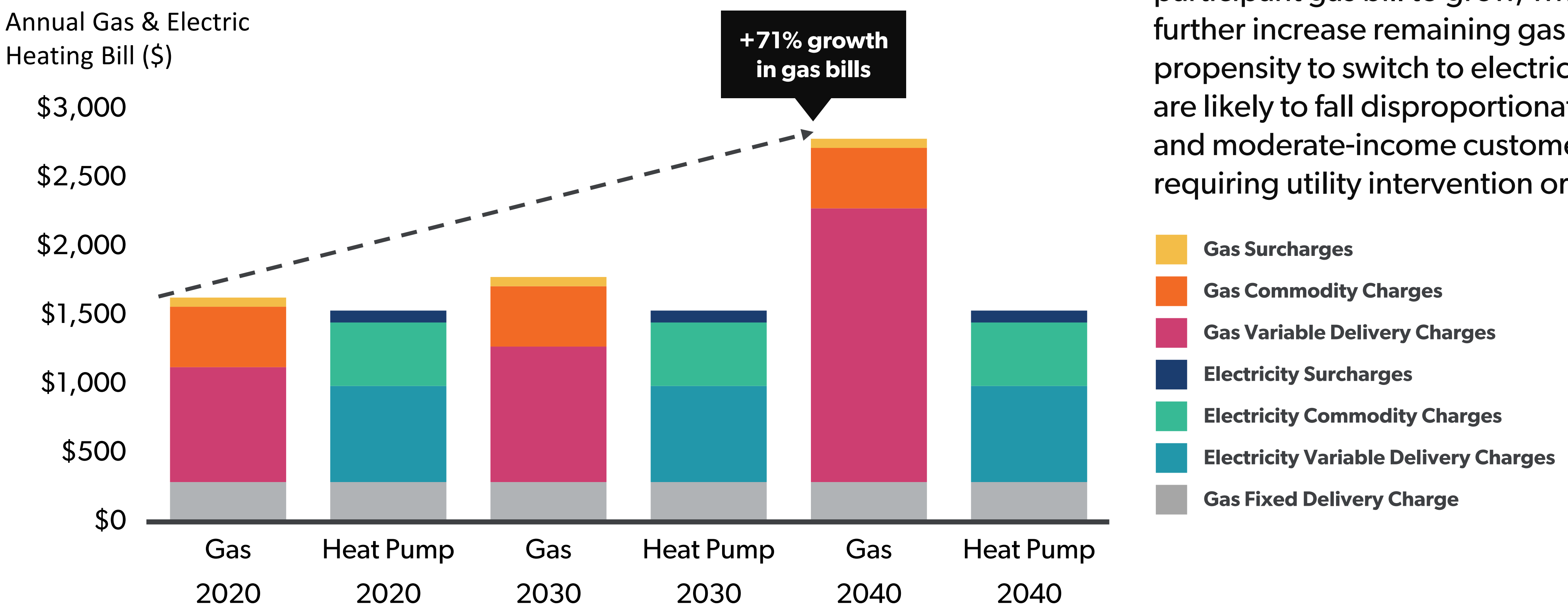
The impact of increasing electrification will vary based on state and local regulations and decarbonization goals.

For example, up to **60% of New York's gas heating sector may be electrified by 2040.**

- This requires around **4 million additional heat pumps**, costing about **$80 billion.***
- Adds about 20% to residential electric consumption.

Death Spiral for Gas Utilities: An Illustrative Example

RATES IMPACT FOR GAS AND ELECTRIC CUSTOMERS
– GAS UTILITY NO-ACTION "DEATH SPIRAL" SCENARIO



There is a large potential for non-participant gas bill to grow, which will further increase remaining gas customer's propensity to switch to electric. Impacts are likely to fall disproportionately on low- and moderate-income customers, requiring utility intervention or offsets.

Source: CCIS NYISO forecast and The Brattle Group analysis. | Note: Rate impacts for a gas furnace and air source heat pump customer.

Adverse Investor Reactions to Risks Are Emerging

Investors' **risk perceptions are shifting** as states and locales transition away from natural gas and reduce GHG emissions.

A Berkeley, CA passes the nation's first gas ban (July 2019)

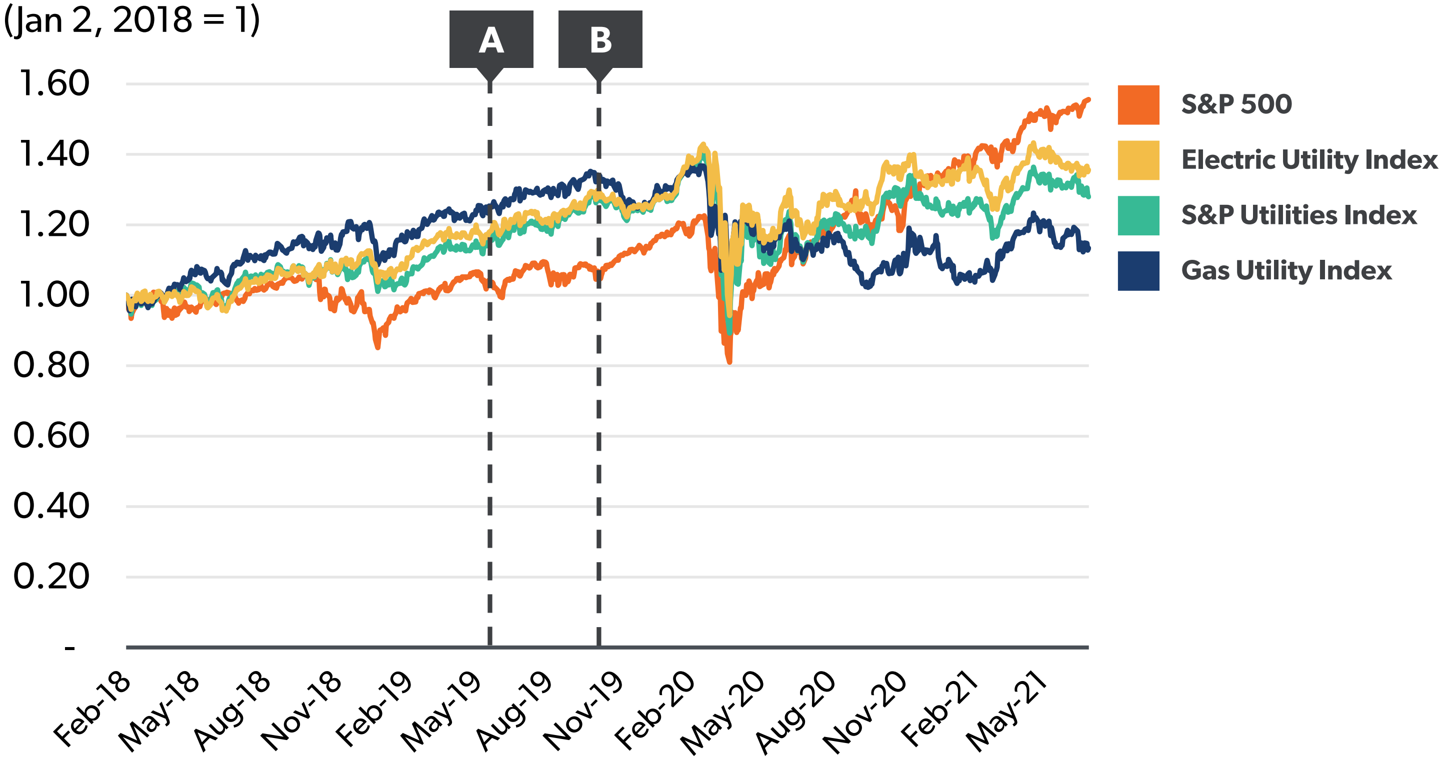
B Brookline, MA passes first East Coast gas ban (Nov 2019)
Five additional CA municipalities have enacted gas bans

All else equal, gas utilities have to **issue more shares to raise the same amount of equity capital**, relative to other utilities.

- Gas utilities currently trade at a ~20% discount relative to electric.
- However, P/E ratios for gas utilities remain elevated at approximately 18 (vs. 19 for electric utilities and 18.5 for S&P util.)

UTILITY STOCK PERFORMANCE

(Jan 2, 2018 = 1)



Notes: **Gas Utility Index includes:** Atmos Energy, Chesapeake Utilities, New Jersey Resources, NiSource, NW Natural, ONE Gas, South Jersey Industries, Southwest Gas, Spire. **Electric Utility Index includes:** AEP, Southern, FirstEnergy, Exelon, Duke, Progress Energy, Evergy, NextEra, Edison International, Dominion. Electric Utility Index is currently trading 3% above S&P Utility Index and 20% above the Gas Utility Index. Data through June 30, 2021.

1: United Nations Environment Programme, Net Zero Banking Alliance.

Investors Are Becoming Actively Involved in the Debate

Environment, Social, and Governance (ESG) investors are pressuring gas utilities to reduce GHG emissions and eliminate usage of fossil fuels.

43 banks across 23 countries announced a pledge to achieve "net-zero banking," meaning their lending and investment portfolios are on track to reach net zero emissions by 2050.[1]

Utilities are increasingly highlighting RNG, hydrogen, and emission reduction efforts in their investor materials.

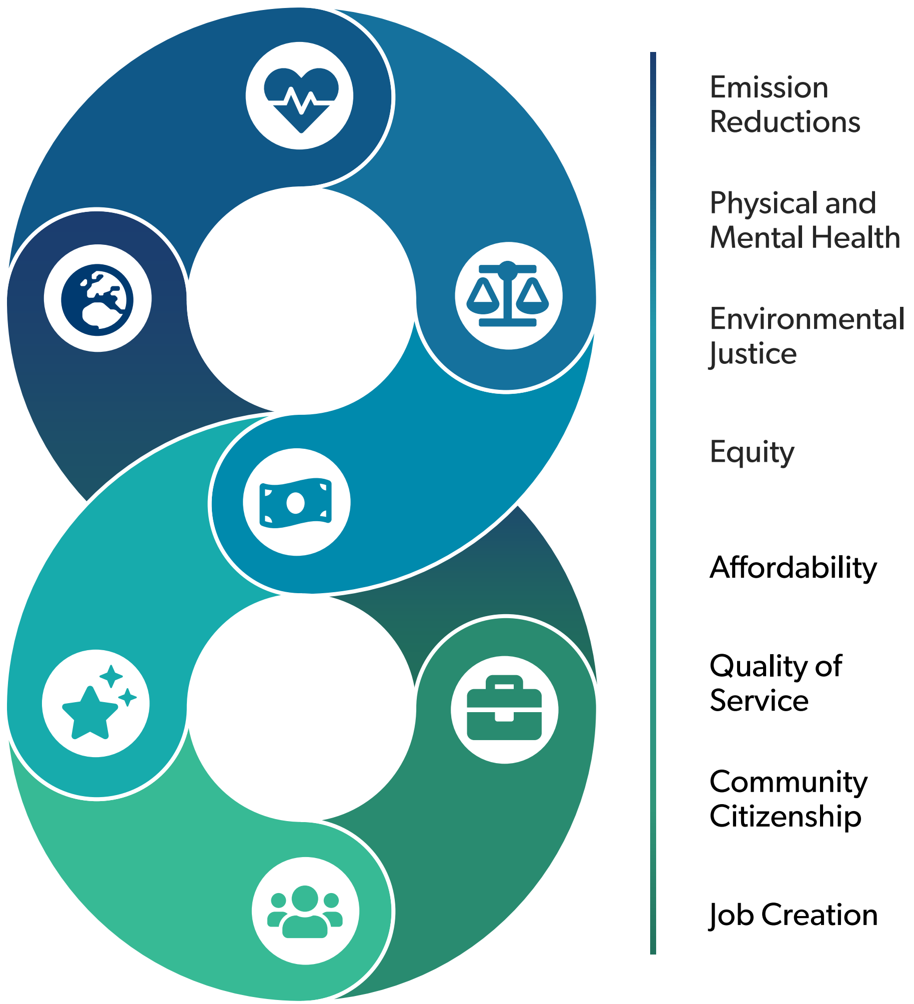
70 gas utilities across 31 states have set corporate carbon emission reduction targets.

1: United Nations Environment Programme, Net Zero Banking Alliance.

Equity and Energy Justice Concerns Must Be Considered

Gas utilities and regulators will also need to **consider the risks and impact of the transition on low-income and less advantaged communities**, who may experience rising bills and longer exposure to emissions.

- Public policy is increasingly focused on fairness of service and equitable access to decarbonization technology.
- As more affluent customers adopt electric heating, low-income gas customers could disproportionately experience rate increases and/or be neglected by developers for obtaining new decarbonization technologies.
- For example, adverse effects from electrification on low-income communities can be observed in rooftop adoption, in which low-income communities subsidize delivery costs for homes with rooftop solar receiving net energy metering (NEM).



Turning Increasing Risk into Opportunity

Gas utilities need to **create an adaptive, long-term business plan that anticipates** the pathways, drivers, accelerators, and decelerators of the transition and identify the type and timing of impacts.

Long-term modeling tools can help

> **Economy Decarbonization Model:** How different might the pace and means of decarbonization be? There are many enabling technologies and policy "knobs" yet to be turned or applied. What are these pathways, and how can they be realized or adjusted? When and how will gas utilities be affected under these different pathways?

> **Distribution System Planning Model:** How can gas distribution investments, operations, pricing, and financing be altered so that utilities not only survive but grow in the face of the transition's long-term effects?

By understanding the possible pathways, utilities can identify their comparative advantages, target market niches, and needed operational and regulatory adjustments.

- A "base case" would look at sales and profits with a passive response to trends in electrification.
- Responsive strategies are then developed for how to influence the path(s) that are likely to occur and how to prepare for their contingencies by selectively avoiding some risks and embracing others.

In Part 2 of this series, we will examine the solution elements available to gas utilities.

How Brattle Can Help

Brattle's Unique Interdisciplinary Experience Provides a Holistic Skillset to Guide Transition

1
Assess Risk
—

2
Evaluate Strategies
—

3
Implement
—

Assess Transition Risks

Analyze how natural gas bans, electrification mandates, and ESG investment trends will impact business risk and cost of capital.

Estimate revenue loss to electrification under different future scenarios.

Use system dynamics to identify rate risks and customer feedback effects.

Evaluate Strategy and Solutions

Facilitate strategy workshops to establish transition principles, identify potential business strategies, and determine near- and long-term action items.

Identify revenue potential from owning and rate-basing electrification infrastructure and evaluate rate impacts using system dynamics.

Implement Regulatory Changes

Design and calculate tariffs to incentivize transition and protect customer costs.

Filed: 2023-03-08, EB-2022-0200, Exhibit I.5.3-ED-146, Attachment 1, Page 26 of 31

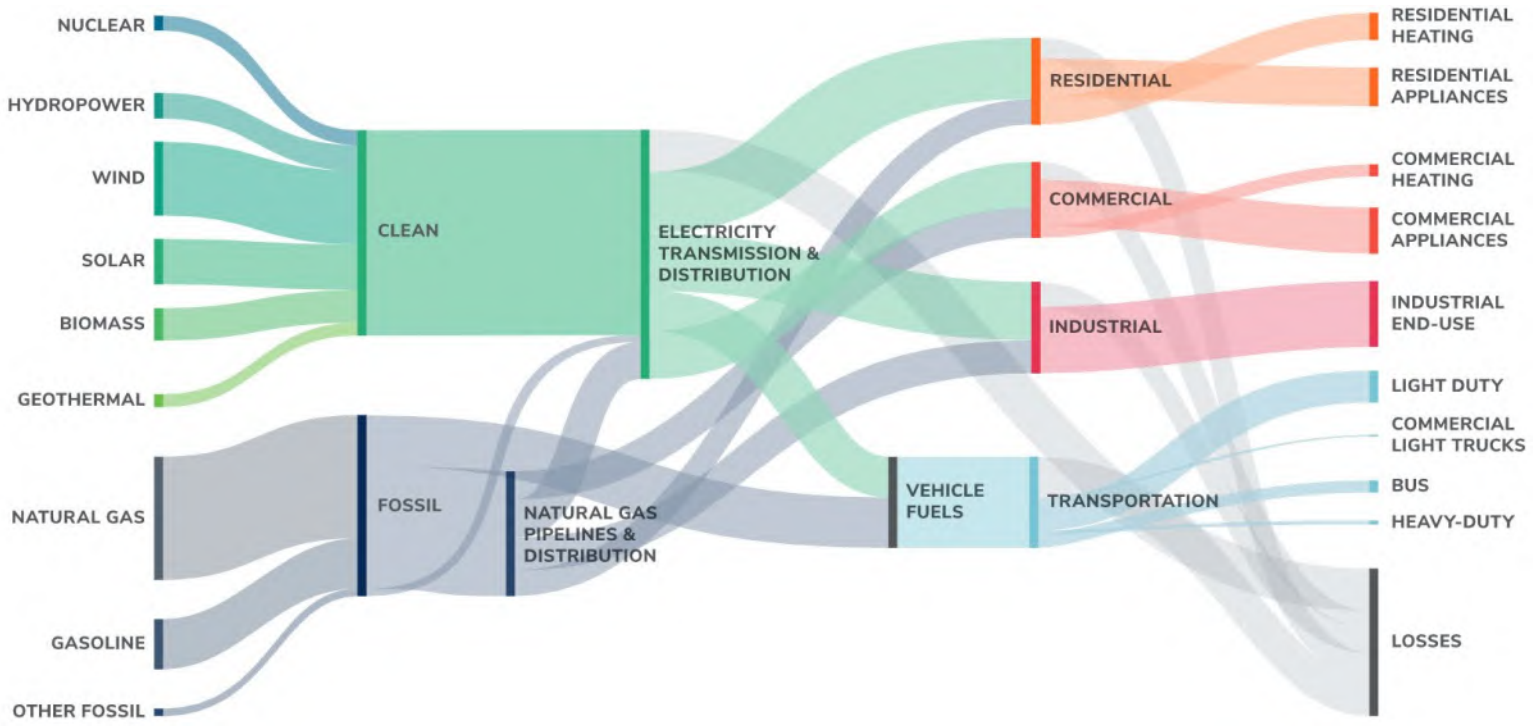
DEEP Can Help Utilities Understand Risks and Evaluate Solutions

Brattle's **Decarbonization, Electrification & Economic Planning (DEEP) Model** is an energy economy modeling tool that can evaluate:

- The uptake of technologies and impact on gas consumption
- The roles of efficiency, electrification, and fuel-switching
- The utility and customer costs of specific technology pathways

DEEP can evaluate long-term planning impacts and the interactions of:

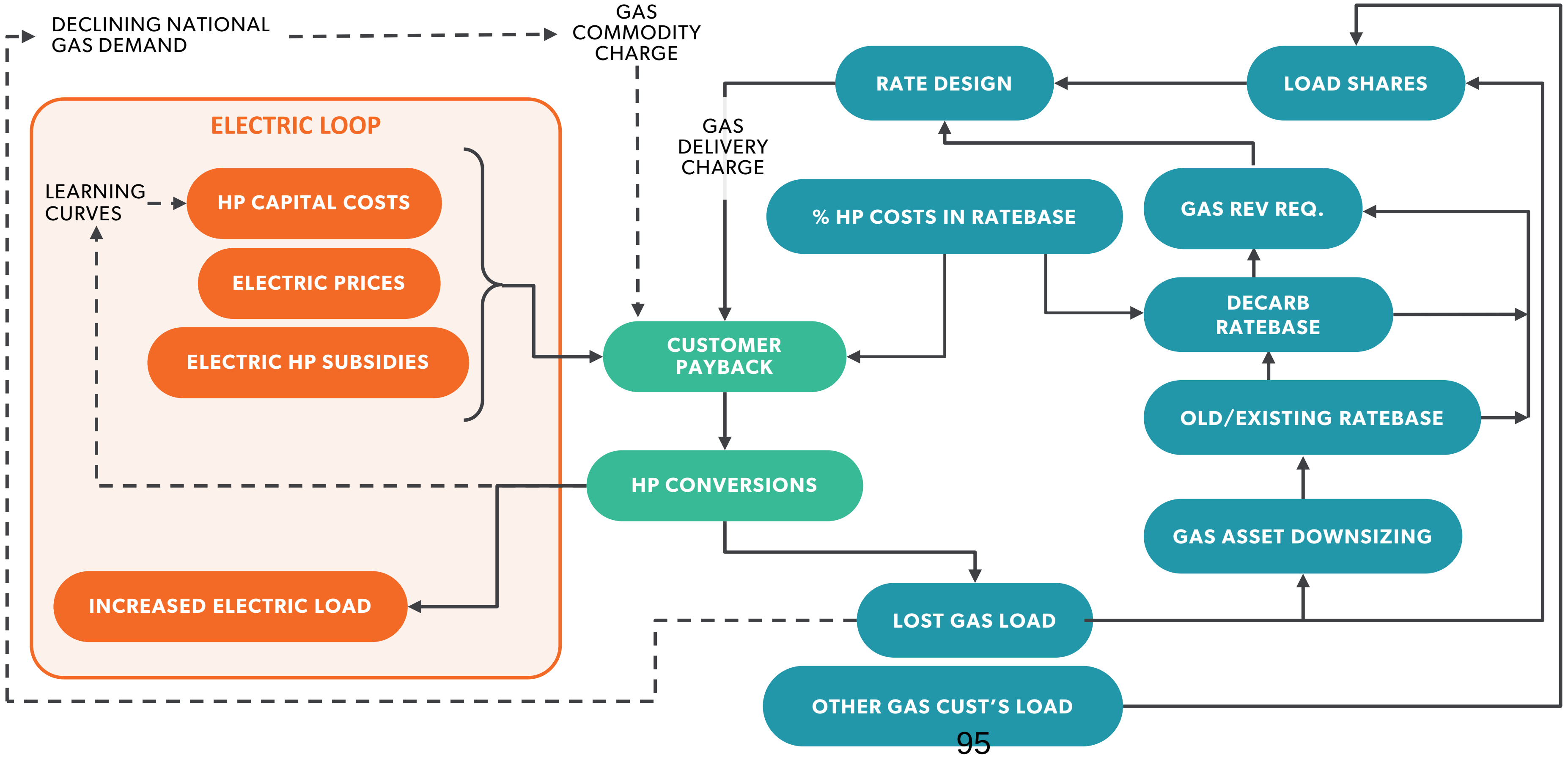
- Technology adoption
- Decarbonization policies
- Macroeconomic conditions
- Supply and demand



The model can be run in **(1) planning mode** and **(2) optimization mode** to meet client-specific needs.

Dynamic Modeling Can Help Utilities Understand Risk and Evaluate Potential Strategies

Brattle's technical and analytical abilities can model pathways for decarbonization and the complex interdependencies both within and between the gas and electric sectors, many of which have not yet been thoroughly studied.



Brattle's **System Dynamics Model** can help utilities analyze the complex feedbacks and interdependencies associated with the transition.

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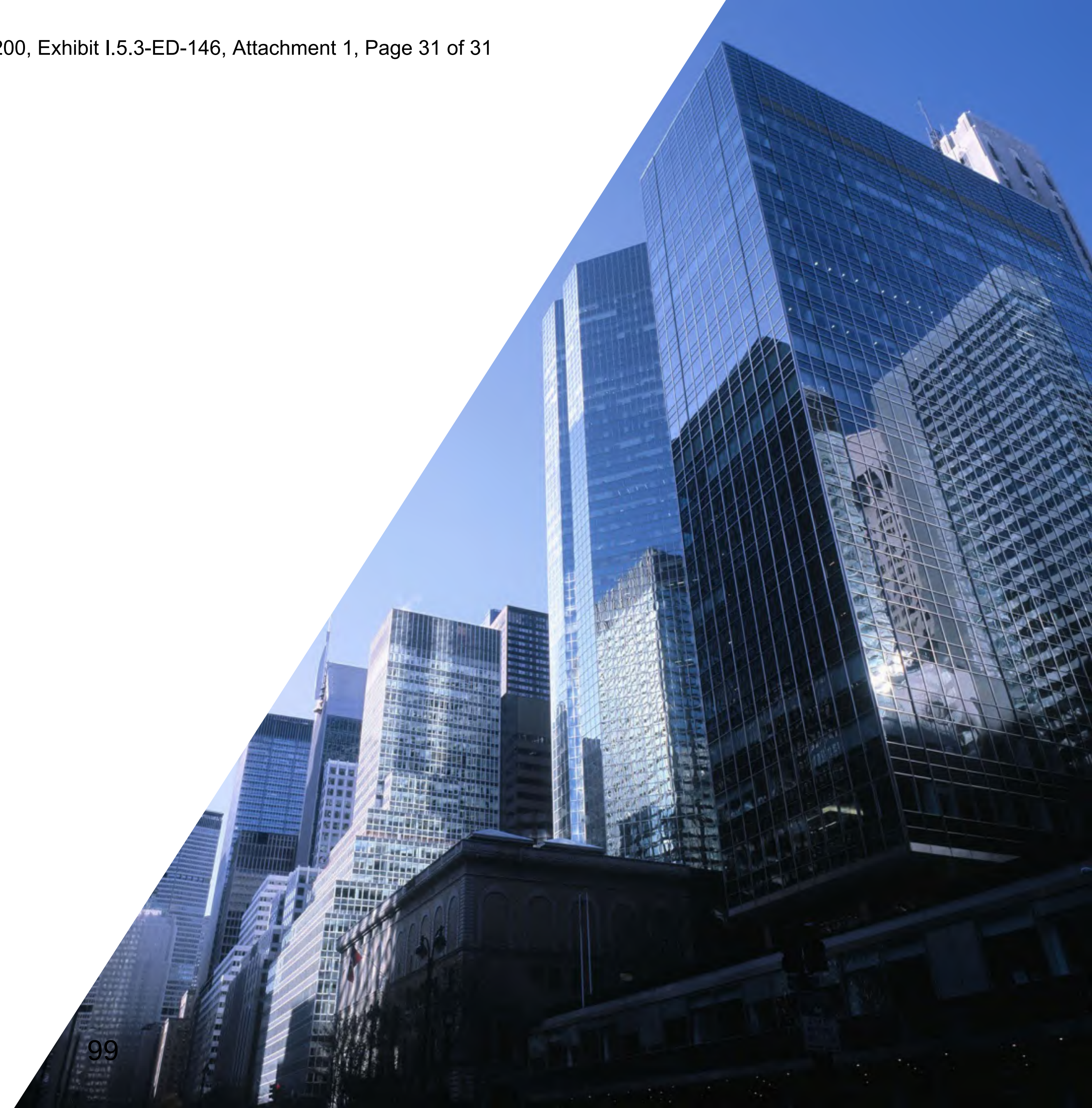
Clarity in the face of complexity

Brattle



Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL AND WEB POSTING

June 27, 2024

TO: All Rate-regulated Electricity Distributors
All Intervenors in Electricity Distribution Cost of Service Proceedings for 2024 and 2025 Rates
All members of the Reliability and Power Quality Review Working Group (EB-2021-0307)
All Other Interested Parties

RE: Vulnerability Assessment and System Hardening Project
Ontario Energy Board File Number: EB-2024-0199

The Ontario Energy Board (OEB) is launching the Vulnerability Assessment and System Hardening (VASH) project in relation to OEB's Distribution Sector Resiliency, Responsiveness, and Cost Efficiency (DRRCE) initiative.

Background

The DRRCE initiative was launched in response to the Minister of Energy's Letter of Direction to the OEB dated October 21, 2022. In 2023, the OEB submitted its report entitled "Improving Distribution Sector Resilience, Responsiveness & Cost Efficiency" (DRRCE Report) describing advice and proposals that reflect on current and anticipated future extreme weather impacts, best practices in climate change resilience, and options to enhance organizational capacity through efficiency measures.

Subsequently, the Minister of Energy's Letter of Direction to the OEB dated November 29, 2023 (2023 Letter of Direction) asked the OEB to develop and implement policies proposed in the DRRCE Report that will require electricity distributors to engage in activities to protect customers in a changing climate.

The VASH project is being launched to address the following three electricity distributor activities identified in the 2023 Letter of Direction:

- Incorporate climate resiliency into their asset and investment planning activities.
- Engage in a regular assessment of the vulnerabilities in their distribution system and operations in the event of severe weather.

2300 Yonge Street, 27th floor, P.O. Box 2319, Toronto, ON, M4P 1E4
2300, rue Yonge, 27e étage, C.P. 2319, Toronto (Ontario) M4P 1E4
T 416-481-1967 1-888-632-6273
F 416-440-7656 OEB.ca

- Prioritize value for customers when investing in system enhancements for resilience purposes.

The remaining two activities referenced in the 2023 Letter of Direction are currently being addressed through the Reliability and Power Quality Review working group. including refining the definition of “resilience events” (High Impact, Low Frequency (HILF) occurrences). For more details, please refer to the letter issued on March 27, 2024.

Initial Proposals

Guidehouse Canada Ltd. has been retained as a consultant to assist the OEB in moving forward on the request set out in the 2023 Letter of Direction.

The OEB intends to explore a standard vulnerability assessment methodology and to include system hardening into distributor system planning processes, and is proposing the following as a starting point for discussion:

- Standardize the methodology for risk-based vulnerability assessments based on the probability and impact of HILF weather events.
- Set out expectations for distributors to assess the value customers place on an avoided outage and develop a Value of Lost Load methodology.
- Develop a cost-benefit analysis incorporating the risk-based vulnerability assessment and Value of Lost Load methodology.
- Set filing requirements for distributors to provide information on system hardening investments as part of their Distribution System Plans and set expectations on how system hardening investments will be reviewed and how the resilience benefits of a project or program will be assessed alongside other planning drivers.

The OEB will work with Guidehouse to develop an approach to address the above for stakeholder input. That approach will be discussed at a stakeholder meeting that will take place in July 2024, at which time stakeholders are encouraged to suggest alternative approaches for the OEB’s consideration in deciding how best to move forward. Details of the July 2024 stakeholder meeting will be communicated in due course.

Participation

Stakeholders that wish to participate in this consultation are asked to email notice of their intention to registrar@oeb.ca before July 5, 2024. The email should include ‘EB-2024-0199 – Vulnerability Assessment and System Hardening’ in the subject line.

The OEB's Distribution Sector Resiliency, Responsiveness, and Cost Efficiency Hub will serve as a central source for information and will include links to the various initiatives. A full list of initiatives identified in the 2023 Letter of Direction is included in Appendix B and available through the Hub. Stakeholders can also register on the Hub to get the latest updates.

Cost Award Matters and Filing Instructions

Cost awards will be available to eligible participants under section 30 of the *Ontario Energy Board Act, 1998* for participation in this consultation. Costs awarded will be recovered from all rate-regulated electricity distributors.

Important information regarding cost awards, including in relation to eligibility requests, is set out in Appendix A to this letter. Appendix A also contains instructions for filing materials with the OEB.

Any questions relating to this letter should be directed to Zubin Panchal at zubin.panchal@oeb.ca or at 416-440-8113. The Board's toll-free number is 1-888-632-6273.

Yours truly,

Theodore Antonopoulos
Vice President
Major Applications

Appendix A

Cost Award Matters and Filing Instructions

Cost Award Eligibility

The OEB will determine eligibility for costs in accordance with its *Practice Direction on Cost Awards*. Any person intending to request an award of costs must file with the OEB a written submission to that effect by **July 5, 2024**. The submission must identify the grounds on which the person believes that it is eligible for an award of costs (addressing the OEB's cost eligibility criteria as set out in section 3 of the *Practice Direction on Cost Awards*). An explanation of any other funding to which the person has access must also be provided, as should the name and credentials of any lawyer, analyst or consultant that the person intends to retain, if known. All requests for cost eligibility will be posted on the OEB's website. If a rate-regulated electricity distributor has any objections to any of the requests for cost eligibility, such objections must be filed with the OEB by **July 12, 2024**. Any objections will be posted on the OEB's website. The OEB will then make a final determination on the cost eligibility of the requesting participants.

Eligible Activities

Cost awards will be available to eligible parties for participation in the initial stakeholder meeting to a maximum of actual meeting time plus one hour for preparation. If further consultation activities are eligible for cost awards, details will be provided at the relevant time.

Cost Awards

When determining the amount of the cost awards, the OEB will apply the principles set out in section 5 of its *Practice Direction on Cost Awards*. The maximum hourly rates set out in the Cost Awards Tariff will also be applied. The OEB expects that groups representing the same interests or class of persons will make every effort to communicate and co-ordinate their participation in this process. In accordance with section 12 of its *Practice Direction on Cost Awards* the OEB will act as a clearing house for all payments of cost awards in this process. For more information on this process, please see the *OEB's Practice Direction on Cost Awards*.

Filing Instructions

Stakeholders are responsible for ensuring that any documents they file with the OEB **do not include personal information** (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

Please quote file number, EB-2024-0199 for all materials filed and submit them in searchable/unrestricted PDF format with a digital signature through the OEB's online filing portal.

- Filings should clearly state the sender's name, postal address, telephone number and e-mail address.
- Please use the document naming conventions and document submission standards outlined in the Regulatory Electronic Submission System (RESS) Document Guidelines found at the File documents online page on the OEB's website.
- Stakeholders are encouraged to use RESS. Those who have not yet set up an account or require assistance using the online filing portal can contact registrar@oeb.ca for assistance.
- Cost claims are filed through the OEB's online filing portal. Please visit the File documents online page of the OEB's website for more information. All participants shall download a copy of their submitted cost claim and serve it on all required parties as per the Practice Direction on Cost Awards.

All communications should be directed to the attention of the Registrar and be received by end of business, 4:45 p.m., on the required date.

Email: registrar@oeb.ca
Tel: 1-877-632-2727 (Toll-free)

APPENDIX B

Improving Distribution Sector Resilience, Responsiveness and Cost Efficiency: Project Breakdown from 2023 Letter of Direction

Resilience Priorities

Steps	OEB Initiative	Initiative Launch
Provide details and report on their current storm recovery planning and preparation activities	Reliability And Power Quality	March 2024
Incorporate climate resiliency into their asset and investment planning	Vulnerability & System Hardening	June 2024
Engage in a regular assessment of the vulnerabilities in their distribution system and operations in the event of severe weather	Vulnerability & System Hardening	June 2024
Prioritize value for customers when investing in system enhancements for resilience purposes	Vulnerability & System Hardening	June 2024
Satisfy minimum targets for customer communication regarding interruptions and restoration of service following major weather events and measure and report on restoration of service following such events.	Reliability And Power Quality	March 2024

Cost Efficiency Priorities

Steps	OEB Initiative	Initiative Launch
Reviewing whether the accounting and associated rate treatment of shared services should be adjusted and develop guidance on a fair approach to cost and risk apportionment for shared service provision	Initial step: Cloud Computing; included in the OEB's Generic proceeding on the Cost of Capital (EB-2024-0063)	March 2024
Engaging stakeholders in a scoping exercise at the outset of the Mergers, Acquisitions, Amalgamations and Divestiture (MAADs) review	Evaluation of Policy on Utility Consolidations (EB-2023-0188)	Input complete; see paper published February 8, 2024
Reviewing elements in its incentive rate-setting mechanisms and examining distributors' spending patterns to identify where changes or incremental incentives are warranted	Spending Pattern Analysis	Q3 2024-5
Developing a performance incentive regime that considers aspects such as customer service, resilience, or managing peak loads to defer distribution system needs, and working with the sector to develop principles, generic designs, and other criteria for performance incentives	Forthcoming	Q3 2024-5

Investor Overview

Post Second Quarter 2024

Hydro One investment overview

hydroOne

A unique low-risk opportunity to participate in the growth of a premium, large scale regulated electric utility

- One of the largest electric utilities in North America with significant scale; largest transmitter and distributor across Canada's most populated province
- Unique combination of **pure-play** electric power transmission and local distribution, with no generation or material exposure to commodity prices
- Stable and growing cash flows with **99% of business** fully rate-regulated in a constructive, transparent and collaborative regulatory environment
- One of the strongest **investment grade** balance sheets in the North American utility sector. No external equity required to fund planned growth
- Predictable self-funding **organic growth profile** with expanding rate base and strong cash flows, together with broad support for refurbishment of aging infrastructure
- Annualized dividend of $1.2568 with **70% - 80% target payout ratio**. Opportunity for continued dividend growth with rate base expansion, continued consolidation and efficiency realization

Combined 2024 Transmission & Distribution **Rate Base of $26.5B**[1]

Predictable self-funding organic growth profile during current rate period (2022 - 2027) with

- **~6% expected rate base CAGR**
- **5% to 7% EPS growth**
- **~6% Average annual dividend growth**

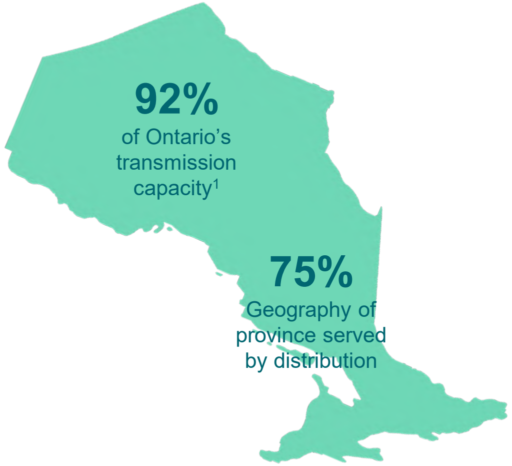
Strong balance sheet with **investment grade** credit ratings

Attractive **70% - 80%** target dividend payout ratio

1) Company estimates subject to change

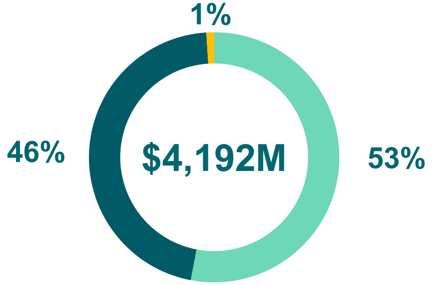
Rate regulated businesses

Hydro One’s regulated business operates under a 5-year rate regulated Custom Incentive Rate Making Framework
Business energizes life for people and communities, helping Ontarians live a better and brighter future



- Regulated pure-play transmission and distribution business with no generation
- 9,700 skilled employees who live and work across Ontario in support of business
- ROE of 9.36% with 40% / 60% deemed equity/debt capital structure through 2027

2023 Revenues, Net of Purchase Power[2]



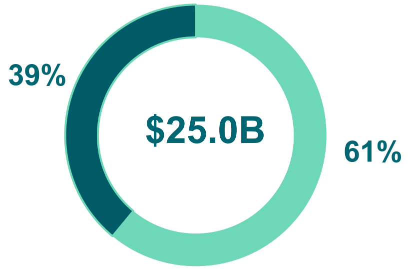
Transmission

35 LDC customers	**87** Large directly connected industrial customers
~30,000 Transmission lines (circuit km)	**309** Transmission stations in service

Distribution

over 90 LDCs consolidated since 1999	**~1.5M** residential and business customers across Ontario
~125,000 Distribution lines (circuit km)	**~1,000** Distribution and regulating stations

2023 Rate Base



1) Based on the network component of the revenue requirement approved by the Ontario Energy Board (OEB). The network component of the revenue requirement is Hydro One’s portion of the transmission revenue requirement attributed to assets that are used for the common benefit of all Hydro One and non-Hydro One customers in the province. Hydro One owns and operates approximately 95% of the transmission system in Ontario when based on the total OEB approved revenue requirement.
2) Revenues, net of purchased power is a non-GAAP financial measure. Non-GAAP financial measures do not have a standardized meaning under United States (US) generally accepted accounting principles (GAAP), which is used to prepare the Company's financial statements and accordingly, these measures might not be comparable to similar financial measures presented by other entities. Additional disclosure in respect of this non-GAAP financial measure is incorporated by reference herein and can be found under the section titled “Non-GAAP Financial Measures” in the Company’s annual management’s discussion and analysis for the year ended December 31, 2023 (Annual MD&A) and in the most recent interim MD&A (Interim MD&A) of the Company, available on SEDAR+ under the Company's profile at. www.sedarplus.com.

Non-Regulated businesses

hydroOne

Unregulated businesses provides opportunity for additional growth; currently accounts for 1% of total assets and 1% of total revenues, net of purchased power

ACRONYM

Acronym Solutions Inc. (formerly, Hydro One Telecom Inc.) offers a comprehensive suite of information and communications technology solutions

ivy Charging Network

Ivy Charging Network™ (Ivy), a joint venture between Hydro One and Ontario Power Generation, providing electric vehicle (EV) fast charging stations across Ontario

aux

Aux Energy Inc. is a behind-the-meter energy company providing auxiliary energy solutions for commercial and industrial customers in Ontario

Executive leadership team

A leadership team with strong operational experience committed to executing Hydro One's strategy

Executive Leadership Team

David Lebeter
President and CEO

Teri French
EVP, Safety, Operations and Customer Experience

Cassidy MacFarlane
General Counsel

Renée McKenzie
EVP, Digital and Technology Solutions

Lisa Pearson
SVP, Corporate Affairs

Andrew Spencer
EVP, Capital Portfolio Delivery

Harry Taylor
EVP, Chief Financial and Regulatory Officer

Megan Telford
EVP, Strategy, Energy Transition and Human Resources

Our refreshed strategy

Our purpose

Energize life with reliable and sustainable solutions for a brighter future

Our vision

A better and brighter future for all

Strategic priorities

Our values

Safety comes first
We make the world a safer place

Stand for people
We believe in equity, diversity and inclusion as the source of our strength

Empowered to act
We recognize our power to improve people's lives

Optimism charges us
We see potential in everything

Win as one
We work together to deliver results

Enrich our customers' experience

1. We deliver easy and exceptional customer experiences
2. We understand and solve our customers' evolving needs
3. We empower our customers to make informed decisions

Enhance grid value needed for sustainable growth

1. We optimize grid assets to create financial value
2. We acknowledge our Indigenous partners as core to our growth
3. We deliver sustainable growth by seizing regulated and unregulated opportunities

Create new solutions for an electrified future

1. We use advanced analytics and digital capabilities to manage an electrified future
2. We collaborate and foster innovation
3. We actively position ourselves as an enabler of the energy transition

Win with partners

1. We collaborate with partners to deliver high value results
2. We create mutually beneficial solutions
3. We are part of a coalition that shapes our net-zero future

Sustainability at Hydro One - 2023 Achievements

At Hydro One, we are committed to operating safely in an environmentally and socially responsible manner and to partnering with our customers and community stakeholders to build a brighter future for all

Target: 30% female executives & board by 2022

~36% / 45%

of women who are executives (VP and above) / board

Target: 50% by 2025, 100% by 2030

~34%

of fleet of sedans/SUVs converted to EVs or hybrids

Target: net-zero by 2050, 30% reduction by 2030[1]

~24%

Reduction in Scope 1 GHG emissions compared to 2018 baseline

Achieved best safety record in our history, delivering a recordable injury rate of 0.56, per 200,000 hours worked

~$2.5 billion in capital investments in 2023 to expand electricity grid and renew and modernize existing infrastructure

~$142 million in Indigenous procurement spend in 2023 (5.7% of sourceable spend; target 5.0% by 2026)[2]

1) Hydro One is currently reviewing its 30% by 2030 target after assessing its Scope 1 and Scope 2 emissions over the past three years.
2) Current target is under review.

Capital Plan

Constructive rate regulator

Ontario Energy Board (OEB) is a consistent, independent regulator with a transparent rate-setting process

- Transmission and Distribution businesses rate-regulated by the OEB
- Deemed debt / equity ratio of 60% / 40% for both transmission and distribution segments
- Reduced regulatory lag through forward-looking test years, revenue decoupling and adjustment mechanisms
- JRAP proposal for transmission and distribution under the OEB's Custom Incentive Rate Making Framework for 2023 – 2027 (5-year term) was successfully settled and approved by the OEB on November 29, 2022

	Rate methodology	Allowed ROE[1]	Expected JRAP rate base[2,4]	Effective term of application	Comments
Transmission	Custom IR	2024 9.36%	2024 $15.3B	2023–27	Custom incentives rates. Application approved November 29, 2022

	Rate methodology	Allowed ROE[1]	Expected JRAP rate base[3,4]	Effective term of application	Comments
Distribution	Custom IR	2024 9.36%	2024 $10.0B	2023–27	Custom incentives rates. Application approved November 29, 2022

1) Allowed ROE for 2023-2027 for JRAP Transmission and Distribution reflects the cost of capital update from the OEB on October 20, 2022.
2) JRAP Transmission rate base excludes 100% of B2M Limited Partnership (LP), Niagara Reinforcement LP, Hydro One Sault Ste. Marie LP and new transmission lines.
3) JRAP Distribution rate base excludes LDC acquisitions (Peterborough Distribution Inc., Orillia Power Distribution Corporation) and Hydro One Remote Communities.
4) Reflects OEB Approved Settlement on November 29, 2022.

JRAP – Segmented incentive regulatory construct

	Distribution OEB Approved[1] 2023-2027	Transmission OEB Approved[1] 2023-2027
Rebasing Year	**2023**	**2023**
Revenue Requirement Determined By	Custom Revenue Cap Index (RCI) by Component (%) **(A)** Inflation Adjustment Factor **(B)** Less: Productivity Stretch Factor Offset **(C)** Add: Capital Factor[2] **(D)** Equals: Custom Revenue Cap Index Total	Custom Revenue Cap Index (RCI) by Component (%) **(A)** Inflation Adjustment Factor **(B)** Less: Productivity Stretch Factor Offset **(C)** Add: Capital Factor[2] **(D)** Equals: Custom Revenue Cap Index Total
Earnings Sharing Method	50% of earnings that exceed allowed ROE by more than 100 basis points in any year of the term of the filing is shared with customers	
OEB ROE (Cost of Capital)	9.36% through test years (2023-2027)	9.36% through test years (2023-2027)
Effective Rate Setting	January 1, 2023	January 1, 2023

Distribution – Revenue Requirement Determined By:

	2023	2024[3]	2025	2026	2027
(A)	2023 revenue requirement of $1,727 million	4.80%	3.70%	3.70%	3.70%
(B)		(0.45%)	(0.45%)	(0.45%)	(0.45%)
(C)		1.01%	0.79%	1.96%	1.12%
(D)		5.36%	4.04%	5.21%	4.37%

Transmission – Revenue Requirement Determined By:

	2023	2024[4]	2025	2026	2027
(A)	2023 revenue requirement of $1,952 million	5.40%	3.80%	3.80%	3.80%
(B)		(0.15%)	(0.15%)	(0.15%)	(0.15%)
(C)		1.27%	0.93%	1.38%	0.08%
(D)		6.52%	4.58%	5.03%	3.73%

1) Source: 2023-2027 Distribution and Transmission Revenue Requirement, Custom Revenue Cap Index Parameters and ROE as approved by the OEB on November 29, 2022.
2) The capital factor will be adjusted each year depending on changes to inflation to ensure that Hydro One recovers the OEB-approved capital related revenue requirement adjusted for productivity.
3) 2024 Distribution revenue requirements and the associated RCI components as approved by the OEB on December 14, 2023.
4) 2024 Transmission revenue requirements and the associated RCI components as approved by the OEB on September 19, 2023.

Capital Plan to support rate base growth

- Organic growth underpinned by continued rate base expansion to both renew and modernize the grid
- Material amounts of deteriorated, end-of-service life infrastructure must be upgraded or replaced
- Customers supportive of replacing aging infrastructure that is in poor condition
- Equity issuance not anticipated for planned capital investment program which is self-funded

1) Reflects settlement agreement approved by the OEB on November 29, 2022.
2) Figures include investments in certain development projects of Hydro One Networks not included in the investment plan approved with JRAP. 2025-2027 years contain Chatham by Lakeshore Transmission Line, and Waasigan Transmission Line.

$11.8 billion

2022 – 2027 Capital Plan

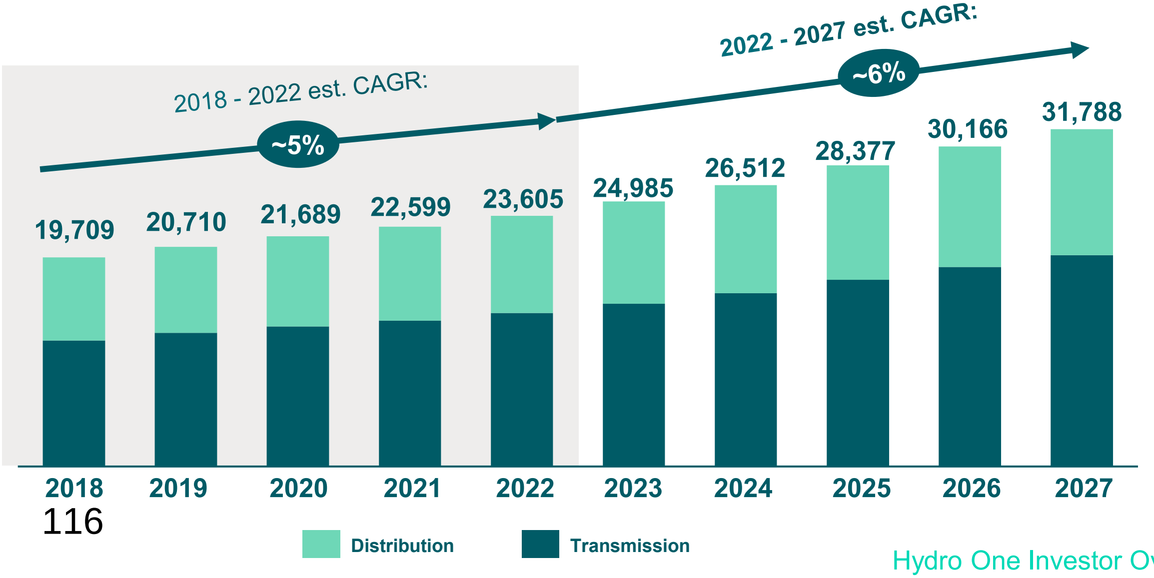
Agreement on ~$11.8 billion in capital expenditure reflects a balanced settlement for all stakeholders[1]

~6%

JRAP Rate Base CAGR

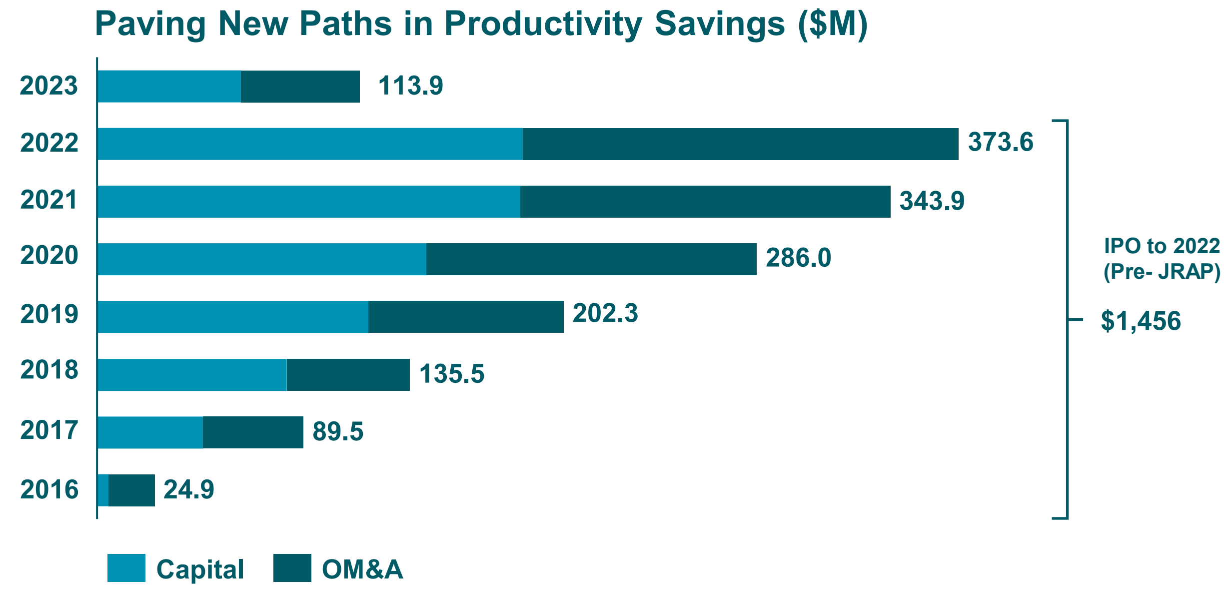
Rate base forecast to grow from $23.6 billion in 2022 to $31.8 billion in 2027

Historical and Projected Rate Base Growth[2] ($M)



Achievements and efficiencies

hydro One



Generated productivity savings of $113.9 million in 2023 comprised of $62.4 million in OM&A and $51.5 million in capital

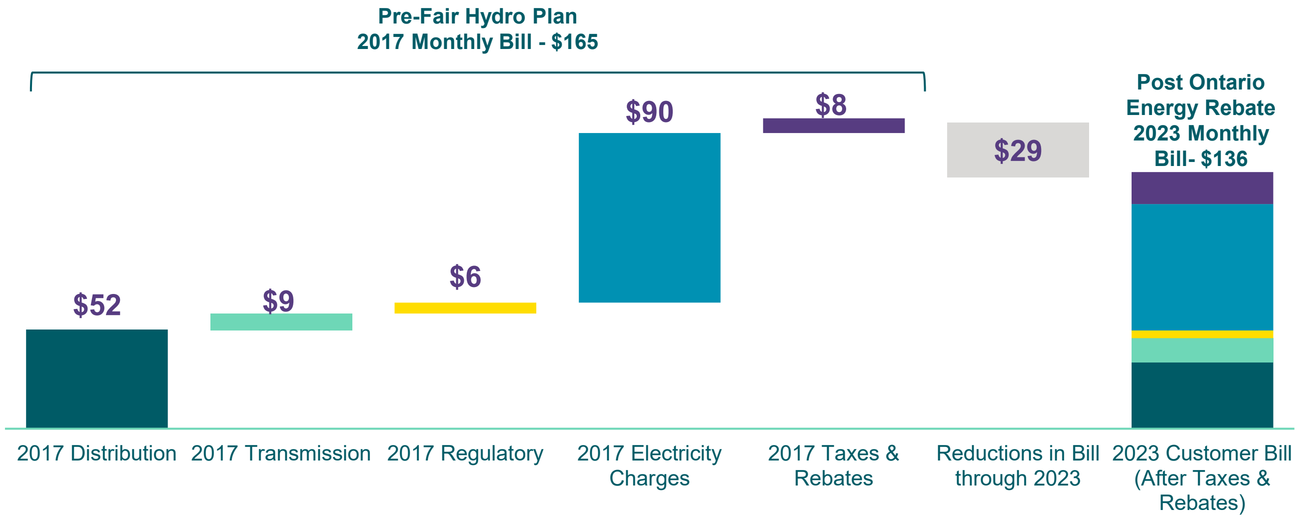
Cost efficiencies from outsourcing equipment testing and inspecting, pole refurbishments, clearing of vegetation growth, and station planning & construction

Strategic sourcing initiatives led to cost reductions for materials and services by leveraging index and market information along with vendor diversification

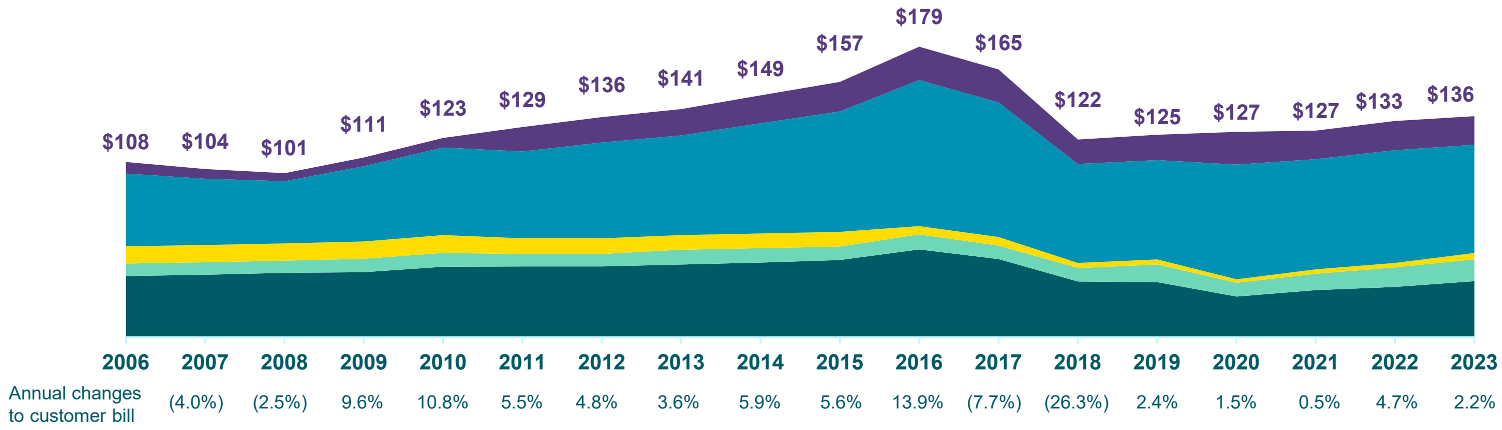
Managing our Facilities and Real Estate contracts led to reduced lease and operating costs

Reducing our customer bills

Since 2017, typical Hydro One residential customer bills have decreased on average from $165 to $136 per month



	% of 2023 Bill[1]
Taxes	13%
Electricity Charges	49%
Regulatory	3%
Transmission	10%
Distribution	25%



	Pre-Fair Hydro Plan CAGR[1,2] 2006-2017	Post Ontario Energy Rebate CAGR[1,2] 2006-2023	
Taxes	1.0%	5.5%	Electricity & other charges
Electricity Charges	6.6%	2.4%	
Regulatory	(5.4%)	(5.7%)	
Transmission	1.4%	3.3%	Hydro One's Portion
Distribution	3.0%	(0.5%)	

Note: The charts represent the breakdown of a typical bill for a Hydro One medium-density residential local distribution end customer using 750 kWh a month. Subject to update upon effective rate setting.

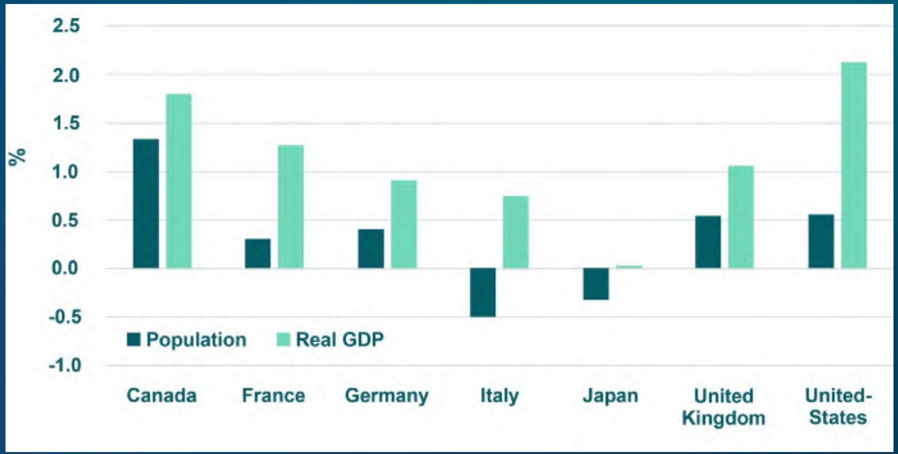
1) Each component includes applicable bill rebates.
2) Compounded Annual Growth Rate.

Growth Update

Why Ontario

Increased capital investment to enable energy transition and enhance grid stability

Average Population and Real GDP Growth Rates for G7 Countries, 2016-2022



Ontario growth in electricity demand

Canada's electricity demand expected to grow between 120% - 135% from 2021 to 2050 to achieve Net Zero target

- Consumer choices, corporate ESG targets and government policies are driving the electrification of transportation, home heating and heavy industry
- Technological advancements and focus on decarbonization expected to drive additional connection to new sources/uses of power

There has been an acceleration and resurgence in industrial activities in Ontario – affects peak demand (Tx)

- Over 90% of the electricity generated in Ontario came from non-emitting sources, attracting investment[1]
- EV battery manufacturing in Windsor
- Mining activities in northern Ontario
- Agricultural development in southern Ontario

There is a large influx of immigrants to support this growth – affects the number of connections (Dx)

- Immigration targets of 0.5 million for 2024 and 2025 up from 0.3 million historical average
- 58% of new immigrants are selected on economic basis, supporting a knowledge-based economy

Canada is among the fastest growing nations within G7

- Highest population growth in G7
- Second highest GDP growth in G7
- Commitment by Federal government for further growth through immigration

Source: Canada Energy Regulator, IMF Reports, IMF – World Development Indicators for 2016-2021, Government of Canada, Government of Ontario

1) IESO, Pathways to Decarbonization, December 15, 2022. https://www.ieso.ca/-/media/Files/IESO/Document-Library/gas-phase-out/Pathways-to-Decarbonization.ashx

Capital investment driving rate base growth

Project Name	Location	Type	Length (KM)	Estimated Cost ($M)	In-service Date
Chatham to Lakeshore Transmission Line[1]	Southwestern Ontario	230 kV	49	237	2024
St. Clair Transmission Line[1]	Southwestern Ontario	230 kV	64	472	2028
Waasigan Transmission Line[1]	Northwestern Ontario	230 kV	360	1,200	2025/2027
Longwood to Lakeshore Transmission Line	Southwestern Ontario	500 kV	TBD	TBD	TBD
Second Longwood to Lakeshore Transmission Line	Southwestern Ontario	500 kV	TBD	TBD	TBD
Lakeshore to Windsor Transmission Line	Southwestern Ontario	230 kV	TBD	TBD	TBD
North Shore Link[2]	Northeastern Ontario	230 kV	~75	TBD	TBD
Northeast Power Line[2]	Northeastern Ontario	500 kV	~200	TBD	TBD
Durham Kawartha Power Line[2]	Eastern Ontario	230 kV	~50	TBD	TBD

1) Data as per regulatory filings.
2) North Shore Line (formerly Mississagi to Third Line); Northeast Power Line (formerly Hanmer to Mississagi Line); Durham Kawartha Power Line (formerly Greater Toronto Area Least Line).

Electric Local Distribution Company (LDC) consolidation

Consolidator of Choice

- Hydro One is the largest LDC in Ontario; 54 LDCs are Hydro One transmission or distribution customers
- Hydro One has significant scale in Ontario and serves customers through a distribution system spanning 125,000 circuit kilometers

Historical Acquisitions

- Hydro One has acquired more than 90 LDCs in Ontario since the year 1999
- Recent acquisitions include Chapleau (2024), Peterborough and Orillia (2020), Woodstock and Haldimand (2015) and Norfolk (2014)

Synergy Potential

- Hydro One can offer Ontario's fragmented distribution sector significant synergies
- Peterborough, Orillia, Woodstock, Haldimand and Norfolk are anticipated or have realized OM&A savings of over 50%

Addressable Market

- 53 LDCs[1] in Ontario
- Total rate base of approximately $15B[1], of which the largest 5 LDCs account for approximately $11B[1]

Consolidation Strategy

- Hydro One is focused on engaging communities, municipalities and LDCs as partners in a number of ways
- Hydro One will likely realize greater synergies than other potential acquirers especially if a target is contiguous to Hydro One's existing service territory

Completed transaction

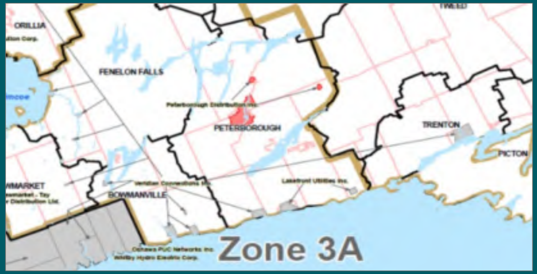
Chapleau Hydro

Transaction closed on August 1, 2024

Orillia Power Distribution Corporation

Transaction closed on September 1, 2020

Peterborough Distribution Inc.



Transaction closed on August 1, 2020

1) Excluding Hydro One Networks Inc.

Financial Update

Guidance range

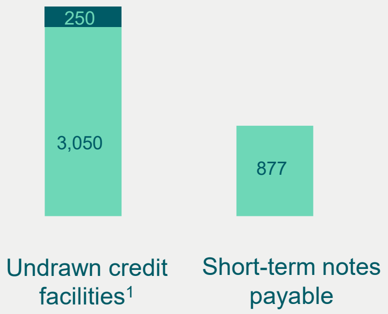
1) Normalizing for 2023 rebase includes 100 basis points over-earn.
2) EPS growth does not include Local Distribution Company Acquisitions, and 7 out of the 9 Transmission Lines. Growth includes the Chatham to Lakeshore and Waasigan transmission lines .

Note: The forward-looking information in this presentation is based on a variety of factors and assumptions described in the Annual MD&A and Interim MD&A. Actual results may differ from those predicted by such forward-looking information. See “Disclaimers – Forward-Looking Information.”

Strong balance sheet and liquidity

Investment grade balance sheet with one of lowest debt costs in utility sector

Significant available liquidity ($M)



Strong investment grade debt ratings (long-term/short-term/outlook)

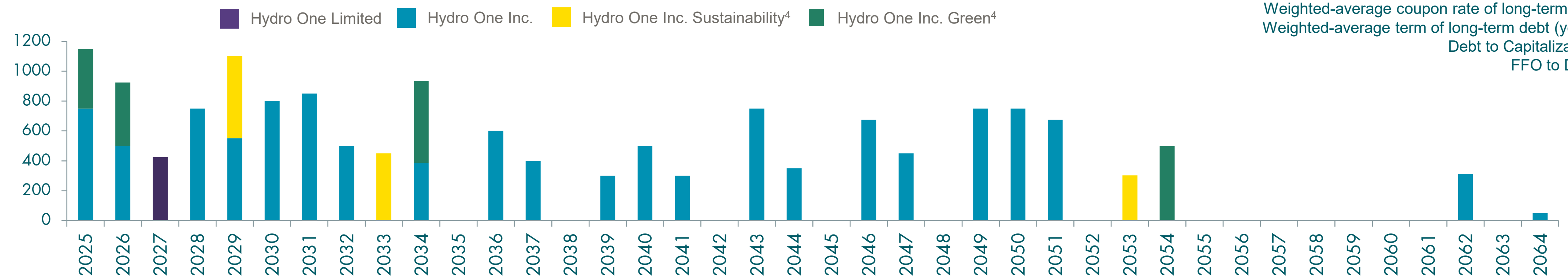
	Hydro One Limited (HOL)	Hydro One Inc. (HOI)
S&P	A- / n/a / stable	A / A-1 (mid) / stable
DBRS	A / n/a / stable	A (high) / R-1 (low) / stable
Moody's	n/a	A3 / Prime-2 / stable

Shelf registrations

HOL
Universal shelf[2]
$2.0B

HOI
Medium-Term Note shelf[3]

Debt maturity schedule ($M)



Weighted-average coupon rate of long-term debt:	4.2%
Weighted-average term of long-term debt (years):	13.5
Debt to Capitalization[5]:	57.8%
FFO to Debt[6]:	13.6%

1) The Operating Credit Facilities include a pricing adjustment which can increase or decrease Hydro One's cost of funding based on its performance on certain Sustainability Performance Measures, which are related to Hydro One's sustainability goals. On June 1, 2024, the HOI credit facilities were increased by $750 million and maturity date extended from 2028 to 2029.
2) In August 2022, HOL filed a universal short form base shelf prospectus (Universal Base Shelf Prospectus) with securities regulatory authorities in Canada, which allows it to offer, from time to time in one or more public offerings, up to $2.0 billion of debt, equity or other securities, or any combination thereof, and expires in September 2024. At June 30, 2024, $2.0 billion remained available for issuance under the Universal Base Shelf Prospectus. A new universal base shelf prospectus is expected to be filed in the third quarter of 2024.
3) In February 2024, HOI filed a short form base shelf prospectus in connection with its Medium-Term Note (MTN) Program, which expires in March 2026.
4) Sustainability and Green bonds (MTN) issued pursuant to Hydro One's Sustainable Financing Framework.
5) Debt to capitalization is a non-GAAP ratio. See the section titled "Non-GAAP Financial Measures" in the Annual MD&A and Interim MD&A which are incorporated by reference, for a discussion of this non-GAAP ratio and its component elements.
6) FFO to Debt is a non-GAAP ratio. See the section titled "Non-GAAP Financial Measures" in the Annual MD&A and Interim MD&A for a discussion of these component elements.

Hydro One's Sustainable Financing Framework Overview

Under the Framework, Hydro One may issue Sustainable, Green or Social bonds, loans or commercial paper

Program developed to support Hydro One's ESG commitments

Program aligned with UN Sustainable Development Goals

$3.2 billion

Proceeds raised under program

Green Grid

Transmission and Distribution Investments Enable the Greening of the Overall Grid

Socio-Economic Benefits

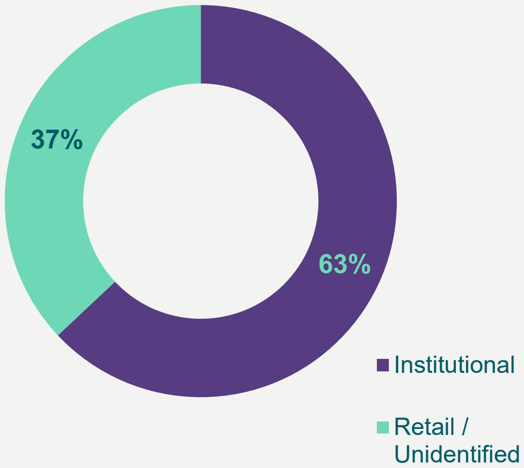
Procurement from Indigenous Businesses and access to essential services

- **Clean Energy**
  Transmission and distribution infrastructure that delivers low-carbon electricity
- **Energy Efficiency**
  Smart grid technology, energy storage, monitoring equipment
- **Clean Transportation**
  EVs, hybrids, electric charging stations
- **Biodiversity Conservation**
  Natural habitat protection initiatives
- **Climate Change Adaptation**
  Investments to enhance resiliency of electrical grid from extreme weather-related events
- **Socio-economic advancement of Indigenous Peoples**
  Procurement from Indigenous Businesses
- **Access to Essential Services**
  Enabling high-speed broadband internet access to unserved and underserved

Equity market cap overview

hydroOne

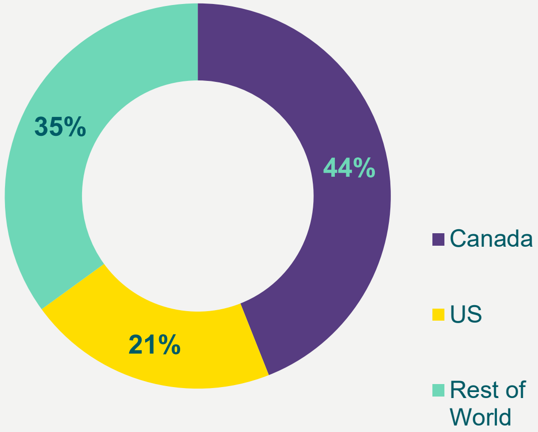
Approximate Ownership of Public Float[1]



Equity Index Inclusions

S&P/TSX Composite Index	S&P/TSX Composite Dividend Index	FTSE All-World (Canada)
S&P/TSX 60 Index	S&P/TSX Composite High Dividend Index	MSCI World (Canada)
S&P/TSX Utilities Index	S&P/TSX Composite Low Volatility Index	Dow Jones Canada Select Utilities
S&P/TSX Canadian Dividend Aristocrats Index		

Approximate Geographic Dispersion of Public Float[1]



Comments

- ~599.4 million common shares outstanding, listed on Toronto Stock Exchange (TSX: H)
- Equity market capitalization[2] of ~$23.9 billion and public float of ~$12.6 billion
- Equity market capitalization amongst the top 50 of all TSX-listed Canadian companies

1) Provincial Government ownership as at June 30, 2024 was 47.1%. Data source: S&P Global.
2) Based on closing share price of the common shares of Hydro One Limited on June 28, 2024.

Common share dividends

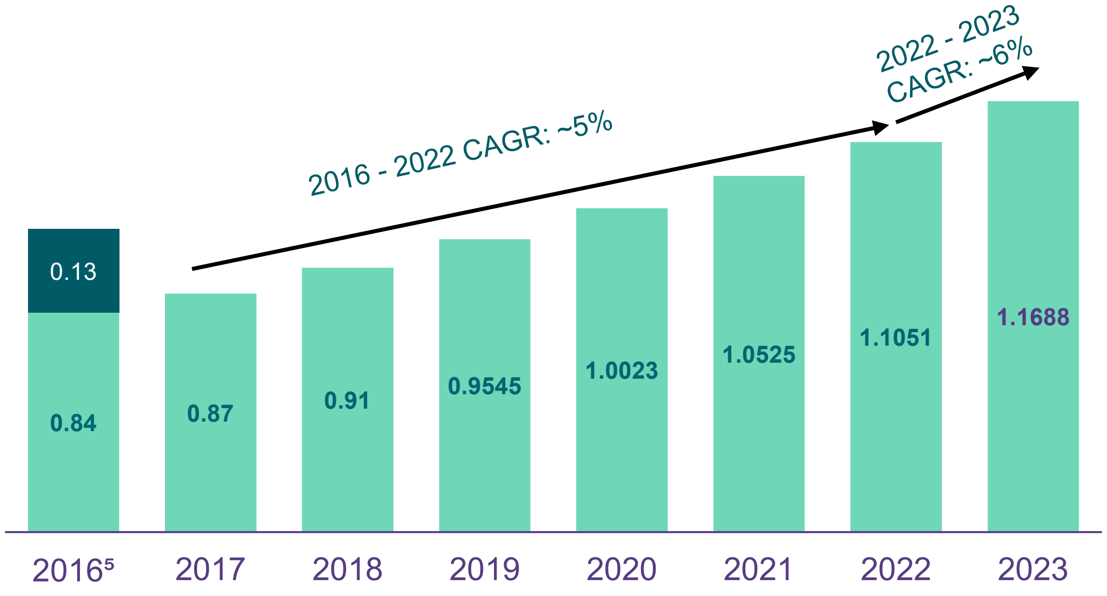
Key Points

- Quarterly dividend declared at $0.3142 per common share ($1.2568 annualized)
- Targeted dividend payout ratio remains at 70% - 80% of net income
- Attractive and growing dividend supported by stable, regulated cash flows and planned rate base growth
- No equity issuance anticipated to fund planned capital investment program
- Non-dilutive dividend reinvestment plan (DRIP) in place (shares purchased on open market, not issued from treasury)

Dividend Statistics

Yield[1]	3.2%
Annualized Dividend[2,3]	$1.2568 / share

A Growing and Sustainable Dividend[4]



Expected Quarterly Dividend Dates[3]

Declaration date	Record date	Payment date
August 13, 2024	September 11, 2024	September 27, 2024
November 6, 2024	December 11, 2024	December 31, 2024

1) Yield is calculated based on annualized dividend divided by closing share price of the common shares of Hydro One Limited on June 28, 2024.
2) Unless indicated otherwise, all common share dividends are designated as "eligible" dividends for the purpose of the Income Tax Act (Canada).
3) All dividend declarations and related dates are subject to Board approval.
4) Denotes annual cash dividends paid.
5) The first common share dividend declared by Hydro One Limited following the November 5, 2015 initial public offering of its common stock included 13 cents for the post IPO fourth quarter period of November 5 through December 31, 2015.

Appendix

2Q24 Financial summary

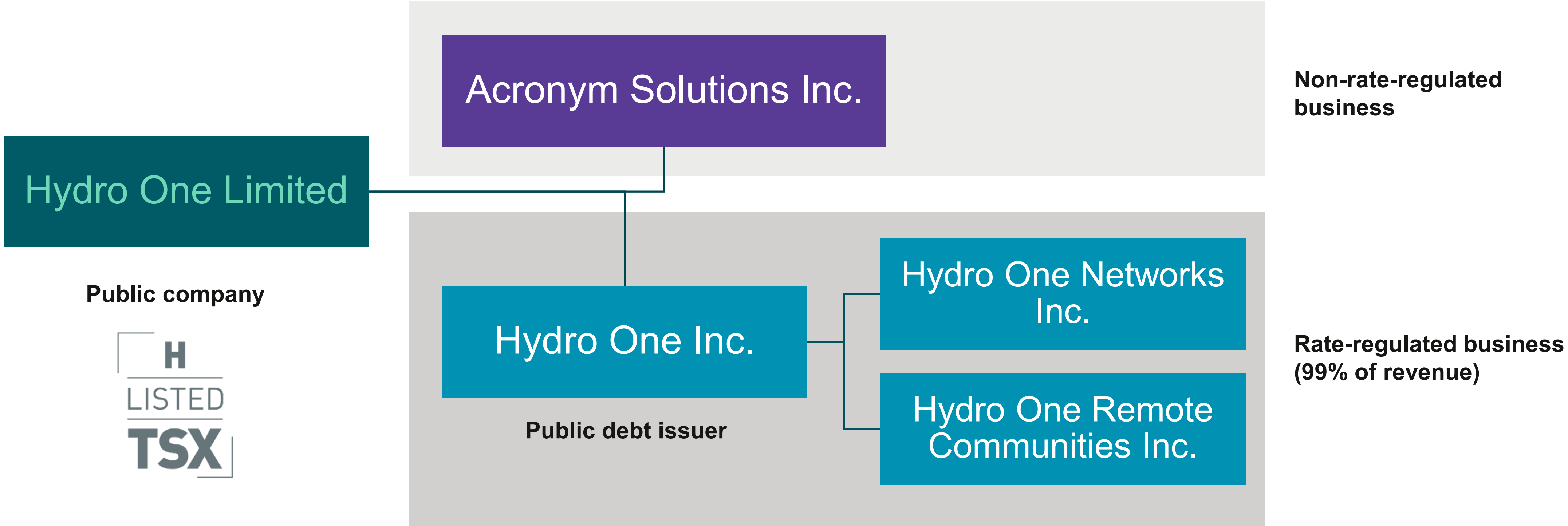
(millions of dollars, except EPS)	Second Quarter 2024	Second Quarter 2023	% Change	Year to Date 2024	Year to Date 2023	% Change
Revenues						
Transmission	583	559	4.3%	1,136	1,114	2.0%
Distribution	1,436	1,285	11.8%	3,041	2,794	8.8%
Distribution Revenues (Net of Purchased Power)[1]	496	487	1.8%	1,005	986	1.9%
Other	12	13	(7.7%)	20	23	(13.0%)
Consolidated	**2,031**	**1,857**	**9.4%**	**4,197**	**3,931**	**6.8%**
Consolidated Revenue (Net of Purchased Power)[1]	1,091	1,059	3.0%	2,161	2,123	1.8%
OM&A Costs	319	336	(5.1%)	641	664	(3.5%)
Earnings before financing charges and income taxes (EBIT)						
Transmission	336	309	8.7%	635	613	3.6%
Distribution	188	181	3.9%	399	373	7.0%
Other	(15)	(14)	(7.1%)	(31)	(26)	(19.2%)
Consolidated	**509**	**476**	**6.9%**	**1,003**	**960**	**4.5%**
Net income[2]	292	265	10.2%	585	547	6.9%
Basic EPS	$0.49	$0.44	11.4%	$0.98	$0.91	7.7%
Capital investments	818	649	26.0%	1,491	1,148	29.9%
Assets placed in-service						
Transmission	290	213	36.2%	354	328	7.9%
Distribution	233	193	20.7%	405	315	28.6%
Other	3	7	(57.1%)	7	7	-%
Total assets placed in-service	526	413	27.4%	766	650	17.8%

Financial Statements reported under U.S. GAAP

1) Revenues, Net of Purchased Power is a non-GAAP financial measure. Non-GAAP financial measures do not have a standardized meaning under US GAAP, which is used to prepare the Company's financial statements and accordingly, these measures might not be comparable to similar financial measures presented by other entities. Additional disclosure for this non-GAAP financial measure is incorporated by reference herein and can be found under the section titled "Non-GAAP Financial Measures" in the Annual MD&A and Interim MD&A available on SEDAR+ under the Company's profile at www.sedarplus.com.
2) Net Income is attributable to common shareholders and is after non-controlling interest.

A look at the organization

Corporate structure



Independent board of directors

hydroOne

Timothy Hodgson
Chair of the Board
Director since 2018

Cherie Brant
Director since 2018

David Hay
Chair of the Indigenous Peoples, Safety & Operating Committee
Director since 2018

Stacey Mowbray
Chair of the Audit Committee
Director since 2020

Mitch Panciuk
Director since 2023

Mark Podlasly
Director since 2022

Helga Reidel
Director since 2023

Melissa Sonberg
Chair of the Human Resources Committee
Director since 2018

Brian Vaasjo
Director since 2023

Susan Wolburgh Jenah
Chair of the Governance & Regulatory Committee
Director since 2020

Note: The only non-independent director is David Lebeter, President and CEO of Hydro One Limited.

Board of Director full bios are available at: https://www.hydroone.com/about/corporate-information/senior-leadership-and-board.

Regulatory stakeholders

Who: Provincial Government, Ministry of Energy
What: Policy, legislation, regulations

Who: Ontario Energy Board
What: Independent electric utility price and service quality regulation

Who: Independent Electricity System Operator
What: Wholesale power market rules, intermediary, North American reliability standards

Who: Canadian Energy Regulator
What: Federal regulator, international power lines and substations

Who: North American Electric Reliability Corporation
What: Continent-wide bulk power reliability standards, certification, monitoring

Who: Northeast Power Coordinating Council
What: Northeastern North American grid reliability, standards, compliance

Disclaimers

Forward Looking Information

This presentation contains “forward-looking information” within the meaning of applicable Canadian securities laws and “forward-looking statements” within the meaning of applicable U.S. securities laws (collectively, “forward-looking information”. Statements containing forward-looking information are made pursuant to the “safe harbour” provisions of applicable Canadian and U.S. securities laws and is based on current expectations, estimates, forecasts and projections about Hydro One Limited’s (Hydro One or the Company) business and the industry in which Hydro One operates and includes beliefs of and assumptions made by management of Hydro One. Such information includes, but is not limited to: statements related to Hydro One’s transmission and distribution regulatory applications, and expected impacts and timing; Hydro One’s projected rate base, cash flows and EPS; statements regarding Hydro One’s organic growth profile and expected rate base CAGR; expectations regarding future equity issuances; expectations to modernize infrastructure and to invest in the health of the distribution system; statements regarding Hydro One’s projected capital investments, and related plans, funding and expectations; statements related to Hydro One’s ongoing and planned projects, including estimated cost and anticipated in-service dates of capital projects; statements regarding Hydro One’s consolidation strategy, including expectations regarding potential synergies to the Company; statements relating to Hydro One’s strategy, expectations regarding growth opportunities for the telecom business; statements about Hydro One’s ongoing and planned sustainability priorities and commitments, including target dates, as they relate to diversity, equity and inclusion, climate change mitigation and adaption, Indigenous and community partnerships and other initiatives and related plans; Hydro One's commitment to achieving 30% female executives and female board members; Hydro One's commitment to achieving a target of 30% reduction of GHG emissions by 2030 and net-zero GHG emissions by 2050 including the Company’s review of its 2030 30% GHG reduction target; Hydro One's commitment to increasing Indigenous procurement spend to 5% of total procurement spend by 2026 including the Company’s review of such target; plans to convert 50% of Hydro One's fleet of sedans and SUVs to electric or hybrid EVs by 2025 and 100% by 2030; expectations regarding Hydro One’s maturing debt and standby credit facilities; expectations that a new universal shelf will be filed for HOL in the third quarter of 2024; statements related to dividends, dividend growth, Hydro One Limited’s targeted payout ratio of 70-80%; statements and guidance relating to EPS growth over 2023 to 2027, relative to a normalized 2022 earnings; and statements related to credit ratings.

Words such as “aim”, “could”, “would”, “expect”, “anticipate”, “intend”, “attempt”, “may”, “plan”, “will”, “believe”, “seek”, “estimate”, “goal”, “target” and variations of such words and similar expression are intended to identify such forward-looking information. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. In particular, the forward-looking information contained in this presentation is based on a variety of factors and assumptions including, but not limited to: no unforeseen changes in the legislative and operating framework for Ontario’s electricity market or for Hydro One specifically; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining required approvals; no unforeseen changes in rate orders or rate setting methodologies for Hydro One’s distribution and transmission businesses; no unfavourable changes in environmental regulation; the continued use and availability of US GAAP; a stable regulatory environment; no significant changes to Hydro One’s current credit ratings; no unforeseen impacts of new accounting pronouncements; no changes to expectations regarding electricity consumption; no unforeseen changes to economic and market conditions; completion of operating and capital projects that have been deferred; Ontario’s electricity demand will increase moderately compared to 2021 demand; energy generation and supply composition will be favourable and support the achievement of GHG emission reduction targets; new GHG mitigation technologies will become more available and more affordable; Hydro One’s growth and activities will be consistent with the information included in its first joint rate application; the number of Hydro One vehicles and facilities will not change significantly; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to Hydro One including information obtained by Hydro One from third-party sources. Actual results may differ materially from those predicted by such forward-looking information. While Hydro One does not know what impact any of these differences may have, Hydro One’s business and results of operations, financial condition and credit stability may be materially adversely affected if any such differences occur.

Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking information are discussed in more detail in the sections entitled “Forward-Looking Information” and “Risk Factors” in Hydro One Limited’s most recent annual information form and the sections entitled “Risk Management and Risk Factors” and “Forward-Looking Statements and Information” in the Annual MD&A and Interim MD&A. Hydro One does not intend, and it disclaims any obligation to update any forward-looking information, except as required by law.

In this presentation, Hydro One presents information about future rate base growth and potential future capital investments and guidance in respect of 2027 basic earnings per share. The purpose of providing information about future rate base growth, potential future capital investments and financial guidance is to give context to the nature of some of Hydro One’s future plans and may not be appropriate for other purposes. Information about future rate base growth, potential future capital investments and financial guidance, including the various assumptions underlying it, should be read in conjunction with “Forward-Looking Information” above and as may be found in Hydro One's filings with the securities regulatory authorities in Canada, which are available under its profile on SEDAR+ at www.sedarplus.com. Hydro One does not intend to update the information about future rate base growth or future capital investments or guidance about 2027 EPS except as required by applicable securities laws.

All dollar amounts in this presentation are in Canadian dollars, unless otherwise indicated. Unless otherwise expressly stated herein, all information in this presentation is presented as at June 30, 2024.

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Ontario Energy Association (OEA)

Answer to Interrogatory from
Consumers Council of Canada (CCC)

INTERROGATORY

Reference:

Ex. M2/pp. 46, 47-50 and Exhibit CEA-2
Ex. M1/p. 129

Question(s):

For each company in each proxy group listed in Exhibit CEA-2, 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 CCC
    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:

Please see CCC-4, Attachment 1, for the information requested in parts (a) through (i), to the extent that information was readily available. Concentric does not have the details requested in part (j) at its disposal. However, please see CCC-4, Attachment 2, which provides ratemaking details and regulatory mechanisms of the operating companies of the companies listed in Exhibit CEA-2.

CANADIAN PROXY GROUP

Company Name	Ticker	S&P Credit Rating	S&P Business Rating	S&P Financial Risk Rating	% of Operating Income from Regulated Operations	% of Regulated Operating Income from Regulated Electric Operations	Raw Five-Year Bloomberg Beta	Adjusted Five-Year Bloomberg Beta	Regulatory Agency(ies)	Regulatory Agency S&P Global Credit Supportiveness Rating
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
AltaGas Limited	ALA	BBB-	Strong	Aggressive	38%	n/a	1.23	1.16	Alberta Utilities Commission, Multiple U.S. Jurisdictions	Highly Credit Supportive; multiple U.S. rankings
Canadian Utilities Limited	CU	A-*	n/a	n/a	92%	n/a	0.79	0.86	Alberta Utilities Commission	Highly Credit Supportive
Emera Inc.	EMA	BBB	Excellent	Aggressive	100%	n/a	0.58	0.72	Nova Scotia Utility and Review Board, Florida Public Service Commission, New Mexico Public Regulation Commission	Credit Supportive, Most Credit Supportive, Credit Supportive
Enbridge Inc.	ENB	BBB+	Excellent	Aggressive	13%	n/a	0.90	0.93	Ontario Energy Board, Régie de l'énergie	Most Credit Supportive (both)
Fortis, Inc.	FTS	A-	Excellent	Significant	99%	n/a	0.58	0.72	Multiple (four or more jurisdictions)	Multiple (four or more jurisdictions)
Hydro One, Ltd.	H	A**	Excellent	Significant	102%	n/a	0.54	0.69	Ontario Energy Board	Most Credit Supportive

**Credit rating from Fitch*

***Upgraded from A- to A from S&P on June 10, 2024*

U.S. ELECTRIC PROXY GROUP

Company Name	Ticker	Credit Rating	S&P Business Rating	S&P Financial Risk Rating	% of Operating Income from Regulated Operations	% of Regulated Operating Income from Regulated Electric Operations	Raw Five-Year Bloomberg Beta	Adjusted Five-Year Bloomberg Beta	Regulatory Agency(ies)	Regulatory Agency S&P Global Credit Supportiveness Rating
Alliant Energy Corporation	LNT	A-	Excellent	Significant	97%	91%	0.81	0.87	Iowa Utilities Board, Public Service Commission of Wisconsin	Most Credit Supportive (both)
Ameren Corporation	AEE	BBB+	Excellent	Significant	98%	85%	0.76	0.84	Missouri Public Service Commission, Illinois Commerce Commission	Very Credit Supportive (both)
American Electric Power Company, Inc.	AEP	BBB+	Excellent	Significant	98%	100%	0.77	0.84	Multiple (four or more jurisdictions)	Multiple (four or more jurisdictions)
Duke Energy Corporation	DUK	BBB+	Excellent	Significant	95%	90%	0.74	0.82	Multiple (four or more jurisdictions)	Multiple (four or more jurisdictions)
Entergy Corporation	ETR	BBB+	Excellent	Significant	99%	99%	0.96	0.97	Multiple (four or more jurisdictions)	Multiple (four or more jurisdictions)
Eversource Energy	ES	A-	Excellent	Significant	95%	81%	0.85	0.90	Massachusetts Department of Public Utilities, Connecticut Public Utilities Regulatory Authority, New Hampshire Public Utilities Commission	Highly Credit Supportive, More Credit Supportive, Highly Credit Supportive
Exelon Corporation	EXC	BBB+	Excellent	Significant	100%	91%	0.97	0.98	Multiple (four or more jurisdictions)	Multiple (four or more jurisdictions)
Evergy, Inc.	EVRG	BBB+	Excellent	Significant	100%	100%	0.84	0.89	Kansas Corporation Commission, Missouri Public Service Commission	Highly Credit Supportive, Very Credit Supportive
NextEra Energy, Inc.	NEE	A-	Excellent	Significant	88%	100%	0.87	0.91	Florida Public Service Commission	Most Credit Supportive
OGE Energy Corporation	OGE	BBB+	Excellent	Significant	100%	100%	1.03	1.02	Oklahoma Corporation Commission, Arkansas Public Service Commission	Very Credit Supportive, Highly Credit Supportive
Pinnacle West Capital Corporation	PNW	BBB+	Excellent	Significant	100%	100%	0.90	0.94	Arizona Corporation Commission	More Credit Supportive
PPL Corporation	PPL	A-	Excellent	Significant	100%	94%	1.10	1.07	Kentucky Public Service Commission, Pennsylvania Public Utilities Commission, Rhode Island Public Utilities Commission	Most Credit Supportive, Highly Credit Supportive, Very Credit Supportive
Portland General Electric Company	POR	BBB+	Excellent	Significant	100%	100%	0.82	0.88	Oregon Public Utility Commission	More Credit Supportive
Southern Company	SO	A-	Excellent	Significant	94%	82%	0.85	0.90	Multiple (four or more jurisdictions)	Multiple (four or more jurisdictions)
Xcel Energy Inc.	XEL	BBB+	Excellent	Significant	100%	86%	0.74	0.83	Multiple (four or more jurisdictions)	Multiple (four or more jurisdictions)

U.S. GAS PROXY GROUP

Company Name	Ticker	Credit Rating	S&P Business Rating	S&P Financial Risk Rating	% of Operating Income from Regulated Operations	% of Regulated Operating Income from Regulated Gas Operations	Raw Five-Year Bloomberg Beta	Adjusted Five-Year Bloomberg Beta	Regulatory Agency(ies)	Regulatory Agency S&P Global Credit Supportiveness Rating
Atmos Energy Corp.	ATO	A-	Excellent	Significant	100%	100%	0.74	0.83	Multiple (four or more jurisdictions)	Multiple (four or more jurisdictions)
Northwest Natural Gas Company	NWN	A+	Excellent	Intermediate	100%	91%	0.62	0.74	Oregon Public Utility Commission, Washington Utilities and Transportation Commission	More Credit Supportive
ONE Gas, Inc.	OGS	A-	Excellent	Significant	100%	100%	0.75	0.83	Kansas Corporation Commission, Oklahoma Corporation Commission, Railroad Commission of Texas	Highly Credit Supportive, Very Credit Supportive, Highly Credit Supportive
Spire, Inc.	SR	BBB+	Excellent	Aggressive	83%	100%	0.80	0.86	Missouri Public Service Commission, Alabama Public Service Commission, Mississippi Public Service Commission	Very Credit Supportive, Most Credit Supportive, Very Credit Supportive

Notes:
[1] - [3] Source: S&P Global, as of August 15, 2024
[4] - [5] Source: Form 10-Ks; 2021-2023 three-year average
[6] - [7] Source: Bloomberg Professional, as of May 31, 2024
[8] Source: Company websites and filings
[9] Source: S&P Global RatingsDirect, "North American Utility Regulatory Jurisdictions Update: Ontario Remains Unchanged, Notable Developments Elsewhere", March 11, 2024

Proxy Group Regulatory Risk Assessment

Company	Ticker	Operating Subsidiary	Service Type	Jurisdiction	Test Year	Credit Rating	Credit Rating (numerical)	Authorized ROE (%)	Authorized Equity Ratio (%)	Electric fuel/gas commodity/purch. power	Full Decoupling	Partial Decoupling	Conserv. program expense	Renewables/ Non-Traditional Generation	Environmental compliance	Delivery infrastructure	Transmission costs	Capital Cost Recovery
					[1]	[2]	[3]	[4]	[4]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]
Canadian Proxy Group																		
AltaGas Limited	ALA	ENSTAR Natural Gas Company	Natural Gas	AK	Historical	NR		11.88	54.11	✓								
		Washington Gas Light Company	Natural Gas	DC	Historical	A-	7	9.65	52.00	✓				✓		✓		✓
		Washington Gas Light Company	Natural Gas	MD	Historical	A-	7	9.50	52.60	✓		✓	✓			✓		✓
		SEMCO Energy, Inc.	Natural Gas	MI	Fully Forecasted	BBB	9	9.87	54.00	✓			✓			✓		✓
		Washington Gas Light Company	Natural Gas	VA	Historical	A-	7	NA	52.53	✓		✓				✓		✓
Canadian Utilities Limited	CU	ATCO Electric	Electric	Alberta	Historical	NR		9.28	37.00	NA						✓	✓	✓
		ATCO Gas	Natural Gas	Alberta	Historical	NR		9.28	37.00	NA		✓				✓	✓	✓
Emera Inc.	EMA	Tampa Electric Company	Electric	FL	Fully Forecasted	BBB+	8	9.95	45.07	✓			✓	✓	✓			✓
		Peoples Gas System	Natural Gas	FL	Fully Forecasted	A-	7	10.15	NA	✓			✓		✓	✓		✓
		New Mexico Gas Company, Inc.	Natural Gas	NM	Historical	NR		9.38	52.00	✓		✓	✓					✓
		Nova Scotia Power Inc.	Electric	Nova Scotia	Fully Forecasted	BBB-	10	9.00	40.00	✓		✓				✓		✓
Enbridge	ENB	Enbridge Gas	Natural Gas	Ontario	Fully Forecasted	A-	7	9.21	38.00	✓		✓						
		Gazifere	Natural Gas	Quebec		NR		9.05	40.00	✓								
Fortis Inc.	FTS	Central Hudson Gas & Electric Corp.	Electric	NY	Fully Forecasted	BBB+	8	9.00	50.00		✓		✓	✓		✓		✓
		Central Hudson Gas & Electric Corp.	Natural Gas	NY	Fully Forecasted	BBB+	8	9.00	50.00	✓	✓		✓		✓	✓		✓
		Tucson Electric Power Company	Electric	AZ	Historical	A-	7	9.55	54.32	✓		✓	✓	✓	✓		✓	✓
		UNS Electric, Inc.	Electric	AZ	Historical	A3	7	9.75	53.72	✓		✓	✓	✓	✓		✓	✓
		UNS Gas, Inc.	Natural Gas	AZ	Historical	A3	7	9.75	50.82	✓		✓	✓					✓
		FortisBC	Electric	British Columbia	Fully Forecasted	A-	7	9.65	41.00	✓	✓		✓			✓		✓
		FortisBC Energy	Natural Gas	British Columbia	Fully Forecasted	A-	7	9.65	45.00	✓	✓		✓			✓		✓
		Newfoundland Power Inc	Electric	Newfoundland & Labrador	Fully Forecasted	Baa1	8	8.50	45.00	✓		✓	✓			✓		✓
		Maritime Electric Company Ltd.	Electric	Prince Edward Island	Fully Forecasted	BBB+	8	9.35	40.00	✓		✓	✓			✓		✓
HydroOne Inc.	H	Hydro One Inc.	Electric	Ontario	Fully Forecasted	A-	7	9.21	40.00	✓			✓		✓	✓	✓	✓
U.S. Electric Proxy Group																		
Alliant Energy Corporation	LNT	Interstate Power and Light Company	Electric	IA	Historical	A-	7	10.02	51.00	✓			✓	✓	✓		✓	✓
		Interstate Power and Light Company	Natural Gas	IA	Historical	A-	7	9.60	51.00	✓								
		Wisconsin Power and Light Company	Electric	WI	Fully Forecasted	A	6	9.80	53.70	✓								
		Wisconsin Power and Light Company	Natural Gas	WI	Fully Forecasted	A	6	9.80	53.70	✓								
Ameren Corporation	AEE	Ameren Illinois Company	Electric	IL	Historical	BBB+	8	8.72	50.00			✓	✓	✓	✓		✓	✓
		Ameren Illinois Company	Natural Gas	IL	Fully Forecasted	BBB+	8	9.44	50.00	✓		✓	✓		✓	✓		✓
		Union Electric Company	Electric	MO	Historical	BBB+	8	NA	NA	✓		✓	✓	✓		✓	✓	✓
		Union Electric Company	Natural Gas	MO	Historical	BBB+	8	NA	NA	✓		✓				✓		✓
American Electric Power Company, Inc.	AEP	Southwestern Electric Power Company	Electric	AR	Historical	BBB+	8	9.50	44.54	✓		✓	✓		✓		✓	✓
		Indiana Michigan Power Company	Electric	IN	Fully Forecasted	BBB+	8	9.85	NA	✓		✓	✓	✓	✓	✓	✓	✓
		Kentucky Power Company	Electric	KY	Historical	BBB	9	9.75	41.25	✓		✓	✓		✓			✓
		Southwestern Electric Power Company	Electric	LA	Historical	BBB+	8	9.50	NA	✓		✓	✓					✓
		Indiana Michigan Power Company	Electric	MI	Fully Forecasted	BBB+	8	9.86	46.56	✓		✓	✓	✓				✓
		Ohio Power Company	Electric	OH	Partially Forecasted	BBB+	8	9.70	54.43			✓	✓	✓		✓	✓	✓
		Public Service Company of Oklahoma	Electric	OK	Historical	BBB+	8	9.30	52.00	✓		✓	✓	✓		✓	✓	✓
		Kingsport Power Company	Electric	TN	Fully Forecasted	NR		9.50	48.90	✓								
		AEP Texas Inc.	Electric	TX	Historical	BBB+	8	9.40	42.50				✓			✓	✓	✓
		Southwestern Electric Power Company	Electric	TX	Historical	BBB+	8	9.25	49.37	✓			✓			✓	✓	✓
		Appalachian Power Company	Electric	VA	Historical	BBB+	8	NA	NA	✓			✓		✓		✓	✓
		Wheeling Power Company	Electric	WV	Historical	BBB+	8	NA	NA	✓			✓		✓			✓

Company	Ticker	Operating Subsidiary	Service Type	Jurisdiction	Test Year	Credit Rating	Credit Rating (numerical)	Authorized ROE (%)	Authorized Equity Ratio (%)	Electric fuel/gas commodity/purch. power	Full Decoupling	Partial Decoupling	Conserv. program expense	Renewables/ Non-Traditional Generation	Environmental compliance	Delivery infrastructure	Transmission costs	Capital Cost Recovery
Duke Energy Corporation	DUK	Duke Energy Florida, LLC	Electric	FL	Fully Forecasted	BBB+	8	10.10	NA	✓			✓	✓	✓			✓
		Duke Energy Indiana, LLC	Electric	IN	Historical	BBB+	8	9.70	40.98	✓		✓	✓	✓	✓	✓	✓	✓
		Duke Energy Kentucky, Inc.	Electric	KY	Fully Forecasted	BBB+	8	9.75	52.15	✓		✓	✓		✓			✓
		Duke Energy Kentucky, Inc.	Natural Gas	KY	Fully Forecasted	BBB+	8	9.38	51.34	✓		✓	✓			✓		✓
		Duke Energy Carolinas, LLC	Electric	NC	Historical	BBB+	8	10.10	53.00	✓			✓	✓	✓			✓
		Duke Energy Progress, LLC	Electric	NC	Historical	BBB+	8	9.80	53.00	✓			✓	✓	✓			✓
		Piedmont Natural Gas Company, Inc.	Natural Gas	NC	Historical	BBB+	8	9.60	51.60	✓	✓		✓			✓		✓
		Duke Energy Ohio, Inc.	Electric	OH	Partially Forecasted	BBB+	8	9.50	50.50			✓	✓	✓		✓	✓	✓
		Duke Energy Ohio, Inc.	Natural Gas	OH	Partially Forecasted	BBB+	8	9.60	52.32	✓					✓	✓		✓
		Duke Energy Progress, LLC	Electric	SC	Historical	BBB+	8	9.60	52.43	✓			✓		✓			✓
		Duke Energy Carolinas, LLC	Electric	SC	Historical	BBB+	8	9.50	53.00	✓			✓		✓			✓
		Piedmont Natural Gas Company, Inc.	Natural Gas	SC	Historical	BBB+	8	9.30	53.13	✓		✓	✓					✓
		Piedmont Natural Gas Company, Inc.	Natural Gas	TN	Fully Forecasted	BBB+	8	9.80	50.09	✓		✓				✓		✓
Entergy Corporation	ETR	Entergy Arkansas, LLC	Electric	AR	Fully Forecasted	A-	7	NA	38.65	✓		✓	✓	✓		✓	✓	✓
		Entergy New Orleans, LLC	Electric	LA	Partially Forecasted	BB	12	9.35	50.00	✓			✓	✓	✓		✓	✓
		Entergy New Orleans, LLC	Natural Gas	LA	Partially Forecasted	BB	12	9.35	50.00	✓								
		Entergy Louisiana, LLC	Electric	LA	Historical	BBB+	8	9.95	NA	✓		✓	✓		✓			✓
		Entergy Mississippi, LLC	Electric	MS	Partially Forecasted	A-	7	10.07	NA	✓		✓					✓	✓
		Entergy Texas, Inc.	Electric	TX	Historical	BBB+	8	9.57	51.21	✓			✓			✓	✓	✓
Eversource Energy	ES	The Connecticut Light and Power Company	Electric	CT	Historical	A	6	9.25	53.00		✓		✓			✓	✓	✓
		Yankee Gas Services Company	Natural Gas	CT	Historical	A-	7	9.30	53.76	✓	✓		✓			✓		✓
		Eversource Gas Company of Massachusetts	Natural Gas	MA	Historical	A-	7	9.70	53.25	✓	✓		✓		✓	✓		✓
		NSTAR Electric Company	Electric	MA	Historical	A	6	NA	NA		✓		✓	✓		✓	✓	✓
		NSTAR Gas Company	Natural Gas	MA	Historical	A-	7	NA	NA	✓	✓		✓		✓	✓		✓
		Public Service Company of New Hampshire	Electric	NH	Historical	A	6	9.30	54.40	✓		✓				✓	✓	✓
Evergy, Inc.	EVRG	Evergy Kansas Central, Inc.	Electric	KS	Historical	BBB+	8	NA	NA	✓		✓	✓	✓	✓		✓	✓
		Evergy Kansas South, Inc.	Electric	KS	Historical	BBB+	8	10.40	50.13	✓		✓	✓	✓	✓		✓	✓
		Evergy Metro, Inc.	Electric	KS	Historical	A-	7	NA	NA	✓			✓			✓	✓	✓
		Evergy Metro, Inc.	Electric	MO	Historical	A-	7	NA	NA	✓		✓	✓			✓	✓	✓
		Evergy Missouri West, Inc.	Electric	MO	Historical	BBB+	8	NA	NA	✓		✓	✓	✓		✓	✓	✓
Exelon Corporation	EXC	Delmarva Power & Light Company	Electric	DE	Historical	A-	7	9.60	50.50				✓			✓	✓	✓
		Delmarva Power & Light Company	Natural Gas	DE	Historical	A-	7	9.60	49.94	✓					✓	✓		✓
		Potomac Electric Power Company	Electric	DC	Historical	A-	7	9.28	50.68			✓		✓		✓		✓
		Commonwealth Edison Company	Electric	IL	Historical	A-	7	8.91	50.00				✓	✓	✓	✓	✓	✓
		Baltimore Gas and Electric Company	Electric	MD	Historical	A	6	9.50	52.00		✓		✓					✓
		Baltimore Gas and Electric Company	Natural Gas	MD	Historical	A	6	9.45	52.00	✓	✓		✓			✓		✓
		Delmarva Power & Light Company	Electric	MD	Historical	A-	7	9.60	50.50		✓		✓					✓
		Potomac Electric Power Company	Electric	MD	Historical	A-	7	9.55	50.50		✓		✓			✓		✓
		Atlantic City Electric Company	Electric	NJ	Partially Forecasted	A-	7	9.60	50.20			✓	✓		✓	✓		✓
		PECO Energy Company	Electric	PA	Fully Forecasted	BBB+	8	NA	NA				✓			✓	✓	✓
		PECO Energy Company	Natural Gas	PA	Fully Forecasted	BBB+	8	NA	NA	✓			✓			✓		✓
NextEra Energy, Inc.	NEE	Florida Power & Light Company	Electric	FL	Fully Forecasted	A	6	10.80	NA	✓			✓	✓	✓			✓
		Pivotal Utility Holdings, Inc.	Natural Gas	FL	Fully Forecasted	NR		9.50	59.60	✓			✓		✓	✓		✓
		Lone Star Transmission, LLC	Electric	TX	Historical	NR		NA	NA							✓	✓	✓
OGE Energy Corporation	OGE	Oklahoma Gas and Electric Company	Electric	AR	Historical	A-	7	NA	38.39	✓		✓	✓	✓	✓	✓	✓	✓
		Oklahoma Gas and Electric Company	Electric	OK	Historical	A-	7	9.50	53.37	✓		✓	✓		✓	✓	✓	✓
Pinnacle West Capital Corporation	PNW	Arizona Public Service Company	Electric	AZ	Historical	BBB+	8	9.55	51.93	✓		✓	✓	✓	✓		✓	✓
PPL Corporation	PPL	Kentucky Utilities Company	Electric	KY	Fully Forecasted	A-	7	9.43	NA	✓		✓	✓		✓			✓
		Louisville Gas and Electric Company	Electric	KY	Fully Forecasted	A-	7	9.43	NA	✓		✓	✓		✓			✓
		Louisville Gas and Electric Company	Natural Gas	KY	Fully Forecasted	A-	7	9.43	NA	✓		✓	✓			✓		✓
		PPL Electric Utilities Corporation	Electric	PA	Fully Forecasted	A	6	NA	NA				✓			✓	✓	✓
		The Narragansett Electric Company	Electric	RI	Historical	A-	7	9.28	50.95		✓		✓			✓	✓	✓
		The Narragansett Electric Company	Natural Gas	RI	Historical	A-	7	9.28	50.95	✓	✓		✓		✓	✓		✓
		Kentucky Utilities Company	Electric	VA	Historical	A-	7	NA	NA	✓								
Portland General Electric Company	POR	Portland General Electric Company	Electric	OR	Fully Forecasted	BBB+	8	9.50	50.00	✓			✓	✓	✓		✓	✓
Southern Company	SO	Alabama Power Company	Electric	AL	Historical	A	6	NA	NA	✓				✓	✓			✓
		Atlanta Gas Light Company	Natural Gas	GA	Partially Forecasted	A-	7	NA	56.00						✓	✓		✓
		Georgia Power Company	Electric	GA	Partially Forecasted	A	6	10.50	56.00	✓					✓			✓
		Northern Illinois Gas Company	Natural Gas	IL	Fully Forecasted	A-	7	9.51	50.00	✓		✓	✓		✓	✓		✓
		Mississippi Power Company	Electric	MS	Partially Forecasted	A-	7	NA	53.00	✓		✓			✓			✓
		Chattanooga Gas Company	Natural Gas	TN	Fully Forecasted	NR		9.80	49.23	✓	✓							
		Virginia Natural Gas, Inc.	Natural Gas	VA	Historical	NR		NA	NA	✓		✓				✓		✓
Xcel Energy Inc.	XEL	Public Service Company of Colorado	Electric	CO	Historical	A-	7	9.30	55.69	✓		✓	✓	✓			✓	✓
		Public Service Company of Colorado	Natural Gas	CO	Historical	A-	7	9.20	53.78	✓		✓	✓			✓		✓
		Northern States Power Company	Electric	MN	Fully Forecasted	A-	7	9.25	52.50	✓		✓	✓	✓	✓		✓	✓
		Northern States Power Company	Natural Gas	MN	Fully Forecasted	A-	7	9.57	52.50	✓			✓			✓		✓
		Southwestern Public Service Company	Electric	NM	Historical	BBB	9	9.50	54.70	✓			✓	✓				✓
		Northern States Power Company	Electric	ND	Fully Forecasted	A-	7	9.50	52.50	✓				✓		✓	✓	✓
		Northern States Power Company	Natural Gas	ND	Fully Forecasted	A-	7	9.80	52.54	✓								
		Northern States Power Company	Electric	SD	Historical	A-	7	NA	NA	✓		✓	✓		✓	✓	✓	✓
		Southwestern Public Service Company	Electric	TX	Historical	BBB	9	NA	NA	✓			✓				✓	✓
		Northern States Power Company	Electric	WI	Fully Forecasted	A-	7	9.80	52.50	✓								
		Northern States Power Company	Natural Gas	WI	Fully Forecasted	A-	7	9.80	52.50	✓								

Company	Ticker	Operating Subsidiary	Service Type	Jurisdiction	Test Year	Credit Rating	Credit Rating (numerical)	Authorized ROE (%)	Authorized Equity Ratio (%)	Electric fuel/gas commodity/purch. power	Full Decoupling	Partial Decoupling	Conserv. program expense	Renewables/ Non-Traditional Generation	Environmental compliance	Delivery infrastructure	Transmission costs	Capital Cost Recovery
US Gas Proxy Group																		
Atmos Energy Corp	ATO	Atmos Energy Corporation	Natural Gas	KS	Historical	A-	7	NA	NA	✓		✓				✓		✓
		Atmos Energy Corporation	Natural Gas	KY	Fully Forecasted	A-	7	9.23	54.50	✓		✓	✓			✓		✓
		Atmos Energy Corporation	Natural Gas	LA	Historical	A-	7	10.77	53.25	✓		✓						
		Atmos Energy Corporation	Natural Gas	MS	Partially Forecasted	A-	7	12.94	77.76	✓		✓				✓		✓
		Atmos Energy Corporation	Natural Gas	TN	Fully Forecasted	A-	7	NA	62.20	✓		✓						
		Atmos Energy Corporation	Natural Gas	TX	Historical	A-	7	9.80	60.12	✓		✓				✓		✓
Northwest Natural Holding Company	NWN	Northwest Natural Gas Company	Natural Gas	OR	Fully Forecasted	A+	5	9.40	50.00	✓		✓	✓		✓			✓
		Northwest Natural Gas Company	Natural Gas	WA	Historical	A+	5	NA	NA	✓			✓					✓
ONE Gas, Inc.	OGS	Kansas Gas Service Company, Inc.	Natural Gas	KS	Historical	NR		NA	NA	✓		✓				✓		✓
		Oklahoma Natural Gas Company	Natural Gas	OK	Historical	NR		NA	NA	✓		✓	✓					✓
		Texas Gas Service Company, Inc.	Natural Gas	TX	Historical	NR		9.70	59.07	✓		✓				✓		✓
Spire, Inc.	SR	Spire Missouri Inc.	Natural Gas	MO	Partially Forecasted	BBB+	8	NA	NA	✓		✓				✓		✓
		Spire Alabama Inc.	Natural Gas	AL	Historical	BBB+	8	NA	NA	✓		✓						
		Spire Gulf Inc.	Natural Gas	AL	Historical	NR		13.60	46.99	✓		✓						
Proxy Group Results				**Total:**	Fully Forecasted = 33%	**Average:**	7	9.66	50.53	**Adjustment Clauses Count & Percentages of Total Proxy Group:**								
				130	Partially Forecasted = 9%	A-				111	17	64	88	34	48	71	44	113
					Historical = 57%					85%	13%	49%	68%	26%	37%	55%	34%	87%

Notes:
[1] Source: S&P Capital IQ Pro, as of May 31, 2024
[2] Bloomberg Professional. S&P Rating, unless noted. May 31, 2024
[3] Bloomberg Professional
[4] Source: S&P Capital IQ Pro, rate cases as of May 31, 2024. "NA" indicates either undisclosed ROE, most recent rate case prior to 2010, or operating subsidiary is not covered by S&P, or an equity ratio observed in a state including zero-cost-of-capital items (AR, IN, FL, MI)
[5] Source: Regulatory Research Associates, "Adjustment Clauses: A State by State Overview", July 18, 2022

AAA	1
AA+	2
AA	3
AA-	4
A+	5
A	6
A-	7
BBB+	8
BBB	9
BBB-	10
BB+	11
BB	12
BB-	13

Aaa	1
Aa1	2
Aa2	3
Aa3	4
A1	5
A2	6
A3	7
Baa1	8
Baa2	9
Baa3	10
Ba1	11
Ba2	12
Ba3	13

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Question(s):

Please provide Concentric's view on the change in Ontario electricity distributor and electricity transmitter business and financial risk for LDCs since 2009.

Response:

Please see Concentric's report, Exhibit M2, at 111-125, which includes Concentric's industry segment-specific risk assessments and concludes that risks for Ontario utilities have increased over time, driven by climate change, Energy Transition, and cyber security risks.

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).

Windsor Canada Utilities Ltd. Outlook Revised To Stable From Negative On Regulatory Developments; Ratings Affirmed

- After further evaluation of the Ontario Energy Board's (OEB) regulatory construct for Windsor Canada Utilities Ltd. (WCU), we affirmed our 'A' issuer credit rating on WCU and revised the outlook to stable from negative.
- We also affirmed our 'A' rating on WCU's senior unsecured debt.
- Our evaluation reflects that OEB has proactively addressed regulatory lag. We now believe that WCU will maintain consistent financial measures sufficient for the ratings.
- The stable outlook reflects our view of Ontario's supportive regulatory framework and our expectation that WCU's funds from operations (FFO) to debt will be 17%-21% across our outlook period.

TORONTO (S&P Global Ratings) June 18, 2024—S&P Global Ratings today took the above rating actions.

Our evaluation of OEB's regulatory construct, which reduces regulatory lag, strengthens WCU's ability to recover transmission costs on a timely basis. During 2023, OEB proactively addressed regulatory lag, particularly with the timely recovery of rising transmission-related costs. Regulatory lag is the timing difference between when costs are incurred by local distribution companies (LDC) and ultimately recovered from ratepayers. Previously, regulatory lag in Ontario was about 24 months, materially weakening the financial measures of most Ontario LDCs, given increasing inflation and rising transmission capital spending.

However, beginning in 2024, OEB allowed LDCs to implement new preliminary transmission rates at about the time it authorizes them, significantly reducing the risk of regulatory lag. Overall, we view OEB's proactiveness to quickly address this regulatory lag as constructive and consistent. We expect WCU's management of regulatory risk and financial measures will be more consistent.

We continue to assess WCU's financial risk profile as intermediate. WCU's financial performance weakened such that FFO to debt was slightly above 11% in 2022, reflecting regulatory lag related to higher transmission costs. In 2023, this improved to 20.4%. Our base case expects FFO to debt to remain in the range of 17%-21% through 2026. As WCU recovers some transmission cost increases from prior years, FFO to debt will remain temporarily elevated at about 20% through 2025. Thereafter, we expect it to gradually moderate to about 17%.

Our forecast assumes capital spending of about C$20 million-C$25 million and dividends of about C$4 million annually. 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 WCU's generally steady cash flow and rate-regulated utility operations with highly supportive cost recovery.

We continue to assess WCU's business risk profile as excellent.This reflects that WCU is a low-risk, regulated LDC, partially offset by its small customer base of approximately 92,000 customers in the city of Windsor. This size and lack of geographic diversity increases its susceptibility to a localized economic downturn or unfavorable local weather development. Our base case assumes that WCU will continue to benefit from Ontario's credit-supportive regulatory mechanisms such as its formula-based incentive rate-making that allows for rate updates annually between cost-of-service applications.

The stable outlook on WCU reflects our view that the low-risk, regulated distribution business will likely remain steady, with predictable cash flow and no adverse regulatory outcomes over the next 24 months. Our outlook also incorporates our expectations that financial measures will improve, reflecting FFO to debt of 17%-21% through 2026.

We could lower our ratings on WCU over the next 24 months if:

— A materially adverse regulatory ruling weakens its operating cash flow; or

— Financial measures weaken such that FFO to debt is consistently below 13%.

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

— Financial measures improve such that FFO to debt is consistently above 20%; and

— The business risk profile does not weaken.

We expect FFO to debt to be about 20% through 2025 as the company recovers transmission costs from prior years and about 17% thereafter.

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- Criteria | Corporates | General: Corporate Methodology, 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: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

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.

NEW YORK (Standard & Poor's) July 24, 2006--Standard & Poor's Ratings Services
today assigned its preliminary ratings to Volkswagen Auto Lease Trust 2006-A's
$1.5 billion asset-backed notes (see list).

The preliminary ratings are based on information as of July 24, 2006.
Subsequent information may result in the assignment of final ratings that
differ from the preliminary ratings.

The preliminary ratings reflect an initial credit enhancement of 9.75%
provided by beginning overcollateralization of 9.00% and a 0.75% nonamortizing
reserve account. In addition, through the application of excess spread,
overcollateralization is expected to build to a 10.50% target, making the
total target credit enhancement 11.25%. All percentages are measured in terms
of the initial securitization value of the leases.

A copy of Standard & Poor's complete presale report for this transaction
can be found on RatingsDirect, Standard & Poor's Web-based credit analysis
system, at www.ratingsdirect.com. The presale can also be found on Standard &
Poor's Web site at www.standardandpoors.com. Select Credit Ratings, and then
find the article under Presale Credit Reports.

PRELIMINARY RATINGS ASSIGNED

Volkswagen Auto Lease Trust 2006-A

Class	Rating	Amount (mil. $)
A-1	A-1+	266
A-2	AAA	483
A-3	AAA	544
A-4	AAA	207

European Endorsement Status

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COMMENTS — 11 Mar, 2024 | 19:32 —
APAC, United States of America, Latin America, Canada, EMEA, APAC

North American Utility Regulatory Jurisdictions Update: Ontario Remains Unchanged, Notable Developments Elsewhere

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Sector	**Oil & Gas, Corporates, Oil & Gas, Infrastructure & Utilities, Utilities & Power**
Tags	**Americas, Latin America, APAC, EMEA**
Topic	**Confronting Credit Headwinds , Energy & Climate Resilience**

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Key Takeaways

- Since our last report in November 2023, we have left unchanged our assessment of one utility regulatory jurisdiction, Ontario, and examined developments in numerous North American utility regulatory jurisdictions. We are also monitoring several changes across North America that, at some point, could help or hinder the business risk of various utility companies.
- After some hiccups in the past, Arizona, Ontario, North Carolina, and Nova Scotia are making progress around cost recovery in rate case proceedings.
- However, Illinois, Kentucky, and West Virginia have pushed back on utilities seeking cost recovery within their states.
- Legislation has been filed in many states that could transform heating and electricity including electrification, natural gas bans, and generation mandates around clean sources including offshore wind power.

S&P Global Ratings has been monitoring recent developments in various U.S. and Canadian utility regulatory jurisdictions in which the utilities we rate operate. Since our last report, published in November 2023, we have completed a review of Ontario and left our assessment unchanged. In other jurisdictions, we have noted the uncertainties of rate recovery on both completed and proposed capital spending, wildfire litigation, and updates on clean energy transitions and natural gas bans.

Our periodic assessments of regulatory jurisdictions provide a reference for determining a utility's regulatory advantage or risk. Regulatory advantage is incorporated into our analysis of a regulated utility's business risk profile. Our analysis covers quantitative and qualitative factors, focusing on regulatory stability, tariff-setting procedures and design, financial stability, and regulatory independence and insulation. (See **Key Credit Factors For the Regulated Utilities Industry**, published Nov. 19, 2013, for more details on each category.)

Utility Regulatory Jurisdiction Assessment

- S&P Global Ratings periodically assesses every regulatory jurisdiction in the U.S. and Canada with a rated utility or where a rated entity operates. Our last full assessment was in November 2023, in which we examined developments in numerous jurisdictions.
- These assessments, with categories from credit supportive to most credit supportive, provide a reference when determining the regulatory risk of a regulated utility or a holding company with more than one utility.
- We base our jurisdictional analyses on quantitative and qualitative factors, focusing on regulatory stability, tariff-setting procedures and design, financial stability, and regulatory independence and insulation.
- Utility regulation, no matter where on the continuum of our assessments, strengthens a utility's business risk profile, and generally underpins our ratings.

U.S. And Canadian Regulatory Utility Jurisdiction Developments

We group jurisdictions by quantitative and qualitative factors that comprise the regulatory advantage determinations we make in rating committees for approximately 220 U.S. and 30 Canadian utilities we rate.

The categories are an important starting point for assessing utility regulation and its effects on ratings. They are all credit-supportive to one degree or another because all utility regulation tends to sustain credit quality. We believe the presence of regulation, regardless of where it falls on the credit-supportive spectrum, reduces business risk and generally supports utility ratings. We therefore designate all these jurisdictions on a continuum from credit supportive to most credit supportive. These descriptions vary only in degree.

The following is a current snapshot of our assessment of each regulatory jurisdiction.

Table 1

Utility Regulatory Jurisdictions Among U.S. States And Canadian Provinces

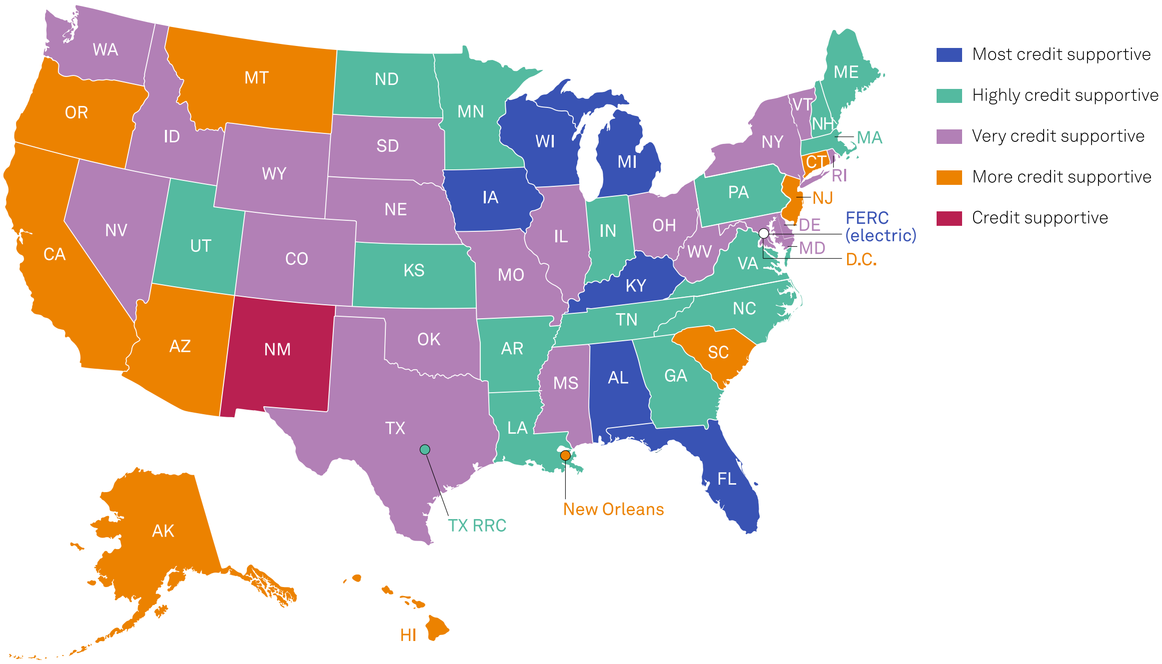
Credit supportive (adequate)	More credit supportive (strong/adequate)	Very credit supportive (strong/adequate)	Highly credit supportive (strong/adequate)	Most credit suppor (strong
New Mexico	Alaska	Colorado	Alberta	Alabama
Nova Scotia	Arizona	Delaware	Arkansas	British Columbi

Prince Edward Island	California	Idaho	Georgia	Federal Energy Regulato Commis (electric
	Connecticut	Illinois	Indiana	Florida
	District of Columbia	Maryland	Kansas	Iowa
	Hawaii	Missouri	Louisiana	Kentuck
	Montana	Mississippi	Maine	Michigai
	New Jersey	Nebraska	Massachusetts	Ontario
	New Orleans	Nevada	Minnesota	Quebec
	Oregon	New York	North Carolina	Wiscons
	South Carolina	Ohio	New Hampshire	
		Oklahoma	Newfoundland & Labrador	
		Rhode Island	North Dakota	
		South Dakota	Pennsylvania	
		Texas	Tennessee	
		Vermont	Texas RRC	
		Washington	Utah	
		West Virginia	Virginia	
		Wyoming		

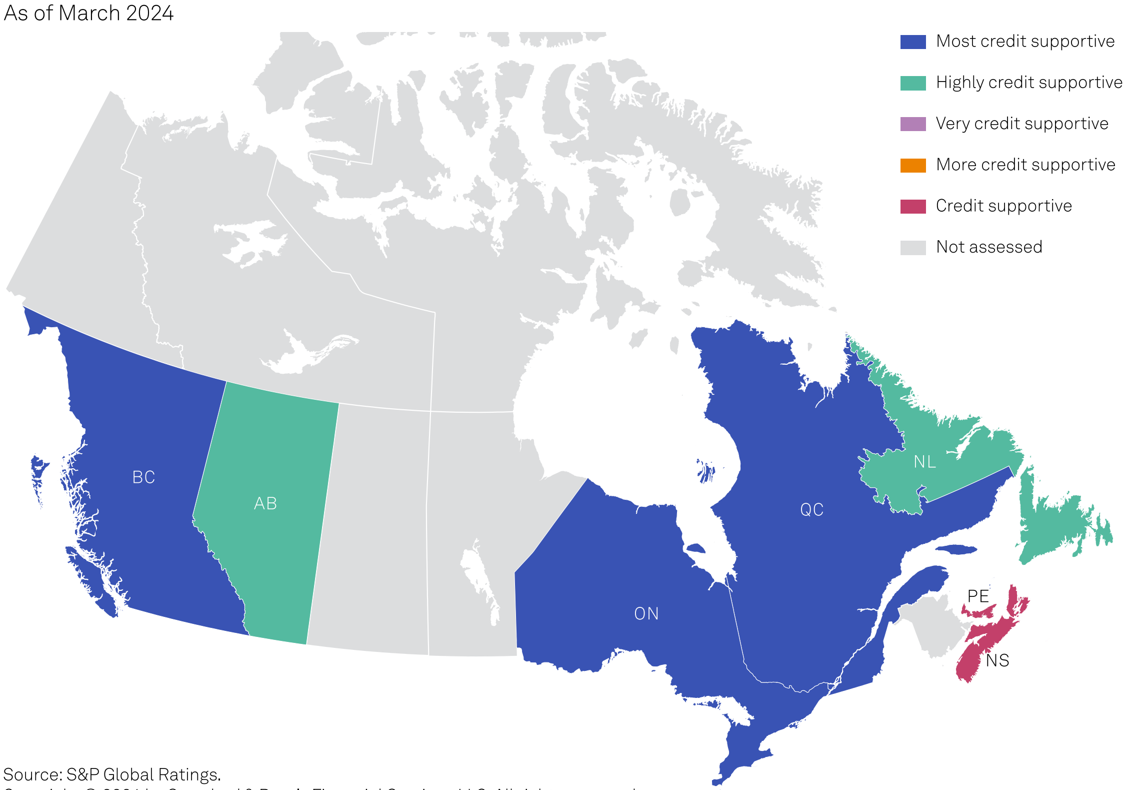
RRC--Railroad Commission of Texas. Source: S&P Global Ratings.

For jurisdictions assessed in Graphics 1 and 2, colors delineate our assessment of credit supportiveness. We do not have assessments for Canadian provinces where we do not have utility ratings. The charts depict scale and offer some detail regarding our assessment of the rules and implementation of regulation. Often, our assessments designate a stable jurisdiction slightly better or worse than its closest peers in credit quality.

Regulatory assessment by state
As of March 2024



Regulatory assessment by Canadian province/territory
As of March 2024



Reviewed, No Changes

Ontario

We concluded our review on Ontario's regulatory environment, including the Ontario Energy Board (OEB), and left our assessment unchanged at most credit supportive. OEB proactively addressed regulatory lag, particularly related to the timely recovery of rising transmission-related costs. Notably, before addressing this cost recovery lag, we had revised outlooks to negative on several Ontario electric local distribution companies (LDC). To address this lag, in July 2023, the OEB pulled forward the issuance of an inflation factor calculation that is an input to calculate uniform transmission rates (UTRs) for transmission utilities' annual rate adjustments. Typically, this had been completed in October or November. Because the inflation factor was available earlier, in September 2023, the OEB was able to approve preliminary UTRs for transmission companies.

With the updated inflation factor and revised UTRs, LDCs can file for new rates with the most current inputs, including updated transmission costs, which mitigates regulatory lag. We expect this more front-loaded rate recovery will align higher operating cash flow with LDCs' requirements to pay the higher transmission costs. In January 2024, the OEB issued its final UTRs that were largely in line with the preliminary UTRs. With this reduced lag in recovering higher transmission costs, we expect LDCs will be able to boost their financial measures.

No Revised Assessments, But Notable Developments

Arizona

In February 2024, the Arizona Corporation Commission (ACC) directed the ACC staff to draft rules to repeal both the state's energy efficiency standards and renewable generation requirements. The ACC largely cited costs to ratepayers as driving the decision. We will closely monitor the rulemaking process and its potential effect on Arizona utilities.

California

The California Public Utilities Commission (CPUC) recently approved advice letters for several regulated electric, gas, and water companies, raising the authorized return on equity (ROE) by approximately 70 basis points (bps) through the cost of capital mechanism (CCM), effective Jan. 1, 2024. In California, authorized ROEs are established separately from general rate case proceedings, based on a formula, to reflect rising bond yields. We view this as supportive of credit quality for affected regulated utilities because it helps mitigate regulatory lag, which protects utilities from the effects of rising interest rates. We believe the boost in recovery through higher rates will strengthen funds from operations (FFO) of California utilities.

Hawaii

In January 2024, House Bill 2265 was introduced in the Hawaii legislative session. This bill proposes to implement a Catastrophic Wildfire Securitization Act to allow public utilities to securitize costs from catastrophic wildfires. We expect a decision on this by June 2024. Separately, in November 2023, Hawaii's Governor announced the One Ohana Initiative, which would provide at least $150 million of public-private funds to compensate victims and their families affected by the August 2023 Lahaina wildfires. We expect this fund to be jointly funded by the State of Hawaii, Hawaiian Electric Co. Inc., Kamehameha Schools, Maui County, and other entities. While both initiatives have yet to be finalized, if approved, they would be supportive for utilities operating in Hawaii by mitigating the costs from catastrophic wildfires.

Illinois

Recent regulatory rulings by the Illinois Commerce Commission (ICC) lead us to believe the ICC may become less credit supportive toward utilities operating in the state. In November 2023, the ICC disallowed capital spending incurred by WEC Energy Group Inc.'s (WEC) subsidiary, The People's Gas Light & Coke Co. (PGL). The disallowed capital spending relates to the construction and improvement of service shops PGL owns throughout Chicago. The ICC's November 2023 rate order also rejected PGL's request to include its forecast test year safety modernization program (SMP) investment in its rate base. The ICC ordered a pause in, and an investigation of, the program, which focuses on replacing aging and at-risk pipelines (such as cast iron or ductile iron), relocating meters, and repressurizing areas of its distribution system.

The ICC recently authorized a limited rehearing of certain items, including \$134 million of SMP emergency work; however, the ICC will not reconsider the disallowed spending related to its service shops. We view the disallowance as negative from a credit standpoint because parent WEC took a \$179 million noncash charge to its 2023 earnings, weakening its FFO to debt in 2023. The disallowance also leads to less predictability of ratemaking under the ICC. Although PGL was able to reduce its capital spending by \$700 million to \$900 million over 2024-2028 to preserve its credit quality, the reduced capital spending could delay the company's progress toward replacing aging and at-risk pipelines. Cast iron and ductile iron account for roughly 25% of the company's gas distribution system.

In addition, in December 2023, the ICC within Commonwealth Edison Co.'s (ComEd) and Ameren Illinois Co.'s (AI) separate multiyear rate plans determined that their respective four-year grid plans did not adequately describe community benefits, transparency, affordability, or cost-effectiveness and did not comply with the state's Climate and Equitable Jobs Act (CEJA) of 2021. Illinois' CEJA law requires the state to transition to 50% renewable energy by 2040 and 100% clean energy by 2050 through reduced emissions and electrification. We believe the wholesale rejection of ComEd's and AI's grid plans by the ICC, which resulted in a much lower revenue increase for each company in their respective four-year rate plans, may indicate a weakening in the ICC's recent historical predictability of regulatory outcomes. Both utilities will file revised grid plans in March 2024, but there is no set deadline for the ICC to rule on the revised plans. In aggregate, the combination of disallowances and lower-than-expected rate increases may be a sign of less regulatory stability that could weaken the attractiveness of the state's regulatory framework to long-term investors.

Kansas

In January 2024, House Bill 2527 was introduced in the Kansas House of Representatives that proposes to authorize cost recovery mechanisms for certain rate base additions as well as proposed changes to the calculation of capital structures. The bill proposes that utilities be allowed to defer as a regulatory asset 100% of all depreciation expense and returns associated with all plant-in-service balances not already included in rate base.

In addition, the bill proposes that the Kansas Corporation Commission (KCC) would set rates for a public utility on a stand-alone basis when determining the revenue requirement. The KCC would be required to use a utility's test year capital structure, without regard to the capital structure or investments of any other affiliated entities, unless the utility's parent company does not hold an investment-grade credit rating from at least one nationally recognized credit rating agency.

The bill also proposes that utilities be allowed to implement a new rate adjustment mechanism to earn a return on 100% of construction work in progress for any new gas-fired generating facilities, unless the KCC determines the plant would not be a prudent addition to the utility's fleet.

We expect that the bill, if passed as presented, will provide more predictable and stable cash flows for utilities in Kansas, further strengthening credit quality. We continue to monitor the developments on the proposed legislation.

Kentucky

The Kentucky Public Service Commission (PSC) recently modified several rate case settlements to modestly lower the ROEs in the settlements, reducing the ultimate rate increases. Recently, Kentucky Power Co.'s (KPC) rate case settlement called for a base rate increase of about $75 million based on a 9.75% ROE. Separately, in KPC's recent rate case, the PSC reduced the settled rate increase by about $15 million largely to address the PSC's concerns regarding the company's transmission costs. In a separate proceeding, however, the PSC was credit supportive toward KPC by authorizing the utility to issue securitization bonds primarily for early retirement of coal generation and storm restoration costs. In aggregate, we continue to view Kentucky as most credit supportive albeit at the lower end of the category.

Maine

In November 2023, Maine voters rejected a referendum that could have resulted in the Maine government attempting to municipalize investor-owned utility transmission and distribution assets in the state. The rejection reinforces regulatory stability and reduces uncertainty, providing for the utilities in Maine to focus on strengthening infrastructure and improving reliability of operations. We view regulatory independence as one of the key attributes that underpins the credit quality of the utility industry. In general, we expect utilities to operate under a regulatory construct that is sufficiently insulated from political intervention, even during periods of economic stress, thereby protecting a utility's credit risk profile.

Massachusetts

In December 2023, the Massachusetts Department of Public Utilities (DPU) required the state's natural gas LDCs to analyze whether low- or zero-carbon non-pipeline alternatives, such as heating electrification and geothermal systems, could replace traditional gas infrastructure investments. Furthermore, the DPU ordered gas LDCs to file Climate Compliance Plans beginning in 2025 that would propose strategies to reduce greenhouse gas emissions (Scope 1 and 3). While these developments are still preliminary, we will continue to monitor them, including potential implications for the state's gas LDC's capital spending and growth prospects over the long term.

Michigan

In late 2023, Michigan passed several legislative measures that affect utilities, including Senate Bills (SB) 271, 273, 277, 502, and 519. Specifically, the actions now require 80% of power generated in the state to be derived from clean energy by 2035 and 100% by 2040; the state commits to 50% renewable energy by 2030 (60% by 2035), increases the cap on distributed generation--including rooftop solar to 10% from 1%--and a 2,500 megawatt (MW) energy storage mandate by 2030.

SB 271 includes a financial incentive for utilities that procure clean energy or storage through a purchased power agreement with third parties. Specifically, if a regulated electric utility enters into a purchase power agreement for renewable energy resources or clean energy storage with a nonaffiliated third-party, the commission shall authorize an annual financial incentive for the utility, which includes the utility's pre-tax weighted average cost of permanent capital (debt and equity) using the utility's regulated capital structure that was authorized in the most recent general rate case.

From a credit perspective, while we view the financial incentive as supportive of credit quality, the broader energy goals could also likely translate into increased capital spending by the utilities to meet the requirements of these legislative measures. As such, we will continue to monitor how affected utilities effectively navigate this development.

New Jersey

The state continues to work toward the goal of 100% of electricity sold in the state being generated from clean and renewable sources by 2035. A new proposal makes a continued effort to accelerate this by prohibiting the construction of new fossil fuel power plants. The state currently generates about 55% of its energy from fossil fuel. We do not view this as completely restrictive because it would allow for the continuation of fossil fuel peaker plants.

In addition, the commission continues to move toward its offshore wind goals of achieving 11 gigawatts (GW) of offshore wind capacity by 2040. In January 2024, the New Jersey Board of Public Utilities approved two new offshore wind proposals for a combined 3.7 GW. The 2.4 GW Leading Light Wind project is being built by Invenergy Renewables LLC and energyRE LLC, and the 1.3 GW Attentive Energy Two project is being built by TotalEnergies SE and Corio Generation Ltd. This is a positive development after the cancellation of two wind projects with Orsted A/S in 2023.

New Mexico

In January 2024, the New Mexico Public Regulation Commission (NMPRC) authorized Public Service Co. of New Mexico (PSNM) a rate increase of about $15 million based on an authorized 9.26% ROE. It also ordered a $38 million rate refund over two years of previously collected payments on an expired power plant lease. In January 2023, NMPRC transitioned to the gubernatorial appointment of commissioners. While we expected that this change could improve New Mexico's support of credit quality, PSNM's first rate order under this new construct has initially fallen short of our expectations. At the same time, we believe there were unique factors in this rate case that make it difficult to determine a long-term view of New Mexico's regulatory environment. These include the participation of only two out of three commissioners and the resolution of legacy issues concerning PSNM's generation. We expect PSNM will be filing more frequent rate cases in the future, which will inform our view of the new NMPRC.

New York

Governor Kathy Hochul introduced The Affordable Gas Transition Act (AGT) bill that, among other things, would empower the New York Public Service Commission (NYPSC) to direct utilities to manage the transition to clean energy sources responsibly and affordably. If passed, AGT would give NYPSC discretion on controlling gas utilities expansions in their existing service territory and would restrict distributors from expanding their service territories beginning in 2026. AGT would further limit growth of gas utilities in the state. This requires substantial and accelerated investments in New York's electric infrastructure consistent with the Climate Leadership and Community Protection Act.

North Carolina

We view recent regulatory outcomes in North Carolina as constructive for credit quality. In December 2023, the North Carolina Utilities Commission (NCUC) authorized a three-year cumulative rate increase for Duke Energy Carolinas LLC (DEC) totaling $769 million. The decision includes revenue increases of about of $469 million in 2024, $174 million in 2025, and $159 million in 2026. In August 2023, affiliate Duke Energy Progress LLC (DEP) also received a multiyear rate increase of $494 million through 2026. We consider both rate case decisions as supportive of credit quality because they bolster both companies' financial measures and further highlight sound management of regulatory risk.

We believe the rate increases will provide stability in cash flows through 2026, which is important given the companies' elevated capital spending. DEC and DEP received ROEs of 10.1% and 9.8% in 2023, respectively, both above industry averages. Potentially offsetting the higher ROE for DEC, the North Carolina Attorney General recently filed an appeal on the DEC rate case because they were authorized a higher ROE than DEP. We will continue to monitor the appeal and future developments and any effect on DEC's rates.

Nova Scotia

We view Nova Scotia's regulatory construct as credit supportive due to the history of political interference that weakens the regulatory jurisdiction's predictability and increases uncertainty for its utilities and stakeholders. However, recently the government of Nova Scotia proposed to compensate Nova Scotia Power Inc. (NSPI) C$117 million to offset a deferred fuel cost liability. Because any further recovery of fuel costs would have significantly pressured customer bills in Nova Scotia, the provincial government proposed to pay NSPI C$117 million up front and recover the amount from customers over the next 10 years. This compensation to NSPI from the provincial government indicates the government's willingness to extend support under challenging circumstances, thereby improving the operating environment for NSPI. We consider this supportive of credit quality in the province.

In addition, the provincial government announced its 2030 Clean Power Plan, which is largely consistent with NSPI's investment strategy. Furthermore, the provincial government also approved legislation to include battery storage projects in base rates.

West Virginia

Earlier this year, the Public Service Commission of West Virginia (WVPSC) disallowed about $232 million of under-recovered energy costs sought during Appalachian Power Co.'s and Wheeling Power Co.'s Expanded Net Energy Cost (ENEC) filing. Furthermore, the WVPSC ordered the companies to recover the remaining under-recovered balance of $321 million over a 10-year period. Previously the companies had reached a settlement with the West Virginia Energy Users Group and West Virginia Coal Association, but not the WVPSC staff, to recover all the under-recovered costs. In arriving at this decision, the WVPSC stated that the companies were imprudent in fuel planning, fuel practices, and market strategies, which caused a lack of adequate coal supplies at a time when energy was more expensive.

While we view this development as negative for Appalachian Power and Wheeling Power, we do not believe this indicates a deterioration in the broader regulatory environment in the state at this time. Other electric utilities in the state, namely Monongahela Power Co. and Potomac Edison Co., recently reached settlements with WVPSC staff, among various other intervenors, concerning the companies' rate case and ENEC filings.

Furthermore, we view both settlements in these cases as constructive. In particular, Monongahela Power's and Potomac Edison's ENEC settlements call for the recovery of the companies' ENEC under-recovered balance of about $255 million over the next three years. We will continue to monitor further developments in these proceedings to determine if they impact our view of West Virginia investor-owned utilities' credit quality.

Related Research

- **WEC Energy Group Inc.'s Financial Measures Hold Up Despite Disallowances In Illinois Rate Cases**, Jan. 23, 2024
- **Commonwealth Edison's Rate Case Outcome Pressures Credit Measures**, Dec. 21, 2023
- **Key Credit Factors For The Regulated Utilities Industry**, Nov. 19, 2013

This report does not constitute a rating action.

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Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2024-0063**	**Generic Proceeding - Cost of Capital and Other Matters**
VOLUME:	**Presentation Day**	
DATE:	**September 5, 2024**	
BEFORE:	**Michael Janigan**	**Presiding Commissioner**
	Lynne Anderson	**Commissioner**
	Pankaj Sardana	**Commissioner**

And this is really a critical point, because it means that Canadian companies are competing for capital with similar risk companies in both Canada and the U.S. So, if Ontario utilities have a lower authorized ROE or a lower deemed equity ratio than their North American peers of comparable risk, it places them at a disadvantage in competing for capital at a time when significant investment is required in the industry. And it's important to go back to the fair return standard here and remember that it requires the return, and the return includes both the ROE and the deemed equity ratio, that return must be comparable to that available to investors in companies with similar risk.

And Dr. Cleary is the only expert in this proceeding who limits his analysis to a group of five Canadian utility companies and, by contrast, we believe it's reasonable to include both U.S. companies and Canadian companies because they do have comparable business, operating, and regulatory risk. The industry has seen a number of cross-border investments in the last 20 years, especially with regard to Canadian companies acquiring utilities in the U.S., and we've worked on several of those transactions between U.S. and Canadian investors and the deals are just further market evidence that investors do consider investments on both sides of the border as they assess their alternatives.

Furthermore, we would note that some have questioned on whether Ontario utilities have raised capital in the U.S. market, but that's not really the most important issue here. What matters more importantly is that investors do have options on both sides of the border, and they are seeking comparable returns on their investments. So, if they can get a higher return in a different company in a different country, they will do that if the risk of those two companies is equivalent.

And finally on this point, I believe the regulators in both British Columbia and Alberta have both recently concluded that using a North American proxy group is their preferred approach and, in particular, the BCUC had a nice summary of this point that we have here on our slide where they say:

"We find that having a proxy group of North American comparators trumps any jurisdictional or structural differences and in making this determination we rely on the fact that financial and capital markets are highly integrated and that utility regulatory regimes in North America are sufficiently similar for the purpose of establish a comparable ROE."

If we can go to the next slide, please. So, here we have a summary for you of the current OEB formula parameters. At the top of the slide and below that are recommended changes to those parameters. And, as you know, there are really four parameters that are included in the formula. We are recommending refinements to certain of those parameters to reflect more recent updated market data and also several modest changes to several of those parameters.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.49]

Question(s):

For each utility in the North American Electric Proxy Group, 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:

Please see N-M2-10-SEC-45, Attachment 1 and N-M2-10-SEC-45, Attachment 2 (Confidential) for the requested information.

Company	Ticker	S&P Credit Rating	Regulated Revenue / Total Revenue	Regulated Electric Revenue / Total Reg. Revenue
Canadian Utilities Limited	CU	NR	84.77%	n/a
Emera Inc.	EMA	BBB	98.03%	n/a
Fortis Inc.	FTS	A-	98.96%	n/a
Hydro One Limited	H	A-	99.42%	n/a
Alliant Energy Corporation	LNT	A-	97.76%	84.69%
Ameren Corporation	AEE	BBB+	100.00%	87.40%
American Electric Power Company, Inc.	AEP	BBB+	96.65%	100.00%
Duke Energy Corporation	DUK	BBB+	100.09%	91.28%
Entergy Corporation	ETR	BBB+	96.84%	98.45%
Eversource Energy	ES	A-	100.00%	81.89%
Exelon Corporation	EXC	BBB+	100.00%	90.90%
Evergy, Inc.	EVRG	BBB+	100.00%	100.00%
NextEra Energy, Inc.	NEE	A-	76.80%	100.00%
OGE Energy Corporation	OGE	BBB+	100.00%	100.00%
Pinnacle West Capital Corporation	PNW	BBB+	100.00%	100.00%
Portland General Electric Company	POR	BBB+	100.00%	100.00%
PPL Corporation	PPL	A-	99.85%	93.54%
Southern Company	SO	A-	90.74%	78.71%
Xcel Energy Inc.	XEL	BBB+	99.29%	81.65%

Annual REPORT 2023

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25
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ALLIANT ENERGY

capital, updated depreciation rates and modifications to certain regulatory asset and regulatory liability amortizations. These retail gas rate changes were effective on January 1, 2023 and extended through the end of 2023.

WPL's Retail Electric and Gas Rate Reviews (2024/2025 Forward-looking Test Period) - In December 2023, the PSCW issued an order authorizing annual base rate increases of $49 million and $13 million for WPL's retail electric and gas customers, respectively, effective January 1, 2024, for the 2024 forward-looking Test Period. The PSCW's order also authorized WPL to implement an additional $60 million increase in annual rates for its retail electric customers, effective January 1, 2025, for the 2025 forward-looking Test Period.

NOTE 3. PROPERTY, PLANT AND EQUIPMENT

At December 31, details of property, plant and equipment on the balance sheets were as follows (in millions):

	Alliant Energy		IPL		WPL	
	2023	2022	**2023**	2022	**2023**	2022
Utility:						
Electric plant:						
Generation in service (a)	**$9,180**	$8,060	**$5,025**	$4,962	**$4,155**	$3,098
Distribution in service	**7,314**	6,912	**4,091**	3,876	**3,223**	3,036
Other in service	**567**	543	**356**	354	**211**	189
Anticipated to be retired early (b)	**1,629**	2,103	**—**	491	**1,629**	1,612
Total electric plant	**18,690**	17,618	**9,472**	9,683	**9,218**	7,935
Gas plant in service	**1,791**	1,705	**951**	910	**840**	795
Other plant in service	**653**	624	**411**	402	**242**	222
Accumulated depreciation (b)	**(5,924)**	(5,690)	**(3,180)**	(3,149)	**(2,744)**	(2,541)
Net plant	**15,210**	14,257	**7,654**	7,846	**7,556**	6,411
Leased Sheboygan Falls Energy Facility, net (c)	**—**	—	**—**	—	**79**	15
Leased land for solar generation, net	**172**	133	**33**	—	**139**	133
Construction work in progress	**1,245**	1,357	**605**	194	**640**	1,163
Other, net	**7**	6	**6**	6	**1**	—
Total utility	**16,634**	15,753	**8,298**	8,046	**8,415**	7,722
Non-utility and other:						
Non-utility Generation, net (d)	**68**	71	**—**	—	**—**	—
Corporate Services and other, net (e)	**455**	423	**—**	—	**—**	—
Total non-utility and other	**523**	494	**—**	—	**—**	—
Total property, plant and equipment	**$17,157**	$16,247	**$8,298**	$8,046	**$8,415**	$7,722

(a) Alliant Energy and WPL currently expect estimated construction costs associated with WPL's approximately 1,100 MW of new solar generation will exceed amounts previously approved by the PSCW by approximately $180 million. In February 2024, the PSCW issued an oral decision approving WPL's deferral request to seek recovery of these costs in a future regulatory proceeding. Alliant Energy and IPL currently expect the estimated construction costs associated with IPL's 400 MW of new solar generation will exceed the cost target of $1,650/kilowatt, including AFUDC and transmission upgrade costs among other costs, approved in the IUB's advance rate-making principles by approximately 10%. Alliant Energy, IPL and WPL concluded that there was not a probable disallowance of anticipated higher rate base amounts as of December 31, 2023 given construction costs were reasonably and prudently incurred.

(b) In 2023, IPL retired Lansing and reclassified the remaining net book value of this EGU from property, plant and equipment to a regulatory asset on Alliant Energy's balance sheets. In 2020 and 2021, WPL received approval from MISO to retire Edgewater Unit 5, and Columbia Units 1 and 2, respectively. WPL currently anticipates retiring Edgewater Unit 5 by June 1, 2025, and Columbia Units 1 and 2 by June 1, 2026. Alliant Energy and WPL concluded that Edgewater Unit 5 and Columbia Units 1 and 2 met the criteria to be considered probable of abandonment as of December 31, 2023. WPL is currently allowed a full recovery of and a full return on these EGUs from both its retail and wholesale customers, and as a result, Alliant Energy and WPL concluded that no disallowance was required as of December 31, 2023. As of December 31, 2023, net book values were $504 million for Edgewater Unit 5, and $428 million for Columbia Units 1 and 2 in aggregate.

(c) Less accumulated amortization of $112 million and $106 million for WPL as of December 31, 2023 and 2022, respectively. Refer to Note 10 for discussion of WPL's renewal of this lease in 2023. For Alliant Energy, the leased Sheboygan Falls Energy Facility is eliminated upon consolidation and is included in the "Non-utility Generation, net" line within Alliant Energy's consolidated property, plant and equipment.

(d) Less accumulated depreciation of $75 million and $71 million for Alliant Energy as of December 31, 2023 and 2022, respectively.

(e) Less accumulated depreciation of $275 million and $269 million for Alliant Energy as of December 31, 2023 and 2022, respectively.

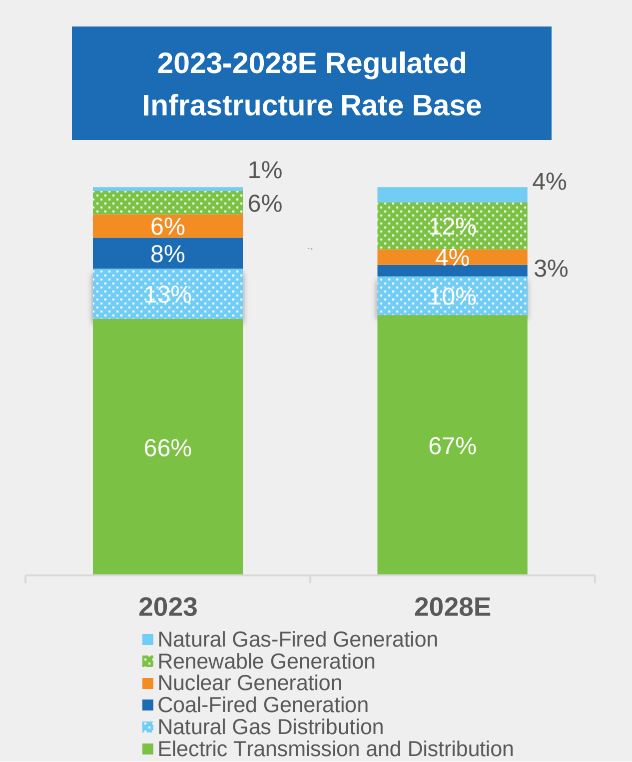
Powering a Reliable, Sustainable Tomorrow

Barclays Annual CEO Energy-Power Conference

September 4, 2024

Investing in the Energy Grid

- **Investing to modernize energy grid, making it cleaner, safer, more reliable, resilient and secure**
  - Ameren Missouri Smart Energy Plan filed with the MoPSC supporting infrastructure investment to modernize the grid
  - Expect greater transmission investments to support additional renewable generation
  - Provide customers with new and improved tools to manage energy usage
- **Transitioning to cleaner energy portfolio - target net-zero carbon emissions by 2045[1]**
  - Expect to add 2,800 MWs of renewable generation by 2030; total of 4,700 MWs by 2036
  - Expected retirement of coal-fired energy centers
    - Rush Island in 2024; Sioux in 2032; Labadie: 2 units in 2036, 2 units in 2042
  - As of Dec. 31, 2023, coal-fired energy center rate base was ~$1.9 billion
- **By 2028, rate base expected to be 77% electric and natural gas transmission and distribution, 12% renewable generation and 4% nuclear generation**
- **Ameren's estimated coal-related revenues in 2023 were 14%[2] and coal-fired generation rate base expected to be 3% by the end of 2028**
  - Coal-related capital expenditures for 2024-2028 are expected to be ~$0.9 billion, or ~4% of Ameren's five-year plan



[1] Ameren's goals include both Scope 1 and 2 emissions including other greenhouse gas emissions of methane, nitrous oxide and sulfur hexafluoride. [2] See page 34 for additional details and calculations.

Building Momentum

2023 ANNUAL REPORT
AND FORM 10-K

DUKE ENERGY®

ITEM 2. PROPERTIES

ELECTRIC UTILITIES AND INFRASTRUCTURE

The following table provides information related to the EU&I's generation stations as of December 31, 2023. The MW displayed in the table below are based on winter capacity for Fossil, Nuclear and Hydro generation stations, and nameplate capacity for Renewable generation stations. Ownership interest in all facilities is 100% unless otherwise indicated.

Prior to December 31, 2023, summer capacity was displayed for all EU&I generation stations in the table below. Certain registrants' IRPs, including those filed in North Carolina and South Carolina in 2023, currently use winter capacity for Fossil, Nuclear and Hydro stations as winter capacity is generally a more accurate representation of that stations' ability to support peak capacity requirements due to a higher risk of reliability challenges during the winter months in those jurisdictions. Additionally, analysis of resource adequacy across all jurisdictions demonstrates that as solar adoption increases, there is a higher risk of reliability challenges in the winter. As such, most of Duke Energy's IRPs are expected to shift toward winter planning. See Item 7, "Other Matters" for additional information on IRPs. Nameplate capacity is generally viewed as a transparent representation of the Renewable stations since their output varies by day, month, and real-time weather conditions, particularly with solar facilities, which may or may not be paired with battery storage depending on the location. The Owned MW Capacity based on summer capacity as of December 31, 2023, is 50,302 MW for all of EU&I.

Facility	Plant Type	Primary Fuel	Location	Owned MW Capacity
Duke Energy Carolinas				
Oconee	Nuclear	Uranium	SC	2,618
McGuire	Nuclear	Uranium	NC	2,386
Catawba[a]	Nuclear	Uranium	SC	588
Belews Creek	Fossil	Coal/Gas	NC	2,220
Marshall	Fossil	Coal/Gas	NC	2,078
Lincoln Combustion Turbine (CT)	Fossil	Gas/Oil	NC	1,507
J.E. Rogers	Fossil	Coal/Gas	NC	1,395
Rockingham CT	Fossil	Gas/Oil	NC	895
Mill Creek CT	Fossil	Gas/Oil	SC	751
Buck CC	Fossil	Gas	NC	718
Dan River CC	Fossil	Gas	NC	718
W.S. Lee Combined Cycle (CC)[b]	Fossil	Gas	SC	706
Allen	Fossil	Coal	NC	426
W.S. Lee CT	Fossil	Gas/Oil	SC	96
Clemson CHP	Fossil	Gas	SC	16
Bad Creek	Hydro	Water	SC	1,600
Jocassee	Hydro	Water	SC	780
Cowans Ford	Hydro	Water	NC	324
Keowee	Hydro	Water	SC	152
Other small facilities (18 plants)	Hydro	Water	NC/SC	584
Distributed generation	Renewable	Solar	NC	178
Total Duke Energy Carolinas				**20,736**
Duke Energy Progress				
Brunswick	Nuclear	Uranium	NC	1,928
Harris	Nuclear	Uranium	NC	1,009
Robinson	Nuclear	Uranium	SC	793
Roxboro	Fossil	Coal	NC	2,462
Smith CC	Fossil	Gas/Oil	NC	1,250
H.F. Lee CC	Fossil	Gas/Oil	NC	1,054
Wayne County CT	Fossil	Gas/Oil	NC	975
Smith CT	Fossil	Gas/Oil	NC	960
L.V. Sutton CC	Fossil	Gas/Oil	NC	719
Mayo	Fossil	Coal	NC	713
Asheville CC	Fossil	Gas/Oil	NC	560
Asheville CT	Fossil	Gas/Oil	NC	370
Darlington CT	Fossil	Gas/Oil	SC	264
Weatherspoon CT	Fossil	Gas/Oil	NC	164
L.V. Sutton CT	Fossil	Gas/Oil	NC	97
Blewett CT	Fossil	Oil	NC	68
Walters	Hydro	Water	NC	112
Other small facilities (3 plants)	Hydro	Water	NC	116
Distributed generation	Renewable	Solar	NC	141
Asheville – Rock Hill Battery	Renewable	Storage	NC	9
Hot Springs Microgrid	Renewable	Storage	NC	6
Total Duke Energy Progress				**13,770**

Facility	Plant Type	Primary Fuel	Location	Owned MW Capacity
Duke Energy Florida				
Hines CC	Fossil	Gas/Oil	FL	2,149
Citrus County CC	Fossil	Gas	FL	1,854
Crystal River	Fossil	Coal	FL	1,442
Bartow CC	Fossil	Gas/Oil	FL	1,259
Intercession City CT	Fossil	Gas/Oil	FL	1,146
Anclote	Fossil	Gas	FL	1,035
DeBary CT	Fossil	Gas/Oil	FL	661
Osprey CC	Fossil	Gas/Oil	FL	611
Tiger Bay CC	Fossil	Gas/Oil	FL	230
Bayboro CT	Fossil	Oil	FL	226
Bartow CT	Fossil	Gas/Oil	FL	212
Suwannee River CT	Fossil	Gas	FL	194
University of Florida CoGen CT	Fossil	Gas	FL	50
Lake Placid Battery (microgrid)	Renewable	Storage	FL	17
Trenton Battery	Renewable	Storage	FL	11
Micanopy Battery	Renewable	Storage	FL	8
Jennings Battery	Renewable	Storage	FL	6
Cape San Blas Battery	Renewable	Storage	FL	6
Distributed generation	Renewable	Solar	FL	1,186
Total Duke Energy Florida				**12,303**
Duke Energy Ohio				
East Bend	Fossil	Coal	KY	600
Woodsdale CT	Fossil	Gas/Propane	OH	564
Distributed generation	Renewable	Solar	KY	9
Total Duke Energy Ohio				**1,173**
Duke Energy Indiana				
Gibson[(c)]	Fossil	Coal	IN	2,845
Cayuga[(d)]	Fossil	Coal/Oil	IN	1,015
Madison CT	Fossil	Gas	OH	704
Edwardsport	Fossil	Coal/Gas	IN	578
Wheatland CT	Fossil	Gas	IN	508
Vermillion CT[(e)]	Fossil	Gas	IN	477
Noblesville CC	Fossil	Gas/Oil	IN	310
Henry County CT[(f)]	Fossil	Gas/Oil	IN	134
Cayuga CT	Fossil	Gas/Oil	IN	105
Purdue CHP	Fossil	Gas	IN	16
Markland	Hydro	Water	IN	54
Distributed generation	Renewable	Solar	IN	29
Camp Atterbury Battery	Renewable	Storage	IN	5
Nabb Battery	Renewable	Storage	IN	5
Crane Battery	Renewable	Storage	IN	5
Total Duke Energy Indiana				**6,790**

Totals by Type	Owned MW Capacity
Total Electric Utilities	**54,772**
Totals by Plant Type	
Nuclear	9,322
Fossil	40,107
Hydro	3,722
Renewable	1,621
Total Electric Utilities	**54,772**

(a) Jointly owned with North Carolina Municipal Power Agency Number 1, NCEMC and PMPA. Duke Energy Carolinas' ownership is 19.25% of the facility.
(b) Jointly owned with NCEMC. Duke Energy Carolinas' ownership is 87.27% of the facility.
(c) Duke Energy Indiana owns and operates Gibson Station Units 1 through 4 and is a joint owner of unit 5 with WVPA and IMPA. Duke Energy Indiana operates unit 5 and owns 50.05%.
(d) Includes Cayuga Internal Combustion.
(e) Jointly owned with WVPA. Duke Energy Indiana's ownership is 62.5% of the facility.
(f) Includes 50 MW, which are contracted to WVPA.

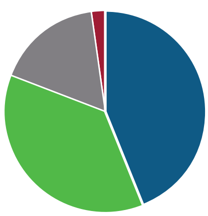
Duke Energy at a Glance

Electric Utilities and Infrastructure

Generation Diversity (percent owned capacity)

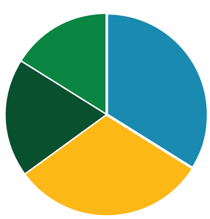
44% Natural Gas/Fuel Oil
29% Coal
17% Nuclear
10% Hydro and Renewable

Generated (net output gigawatt-hours (GWh))



44% Natural Gas/Fuel Oil
37% Nuclear
17% Coal
2% Hydro and Renewable

Customer Diversity (in billed GWh sales)



34% Residential
31% General Services
19% Industrial
16% Wholesale/Other

Electric Utilities and Infrastructure conducts operations primarily through the regulated public utilities of Duke Energy Carolinas, Duke Energy Progress, Duke Energy Florida, Duke Energy Indiana, Duke Energy Ohio and Duke Energy Kentucky.

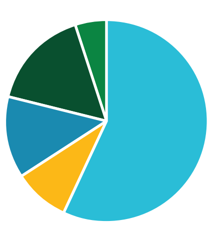
Electric Operations

- Owns approximately 54,772 megawatts (MW) of generating capacity
- Service area covers about 90,000 square miles with an estimated population of 27 million
- Service to approximately 8.4 million residential, commercial and industrial customers
- 282,900 miles of distribution lines and a 31,400-mile transmission system
- 21% of coal generation capacity has dual-fuel capability

Natural Gas Customer Diversity

Gas Utilities and Infrastructure conducts natural gas distribution operations primarily through the regulated public utilities of Piedmont Natural Gas and Duke Energy Ohio.

Natural Gas Operations (throughput)



57% Power Gen
16% Industrial
13% Residential
9% General Services
5% Other

- Regulated natural gas transmission and distribution services to approximately 1.7 million customers in the Carolinas, Tennessee, southwestern Ohio and Northern Kentucky
- Maintains 35,700 miles of natural gas transmission and distribution pipelines and 28,800 miles of natural gas service pipelines

December 31, 2023.

entergy

Entergy Corporation
and Subsidiaries

2023 Annual Report

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Net property, plant, and equipment (including property under lease and associated accumulated amortization) for Entergy by functional category, as of December 31, 2023 and 2022, is shown below:

	2023	**2022**
	(In Millions)	
Production		
Nuclear	$7,944	$7,936
Other	7,045	7,256
Transmission	9,927	9,590
Distribution	12,927	12,363
Other	3,173	2,906
Construction work in progress	2,110	1,844
Nuclear fuel	708	582
Property, plant, and equipment - net	$43,834	$42,477

Depreciation rates on average depreciable property for Entergy approximated 2.9% in 2023, 2.8% in 2022, and 2.7% in 2021.

Entergy amortizes nuclear fuel using a units-of-production method. Nuclear fuel amortization is included in fuel expense in the income statements.

Non-utility property - at cost (less accumulated depreciation) for Entergy is reported net of accumulated depreciation of $193 million as of December 31, 2023 and $208 million as of December 31, 2022.

NEXTera ENERGY

ANNUAL REPORT **2023**

7. Property, Plant and Equipment

Property, plant and equipment consists of the following at December 31:

	NEE		FPL	
	2023	2022	**2023**	2022
	(millions)			
Electric plant in service and other property	**$ 139,049**	$ 124,963	**$ 79,801**	$ 74,353
Nuclear fuel	**1,564**	1,684	**1,125**	1,190
Construction work in progress	**18,652**	15,675	**8,311**	7,026
Property, plant and equipment, gross	**159,265**	142,322	**89,237**	82,569
Accumulated depreciation and amortization	**(33,489)**	(31,263)	**(18,629)**	(17,876)
Property, plant and equipment – net	**$ 125,776**	$ 111,059	**$ 70,608**	$ 64,693

FPL – At December 31, 2023, FPL's gross investment in electric plant in service and other property for the electric generation, transmission, distribution and general facilities of FPL represented approximately 43%, 14%, 36% and 7%, respectively; the respective amounts at December 31, 2022 were 44%, 14%, 35% and 7%. Substantially all of FPL's properties are subject to the lien of FPL's mortgage, which secures most debt securities issued by FPL. The weighted annual composite depreciation and amortization rate for FPL's electric plant in service, including capitalized software, but excluding the effects of decommissioning, dismantlement and the depreciation adjustments discussed in the following sentences, was approximately 3.4%, 3.6% and 3.8% for 2023, 2022 and 2021, respectively. In accordance with the 2021 rate agreement (see Note 1 – Rate Regulation – Base Rates Effective January 2022 through December 2025), FPL recorded reserve amortization of approximately $227 million in 2023. In 2022, FPL recorded a one-time reserve amortization adjustment of approximately $114 million, as required under the 2021 rate agreement, 50% of which was used to reduce the capital recovery regulatory asset balance and the other 50% to increase the storm reserve regulatory liability (see Note 1 – Storm Funds, Storm Reserves and Storm Cost Recovery). In accordance with the 2016 rate agreement (see Note 1 – Rate Regulation – Base Rates Effective January 2017 through December 2021), FPL recorded reserve amortization of approximately $429 million in 2021. During 2023, 2022 and 2021, FPL recorded AFUDC of approximately $190 million, $136 million and $176 million, respectively, including the equity component of AFUDC of approximately $155 million, $105 million and $132 million, respectively.

NEER – At December 31, 2023, wind, solar, nuclear and rate-regulated transmission facilities represented approximately 47%, 18%, 6% and 6%, respectively, of NEER's depreciable electric plant in service and other property; the respective amounts at December 31, 2022 were 51%, 14%, 7% and 7%. The estimated useful lives of NEER's plants range primarily from 30 to 35 years for wind facilities, 30 to 35 years for solar facilities, 23 to 47 years for nuclear facilities and 40 years for rate-regulated transmission facilities. NEER's oil and gas production assets represented approximately 16% and 15% of NEER's depreciable electric plant in service and other property at December 31, 2023 and 2022, respectively. A number of NEER's generation, regulated transmission and pipeline facilities are encumbered by liens securing various financings. The net book value of NEER's assets serving as collateral was approximately $27.8 billion at December 31, 2023. Interest capitalized on construction projects amounted to approximately $310 million, $172 million and $139 million during 2023, 2022 and 2021, respectively.

Jointly-Owned Electric Plants – Certain NEE subsidiaries own undivided interests in the jointly-owned facilities described below, and are entitled to a proportionate share of the output from those facilities. The subsidiaries are responsible for their share of the operating costs, as well as providing their own financing. Accordingly, each subsidiary's proportionate share of the facilities and related revenues and expenses is included in the appropriate balance sheet and statement of income captions. NEE's and FPL's respective shares of direct expenses for these facilities are included in fuel, purchased power and interchange expense, O&M expenses, depreciation and amortization expense and taxes other than income taxes and other – net in NEE's and FPL's consolidated statements of income.

DELIVERING ON OUR PROMISE

2023 ANNUAL REPORT

PINNACLE WEST CAPITAL CORPORATION

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Certain cost recovery mechanisms may qualify as alternative revenue programs. For alternative revenue programs that meet specified accounting criteria, we recognize revenues when the specific events permitting billing of the additional revenues have been completed.

See Notes 2 and 3 for additional information.

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of accounts receivable and accrued unbilled revenues that will ultimately be uncollectible due to credit loss risk. The allowance includes a write-off component that is calculated by applying an estimated write-off factor to retail electric revenues. The write-off factor used to estimate uncollectible accounts is based upon consideration of historical collections experience, the current and forecasted economic environment, changes to our collection policies, and management's best estimate of future collections success. See Note 2.

Property, Plant and Equipment

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission, and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;
- capitalized leases;
- construction overhead costs (where applicable); and
- AFUDC.

Pinnacle West's property, plant and equipment included in the December 31, 2023, and 2022 Consolidated Balance Sheets is composed of the following (dollars in thousands):

Property, Plant and Equipment:	**2023**	**2022**
Generation	$ 10,446,291	$ 9,563,145
Transmission	3,773,253	3,589,456
Distribution	8,448,293	7,951,867
General plant	1,543,330	1,347,678
Plant in service and held for future use	24,211,167	22,452,146
Accumulated depreciation and amortization	(8,408,040)	(7,929,878)
Net	15,803,127	14,522,268
Construction work in progress	1,724,004	1,882,791
Palo Verde sale leaseback, net of accumulated depreciation	86,426	90,296
Intangible assets, net of accumulated amortization	267,110	258,880
Nuclear fuel, net of accumulated amortization	99,490	100,119
Total property, plant and equipment	$ 17,980,157	$ 16,854,354

Property, plant and equipment balances and classes for APS are not materially different than Pinnacle West.

Southern Company

2023 Annual Report

The Registrants' property, plant, and equipment in service consisted of the following at December 31, 2023 and 2022:

At December 31, 2023:	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Electric utilities:						
Generation	**$ 57,325**	**$16,584**	**$22,587**	**$2,909**	**$14,649**	**$ —**
Transmission	**15,561**	**6,152**	**8,402**	**966**	**—**	**—**
Distribution	**26,482**	**9,775**	**15,380**	**1,327**	**—**	**—**
General/other	**6,305**	**2,918**	**3,001**	**321**	**41**	**—**
Electric utilities' plant in service	**105,673**	**35,429**	**49,370**	**5,523**	**14,690**	**—**
Southern Company Gas:						
Natural gas transportation and distribution	**17,798**	**—**	**—**	**—**	**—**	**17,798**
Storage facilities	**1,565**	**—**	**—**	**—**	**—**	**1,565**
Other	**1,477**	**—**	**—**	**—**	**—**	**1,477**
Southern Company Gas plant in service	**20,840**	**—**	**—**	**—**	**—**	**20,840**
Other plant in service	**1,915**	**—**	**—**	**—**	**—**	**—**
Total plant in service	**$128,428**	**$35,429**	**$49,370**	**$5,523**	**$14,690**	**$20,840**

At December 31, 2022:	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Electric utilities:						
Generation	$ 51,756	$15,920	$17,755	$2,826	$14,619	$ —
Transmission	14,201	5,658	7,576	927	—	—
Distribution	24,200	9,154	13,819	1,228	—	—
General/other	5,806	2,740	2,729	273	39	—
Electric utilities' plant in service	95,963	33,472	41,879	5,254	14,658	—
Southern Company Gas:						
Natural gas transportation and distribution	16,810	—	—	—	—	16,810
Storage facilities	1,553	—	—	—	—	1,553
Other	1,360	—	—	—	—	1,360
Southern Company Gas plant in service	19,723	—	—	—	—	19,723
Other plant in service	1,843	—	—	—	—	—
Total plant in service	$117,529	$33,472	$41,879	$5,254	$14,658	$19,723

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of nuclear refueling costs and certain maintenance costs including those described below.

In accordance with orders from their respective state PSCs, Alabama Power and Georgia Power defer nuclear refueling outage operations and maintenance expenses to a regulatory asset when the charges are incurred. Alabama Power amortizes the costs over a subsequent 18-month period with Plant Farley's fall outage cost amortization beginning in January of the following year and spring outage cost amortization beginning in July of the same year. Georgia Power amortizes its costs over each unit's operating cycle, or 18 months for Plant Vogtle Units 1, 2, and 3 and 24 months for Plant Hatch Units 1 and 2. Georgia Power's amortization period begins the month the refueling outage starts.

A portion of Mississippi Power's railway track maintenance costs is charged to fuel stock and recovered through Mississippi Power's fuel clause.

The portion of Southern Company Gas' non-working gas used to maintain the structural integrity of natural gas storage facilities that is considered to be non-recoverable is depreciated, while the recoverable or retained portion is not depreciated.

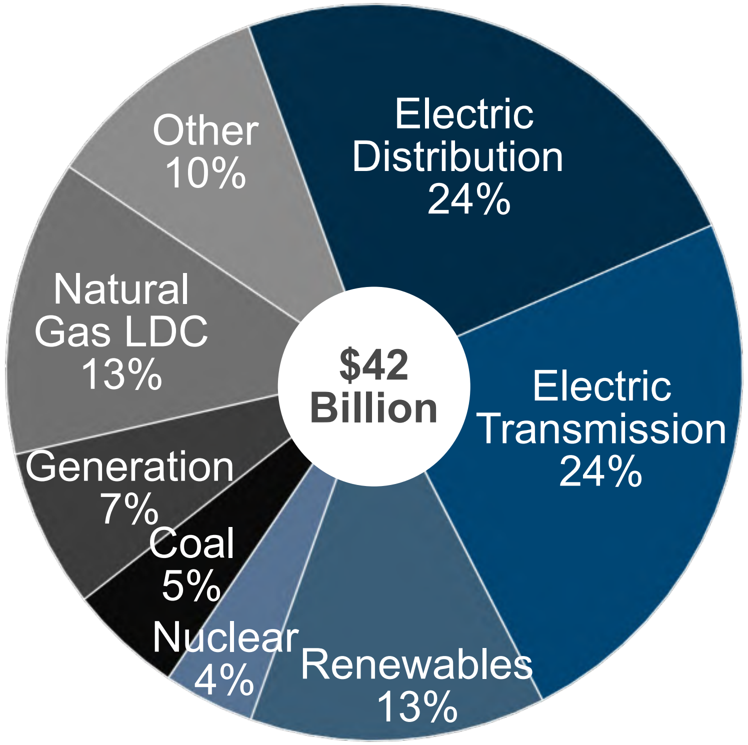
See Note 9 for information on finance lease right-of-use (ROU) assets, net, which are included in property, plant, and equipment.

STEEL FOR FUEL 2.0

September Investor Meetings

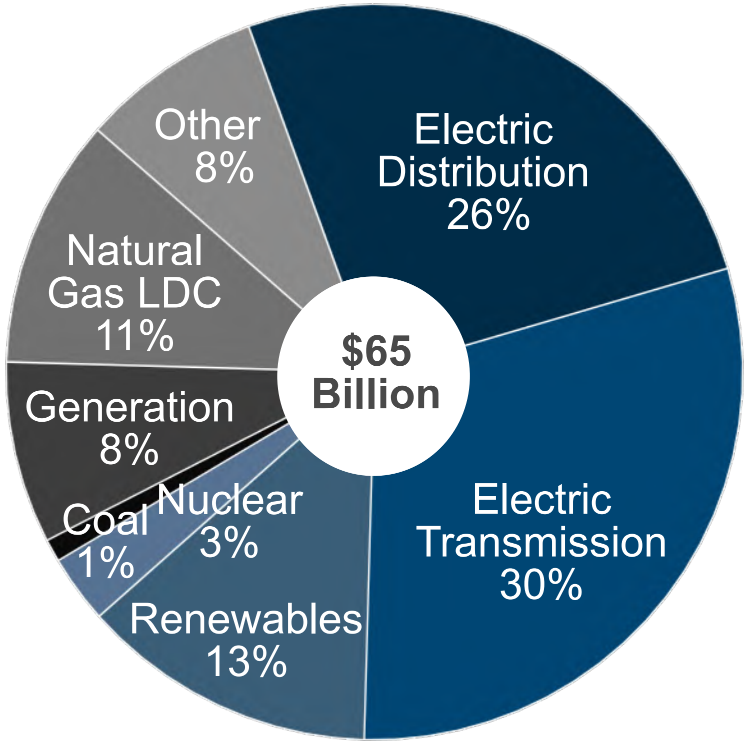
September 2024

Diverse Asset Base



2023

Coal Rate Base Declines from 5% to 1%



2028E

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.126]

Question(s):

With respect to Fuel Price Risk, Concentric states: “Like the Ontario utilities, the North American proxy group companies have little to no exposure to commodity price risk or supply risk due either to the elimination of the utility supply function in competitive electric and gas markets or through the prevalence of fuel pass-through mechanisms – 100 percent of the proxy companies are protected from normal commodity price risk.” Please identify which non-Ontario electric utilities included in the North American proxy group as Load Serving Entities (or similar role) in which they procure electricity supply on behalf of at least some of its customers. For those utilities, please explain if those documents are subject to any form of prudence review, even if the amounts are treated as pass-through costs.

Response:

Concentric is aware that several Northeast utilities in the U.S., including the electric operating utilities owned by Eversource Energy, have the Load Serving Entities (“LSE”) function and procure electricity supply on behalf of customers. The contracts for this supply are subject to prudence review as to the reasonableness of the costs. In Ontario, electric distribution utilities such as Hydro One do not have the LSE function; that role is served by the Ontario IESO. Ontario electric distributors have no legal obligation to provide electricity supply, only to connect customers. In that regard, Ontario’s electric distribution utilities have lower risk than electric utility companies that have the LSE obligation. This situation, however, has not changed since the 2009 review of the Ontario formula or since 2006, when the OEB set the deemed equity ratio for electric distributors at 40%. Furthermore, the Ontario electric distributors are responsible for billing all parts of the end use electricity customers bill, generation, transmission, and regulatory charges, and manage the related bad debt. Although these costs are intended to be flowthrough charges, distributors manage the cashflow impacts of rates charged to customer not being equal to what is charged to distributors and hold the risk of settlement errors. Distributors also settle for some generators. Lastly, the OEB has new requirements for Ontario electric distributors to consider non-wires solutions as part of their Distribution System Plan and Ontario distributors are taking on new roles in the Ontario Market in order to support load growth, grid modernization and the expanded use of DERs.

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PUC DOCKET NO. 53601
SOAH DOCKET NO. 473-22-2695

APPLICATION OF ONCOR ELECTRIC	§	**PUBLIC UTILITY COMMISSION**
DELIVERY COMPANY LLC FOR	§	
AUTHORITY TO CHANGE RATES	§	**OF TEXAS**

ORDER

This Order addresses the application of Oncor Electric Delivery Company LLC (Oncor) for authority to change its rates and to consolidate Oncor and Oncor NTU for ratemaking purposes as directed by the Commission in Docket No. 48929.[1] Oncor NTU is a wholly owned subsidiary of Oncor that acquired certificate of convenience and necessity rights previously owned by Sharyland Distribution & Transmission Services, L.L.C. in Docket No. 48929. Oncor seeks a $5,810,772,332 revenue requirement based on a 7.05% overall rate of return. The requested revenue requirement is $250,691,114 or 4.51% higher than Oncor's adjusted test-year revenues of $5,560,081,218.

A hearing on the merits convened from September 26 through October 4, 2022 through videoconferences hosted by the State Office of Administrative Hearings (SOAH). On December 28, 2022, the SOAH administrative law judges (ALJs) filed their proposal for decision. The ALJs recommend the Commission set Oncor's retail revenue requirement at $5,313,404,970, an amount $246,676,248 or 4.44% lower than Oncor's adjusted test-year revenues. The ALJs also recommend the Commission adopt an agreement on rate-case expenses filed by Oncor, Commission Staff, the Steering Committee of Cities Served by Oncor (Cities), and the Alliance of Oncor Cities (Alliance of Cities). On February 9, 2023, the ALJs filed a letter that made changes to the proposal for decision in response to the parties that filed exceptions and replies to the proposal for decision.

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[1] *Joint Report and Application of Oncor Electric Delivery Company LLC, Sharyland Distribution & Transmission Services, L.L.C., Sharyland Utilities, L.P., and Sempra Energy for Regulatory Approvals under PURA §§ 14.101, 37.154, 39.262, and 39.915*, Docket No. 48929, Order, Ordering Paragraph No. 16 (May 9, 2019).

The Commission adopts in part and rejects in part the proposal for decision, including findings of fact and conclusions of law, and authorizes Oncor to change its rates to the extent provided in this order. The Commission makes the following changes to the proposal for decision.

I. Discussion

The Commission's decision results in a $5,547,515,324 base-rate revenue requirement and an overall 6.65% rate of return. New findings of fact 48A through 48F are added to address the procedural history of this docket after the close of the evidentiary record at SOAH.

A. Rate Base

1. Acquisition Adjustment

The Commission agrees with the ALJs' recommendation to disallow Oncor's requested recovery of $23.5 million from rate base and to disallow Oncor's requested annual amortization of $851,000 for costs associated with an acquisition adjustment. However, the Commission clarifies the basis for the disallowance. This acquisition adjustment was first recognized by the Commission in a sale, transfer, merger proceeding between Sharyland and Southwestern Public Service Company (SPS) in 2013.[2] Oncor later purchased the assets associated with the acquisition adjustment in 2019.[3]

The Commission has previously determined that acquisition adjustments may be included in rate base if a utility demonstrates that the purchase price of the acquired assets was not excessive and that specific and offsetting benefits have accrued to ratepayers.[4] The ALJs based their recommendation upon the Office of Public Utility Counsel's (OPUC) arguments. OPUC argued Oncor should not receive the acquisition adjustment because Oncor was not a party to Sharyland's

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[2] *Joint Report and Application of Sharyland Utilities, L.P., Sharyland Distribution & Transmission Services, L.L.C., and Southwestern Public Service Company for Approval of Purchase and Sale of Facilities, for Regulatory Accounting Treatment of Gain on Sale, and for Transfer of Certificate Rights*, Docket No. 41430, Order (Dec. 30, 2013).

[3] *Joint Report and Application of Oncor Electric Delivery Company, LLC, Sharyland Distribution & Transmission Services, L.L.C., Sharyland Utilities, L.P., and Sempra Energy for Regulatory Approvals under PURA §§ 14.101, 37.154, 39.262, and 39.915*, Docket No. 48929 (May 9, 2019).

[4] *Application of Electra Telephone Company, Inc. for Transfer of a Certificate of Public Convenience and Necessity from Electra Telephone Company*, Docket No. 8374, Order at 1 (Aug. 6, 1998); *id.*, Examiner's Report on Remand at 6 (Aug. 1, 1990).

proceedings every four years,[25] and could result in asset balances being carried forward year-after-year, resulting in a snowballing of costs. Accordingly, a five-year amortization period is reasonable and appropriate. To reflect the Commission's decision on this issue, the Commission modifies proposed finding of fact 173; adds new finding of fact 167A; and deletes proposed findings of fact 168 through 172, 241, and 242.

B. Rate of Return

The ALJs determined that a reasonable range for Oncor's return on equity would be from 8.9% to 9.7% and recommended the Commission adopt the mid-point of 9.3% as the best approximation of an appropriate return on equity for Oncor. After consideration of the record evidence, the Commission determines that a return on equity of 9.70% is appropriate for Oncor. Electric utilities face increasing inflation and less favorable short- and long-term interest rates than in recent years, which saw steady decreases in utility returns on equity. Furthermore, in establishing a reasonable return on invested capital the Commission has the authority to consider the efforts of the utility in conserving resources; the quality of service; the efficiency of operations; and the quality of management.

The Commission recognizes Oncor's high performance throughout its service territory in minimizing the number and duration of outages, maintaining system frequency, responding to storm damage, and restoring power to customers. The Commission also recognizes, however, that Oncor could improve timing of, and reduce the delays in, its interconnection process. For the reasons discussed above, the Commission determines that 9.7% is the appropriate return on equity for Oncor. To reflect this determination, the Commission modifies proposed findings of fact 184, 185, 186, and 190. The Commission also modifies proposed conclusion of law 11 for completeness and consistency with past Commission orders.

C. Operating Expenses

1. Long-term Incentive Compensation Expenses

The Commission does not agree with the ALJs' recommendation to disallow approximately $14.4 million in expenses associated with its long-term incentive compensation long-term incentive plan. Instead, the Commission modifies the proposal for decision to

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[25] 16 TAC § 25.247(b)(1).

<u>ORDER NO. 90948</u>

Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan	* * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9692

ORDER ON APPLICATION FOR A MULTI-YEAR RATE PLAN

Before: Frederick H. Hoover, Jr., Chair
Michael T. Richard, Commissioner
Anthony J. O'Donnell, Commissioner
Kumar P. Barve, Commissioner
Bonnie A. Suchman, Commissioner

Issued: December 14, 2023

P. Energy Storage Pilot Project Costs

BGE

BGE seeks rate recovery for costs associated with its Chesapeake Beach energy storage pilot project, which is owned and operated by a third-party.[1007] The project became operational January 20, 2023.[1008]

Staff

Staff witness Wilson recommended that the Commission approve BGE's request for recovery of the project costs associated with its Chesapeake Beach energy storage project.[1009] He testified that, despite some cost increases, the project continues to be cost effective.

Commission Decision

The Commission, in Order No. 89240, approved standard cost recovery rules for O&M costs attributable to the use of third-party owned assets under the energy storage pilot. The Commission accepts the undisputed recommendation of Staff and finds that the record supports the conclusion that the project is cost effective and should be included in the revenue requirement.

III. COST OF CAPITAL

The cost of capital is the rate of return ("ROR") that a utility pays investors in common stock (equity) and bonds (debt) to attract and retain investment in a financially competitive market. The utility recovers its return on equity ("ROE") and cost of (or "return on") debt through charges paid by its ratepayers. While the cost of debt can be directly

[1007] BGE Exhibit OIA-15.
[1008] Maillog No. 242463.
[1009] Wilson Direct at 21.

observed, as bonds are issued subject to specific interest rates, this rate case features competing cost of debt projections based on the projected movement of bond yields throughout the three-year effective period of rates.

The ROE also requires analysis, as it is typically estimated based on market conditions and different analytical approaches. Once the cost of debt and ROE are determined, they are weighted according to the percentage of debt and equity in the utility's capital structure. The sum of the weighted cost of debt and ROE is the utility's overall ROR. Although BGE is a subsidiary of Exelon, and thus its stock is not publicly traded, the Commission must still examine BGE's level of risk and its capital structure to determine its cost of capital.

In this case, the Commission heard testimony on cost of capital from witnesses for BGE, Commission Staff, OPC, Walmart, and the Department of Defense ("DoD"), which recommended the following ROEs for gas and electric operations:

Table 7

Parties' Recommended ROEs for Electric and Gas Utilities		
Party	**ROE Range**	**ROE**
BGE	9.7%-11.1%	10.4% for electric and gas[1010]
Staff	9.04%-9.70%	9.45% for electric and gas[1011]
OPC	8.55% - 9.30%	9.10 for electric and gas%[1012]
Walmart		9.50% electric[1013] 9.65% gas
DoD	9.20% - 9.90%	9.40 for electric and gas%[1014]

[1010] McKenzie Direct at 50.
[1011] McAuliffe Direct at 11.
[1012] Woolridge Direct at 60.
[1013] Kronauer Direct at 19.
[1014] Walters Direct at 3.

In support of those recommendations, the Parties presented competing financial analyses, which involved comparing BGE to other utilities for the purposes of developing a proxy group. As part of their analyses, most of the Parties attempted to create proxy groups of companies with comparable risk to BGE's gas and electric businesses.[1015] While the Parties generally did not dispute BGE's proposed capital structure of 52% equity and 48% debt across all three MYP years, certain Parties raised concerns regarding the proposed ROEs.

A. Proxy Groups and ROE

As part of their analyses, the Parties attempted to create proxy groups of companies with comparable risk to BGE's electric and gas distribution businesses.

BGE

BGE witness Adrien M. McKenzie testified that he created a separate electric proxy group of 26 electric utilities that he referred to as the "Electric Group."[1016] He identified his proxy group using the following criteria: (1) included in the Electric Utility Industry groups compiled by Value Line; (2) paid common dividends over the last six months and have not announced a dividend cut since that time; (3) had no ongoing involvement in a major merger or acquisition that would distort quantitative results; (4) assigned a Value Line Safety Rank of "1" or "2;" and (5) assigned a Value Line Financial Strength Rating of B++ or higher.[1017] Witness McKenzie also stated that his analysis considered credit ratings from S&P and Moody's in evaluating relative risk. Specifically, his analysis

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[1015] Walmart's direct testimony does not include discussion of the creation or use of a proxy group.
[1016] McKenzie Direct at 15.
[1017] *Id.* at 15.

excluded any companies with ratings below Baa2 and BBB assigned by Moody's and S&P respectively.[1018]

Mr. McKenzie noted that he also created a separate gas proxy group of eight gas utilities that he referred to as the "Gas Group."[1019] He identified the gas proxy group with the following criteria: (1) using companies included in the Natural Gas Utility industry group compiled by Value Line; (2) eliminating South Jersey Industries due to its pending acquisition by Infrastructure Investment Fund, and excluding UGI Corporation because it is engaged primarily in propane sales and marketing, which are not directly comparable to BGE's gas distribution operations; (3) verifying that the remaining firms have not cut dividend payments during the past six months and have not announced a dividend cut since that time; and (4) confirming that all of the proxy group firms have investment-grade credit ratings from S&P and Moody's.[1020]

Witness McKenzie also evaluated the investors risk perceptions for the Electric and Gas groups by looking at Value Line's primary risk indicator of Safety Rank, Value Line's Financial Strength Ratings, and finally beta which measures a utility's stock price volatility relative to the market as a whole and reflects the tendency of a stock's price to follow changes in the market.[1021] Based on Mr. McKenzie's analysis, a comparison of these risk indicators between his proxy electric and gas groups and BGE shows that "investors would likely conclude that the overall investment risks for the firms in the Electric and Gas Groups are generally comparable to BGE."[1022]

[1018] *Id.*
[1019] *Id.* at 16.
[1020] *Id.* at 15-16.
[1021] *Id*. at 17.
[1022] *Id*. at 18.

Mr. McKenzie used two ROE models—discounted cash flow ("DCF") and capital asset pricing ("CAPM")—as well as the risk premium method, in his analysis.[1023] He recommended an ROE of 10.4% for both BGE's electric and gas utility operations.[1024]

Staff

Staff witness McAuliffe testified that he identified an electric proxy group of 32 companies and a gas proxy group of eight companies that are identified as electric or gas utilities by Value Line that have a Value Line financial strength rating of B++ or greater.[1025] For his analysis, he required that each company have all relevant data from Value Line necessary and also used the DCF and capital asset pricing CAPM models to develop his recommended ROE, excluding parent company Exelon, as well as any utility that was involved in a merger during his sample period.[1026] Mr. McAuliffe removed from his results any company that had an ROE below seven percent or above 14 percent.[1027] He recommended an ROE of 9.45% for electric and gas utility operations, lowering BGE's current gas operations from 9.65% and raising current electric operations from 9.40%.[1028] He stated that his recommendation fell within the range of his analysis results and adhered to the Commission's precedent for applying gradualism to determinations of ROE.[1029] He stated that BGE's proposed ROE is much higher than the nationwide average for electric and gas utilities.[1030]

[1023] McKenzie Direct at 50.
[1024] *Id.* at 51.
[1025] McAuliffe Direct at 19.
[1026] *Id.*
[1027] *Id.*
[1028] *Id.* at 11.
[1029] *Id.*
[1030] *Id.* at 36.

OPC

OPC witness Woolridge adopted BGE's proposed capital structure with a common equity ratio of 52.0% while noting that it has more equity and less financial risk than his three proxy groups and BGE's parent company, Exelon.[1031] Dr. Woolridge also adopted BGE's proposed long-term debt rates and used the DCF and CAPM to develop his recommended ROE.[1032] Dr. Woolridge used three proxy groups–a proxy group of publicly held electric utility companies, witness McKenzie's proxy group, and a group of publicly held gas distribution companies.[1033] Dr. Woolridge testified that because BGE's investment risk level is below the average of the three proxy groups, he developed a risk adjustment of 15 basis points for BGE and resulted in an ROE of 9.10%.[1034]

Walmart

Walmart witness Kronauer recommended that the Commission reject BGE's proposed 10.40% ROE for both electric and gas operations and not approve an ROE higher than BGE's current 9.50% for electric and 9.65% for gas unless "BGE can sufficiently and substantially demonstrate that a higher ROE is required."[1035] He testified that the Commission should closely examine any requested ROE increases in light of the Commission's and other states' recently approved rate case ROEs, customer impact of the resulting revenue requirement increase from BGE's currently approved electric and gas ROEs, and the proposed use of an MYP, which permits BGE to include projected costs in its rates at the time they will be in effect.[1036] He testified that the difference between the

[1031] Woolridge Direct at 4.
[1032] *Id.*
[1033] *Id.* at 4-5.
[1034] *Id.* at 5.
[1035] Kronauer Direct at 4.
[1036] *Id.* at 8.

currently authorized electric ROE of 9.50% and the proposed 10.40% ROE resulted in an estimated requested revenue increase of 37.9% for 2024, 33.5% for 2025 and 29.7% for 2026.[1037] He further stated that the difference between the currently authorized gas ROE of 9.65% and the proposed 10.40% ROE resulted in an estimated requested revenue increase of 11.4% for 2024, 12.6% for 2025 and 7.5% for 2026.[1038] Mr. Kronauer noted that the Company's proposed electric and gas ROEs are counter to recent Commission decisions and are significantly higher than ROEs approved by the Commission in cases decided from 2019 to present.[1039]

DoD

DoD witness Walters testified that the trend in approved utility ROEs has declined in recent years and has more recently remained below 10.0%. He recommended an ROE of 9.40% and requested that the Commission reject BGE's proposed 10.40% as excessive.[1040]

Mr. Walters stated that he used the following models to estimate BGE's cost of common equity: (1) DCF model using consensus analysts' growth rate projections; (2) constant growth DCF using sustainable growth rate estimates; (3) multi-stage growth DCF model; (4) risk premium model; and (5) CAPM.[1041] Witness Walters relied on the same electric proxy group developed by BGE's witness McKenzie, but excluded one company, Chesapeake Utilities, that did not have a credit rating from S&P or Moody's.[1042] His proxy group had average credit ratings of BBB+ and Baa1 from S&P and Moody's,

[1037] *Id.* at 9.
[1038] *Id.* at 10.
[1039] *Id.* at 10-13.
[1040] Waters Direct at 3.
[1041] *Id.* at 23.
[1042] *Id.* at 28-29.

respectively.[1043] He noted that his proxy group had an average common equity ratio of 40.7% (including short-term debt), as calculated by S&P Global Market Intelligence, and 45.0% (excluding short-term debt), as calculated by Value Line.[1044] He stated that BGE's requested common equity ratio of 52.00% (excluding short-term debt) significantly exceeded the proxy group's equity ratio, and the evidence suggested that BGE was significantly less risky than the proxy group.

B. Rates of Return

BGE witness Vahos testified that BGE requests overall ROR for both electric and gas operations of 7.39% for 2024, 7.45% for 2025, and 7.56% for 2026 in the MYP, based on BGE's projected embedded cost of debt for each year, as well as a 10.40% return on equity for both electric and gas, as recommended by Company witness McKenzie in his testimony.[1045]

Mr. Vahos explained that because interest rates have recently risen significantly, and BGE's requested rates are based on a cost of debt forecast for the 2024-2026 MYP period, actual interest rates for the period will likely substantially differ, even decrease, from any interest rate forecast today. He described BGE's proposal to true-up the long-term cost of debt during the reconciliation process in order to mitigate against long-term interest rate volatility and to keep customers and the Company whole.[1046] Mr. Vahos also recommended an alternative where the Commission could authorize the Company to enter into an interest rate hedging mechanism.[1047] However, he emphasized that BGE

[1043] *Id.* at 29.
[1044] *Id.*
[1045] Vahos Direct at 21.
[1046] *Id.* at 26.
[1047] *Id.*

recommended the Commission recognize the risk of fluctuating interest rates and allow the forecasted cost of debt to be reconciled within the MYP reconciliation process to allow for a true-up to the actual cost of debt.[1048]

BGE maintained that the current volatility of interest rates justifies BGE's proposal of projected long-term interest rates, along with one of the Company's proposed mitigation methods, would protect both BGE and customers against long-term interest rates differing from those used to calculate the overall rates of return in this matter.[1049]

Witness McAuliffe, using BGE's capital structure, recommended a ROR of 6.74%, and that BGE's current cost of debt as of December 31, 2022, be used in the capital structure, and that the cost of debt remain the same each year of the MYP.[1050]

Dr. Woolridge recommended a rate of return for BGE of 6.71% in 2024, 6.78% in 2025, and 6.88% in 2026.[1051]

On rebuttal, Mr. Vahos objected to Staff witness McAuliffe's recommended ROE. He stated that Staff witness McAuliffe's recommended ROE of 9.45% for electric and gas, compared to his recommendation of 9.50% in the previous BGE rate case (Case No. 9645) revealed that Mr. McAuliffe did not contemplate the rising financial costs to the same degree he considered the decrease of financial costs in Case No. 9645.[1052] He noted that the other ROE witnesses in Case No. 9645 "seem to at least recognize the upward pressure on ROE and impacts of the increased cost of capital and record inflation with increases in their ROEs [sic] recommendations in comparison to their recommendations in Case No.

[1048] *Id.* at 26-27.
[1049] BGE Initial Brief at 68.
[1050] McAuliffe Direct at 34.
[1051] Woolridge Direct at 96.
[1052] Vahos Rebuttal at 46.

9645."[1053] He provided information comparing the recommended ROEs of Staff, OPC and DoD, in Case No. 9645 and the present rate case, indicating that only Staff's ROE recommendation is lower in the present rate case than in Case No. 9645.[1054] Mr. Vahos also compared the 30-year U.S. Treasury yields and BGE's authorized ROEs at the time of this case and Case No, 9645, with Mr. McAuliffe's recommended electric and gas ROEs.[1055] He asserted that a "clear disconnect" existed between Mr. McAuliffe's recommendations and the 30-year U.S. Treasury yields.[1056]

Mr. Vahos stated that Dr. Woolridge's recommended ROEs in three of BGE's last four rate cases are consistently lower than BGE's authorized ROEs and continue to be unreasonable.[1057] With regard to Mr. Walters' recommended ROEs, Mr. Vahos stated that the recommendations aligned with averages from previous years, such as before 2021, that saw substantially lower financing costs.[1058] He similarly found that the other interveners' ROE recommendations were lower than the national industry average of 9.75% for gas and 9.70% electric distribution utilities during the three-month period ending March 31, 2023, and therefore significantly lower than a reasonable and appropriate ROE.[1059] He emphasized that the Commission should consider the increase in cost of capital, record high inflation, and alignment to recent national averages of authorized ROEs since Case No. 9645 when authorizing an ROE for the present case.[1060]

[1053] *Id.* at 45-46.
[1054] *Id.* at 46.
[1055] *Id.*
[1056] *Id.*
[1057] *Id.* at 47.
[1058] *Id.* at 48.
[1059] *Id.* at 48-49.
[1060] *Id.* at 50.

Mr. Vahos was similarly concerned regarding Mr. McAuliffe's recommendation of a fixed cost of debt for the MYP period without consideration of fluctuating interest rates, as opposed to BGE's inclusion of projected long-term rates in its estimate.[1061]

Witness McKenzie on rebuttal agreed with Mr. Vahos that Staff, OPC and DoD witness' recommended ROEs are too low and counter to the standards for a fair and reasonable ROE for BGE's electric and gas operations, based on current interest rates and authorized ROEs for other utilities, and the Commission must grant BGE the opportunity to earn a competitive return that reflects a significant increase in long-term capital costs.[1062] Mr. McKenzie testified that the expected earned RORs for the companies in the other witnesses' proxy groups suggested a 10.9% to 11% ROE.[1063] He analyzed what he described as flaws in the other Parties' analysis methodologies, including the use of CAPM, and opined that other witnesses' appraisals of current capital market conditions were incomplete and possibly misleading.[1064]

Witness McKenzie noted that key interest rate indicators, as cited by the other witnesses, reveal that required return on debt securities have increased by 276 basis points between August 2020, during BGE's Case No. 9645, and the current case.[1065] He noted further that the Federal Reserve's target range midpoint for federal funds increased by 525 basis points, and the anticipated long-term inflation rate increased by 52 basis points.[1066] He compared these numbers to the other witnesses' ROE recommendations, which

[1061] *Id.* at 51.
[1062] McKenzie Rebuttal at 2 and 4.
[1063] *Id.* at 3.
[1064] *Id.*
[1065] *Id.* at 7.
[1066] *Id.*

indicated an average increase of 15 basis points during the above-referenced time period.[1067]

Witness McKenzie also disputed the claims of witnesses McAuliffe and Woolridge that investors expect interest rates and yields to decrease, stating that long-term consensus projections of top economists that pointed to predictions of consistently elevated bond yields through 2028.[1068] Mr. Kenzie also disagreed with witness McAuliffe's testimony that a recession would lead to lower ROE's.[1069]

On surrebuttal, Dr. Woolridge maintained that he noted increased interest rates in his testimony, and stated that since interest rates declined much further than authorized ROEs in 2020-2021, authorized ROEs need not increase to the same degree that interest rates have increased in 2022-2023.[1070] According to Dr. Wooldridge, Mr. McKenzie inaccurately claimed that OPC's ROE recommendation is too low after comparing it to authorized electric and gas utility ROEs and the results of Mr. McKenzie's expected earnings approach.[1071] Dr. Woolridge objected to this approach, stating that it does not measure cost of equity capital and ignores capital markets.[1072] Dr. Woolridge argued that Mr. McKenzie provided no evidence that his 9.1% ROE recommendation failed to meet the standards that it should be comparable to returns investors expect to earn on other investments of similar risk, sufficient to assure confidence in the utility's financial integrity, and adequate to maintain and support the utility's credit and attract capital.[1073]

[1067] *Id.* at 9.
[1068] *Id.* at 11.
[1069] *Id.* at 12.
[1070] Woolridge Surrebuttal at 3.
[1071] *Id.* at 29.
[1072] *Id.* at 27-28.
[1073] *Id*. at 29-30.

He noted that his recommendation was based on BGE's consistent financial performance, growing revenues and an average ROE of 9.21% in the past five years.[1074]

Staff witness McAuliffe, on surrebuttal, dismissed as simplistic Mr. McKenzie's statements regarding the need to match the degree of interest rate increase to the ROE increase.[1075] He questioned BGE witness McKenzie's disagreement with his assessment that the MYP would reduce regulatory lag and reduce risk to BGE, noting that BGE was not required to file an MYP and could have chosen to resume filing rate cases based on a historical test year.[1076] Witness McAuliffe stressed that he abided by the Commission's preference for the use of gradualism in proposing an ROE, although it was less of a concern than in the previous BGE rate case because his analysis resulted in ROE recommendations similar to BGE's current authorized ROEs. [1077]

He defended his recommendation for a reduction in ROE in return for a true-up of BGE's cost of debt, stating that the true-up would guarantee BGE's recovery of nearly half of its capital structure, and the guarantee would be favorably viewed by investors as a lowered risk.[1078] Therefore, he stated, if the risk in investing in BGE is reduced, a corresponding ROE reduction is needed because investors would require less of a return.[1079]

Witness McAuliffe disagreed with Witness McKenzie's testimony that an underperforming utility should receive a higher allowed ROE in order to compete for

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[1074] *Id*. at 30.
[1075] McAuliffe Surrebuttal at 4.
[1076] *Id.* at 11.
[1077] *Id.* at 12.
[1078] *Id.*
[1079] *Id.*

capital, stating that a utility controls its ability to earn its return.[1080] Mr. McAuliffe added that such an increase in an allowed ROE would undermine the Commission's goal of balancing utility and ratepayer interests by allowing utilities to continue over-investing in rate base, lowering earned returns and causing the Commission to allow the utilities to have higher ROEs.[1081]

Witness McAuliffe continued to reject witness Vahos' recommendation of a projected cost of debt, arguing it was "highly subjective and provides little to no benefit to BGE or its ratepayers."[1082]

C. Cost of Debt

BGE witness Vahos described BGE's proposed embedded cost of debt for each of the 2024-2026 MYP years, which he explained was representative of the overall cost for all long-term debt projected to be outstanding at the end of each MYP year, including any new long-term debt issuances and retirements planned for each period.[1083] Mr. Vahos stated that the projections interest rate assumptions applied to the debt issuance balances are based on the 2022 year-end 30-year Treasury forward curve, plus an adder of 143 basis points based on indicative pricing for comparable utilities at the time the budget was finalized in January 2023.[1084] He noted that in BGE's previous MYP Case No. 9645, the Commission approved a rate of return that included fixed cost of debt for the MYP period, with no consideration for interest rate fluctuations.[1085] Mr. Vahos stated that because of fluctuating interest rates, the actual cost of debt led to an over-recovery of interest expense

[1080] *Id*. at 24.
[1081] *Id.* at 24-25.
[1082] *Id.* at 27.
[1083] Vahos Direct at 24.
[1084] *Id.*
[1085] *Id.*

in 2021 and an under recovery of interest expense in 2022, while BGE is also projecting an under-recovery in 2023.[1086]

He stated that BGE also proposes to include in the reconciliation process a true-up for the actual cost of long-term debt starting in MYP 2 and going forward, in order to recover the actual cost of debt, while ensuring customers can recover any costs resulting from a lower actual cost of debt.[1087]

Mr. Vahos described an alternative proposal to the true-up, where BGE would enter into a "forward starting interest rate hedging mechanism," lock in a specific interest rate for up to 70% of the principal of an issuance.[1088] He explained that if the interest rate at the time of issuance was higher than the agreed upon rate in the hedging mechanism, BGE would receive proceeds that represented the rate differences, and if the interest rate at the time of issuance was lower than the agreed upon rate in the hedging mechanism, BGE would pay the difference.[1089] BGE proposed to include any hedging mechanism impacts associated with the interest rate hedging agreement in future MYP reconciliations.[1090]

Staff witness McAuliffe objected to BGE's proposal to include a cost of debt true-up for BGE's last MYP, which BGE witness Vahos described as necessary in light of recent interest rate increases.[1091] Mr. McAuliffe stressed that despite recent interest rate increases, there are predictions that rates will begin to decrease in the next year and rate predictions over the next three years will be inaccurate. Therefore, he stated, allowing the cost of debt true-up would reduce or eliminate the incentive for BGE to prudently obtain debt at the

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[1086] *Id.* at 25.
[1087] *Id.* at 26.
[1088] *Id.* at 27.
[1089] *Id.* at 28.
[1090] *Id.*
[1091] Testimony of Staff witness McAuliffe at 21.

most advantageous rate, because the Company would be made whole regardless of the cost of debt.[1092] He noted that the Commission previously rejected a cost of debt true-up in BGE's previous MYP Case No. 9645.[1093]

Mr. McAuliffe recommended that if the Commission approves BGE's proposal to true-up its cost of debt, the Commission should also assess a minimum five-basis point reduction to BGE's awarded ROE to account for the decrease in risk.[1094]

Mr. McAuliffe also objected to Mr. Vahos' proposal that, as an alternative to the true-up proposal, BGE would begin an interest rate hedging mechanism, where BGE would hedge 70% of the principal of the issuance, and requiring BGE to receive proceeds or pay proceeds based on what the agreed interest rate was and what rates were at the time of issuance.[1095] He added that BGE's proposal would extend to any hedging mechanism impacts in future MYP reconciliations, similar to BGE's proposed true-up.[1096] He recommended that the Commission also reject the hedging proposals.[1097]

Mr. McAuliffe further objected to and recommended rejection of witness Vahos' proposal to use three different projected cost of debt levels for each year of BGE's MYP – a similar proposal to that made in Case No. 9645, which the Commission rejected in favor of a fixed cost of debt rate to be applied to BGE's capital structure over the course of the MYP.[1098]

[1092] *Id*. at 22.
[1093] *Id.*
[1094] *Id.* at 21-22.
[1095] *Id*. at 22.
[1096] *Id.* at 23.
[1097] *Id.*
[1098] *Id*.

Witness Vahos disputed Staff witness McAuliffe's recommended fixed cost of debt for the 2024-2026 MYP years, based on the Company's cost of debt as of December 2022, with no recognition of interest rate fluctuations.[1099] Mr. Vahos countered that BGE's use of projected long-term debt interest rates in its forecasted cost of debt (based on the 2022 30-year Treasury curve, with an adder based on indicative pricing for similarly rated utilities) provides the best cost of debt estimate for the MYP period, since BGE is limited by current market conditions and interest rates.[1100] He expressed concerns regarding a lack of ability to true-up the actual cost of debt in the previous MYP Case No. 9645.[1101] Mr. Vahos stated that that exclusion leaves BGE and customers at the mercy of any volatility of interest rates, leading to over or under recoveries of actual interest costs.[1102] He explained that the cost of debt has a direct input to the rate of return, and the lack of a true-up could lead to a lack of recovery and amount to a permanent disallowance.[1103] He emphasized BGE's proposal to include cost of debt in future reconciliations would provide a fair and balanced opportunity for the Company to recover its actual cost of long-term debt and help ensure that customers are made whole.[1104] Mr. Vahos recommended that the Commission approve the use of BGE's projected cost of debt over the MYP period, and authorize the inclusion of the cost of debt in future MYP reconciliations.

[1099] Vahos Rebuttal at 51.
[1100] *Id.*
[1101] *Id*. at 52.
[1102] *Id.*
[1103] *Id.* at 53.
[1104] *Id.* at 24.

Commission Decision

A public utility must charge just and reasonable rates for the regulated services that it provides.[1105] Pursuant to well-established regulatory principles, regulated utilities are allowed the opportunity to recover the costs of prudently incurred debt financing. Court precedent, primarily *Bluefield*[1106] and *Hope Natural Gas*,[1107] established a standard by which the Commission is to consider certain relevant factors when determining whether to allow a change in a utility's rates so as to allow the recovery of financing costs. In a proceeding involving a change in rate, the burden of proof is on the proponent of the change. Thus, in the instant matter, BGE bears the burden to support every element of its request for a rate increase.[1108]

The parties in this rate proceeding have used a variety of models, methodologies, and assumptions to estimate BGE's fair ROE. Given that the cost of equity cannot be observed directly, the Commission must carefully consider both traditional methods and novel approaches, when justified.

The Commission finds that ROEs of 9.5% for BGE's electric distribution service and 9.45% for BGE's gas distribution service are supported by the evidence and consistent with statutory and other legal standards. These ROEs are comparable to returns that investors expect to earn on investments of similar risk as demonstrated through the use of the witnesses' proxy groups, are sufficient to assure confidence in BGE's financial

[1105] A "just and reasonable rate" is one that: (1) does not violate any provision of the Public Utility Article of the Maryland Code; (2) fully considers and is consistent with the public good; and (3) will result in an operating income to the public service company that yields, after reasonable deduction for depreciation and other necessary and proper expenses and reserves, a reasonable return on the fair value of the public service company's property used and useful in providing service to the public. PUA § 4-201.
[1106] *Bluefield Water Works and Improvement Co. v. Pub. Serv. Comm'n of W. Va.,* 262 U.S. 679 (1923).
[1107] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944).
[1108] PUA § 3-112.

integrity, and are adequate to maintain and support BGE's credit and attract any needed capital.

The recommended ranges of reasonableness found by the Parties showed considerable variation, but these ROEs fall toward the center of the total range of recommended results. They fall at the center range recommended by Staff.[1109] They fall below the high end of DOD's recommended range, except for BGE.[1110] They fall above the range of reasonableness recommended by OPC, again except for BGE.[1111] And they fall toward the middle of the bottom half of the range recommended by BGE.[1112]

The Commission further finds that the ROEs approved in this Order for both gas and electric are within the range of solutions proposed by Staff and are justifiable based on the *Bluefield* and *Hope* decisions, including principles of comparable risk (i.e. being commensurate with returns on investments in other enterprises with corresponding risks), financial integrity, attracting needed capital, and considering the impact of current market conditions.

The Commission, in light of recent laws and policies that are ushering in a reduction in the use of gas and an increase of electrification, prefers a higher ROE for electric distribution as a reflection of the policy shift. The slightly lower gas ROE should incentivize BGE, a dual fuel utility, to invest in its electric distribution system rather than gas distribution.

[1109] Mr. McAuliffe recommended an ROE for BGE's gas business of 9.45% and for BGE's electric business of 9.45%. McAuliffe Direct at 11.

[1110] Mr. Walters found a range of reasonableness for BGE's combined gas and electric businesses of 9.20% - 9.90%. Walters Direct at 3.

[1111] Dr. Woolridge found a recommended range of reasonableness of between 8.55% - 9.30%. Woolridge Direct at 60.

[1112] Mr. McKenzie found a range from 9.7%-11.1%. McKenzie Direct at 50.

Despite the current market conditions comprising higher interest rates and inflation, the above-referenced authorized ROEs are just and reasonable and will provide BGE with sufficient access to capital. The Commission also recognizes OPC's argument that the rate that is set does not have to absolutely reflect the interest rates in the economy as a whole.

The Commission's approval of BGE's request for an MYP, including a reconciliation, provides an overall lower risk for the utility and an opportunity to revisit the ROE should economic conditions deteriorate. The Commission finds that attempts to project interest rate variations over the three-year MYP are too speculative and declines to use them here. The MYP which BGE initially requested and the continuation that BGE is requesting in this proceeding provides faster cost recovery which consequently lowers the Company's risk profile.

The Commission approves BGE's proposed capital structure except for the proposed cost of debt. The long-standing precedent in Maryland is that a utility's actual test-year-ending capital structure should be used when determining its authorized rate of return in a base rate proceeding, absent evidence that the actual capital structure would impose an undue burden on ratepayers.[1113] BGE's proposed capital structure, except for the cost of debt, was not challenged by other Parties and is in line with BGE's actual capital structure and with those historically approved by this Commission.

The Commission denies BGE's proposed cost of debt and any associated true-up mechanisms and accepts Staff's proposal. Staff witness McAuliffe is correct that the Commission in the previous BGE MYP order expressed preference for the use of a single,

[1113] Case No. 9484, *Application of Baltimore Gas & Electric*, Order No. 88975 at 70-71.

fixed cost of debt rate over the course of the MYP.[1114] Additionally, the Commission agrees with Staff witness McAuliffe that it is difficult to project interest rates.[1115] The Commission also reaffirms its previous finding to not include a cost of debt true-up within a MYP to ensure BGE continues to have the appropriate incentives to obtain debt capital at the most favorable rates.[1116]

IV. Cost of Service

The purpose of a cost of service study ("COSS") is to determine the costs a customer class, or in some cases a jurisdiction, imposes upon a utility company. Costs may be directly assigned or allocated based upon various allocation methodologies. Once costs are assigned, then class (and jurisdictional) rates of return can be developed, which are used to design customer rates. The Commission uses the results from cost of service studies ("COSSs") as a guide in developing appropriate rates for the numerous customer classes.

BGE's Electric COSS ("ECOSS") is presented in the Direct Testimony of April M. O'Neill and the Gas COSS ("GCOSS") is presented in the Direct Testimony of Jason Manuel.

BGE witness Manuel explained that there are generally three basic steps to measure customer class responsibility for rate base and expense: (1) functionalization; (2) classification; and (3) allocation.[1117]

Functionalization is the process of dividing rate base and expense components of the cost of service study into specified utility functions based on the characteristics of those

[1114] Order No. 89678, Case No. 9645 at 155.
[1115] McAuliffe Direct Testimony at 24.
[1116] Order No. 89678, Case No. 9645 at 155.
[1117] Manuel Direct at 5-6.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Question(s):

For each proceeding where the authors of the Concentric 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:

Please see N-M2-0-SEC-31, Attachment 1. Concentric has provided the information requested in parts (i) through (xi) for the authors of its report for utility cost of capital proceedings filed since 2019, except for the information in parts (vi) and (ix), which Concentric does not track. The testimony listings for Mr. Coyne, Mr. Dane, and Mr. Trogonoski provide a full list of all cost of capital cases in which the authors have been involved. Because all of these cases are a matter of public record, the information requested in parts (xii) and (xiii) can be found on the websites of the respective Boards and Commissions.

DIRECT TESTIMONY OF
JAMES M. COYNE
ON BEHALF OF
GEORGIA POWER COMPANY

DOCKET NO. 44280

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is James M. Coyne, and I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Senior Vice President. Concentric is a management consulting and economic advisory firm, focused on the North American energy and water industries. Based in Marlborough, Massachusetts and Washington, D.C., Concentric specializes in regulatory and litigation support, financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am submitting this testimony to the Georgia Public Service Commission (the "Commission") on behalf of Georgia Power Company ("Georgia Power" or the "Company"), which is a wholly owned subsidiary of the Southern Company ("Southern Company").

These circumstances collectively reinforce the importance of using forward-looking model inputs and multiple models, as I have with the CAPM, DCF, Risk Premium, and Expected Earnings approaches.

V. PROXY GROUP SELECTION

Q. WHY IS IT NECESSARY TO SELECT A PROXY GROUP TO ESTIMATE THE COST OF EQUITY FOR GEORGIA POWER?

A. Since the ROE is a market-based concept and Georgia Power is not publicly traded, it is necessary to establish a group of companies that is both publicly traded and comparable to Georgia Power. Even if Georgia Power were a publicly traded entity, it is possible that transitory events could bias the Company's market value in one way or another in a given period. A significant benefit of using a proxy group is the ability to mitigate the effects of short-term events that may be associated with any one company. The proxy companies used in my ROE analyses possess a set of business and operating characteristics similar to Georgia Power's vertically integrated electric utility operations, and thus provide a reasonable basis for estimating the Company's ROE.

Q. PLEASE PROVIDE A SUMMARY PROFILE OF GEORGIA POWER.

A. Georgia Power is a wholly owned subsidiary of Southern Company, providing electric generation, transmission, and distribution service to more than 2.6 million residential, commercial, and industrial customers in Georgia.[30] It owns 14,541 MW of regulated generation assets, including nuclear, coal, oil, gas, hydroelectric, and solar generation facilities.[31] The Company has long-term issuer ratings from S&P of BBB+ (Outlook: Stable), Moody's Investors Service ("Moody's") of Baa1 (Outlook: Stable), and FitchRatings ("Fitch") of BBB (Outlook: Stable).[32]

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30 The Southern Company, SEC Form 10-K, at I-6 (December 31, 2021).

31 The Southern Company, SEC Form 10-K, at I-31 (December 31, 2021).

32 S&P Capital IQ.

Q. PLEASE DESCRIBE THE SPECIFIC SCREENING CRITERIA YOU HAVE UTILIZED TO SELECT A PROXY GROUP.

A. I began with the 36 investor-owned domestic electric utilities covered by Value Line and then screened companies according to the following criteria:

1. Consistently pays quarterly cash dividends;
2. Maintains an investment grade long-term issuer rating (BBB- or higher) from S&P;
3. Is covered by more than one equity analyst;
4. Has positive earnings growth rates published by at least two of the following sources: Value Line, Thomson First Call (as reported by Yahoo! Finance), and Zack's Investment Research ("Zacks");
5. Owns regulated electric generation assets;
6. Regulated revenue and net operating income make up more than 60 percent of the consolidated company's revenue and net operating income (based on a 3-year average from 2019-2021);
7. Regulated revenue and net operating income from regulated electric operations makes up more than 80 percent of the consolidated company's regulated revenue and net operating income (based on a 3-year average from 2019-2021); and
8. Is not involved in a merger or other transformative transaction for an approximate six-month period prior to my analysis.

Q. DID YOU INCLUDE SOUTHERN COMPANY IN YOUR ANALYSIS?

A. No, I did not. To avoid the circular logic that would otherwise occur, it is my practice to exclude the subject company, or its parent holding company, from the proxy group.

Q. WHAT IS THE COMPOSITION OF YOUR RESULTING PROXY GROUP?

A. Based on the screening criteria discussed above, and financial information through fiscal year 2021, I arrived at a proxy group consisting of the 14 companies shown in Figure 6. The results of my screening process are shown in Exhibit JMC-3.

Figure 6: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Duke Energy Corporation	DUK
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
Hawaiian Electric Industries, Inc.	HE
IDACORP, Inc.	IDA
NextEra Energy	NEE
OGE Energy Corporation	OGE
Portland General Electric Company	POR
Xcel Energy Inc.	XEL

Q. DOES YOUR SCREENING CRITERIA RESULT IN A GROUP OF COMPANIES THAT INVESTORS WOULD VIEW AS COMPARABLE TO GEORGIA POWER?

A. Yes. While no proxy group will be identical in risk as the Company, I believe this group of electric utilities is reasonably comparable to the financial and operational characteristics of Georgia Power. The proxy group screening criterion requiring an investment grade credit rating ensures that the proxy group companies, like Georgia Power, are in sound financial condition. Because credit ratings take into account business and financial risks, the ratings provide a broad measure of investment risk for investors. I have only included companies in the proxy group that own regulated generation assets because vertically integrated electric utilities have unique operating characteristics and business risks that cause investors to require a higher return on equity to compensate for those risks. These unique risks are not shared by pure Transmission and Distribution electric utilities. Additionally, I have screened on the percent of revenue and net operating income from regulated operations to differentiate between utilities that are protected by regulation and those with substantial unregulated operations or market-related risks. Also, I have screened on the percentage contribution of the electric utility segment to regulated consolidated financial results to select companies that, like Georgia Power, derive the majority of their revenue and operating income from regulated electric operations. These screens collectively reflect key risk factors that investors consider in making investments in electric utilities.

Q. WHAT IS YOUR CONCLUSION WITH REGARD TO THE PROXY GROUP FOR GEORGIA POWER?

A. I conclude that my group of 14 vertically integrated electric utilities adequately reflects the broad set of risks that investors consider when investing in a U.S. regulated vertically integrated electric utility such as Georgia Power.

VI. DETERMINATION OF THE APPROPRIATE COST OF EQUITY

Q. WHAT MODELS DID YOU USE IN YOUR ROE ANALYSES?

A. I have considered the results of several ROE estimation models, including the Constant Growth DCF model, the CAPM, the Bond Yield Plus Risk Premium approach, and an Expected Earnings analysis. When faced with the task of estimating the cost of equity, analysts are inclined to gather and evaluate as much relevant data (both quantitative and qualitative) as can be reasonably obtained.

A. CONSTANT GROWTH DCF MODEL

Q. PLEASE DESCRIBE THE DCF APPROACH.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the DCF model expresses the ROE as the sum of the expected dividend yield and long-term growth rate:

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2023-388-E

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Carolinas, LLC	)	**JAMES M. COYNE**
For Authority to Adjust and Increase its Electric	)	**FOR DUKE ENERGY**
Rates and Charges	)	**CAROLINAS, LLC**
	)	

inflationary pressure by further increases in short-term interest rates to a level that causes a slowdown in economic growth or a recession.

V. PROXY GROUP SELECTION

Q. WHY IS IT NECESSARY TO SELECT A PROXY GROUP TO ESTIMATE THE COST OF EQUITY FOR DEC?

A. Since the ROE is a market-based concept and DEC is not publicly traded, it is necessary to establish a group of companies that is both publicly traded and comparable to DEC. Even if DEC were a publicly traded entity, it is possible that transitory events could bias the Company's market value in one way or another in a given period of time. A significant benefit of using a proxy group is the ability to mitigate the effects of short-term events that may be associated with any one company. The proxy companies used in my ROE analyses possess a set of business and operating characteristics similar to DEC's electric operations, and thus provide a reasonable basis for estimating the Company's ROE.

Q. PLEASE PROVIDE A SUMMARY PROFILE OF DEC.

A. DEC is a wholly owned subsidiary of Duke Energy Corporation, providing electric utility service to approximately 2.8 million residential, commercial, and industrial and power generation customers in portions of North Carolina and South Carolina.[14] DEC has long-term issuer ratings from Moody's Investors

[14] Duke Energy, 2022 SEC Form 10-K, at 22.

Service ("Moody's") of A2 (Outlook: Stable), and S&P Global ("S&P") of BBB+ (Outlook: Stable).[15]

Q. PLEASE DESCRIBE THE SPECIFIC SCREENING CRITERIA YOU HAVE UTILIZED TO SELECT A PROXY GROUP.

A. I began with the investor-owned domestic electric utility companies covered by Value Line and then screened companies according to the following criteria:

1. Consistently pays quarterly cash dividends;
2. Maintains an investment grade long-term issuer rating (BBB- or higher) from S&P;
3. Is covered by more than one equity analyst;
4. Has positive earnings growth rates published by at least two of the following sources: Value Line, First Call (as reported by Yahoo! Finance), and Zacks Investment Research ("Zacks");
5. Owns regulated electric generation assets;
6. Regulated revenue and net operating income make up more than 60 percent of the consolidated company's revenue and net operating income (based on a 3-year average from 2020-2022);
7. Regulated revenue and net operating income from regulated electric operations makes up more than 80 percent of the consolidated company's regulated revenue and net operating income (based on a 3-year average from 2020-2022); and

[15] Source: S&P Capital IQ Pro.

8. Is not involved in a merger or other transformative transaction for an approximate six-month period prior to my analysis.

Q. **WHAT IS THE COMPOSITION OF YOUR RESULTING PROXY GROUP?**

A. Based on the screening criteria discussed above, I arrived at a proxy group consisting of the companies shown in Figure 5. The results of my screening process are shown in Coyne Direct Exhibit 3.

Figure 5: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Pinnacle West Corporation	PNW
Portland General Electric Company	POR
Southern Company	SO
Xcel Energy Inc.	XEL

Q. DID YOU INCLUDE DUKE ENERGY IN YOUR PROXY GROUP?

A. No, I did not. To avoid the circular logic that would otherwise occur, it is my practice to exclude the subject company, or its parent holding company, from the proxy group.

Q. DO YOUR SCREENING CRITERIA RESULT IN A GROUP OF COMPANIES THAT INVESTORS WOULD VIEW AS COMPARABLE TO DEC?

A. Yes. I have selected this group of utilities to best align with the financial and operational characteristics of DEC. The proxy group screening criterion requiring an investment grade credit rating ensures that the proxy group companies, like DEC, are in sound financial condition. Additionally, I have screened on the percent of revenue and net operating income from regulated operations to differentiate between utilities that are subject to regulation and those with substantial unregulated operations or market-related risks. The proxy group also reflects DEC's vertically integrated electric operations. These screens collectively reflect key risk factors that investors consider in making investments in vertically integrated electric utilities.

Q. WHAT IS YOUR CONCLUSION WITH REGARD TO THE PROXY GROUP FOR DEC?

A. My conclusion is that my group of 15 utilities adequately reflects the broad set of risks that investors consider when investing in a U.S. regulated vertically integrated electric utility such as DEC. Later in my testimony, I will evaluate whether an adjustment should be made to the results of my ROE analyses to account for differences in DEC's company-specific risks relative to the proxy group companies.

VI. DETERMINATION OF THE APPROPRIATE COST OF EQUITY

Q. WHAT MODELS DID YOU USE IN YOUR ROE ANALYSES?

A. I have utilized four ROE estimation models: the Constant Growth DCF, the CAPM, the Bond Yield Plus Risk Premium, and Expected Earnings. The following describes each of the models and inputs I have utilized to estimate DEC's cost of equity.

A. Constant Growth DCF Model

Q. PLEASE DESCRIBE THE DCF APPROACH.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the DCF model expresses the ROE as the sum of the expected dividend yield and long-term growth rate:

$$k = \frac{D(1+g)}{P_0} + g \qquad [1]$$

Where "*k*" equals the required return, "*D*" is the current dividend, "*g*" is the expected growth rate, and "*P*" represents the subject company's stock price.

Assuming a constant growth rate in dividends, the model may be rearranged to compute the ROE accordingly, as shown in Formula [2]:

$$r = \frac{D}{P} + g \qquad [2]$$

Stated in this manner, the cost of common equity is equal to the dividend yield plus the dividend growth rate.

D. Flotation Cost Adjustment

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance of common stock. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diminishing the utility's ability to attract adequate capital on reasonable terms.

Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE ALLOWED ROE?

A. Allowed ROE is the only ratemaking mechanism through which these necessary costs may be recovered. Flotation costs are reflected on the utility's balance sheet as "paid in capital" and are not expensed on the utility's income statement. When a company issues common stock, flotation costs are incurred and netted against the proceeds from the issuance reducing the amount available for investment in rate base by the amount of the flotation costs. If DEC is denied the opportunity to recover its prudently incurred flotation costs through its allowed ROE, actual returns will fall short, and equity share value will be diluted.

Q. DO ACADEMIC AND FINANCIAL EXPERTS RECOGNIZE THE NEED TO CONSIDER FLOTATION COSTS IN A UTILITY'S COST OF EQUITY?

A. Yes. Dr. Roger Morin, a recognized expert in regulatory economics and finance, notes:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit recovery of these costs.... The simple fact of the matter is that common equity capital is not free....[Flotation costs] must be recovered through a rate of return adjustment.[34]

According to Dr. Shannon Pratt, a published expert in cost of capital estimation:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[35]

Q. WHAT IS YOUR RECOMMENDED FLOTATION COST ADJUSTMENT AND HOW DID YOU CALCULATE IT?

A. Based on the proxy group issuance costs shown in Coyne Direct Exhibit 9, I conclude that flotation costs for the proxy companies have equaled roughly 2.46 percent of gross equity raised. To properly reflect these issuance costs in my

[34] Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 321.

[35] Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-221.

cost of capital estimates, it would be appropriate to increase the authorized ROE by approximately 11 basis points for DEC, as shown in Coyne Direct Exhibit 9. While an 11 basis point adjustment to the analytical results would be appropriate and reasonable to allow the Company the opportunity to recover flotation costs, I have not made an explicit adjustment in my analysis. As such, the analytical range of estimates of cost of equity estimates are conservative estimates of the Company's cost of equity.

VIII. CAPITAL STRUCTURE

Q. WHAT IS DEC'S PROPOSED CAPITAL STRUCTURE?

A. DEC is proposing a financial capital structure consisting of 53 percent common equity and 47 percent debt.

Q. HOW HAVE YOU ASSESSED THE REASONABLENESS OF DEC'S PROPOSED CAPITAL STRUCTURE WITH RESPECT TO THE PROXY GROUP?

A. The proxy group has been selected to reflect comparable companies in terms of business and financial risks. Therefore, it is appropriate to compare the financial capital structures of the proxy group companies to the financial capital structure proposed by DEC in order to assess whether the Company's capital structure is reasonable and consistent with industry standards for companies with commensurate risk. I calculated the capital structure for each of the proxy group operating companies for the most recent two years reported. Coyne Direct Exhibit 10 shows that the Company's proposed common equity ratio of 53 percent is within the range of actual common equity ratios of 42.65 percent

FLOTATION COST ADJUSTMENT

Company	Date	[1] Shares Issued (000)	[2] Offering Price	[3] Under-writing Discount	[4] Offering Expense (000)	[5] Net Proceeds Per Share	[6] Total Flotation Costs (000)	[7] Gross Equity Issue Before Costs (000)	[8] Net Proceeds (000)	[9] Flotation Cost Percentage
ALLETE, Inc.	3/31/2022	3,680	$ 63.00	$ 2.21	$ 700	$ 60.60	$ 8,814	$ 231,840	$ 223,026	3.80%
ALLETE, Inc.	2/26/2014	3,220	$ 49.75	$ 1.74	$ 450	$ 47.87	$ 6,057	$ 160,195	$ 154,138	3.78%
Alliant Energy Corporation	11/14/2019	4,833	$ 52.63	$ 0.40	$ 500	$ 52.13	$ 2,409	$ 254,348	$ 251,939	0.95%
Alliant Energy Corporation	12/13/2018	8,359	$ 44.85	$ 0.52	$ 1,000	$ 44.21	$ 5,347	$ 374,900	$ 369,553	1.43%
Ameren Corporation	8/5/2019	7,549	$ 74.30	$ 0.12	$ 750	$ 74.08	$ 1,656	$ 560,906	$ 559,250	0.30%
Ameren Corporation	9/9/2009	21,850	$ 25.25	$ 0.76	$ 450	$ 24.47	$ 17,001	$ 551,713	$ 534,711	3.08%
American Electric Power Company, Inc.	4/1/2009	69,000	$ 24.50	$ 0.74	$ 400	$ 23.76	$ 51,115	$ 1,690,500	$ 1,639,385	3.02%
American Electric Power Company, Inc.	2/27/2003	57,500	$ 20.95	$ 0.63	$ 550	$ 20.31	$ 36,689	$ 1,204,625	$ 1,167,936	3.05%
Edison International	7/30/2019	32,200	$ 68.50	$ 1.63	$ 725	$ 66.85	$ 53,110	$ 2,205,700	$ 2,152,590	2.41%
Entergy Corporation	6/6/2018	13,289	$ 75.25	$ 0.80	$ 650	$ 74.40	$ 11,281	$ 1,000,000	$ 988,719	1.13%
Evergy, Inc.	9/27/2016	52,600	$ 26.45	$ 0.79	$ 500	$ 25.65	$ 42,238	$ 1,391,270	$ 1,349,032	3.04%
Evergy, Inc.	5/11/2009	11,500	$ 14.00	$ 0.49	$ 500	$ 13.47	$ 6,135	$ 161,000	$ 154,865	3.81%
IDACORP, Inc.	12/9/2004	4,025	$ 30.00	$ 1.20	$ 300	$ 28.73	$ 5,130	$ 120,750	$ 115,620	4.25%
OGE Energy Corp.	8/21/2003	5,324	$ 21.60	$ 0.79	$ 325	$ 20.75	$ 4,531	$ 115,000	$ 110,469	3.94%
Portland General Electric Company	10/25/2022	10,100	$ 43.00	$ 1.24	$ 500	$ 41.71	$ 12,986	$ 434,300	$ 421,314	2.99%
Portland General Electric Company	6/11/2013	12,765	$ 29.50	$ 0.96	$ 600	$ 28.49	$ 12,838	$ 376,568	$ 363,729	3.41%
Xcel Energy Inc.	10/30/2019	11,845	$ 63.32	$ 0.63	$ 650	$ 62.64	$ 8,112	$ 750,025	$ 741,913	1.08%
Xcel Energy Inc.	11/7/2018	9,359	$ 49.15	$ 0.15	$ 650	$ 48.93	$ 2,054	$ 460,000	$ 457,946	0.45%
							$ 287,504	$ 12,043,639	$ 11,756,135	2.39%

Notes

Evergy, Inc. issuances reflect equity issuances as Great Plains Energy Inc.

[1] - [3] Source: SNL Financial; Two most recent equity issuances of each company in the proxy group, excluding issuances without gross underwriting discount

[4] Source: Company Prospectus Supplements

[5] Equals Col. [8] / Col. [1]

[6] Equals (Col. [1] x Col. [3]) + Col. [4]

[7] Equals Col. [1] x Col. [2]

[8] Equals Col. [7] - Col. [6]

[9] Equals Col. [6] / Col. [7]

FLOTATION COST ADJUSTMENT

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Expected Div. Yield Adj. for Flotation Costs	[6] Value Line EPS Growth	[7] First Call EPS Growth	[8] Zacks Earnings Growth	[9] Average Earnings Growth	[10] DCF	[11] Flotation Adjusted DCF
ALLETE, Inc.	ALE	$2.71	$53.40	5.08%	5.26%	5.39%	6.00%	8.10%	8.10%	7.40%	12.66%	12.79%
Alliant Energy Corporation	LNT	$1.81	$49.16	3.68%	3.80%	3.90%	6.50%	6.80%	6.30%	6.53%	10.34%	10.43%
Ameren Corporation	AEE	$2.52	$76.34	3.30%	3.41%	3.49%	6.50%	6.20%	6.60%	6.43%	9.84%	9.92%
American Electric Power Company, Inc.	AEP	$3.32	$75.09	4.42%	4.53%	4.64%	6.50%	3.70%	4.80%	5.00%	9.53%	9.64%
Edison International	EIX	$2.95	$64.18	4.60%	4.70%	4.82%	4.50%	5.50%	3.70%	4.57%	9.27%	9.38%
Entergy Corporation	ETR	$4.28	$93.45	4.58%	4.68%	4.79%	0.50%	6.60%	5.80%	4.30%	8.98%	9.09%
Evergy, Inc.	EVRG	$2.45	$49.94	4.91%	5.03%	5.15%	7.50%	2.50%	4.80%	4.93%	9.96%	10.08%
IDACORP, Inc.	IDA	$3.32	$95.27	3.48%	3.55%	3.64%	4.00%	3.70%	3.70%	3.80%	7.35%	7.44%
NextEra Energy, Inc.	NEE	$1.87	$56.16	3.33%	3.47%	3.56%	9.50%	8.40%	8.20%	8.70%	12.17%	12.26%
NorthWestern Corporation	NWE	$2.56	$48.46	5.28%	5.39%	5.53%	3.50%	4.08%	5.20%	4.26%	9.65%	9.79%
OGE Energy Corporation	OGE	$1.67	$33.79	4.95%	5.08%	5.20%	6.50%	negative	3.70%	5.10%	10.18%	10.30%
Pinnacle West Capital Corporation	PNW	$3.52	$74.63	4.72%	4.84%	4.96%	2.50%	7.50%	5.90%	5.30%	10.14%	10.26%
Portland General Electric Company	POR	$1.90	$40.97	4.64%	4.76%	4.87%	5.00%	4.60%	6.00%	5.20%	9.96%	10.07%
Southern Company	SO	$2.80	$66.50	4.21%	4.33%	4.44%	6.50%	7.10%	4.00%	5.87%	10.20%	10.31%
Xcel Energy Inc.	XEL	$2.08	$58.29	3.57%	3.68%	3.77%	6.00%	6.75%	6.30%	6.35%	10.03%	10.12%
MEAN											10.02%	10.13%
											[12]	0.11%

The flotation adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9736, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of October 31, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Equals [4] / (1 − Flotation Cost)
[6] Source: Value Line
[7] Source: Yahoo! Finance
[8] Source: Zacks Earnings Growth
[9] Equals Average ([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals Average of [11] − Average of [10]

Company: San Diego Gas & Electric Company (U 902 M)
Proceeding: 2023 Cost of Capital
Application: A.22-04-XXX
Exhibit No.: SDG&E-04

PREPARED DIRECT TESTIMONY OF

JAMES M. COYNE - RETURN ON EQUITY

ON BEHALF OF

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

APRIL 20, 2022

average stock prices which do not fully reflect these expectations. These circumstances reinforce the importance of considering the results of multiple models, as I have with the CAPM, DCF, Risk Premium, and Expected Earnings approaches.

V. PROXY GROUP SELECTION

Q. Why is it necessary to select a proxy group to estimate the cost of equity for SDG&E?

A. Since the ROE is a market-based concept and SDG&E is not publicly traded, it is necessary to establish a group of companies that is both publicly traded and comparable to SDG&E. Even if SDG&E were a publicly traded entity, it is possible that transitory events could bias the Company's market value in one way or another in a given period of time. A significant benefit of using a proxy group is the ability to mitigate the effects of short-term events that may be associated with any one company. The proxy companies used in my ROE analyses possess a set of business and operating characteristics similar to SDG&E's electric and gas utility operations, and thus provide a reasonable basis for estimating the Company's ROE.

Q. Please provide a summary profile of SDG&E.

A. SDG&E is a wholly owned subsidiary of Sempra Energy, providing electric services to a population of approximately 3.6 million and natural gas services to a population of approximately 3.3 million. In addition, SDG&E owns and operates four natural gas-fired power plants, three of which are in California and one of which is in Nevada.[30] SDG&E has long-term issuer ratings from S&P of BBB+ (Outlook: Stable), Moody's Investors

[30] Sempra Energy, 2021 SEC Form 10-K (February 25, 2022) at 13-14.

Service ("Moody's") of A3 (Outlook: Stable), and FitchRatings ("Fitch") of BBB+ (Outlook: Stable).[31]

Q. Please describe the specific screening criteria you have utilized to select a proxy group.

A. I began with the 36 investor-owned domestic electric or combination gas and electric utilities covered by Value Line and then screened companies according to the following criteria:

1. Consistently pays quarterly cash dividends;
2. Maintains an investment grade long-term issuer rating (BBB- or higher) from S&P;
3. Is covered by more than one equity analyst;
4. Has positive earnings growth rates published by at least two of the following sources: Value Line, Thomson First Call (as reported by Yahoo! Finance), and Zack's Investment Research ("Zacks");
5. Regulated revenue and net operating income make up more than 80 percent of the consolidated company's revenue and net operating income (based on a 3-year average from 2018-2020); and
6. Is not involved in a merger or other transformative transaction for an approximate six-month period prior to my analysis.

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[31] *Id.* at 78.

Q. What is the composition of your resulting proxy group?

A. Based on the screening criteria discussed above, I arrived at a proxy group consisting of the companies shown in Figure 8. The results of my screening process are shown in Exhibit JMC-3.

Figure 8: Proxy Group

Company	Ticker
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
Black Hills Corporation	BKH
CMS Energy Corporation	CMS
Consolidated Edison, Inc.	ED
Duke Energy Corporation	DUK
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
Eversource Energy	ES
IDACORP, Inc.	IDA
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
Southern Company	SO
Wisconsin Energy Corporation	WEC
Xcel Energy Inc.	XEL

Q. Do your screening criteria result in a group of companies that investors would view as comparable to SDG&E?

A. Yes. I have selected this group of utilities to best align with the financial and operational characteristics of SDG&E. The proxy group screening criterion requiring an investment grade credit rating ensures that the proxy group companies, like SDG&E, are in sound financial condition. Additionally, I have screened on the percent of revenue and net operating income from regulated operations to differentiate between utilities that are protected by regulation and those with substantial unregulated operations or market-related risks. The proxy group also reflects SDG&E's electric and gas operations, and results in a proxy group with an average of 86 percent of regulated revenue and net operating income from electric operations and 14 percent from natural gas utility operations, which is comparable to SDG&E's composition. These screens collectively reflect key risk factors that investors consider in making investments in electric and gas utilities.

Q. What is your conclusion with regard to the proxy group for SDG&E?

A. My conclusion is that my group of 20 electric and gas utilities adequately reflects the broad set of risks that investors consider when investing in a U.S.-regulated electric and gas utility such as SDG&E. Later in my testimony, I will evaluate whether an adjustment should be made to the results of my ROE analyses to account for differences in SDG&E's company-specific risks relative to the proxy group companies.

VI. DETERMINATION OF THE APPROPRIATE COST OF EQUITY

Q. What models did you use in your ROE analyses?

A. As noted, I have utilized four ROE estimation models: the Constant Growth DCF, the CAPM, the Bond Yield Plus Risk Premium, and Expected Earnings. The following

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF JAMES M. COYNE

DOCKET NO. 20210015-EI

MARCH 12, 2021

recent market conditions that have contributed to that decline. Further, there are reasons to believe that the recent declines in Treasury bond yields are not representative of the longer-term trend in government and corporate bond yields. Rather, those lower interest rates are directly attributable to the COVID-19 pandemic. The Federal Reserve has taken steps to contain the economic effects of COVID-19, including reducing the federal funds rates and taking additional measures to support the U.S. economy and provide liquidity and stability in financial markets. These are short-term events that have little to do with the longer-term trend in bond yields or equity costs. The steepening yield curve indicates that investors believe the economy is in the early stages of an economic recovery and suggests that yields on longer-term Treasury bonds will continue to increase as the recovery progresses.

V. PROXY GROUP SELECTION

Q. Why is it necessary to select a proxy group to estimate the cost of equity for FPL?

A. Since the ROE is a market-based concept and FPL is not publicly traded, it is necessary to establish a group of companies that is both publicly traded and comparable to FPL. Even if FPL were a publicly traded entity, it is possible that transitory events could bias the Company's market value in one way or another in a given period of time. A significant benefit of using a proxy group is the ability to mitigate the effects of short-term events that may be associated with any one company. The proxy companies used in my ROE analyses possess a set of business and operating characteristics similar to FPL's vertically integrated electric utility operations, and thus provide a reasonable basis for estimating the Company's ROE.

Q. Please provide a summary profile of FPL, including Gulf.

A. FPL is a wholly owned subsidiary of NextEra Energy, Inc., providing electric generation, transmission, and distribution service to more than five million residential, commercial, and industrial customers in Florida, and Gulf provides electric utility service to approximately 470,000 customers in northwest Florida. FPL owns 27,440 MW of regulated generation assets, including nuclear facilities, gas-fired plants, and solar generation facilities, while Gulf owns 2,300 MW net generating capacity that includes fossil-fueled units and some solar generation.[29] As demonstrated in the testimony of FPL witness Reed, FPL is the most efficient provider of electricity services in the U.S., as measured by average O&M costs per kilowatt hour. FPL is making significant investments in renewable energy generation, while continuing to maintain and expand its fleet of nuclear and advanced gas combined cycle power plants. In addition, FPL has a substantial capital expenditure program that is focused on improving the reliability of the electricity grid and increasing storm resiliency. FPL has long-term issuer ratings from S&P of A (Outlook: Stable), Moody's Investors Service ("Moody's") of A1 (Outlook: Stable), and FitchRatings ("Fitch") of A (Outlook: Stable).[30]

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[29] NextEra Energy, Inc., 2019 SEC Form 10-K, at 7 and 18.
[30] Ibid, at 46.

Q. Please describe the specific screening criteria you have utilized to select a proxy group.

A. I began with the 36 investor-owned domestic electric utilities covered by Value Line and then screened companies according to the following criteria:

1. Consistently pays quarterly cash dividends;
2. Maintains an investment grade long-term issuer rating (BBB- or higher) from S&P;
3. Is covered by more than one equity analyst;
4. Has positive earnings growth rates published by at least two of the following sources: Value Line, Thomson First Call (as reported by Yahoo! Finance), and Zack's Investment Research ("Zacks");
5. Owns regulated electric generation assets;
6. Regulated revenue and net operating income make up more than 60 percent of the consolidated company's revenue and net operating income (based on a 3-year average from 2017-2019);
7. Regulated revenue and net operating income from regulated electric operations makes up more than 80 percent of the consolidated company's regulated revenue and net operating income (based on a 3-year average from 2017-2019); and
8. Is not involved in a merger or other transformative transaction for an approximate six-month period prior to my analysis.

Q. Did you include NextEra Energy, Inc. in your analysis?

A. No, I did not. In order to avoid the circular logic that would otherwise occur, it is my practice to exclude the subject company, or its parent holding company, from the proxy group.

Q. What is the composition of your resulting proxy group?

A. Based on the screening criteria discussed above, and financial information through fiscal year 2019, I arrived at a proxy group consisting of the companies shown in Figure 10. The results of my screening process are shown in Exhibit JMC-3.

Figure 10: Proxy Group

Company	**Ticker**
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Duke Energy Corporation	DUK
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
Hawaiian Electric Industries, Inc.	HE
IDACORP, Inc.	IDA
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
Xcel Energy Inc.	XEL

Q. Do your screening criteria result in a group of companies that investors would view as comparable to FPL?

A. Yes. I have selected this group of electric utilities to best align with the financial and operational characteristics of FPL. The proxy group screening criterion requiring an investment grade credit rating ensures that the proxy group companies, like FPL, are in sound financial condition. Because credit ratings take into account business and financial risks, the ratings provide a broad measure of investment risk for investors. I have only included companies in the proxy group that own regulated generation assets because vertically-integrated electric utilities have operating characteristics and unique business risks that cause investors to require a higher return on equity to compensate for those risks. These unique risks are not shared by pure Transmission and Distribution utilities. Additionally, I have screened on the percent of revenue and net operating income from regulated operations to differentiate between utilities that are protected by regulation and those with substantial unregulated operations or market-related risks. Also, I have screened on the percentage contribution of the electric utility segment to regulated consolidated financial results to select companies that, like FPL, derive the majority of their revenue and operating income from regulated electric operations. These screens collectively reflect key risk factors that investors consider in making investments in electric utilities.

Q. What is your conclusion with regard to the proxy group for FPL?

A. My conclusion is that my group of 14 vertically integrated electric utilities adequately reflects the broad set of risks that investors consider when investing in a U.S.-regulated vertically integrated electric utility such as FPL. Later in my testimony, I will evaluate whether an adjustment should be made to the results of my ROE analyses to account for differences in FPL's company-specific risks relative to the proxy group companies.

these reasons, it is important that the authorized ROE be set at a level that allows FPL to continue to attract both debt and equity under favorable terms under a variety of economic and financial market conditions.

B. Nuclear Generation Ownership

Q. Does the Company's generation portfolio include nuclear generating assets?

A. Yes. FPL's generation portfolio includes approximately 3,479 MW of owned nuclear generating capacity. Specifically, the Company owns 1,821 MW of existing operating capacity at the St. Lucie plant (which excludes the Orlando Utilities Commission's and Florida Municipal Power Agency's 15 percent ownership interest in St. Lucie Unit No. 2) and 1,658 MW of existing operating capacity at the Turkey Point plant.

Q. Please discuss the risk associated with nuclear generation ownership.

A. Nuclear generation resources are regulated by the U.S. Nuclear Regulatory Commission ("NRC"). FPL is subject to NRC mandates to meet licensing and safety-related standards that may require increased capital spending and incremental operating costs to ensure the continued operation of this very low cost and emission-free generating source. With respect to the risk associated with NRC regulation generally, NextEra Energy's SEC Form 10-K specifically notes that, "NRC orders or new regulations related to increased security measures and any future safety requirements promulgated by the NRC could require NEE and FPL to incur substantial operating and capital expenditures and/or result in reduced revenues."[50] Further, NextEra Energy also notes the risk associated with new regulatory requirements from the NRC as follows: "A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear generation facility. An incident at a nuclear facility anywhere in the world could also cause the NRC to impose additional conditions or other requirements on the industry, or on certain types of nuclear generation units, which could increase costs, reduce revenues, or result in additional capital expenditures."[51]

Q. Are there examples of the increased risk of new regulatory requirements that nuclear generation plant operators face?

A. Yes. One example is the increased oversight and regulatory requirements put in place after the March 11, 2011 earthquake and tsunami which caused significant damage to the Fukushima Daiichi nuclear complex in Japan and threatened the public health. After the Fukushima accident, the NRC formed a task force to assess current regulation and determine if new measures were required to ensure safety. The task force issued a report in July 2011 that included a set of recommendations for NRC consideration, and NRC Staff issued the first set of related regulatory requirements in March 2012. The Fukushima accident clearly demonstrates that additional regulatory oversight and requirements, which affect the cost of operating FPL's nuclear plants, can result from events wholly unrelated to FPL or its facilities.

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50 NextEra Energy, Inc., 2019 SEC Form 10-K, at 29.
51 Ibid, at 30.

Q. How does the investment community view the risk associated with nuclear generation assets?

A. Both equity analysts and credit rating agencies are aware of the operating and safety risks associated with nuclear generation assets. For example, S&P noted in a recent report on Evergy, Inc. that, "[n]uclear generation increases operational risks and carries with it long-term storage concerns."[52] UBS refers to FPL's nuclear operating risk; BMO notes that the Company's nuclear assets are subject to federal and state operational and safety standards;[53] and Atlantic Equities notes that despite receiving federal approval to expand its 3,500 MW of existing nuclear capacity in Florida, FPL has paused capital spending for new nuclear, partly due to construction/cost problems elsewhere in non-associated nuclear plants and partly due to cost effective alternatives with lower up-front costs, including solar.[54] Further, a recent equity analyst report from CFRA indicates that, "[f]or economic reasons, several nuclear plants have been retired and we expect that more will be, although a handful of plants have been rescued from early retirement through state legislation in New Jersey, New York and Illinois."[55]

Credit rating firms consider the risk of nuclear generation in their ratings analysis. For example, S&P Global Ratings made the following comments on the challenges for nuclear operators:

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52 S&P Global Ratings, "Evergy Inc.," May 27, 2020, at 7.
53 BMO Capital Markets, "NEE Gets Clean Bill of Health," April 22, 2020, at 2.
54 Atlantic Equities, "Utilities: Initiate NEE, WEC at Overweight," September 4, 2020, at 45.
55 CFRA, S&P Global Market Intelligence, NextEra Energy, Inc. Stock Report, October 10, 2020.

> Nuclear energy has faced mounting criticism over security concerns, especially in the aftermath of the Fukushima disaster on March 11, 2011. Nuclear operators face unique risks of low-probability, but high-impact catastrophic events. As a consequence, operators face increasing political and social pressures on safety, waste disposal, and storage. While profitability remains a key pillar of our business risk assessment of nuclear operators, we equally take these other risks into account. Furthermore, nuclear-related long-term liabilities typically represent a large portion of nuclear operators' overall S&P-adjusted debt.[56]

Q. Do other companies in the proxy group also face nuclear generation risk?

A. Yes. Eight of the 14 companies in the proxy group also own regulated nuclear generating assets. From that perspective, all other things equal, FPL has higher risk than six of the companies in the proxy group and comparable risk to eight of the companies in the proxy group. Moreover, FPL's generation mix is 22.4 percent nuclear versus an average of. 17.1 percent for the proxy group, based on 2019 data. Even though the investment community may consider nuclear risk binomial, the extent of nuclear risk does vary by company according to the age, technologies, invested assets, fleet management capabilities, location, and other factors that would distinguish one company from another. Even though FPL has established a track record of an above average nuclear plant operator, I conclude that FPL has greater risk than the proxy group companies, on average, with respect to nuclear generating assets, which supports an authorized ROE higher than the average for the proxy companies.

56 "The Energy Transition: Nuclear Dead or Alive," S&P Global Ratings, November 11, 2019, p. 10.

C. Severe Weather Risk

Q. Please explain the risk associated with severe weather in FPL's service territory.

A. FPL faces the risk of sudden, unexpected damage from severe storms. The prevalence of hurricanes, such as Hurricane Irma, make FPL's operating area an especially high-risk area for incurring weather-related infrastructure repair costs and service disruptions. For example, FPL incurred approximately $1.3 billion in storm recovery costs to restore electric transmission and distribution services in 2017, which was equivalent to approximately 4.4 percent of the Company's average rate base in 2016. As FPL witness Barrett reports, hurricanes, and storms over 2016-2020 (Matthew, Irma, Dorian, Isaias, and Eta) inflicted a total of more than $2.0 billion of damage to FPL's system. Mr. Barrett shows how these risks have grown substantially over the decades. Even since the last Settlement, in the Atlantic Basin there were 17 named storms in 2017, 10 of which became hurricanes. In 2018, there were 15 named storms of which 8 became hurricanes. The 2019 season yielded 18 named storms of which 6 became hurricanes. The record-breaking 2020 season produced 30 named storms of which 13 became hurricanes.[57] The addition of Gulf to FPL does not diminish these storm related risks.

57 Insurance Information Institute: https://www.iii.org/fact-statistic/facts-statistics-hurricanes#Top%20Coastal%20Counties%20Most%20Frequently%20Hit%20By%20Hurricanes:%201960-2008

In addition to the need to fund repair costs, severe weather causes FPL to incur unplanned expenses (such as labor costs that aren't recovered in existing rates) and results in lower sales due to damage of transmission or distribution infrastructure, the disruption of generating capacity, or property damage so extensive that it prevents customers from taking service. Together, these effects can reduce FPL's revenue and strain the Company's operating cash flow. In order to continue to attract capital on reasonable terms, FPL must have the financial strength and flexibility to cover these severe weather costs until the Company is able to recover the costs from customers, which can take several years.

Q. Have credit rating agencies commented on FPL's risk related to severe weather?

A. Yes. For example, Moody's has noted that, "FPL's credit profile considers its high geographic concentration risk, as it operates solely in one state that is exposed to extreme weather events such as hurricanes and tropical storms."[58]

Q. Does FPL have a regulatory mechanism that mitigates the risk related to severe weather?

A. Yes. The approved settlement from the 2016 rate case provides that FPL's future storm costs would be recoverable on an interim basis beginning 60 days from the filing of a cost recovery request but would be capped at an amount that would produce a surcharge no greater than $4/1,000 kWh of usage on residential bills during the first 12 months of cost recovery. Any additional

[58] Moody's Investor Service, Florida Power & Light Company Credit Opinion, August 25, 2020, at 1.

costs are eligible for recovery in subsequent years. If storm restoration costs exceed $800 million in any given calendar year, FPL can request an increase to the $4 surcharge limit. More recently, the Florida Legislature passed SB 796 in 2019 entitled "Storm protection plan cost recovery." The law mandates the preparation of 10-year storm protection plans for utilities that must be updated every three years. According to the Commission:

> Section 366.96, F.S., requires each investor owned electric utility (IOU) to file a transmission and distribution storm protection plan (storm protection plan) for the Commission's review and directs the Commission to hold an annual proceeding to determine the IOU's prudently incurred costs to implement the plan and allow recovery of those costs through a Storm Protection Plan Cost Recovery Clause (SPPCRC).[59]

Q. Do other companies in the proxy group also have storm-related risk?

A. Several other companies in the proxy group have storm-related risk. However, the severe weather risk for FPL is greater in magnitude due to the potential for storm damage that may cause extended outages and cost a substantial amount to repair. As FPL witness Barrett points out in his testimony, "Florida's geographic peninsular location, within the subtropical latitudes, and its topography exposes its electrical infrastructure to a higher likelihood of adverse weather events and overall climate risks than most other parts of the country." Florida is consistently ranked among, or at the top, of the highest level of natural disaster risk in comparison to other U.S. states.

[59] http://www.psc.state.fl.us/library/filings/2019/08909-2019/08909-2019.pdf

Q. Is risk associated with climate change and severe weather an increasing concern for utilities and their investors?

A. Yes. McKinsey and Company published a report in April 2019 in which the consulting firm made specific recommendations to the utility industry with regard to managing climate change risk. While noting that severe weather events such as hurricanes and wildfires are getting worse, McKinsey writes: "In other ways, too, utilities are more vulnerable to extreme weather events than in the past."[60] The report goes on to observe: "Unless utilities become more resilient to extreme weather events, they put themselves at unnecessary risk, in both physical and financial terms. Repairing storm damage and upgrading infrastructure after the fact is expensive and traumatic."[61] McKinsey also quotes from a 2018 report by the National Climate Assessment which stated that "utilities could see negative impacts from increased temperatures and heat waves, as well as sea level rises even in the absence of storms. This will increase the financial cost to utilities of climate change and increase the benefits of being prepared."[62]

Accentuating these reports, as mentioned the 2020 Atlantic storm season was the most active on record for the number of named storms (with 30 through November), exceeding the total of 27 in 2005. Prior to 2005, no season had

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60 McKinsey and Company, "Why, and how, utilities should start to manage climate change risk," April 2019, at 3.

61 *Ibid*.

62 *Ibid*., at 4.

exceeded 20 since reliable record keeping began in 1944, and only once prior to then in 1933, with 21.[63]

Q. What is your conclusion with respect to FPL's risk due to severe weather?

A. My conclusion is that FPL has above average risk due to severe weather compared to the proxy group companies. As Moody's observes, FPL provides service in a state that is exposed to extreme weather events such as hurricanes and tropical storms. While FPL has a storm cost recovery mechanism that allows the Company to petition for recovery of cost associated with restoring service after severe weather events, the recovery is capped in the first year, additional costs above the cap may not be sought for recovery until after the first year, and final cost recovery has continually been the subject of protracted litigation before the Commission. The more recent storm hardening mandate under Section 366.96, Florida Statutes offers the ability to further mitigate these risks, but climate change increases the risk that severe weather events will increase in frequency and magnitude. As FPL witness Barrett points out, "These risks have the potential to directly impact FPL's credit profile and therefore, financial strength, if the Company is unable to deploy the necessary capital to continue to mitigate these risks and respond quickly and efficiently when these events occur." FPL is undertaking substantial capital spending over the next decade to improve the reliability of its electric transmission and distribution system. It is necessary for the Company to have an authorized ROE

[63] https://www.ncdc.noaa.gov/sotc/tropical-cyclones/20051

Q. Are there other risks related to a multi-year rate plan?

A. Yes, in addition to the potential for higher interest rates over the term of the four-year rate plan, a multi-year rate plan limits the Company's ability to request a change in rates due to other factors. This inability to seek recovery of higher operating costs during the term of the rate plan increases the utility's risk. Further, if any of the inputs to the DCF or CAPM methods (e.g., growth rates, dividend yields, Beta coefficients, market risk premiums, or long-term Treasury yields) increase, the cost of equity for FPL will increase without a corresponding increase in the authorized ROE. Given the currently low levels of inflation and interest rates, one could conclude that these risks are asymmetric – with the probability that external cost pressures will more likely increase over the rate period.

Q. What is your conclusion with regard to the multi-year rate plan?

A. While FPL's proposed four-year rate plan provides rate certainty for both customers and the Company, there are attendant costs and risks of any multi-year rate plan. In particular, a multi-year stay-out agreement places certain risks on FPL's shareholders, including unexpected increases in operating costs or interest rates.

F. Flotation Costs

Q. What are flotation costs, and how do they affect the cost of capital?

A. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance of common stock. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diminishing the utility's ability to attract adequate capital on reasonable terms. To appropriately reflect flotation costs, the DCF calculation should be modified to provide a dividend yield that would reimburse investors for issuance costs. Based on the proxy group issuance costs shown in Exhibit JMC-10.1, I conclude that flotation costs for the proxy companies have equaled roughly 2.64 percent of gross equity raised. To properly reflect these issuance costs in my cost of capital estimates, it would be appropriate to increase the authorized ROE by approximately 11 basis points for FPL, as shown in Exhibit JMC-10.2.

Q. Do your final results include an adjustment for flotation cost recovery?

A. Yes. I have adjusted the results of my various models to include an adjustment of 11 basis points for flotation costs, while rounding down to 11.0 percent.

G. Management Performance

Q. Please summarize the superior management performance proposal of FPL.

A. As discussed in the testimony of FPL witness Barrett, the Company is proposing a 0.50 percent ROE incentive in recognition of its superior management performance, and to incent continued superior performance over the course of the 4-year rate plan.

Q. Is the proposed adjustment to FPL's authorized ROE reasonable considering the management performance of the Company?

A. Yes. I believe it sends a signal to management and employees of the Company that efficiencies that benefit customers will be rewarded, and these types of incentives can be effective in promoting continuous pursuit of additional efficiencies. Standard ROE analysis does not capture these signals, and the total ROE would still fall well within the appropriate range for a company with FPL's business profile.

VIII. CAPITAL STRUCTURE

Q. What is FPL's proposed capital structure?

A. FPL is proposing a financial capital structure consisting of 59.6 percent common equity and 40.4 percent debt. In Florida, Accumulated Deferred Income Taxes are included in rate base and are part of the regulatory capital structure at 0 percent cost. Florida also includes customer deposits in the regulatory capital structure. FPL's proposed equity ratio using a regulatory capital structure is 48.04 percent in the 2022 Test Year. As explained by FPL witness Barrett, this is the Company's actual capital structure and how the Company has been financed for more than twenty years.

Q. How have you assessed the reasonableness of FPL's proposed capital structure with respect to the proxy group?

A. The proxy group has been selected to reflect comparable companies in terms of business and financial risks. Therefore, it is appropriate to compare the

COMPARISON OF PROXY GROUP COMPANIES
REGULATORY FRAMEWORK - ADJUSTMENT CLAUSES

	[1]			[2]		[3]				[4]
						Decoupling		New Capital		
Proxy Group Company	Operation State	Operation		Test Year	Rate Base	Full	Partial	Generation Capacity	Generic Infrastructure	CWIP in Rate Base
ALLETE, Inc.	Minnesota	Electric	1	Fully Forecast	Average					Partial
	Wisconsin [4]	Electric	1	Fully Forecast	Average					Rider
Alliant Energy Corporation	Iowa	Electric	1	Historical	Average					No
	Iowa	Gas	1	Historical	Average					No
	Wisconsin	Electric	1	Fully Forecast	Average					Rider
	Wisconsin	Gas	1	Fully Forecast	Average					Rider
Ameren Corporation	Illinois	Electric	1	Fully Forecast	Average					Partial
	Illinois	Gas	1	Fully Forecast	Average		x		x	Partial
	Missouri	Electric	1	Partially Forecast	Year End		x		x	No
	Missouri	Gas	1	Partially Forecast	Year End		x		x	No
American Electric Power Company, Inc.	Arkansas	Electric	1	Partially Forecast	Year End		x	x		No
	Indiana	Electric	1	Historical	Year End		x		x	Rider
	Kentucky	Electric	1	Historical	Year End		x			Yes
	Louisiana	Electric	1	Historical	Average		x			Partial
	Michigan	Electric	1	Fully Forecast	Average					Large projects only
	Ohio	Electric	1	Partially Forecast	Year End		x		x	Partial
	Oklahoma	Electric	1	Historical	Year End		x		x	Yes
	Tennessee	Electric	1	Fully Forecast	Average					Yes
	Texas	Electric	1	Historical	Year End				x	No
	Virginia	Electric	1	Historical	Year End			x		Rider
	West Virginia	Electric	1	Historical	Average					Large projects only
Duke Energy Corporation	Florida	Electric	1	Fully Forecast	Average			x		Yes
	Indiana	Electric	1	Historical	Year End		x	x	x	Rider
	Kentucky	Electric	1	Fully Forecast	Average		x			Yes
	Kentucky	Gas	1	Fully Forecast	Average		x			Yes
	North Carolina	Electric	1	Historical	Year End					Large projects only
	North Carolina	Gas	1	Historical	Year End	x			x	Large projects only
	Ohio	Electric	1	Partially Forecast	Year End		x		x	Partial
	Ohio	Gas	1	Partially Forecast	Year End				x	Partial
	South Carolina	Electric	1	Historical	N/A					Yes
	South Carolina	Gas	1	Historical	N/A		x			Yes
	Tennessee	Gas	1	Fully Forecast	Average		x		x	Yes
Edison International	California	Electric	1	Fully Forecast	Average	x				Rider

COMPARISON OF PROXY GROUP COMPANIES
REGULATORY FRAMEWORK - ADJUSTMENT CLAUSES

	[1]			[2]		[3]				[4]
						Decoupling		New Capital		
Proxy Group Company	Operation State	Operation		Test Year	Rate Base	Full	Partial	Generation Capacity	Generic Infrastructure	CWIP in Rate Base
ALLETE, Inc.	Minnesota	Electric	1	Fully Forecast	Average					Partial
Entergy Corporation	Arkansas	Electric	1	Partially Forecast	Average		x	x	x	No
	Louisiana-NOCC	Electric	1	Fully Forecast	Average		x	x		Partial
	Louisiana-NOCC	Gas	1	Fully Forecast	Average					Partial
	Louisiana	Electric	1	Historical	Average		x	x	x	Partial
	Louisiana	Gas	1	Historical	Average		x		x	Partial
	Mississippi	Electric	1	Fully Forecast	Average		x			Partial
	Texas	Electric	1	Historical	Year End				x	No
Evergy, Inc.	Kansas	Electric	1	Historical	Year End		x			Partial
	Missouri	Electric	1	Partially Forecast	Year End		x		x	No
Hawaiian Electric Industries Inc.	Hawaii	Electric	1	Fully Forecast	Average	x		x	x	No
IDACORP	Idaho	Electric	1	Partially Forecast	Average	x				Known & measurable
	Oregon	Electric	1	Fully Forecast	Average					No
OGE Energy Corporation	Arkansas	Electric	1	Partially Forecast	Year End		x	x		No
	Oklahoma	Electric	1	Historical	Year End		x		x	Yes
Pinnacle West Capital Corporation	Arizona	Electric	1	Historical	Year End		x			No
Portland General Electric Company	Oregon	Electric	1	Fully Forecast	Average		x	x		No
Xcel Energy Inc.	Colorado	Electric	1	Historical	Average			x	x	Partial
	Colorado	Gas	1	Historical	Average		x		x	Partial
	Minnesota	Electric	1	Fully Forecast	Average		x			Partial
	Minnesota	Gas	1	Fully Forecast	Average				x	Partial
	New Mexico	Electric	1	Historical	Year End					Yes
	North Dakota	Electric	1	Fully Forecast	Average				x	Rider
	North Dakota	Gas	1	Fully Forecast	Average					No
	South Dakota	Electric	1	Historical	Average		x	x	x	No
	Texas	Electric	1	Historical	Year End				x	No
	Wisconsin	Electric	1	Fully Forecast	Average					Rider
	Wisconsin	Gas	1	Fully Forecast	Average					Rider
Proxy Company Totals				Historical: 25 Forecast: 35	Average: 36 Year End: 22	4	29	12	25	44
Total Jurisdictions			60							
Percent of Jurisdictions				Forecast: 58%	Average: 62%	6.7%	48.3%	20.0%	41.7%	73.3%
Florida Power & Light	Florida	Electric		Fully Forecast	Average					Yes

Notes:
[1] Source: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit.
[2] Source: "Alternative Regulation for Evolving Utility Challenges," Prepared by Pacific Economics Group Research for Edison Electric Institute, Table 6, November 2015; S&P RRA Research; Company Investor Presenta
[3] Source: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019.
[4] Source: S&P Global Market Intelligence, Regulatory Research Associates, Commission Profiles
[5] This exhibit includes the adjustment mechanisms for the electric and gas distribution companies.

FLOTATION COST ADJUSTMENT

Company	Date	[1] Shares Issued (000)	[2] Offering Price	[3] Under-writing Discount	[4] Offering Expense (000)	[5] Net Proceeds Per Share	[6] Total Flotation Costs (000)	[7] Gross Equity Issue Before Costs (000)	[8] Net Proceeds (000)	[9] Flotation Cost Percentage
ALLETE, Inc.	2/26/2014	3,220	$ 49.75	$ 1.74	$ 450	$ 47.87	$ 6,057	$ 160,195	$ 154,138	3.78%
ALLETE, Inc.	5/24/2001	6,600	$ 23.68	$ 0.95	$ 350	$ 22.68	$ 6,602	$ 156,288	$ 149,686	4.22%
Alliant Energy Corporation	11/14/2019	3,718	$ 52.63	$ 0.40	$ 500	$ 52.10	$ 1,968	$ 195,652	$ 193,684	1.01%
Alliant Energy Corporation	12/13/2018	7,269	$ 44.85	$ 0.52	$ 1,000	$ 44.19	$ 4,780	$ 326,000	$ 321,220	1.47%
Ameren Corporation	8/5/2019	7,549	$ 74.30	$ 0.12	$ 750	$ 74.08	$ 1,656	$ 560,906	$ 559,250	0.30%
Ameren Corporation	9/9/2009	21,850	$ 25.25	$ 0.76	$ 450	$ 24.47	$ 17,001	$ 551,713	$ 534,711	3.08%
American Electric Power Company, Inc.	4/1/2009	69,000	$ 24.50	$ 0.74	$ 400	$ 23.76	$ 51,115	$ 1,690,500	$ 1,639,385	3.02%
American Electric Power Company, Inc.	2/27/2003	56,000	$ 20.95	$ 0.63	$ 550	$ 20.31	$ 35,746	$ 1,173,200	$ 1,137,454	3.05%
Duke Energy Corporation	3/1/2016	10,638	$ 72.00	$ 2.16	$ 400	$ 69.80	$ 23,377	$ 765,900	$ 742,523	3.05%
Edison International	7/30/2019	32,200	$ 68.50	$ 1.63	$ 725	$ 66.85	$ 53,110	$ 2,205,700	$ 2,152,590	2.41%
Entergy Corporation	6/6/2018	13,289	$ 75.25	$ 0.80	$ 650	$ 74.40	$ 11,281	$ 1,000,000	$ 988,719	1.13%
Hawaiian Electric Industries, Inc.	3/10/2004	2,000	$ 51.86	$ 2.07	$ 150	$ 49.71	$ 4,299	$ 103,720	$ 99,421	4.14%
IDACORP, Inc.	12/9/2004	4,025	$ 30.00	$ 1.20	$ 300	$ 28.73	$ 5,130	$ 120,750	$ 115,620	4.25%
OGE Energy Corp.	8/21/2003	5,324	$ 21.60	$ 0.79	$ 325	$ 20.75	$ 4,531	$ 115,000	$ 110,469	3.94%
Pinnacle West Capital Corporation	4/8/2010	6,900	$ 38.00	$ 1.33	$ 190	$ 36.64	$ 9,367	$ 262,200	$ 252,833	3.57%
Pinnacle West Capital Corporation	4/27/2005	6,095	$ 42.00	$ 1.37	$ 250	$ 40.59	$ 8,570	$ 255,990	$ 247,420	3.35%
Portland General Electric Company	6/11/2013	12,765	$ 29.50	$ 0.96	$ 600	$ 28.49	$ 12,839	$ 376,568	$ 363,728	3.41%
Portland General Electric Company	3/5/2009	12,478	$ 14.10	$ 0.49	$ 375	$ 13.58	$ 6,533	$ 175,933	$ 169,400	3.71%
Xcel Energy Inc.	8/3/2010	21,850	$ 21.50	$ 0.65	$ 600	$ 20.83	$ 14,693	$ 469,775	$ 455,082	3.13%
Xcel Energy Inc.	2/25/2002	23,000	$ 22.50	$ 0.73	$ 300	$ 21.76	$ 17,090	$ 517,500	$ 500,410	3.30%
							$ 295,745	$ 11,183,489	$ 10,887,744	2.64%

Notes
[1] - [3] Source: SNL Financial; Two most recent equity issuances of each company in the proxy group, excluding issuances without gross underwriting discount
[4] Source: Company Prospectus Supplements
[5] Equals Col. [8] / Col. [1]
[6] Equals (Col. [1] x Col. [3]) + Col. [4]
[7] Equals Col. [1] x Col. [2]
[8] Equals Col. [7] - Col. [6]
[9] Equals Col. [6] / Col. [7]

The flotation adjustment is derived by dividing the dividend yield by 1− F (where F = flotation costs expressed in percentage terms), or by 0.9736, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

FLOTATION COST ADJUSTMENT

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Expected Div. Yield Adj. for Flotation Costs	[6] Value Line EPS Growth	[7] First Call EPS Growth	[8] Zacks Earnings Growth	[9] Average Earnings Growth	[10] DCF	[11] Flotation Adjusted DCF
ALLETE, Inc.	ALE	$2.52	$64.82	3.89%	4.00%	4.11%	4.50%	7.00%	NA%	5.75%	9.75%	9.86%
Alliant Energy Corporation	LNT	$1.61	$48.74	3.30%	3.40%	3.49%	5.50%	5.70%	5.80%	5.67%	9.06%	9.16%
Ameren Corporation	AEE	$2.06	$73.02	2.82%	2.91%	2.99%	6.00%	6.60%	6.80%	6.47%	9.38%	9.46%
American Electric Power Company, Inc.	AEP	$2.96	$79.89	3.70%	3.81%	3.92%	6.00%	6.00%	5.80%	5.93%	9.75%	9.85%
Duke Energy Corporation	DUK	$3.86	$91.03	4.24%	4.35%	4.47%	5.00%	4.99%	5.20%	5.06%	9.41%	9.53%
Edison International	EIX	$2.65	$58.05	4.57%	4.74%	4.87%	12.00%	Negative	3.10%	7.55%	12.29%	12.42%
Entergy Corporation	ETR	$3.80	$93.80	4.05%	4.14%	4.25%	3.00%	5.15%	5.20%	4.45%	8.59%	8.70%
Evergy, Inc.	EVRG	$2.14	$54.07	3.96%	4.09%	4.20%	7.50%	5.90%	6.10%	6.50%	10.59%	10.70%
Hawaiian Electric Industries, Inc.	HE	$1.36	$34.26	3.97%	4.00%	4.11%	1.50%	1.30%	2.50%	1.77%	5.77%	5.88%
IDACORP, Inc.	IDA	$2.84	$88.22	3.22%	3.27%	3.36%	4.50%	2.60%	2.60%	3.23%	6.50%	6.59%
OGE Energy Corp.	OGE	$1.61	$31.16	5.17%	5.24%	5.38%	3.00%	2.10%	3.60%	2.90%	8.14%	8.28%
Pinnacle West Capital Corporation	PNW	$3.32	$76.37	4.35%	4.43%	4.55%	4.50%	3.50%	3.40%	3.80%	8.23%	8.35%
Portland General Electric Company	POR	$1.63	$42.42	3.84%	4.04%	4.15%	4.00%	13.40%	13.40%	10.27%	14.31%	14.42%
Xcel Energy Inc.	XEL	$1.72	$62.91	2.73%	2.82%	2.89%	6.00%	6.20%	6.10%	6.10%	8.92%	8.99%
MEAN											9.33%	9.44%
											[12]	0.11%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of February 28, 2021
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Equals [4] / (1 − Flotation Cost)
[6] Source: Value Line
[7] Source: Yahoo! Finance
[8] Source: Zacks Earnings Growth
[9] Equals Average ([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals Average of [11] − Average of [10]

Exhibit No. DCRT-13

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
DCR Transmission, L.L.C.	)	**Docket No. ER23-___-000**
	)	

DIRECT TESTIMONY

OF

JAMES M. COYNE

ON BEHALF

OF

DCR TRANSMISSION, L.L.C.

energy utility industry. This work includes calculating the cost of capital for the purpose of ratemaking and providing expert testimony and studies on matters pertaining to rate policy, valuation, capital costs, and performance-based regulation. I have authored numerous articles on the energy industry, lectured on utility regulation for regulatory commission staff, and provided testimony before the Federal Energy Regulatory Commission ("FERC" or "Commission") as well as state and provincial jurisdictions in the United States and Canada. I hold a Bachelor of Science in Business Administration from Georgetown University and a Master of Science in Resource Economics from the University of New Hampshire. My educational and professional background is summarized more fully in Attachment JMC-1.

Q3. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A3. I am submitting this testimony on behalf of DCR Transmission, L.L.C. ("DCRT") as it relates to the appropriate Return on Equity ("ROE"),[1] capital structure, and cost of debt for the Ten West Link 500 kilovolt ("kV") Transmission Line ("Project").

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A4. DCRT has asked me to prepare an independent estimate of the Project's cost of equity and recommend to the Commission an ROE rate that is fair, allows DCRT to attract capital on reasonable terms and maintain its financial integrity, and results in just and reasonable rates for the Project. In addition, I provide the overall rate of return to be used for purposes of determining the annual Base Transmission Revenue Requirement ("Base TRR") as defined

[1] I use the terms "ROE" and "cost of equity" interchangeably throughout my Direct Testimony.

V. PROXY GROUP SELECTION

Q18. PLEASE DESCRIBE THE SPECIFIC SCREENING CRITERIA YOU HAVE UTILIZED TO SELECT YOUR PROXY GROUP.

A18. I have used the screening criteria prescribed by FERC to select a proxy group for cases involving electric transmission assets. Specifically, I began with the thirty-six companies that Value Line classifies as "Electric Utilities" and then included companies that consistently pay quarterly cash dividends, with no dividend cuts in the six-month study period, and have had no major merger activity in the six-month study period. In addition to these criteria, FERC typically requires each proxy company's credit rating to be within one notch above or below the S&P Global ("S&P") or Moody's rating of the Project.

Q19. WHAT IS THE PROJECT'S CREDIT RATING?

A19. The Project is a single asset Transco and does not have a credit rating. Therefore, I included all companies with an investment grade credit rating from S&P or Moody's.

Q20. WHAT IS THE COMPOSITION OF YOUR PROXY GROUP?

A20. Based on the screening criteria discussed above, I arrived at a proxy group consisting of the thirty-one companies shown in Figure 4, below. Please refer to Schedule 1 for my proxy group screening data and results (Exhibit No. DCRT-14).

Figure 4: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
Black Hills Corporation	BKH
CenterPoint Energy, Inc.	CNP
CMS Energy Corporation	CMS
Dominion Resources, Inc.	D
DTE Energy Company	DTE
Duke Energy Corporation	DUK
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
Eversource Energy	ES
Exelon Corporation	EXC
Hawaiian Electric Industries, Inc.	HE
IDACORP, Inc.	IDA
MGE Energy, Inc.	MGEE
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corp.	OGE
Otter Tail Corporation	OTTR
Pinnacle West Capital Corp.	PNW
Portland General Electric Company	POR
PPL Corporation	PPL
Public Service Enterprise Group Inc.	PEG
Sempra Energy	SRE
Southern Company	SO
WEC Energy Group, Inc.	WEC
Xcel Energy Inc.	XEL

PROXY GROUP SCREENING DATA AND RESULTS

Company	Ticker	[1] Pays Dividends, No Reductions or Cuts in Study Period	[2] S&P Credit Rating	[3] Moody's Credit Rating	[4] Engaged in Merger during Study Period (12/1/2022 through 5/31/2023)	[5] In Proxy Group
ALLETE, Inc.	ALE	Yes	BBB	Baa1	No	Yes
Alliant Energy Corporation	LNT	Yes	A-	Baa2	No	Yes
Ameren Corporation	AEE	Yes	BBB+	Baa1	No	Yes
American Electric Power Company, Inc.	AEP	Yes	A-	Baa2	No	Yes
Avangrid, Inc.	AGR	Yes	BBB+	Baa2	Yes	No
Avista Corporation	AVA	Yes	BBB	Baa2	No	Yes
Black Hills Corporation	BKH	Yes	BBB+	Baa2	No	Yes
CenterPoint Energy, Inc.	CNP	Yes	BBB+	Baa2	No	Yes
CMS Energy Corporation	CMS	Yes	BBB+	Baa2	No	Yes
Consolidated Edison, Inc.	ED	Yes	A-	Baa2	Yes	No
Dominion Resources, Inc.	D	Yes	BBB+	Baa2	No	Yes
DTE Energy Company	DTE	Yes	BBB+	Baa2	No	Yes
Duke Energy Corporation	DUK	Yes	BBB+	Baa2	No	Yes
Edison International	EIX	Yes	BBB	Baa2	No	Yes
Entergy Corporation	ETR	Yes	BBB+	Baa2	No	Yes
Eversource Energy	ES	Yes	A-	Baa1	No	Yes
Exelon Corporation	EXC	Yes	BBB+	Baa2	No	Yes
FirstEnergy Corporation	FE	Yes	BBB-	Ba1	Yes	No
Evergy, Inc.	EVRG	Yes	A-	n/a	No	Yes
Hawaiian Electric Industries, Inc.	HE	Yes	BBB-	n/a	No	Yes
IDACORP, Inc.	IDA	Yes	BBB	Baa2	No	Yes
MGE Energy, Inc.	MGEE	Yes	AA-	n/a	No	Yes
NextEra Energy, Inc.	NEE	Yes	A-	Baa1	No	Yes
NorthWestern Corporation	NWE	Yes	BBB	Baa2	No	Yes
OGE Energy Corporation	OGE	Yes	BBB+	Baa1	No	Yes
Otter Tail Corporation	OTTR	Yes	BBB	Baa2	No	Yes
PG&E Corporation	PCG	No	BB-	Ba2	No	No
Pinnacle West Capital Corporation	PNW	Yes	BBB+	Baa1	No	Yes
PNM Resources, Inc.	PNM	Yes	BBB	Baa3	Yes	No
Portland General Electric Company	POR	Yes	BBB+	A3	No	Yes
PPL Corporation	PPL	Yes	A-	Baa1	No	Yes
Public Service Enterprise Group Inc.	PEG	Yes	BBB+	Baa2	No	Yes
Sempra Energy	SRE	Yes	BBB+	Baa2	No	Yes
Southern Company	SO	Yes	BBB+	Baa2	No	Yes
Wisconsin Energy Corporation	WEC	Yes	A-	Baa1	No	Yes
Xcel Energy Inc.	XEL	Yes	A-	Baa1	No	Yes
						31

Notes:
[1] Source: Bloomberg Professional
[2] Source: S&P Capital IQ Pro
[3] Source: S&P Capital IQ Pro
[4] Source: S&P Capital IQ Pro

REPORT:

COST OF CAPITAL

PREPARED FOR:

FORTISBC ENERGY INC. AND FORTISBC INC.

BEFORE THE:

BRITISH COLUMBIA UTILITIES COMMISSION

JANUARY 2022

www.ceadvisors.com

IV. SELECTION OF PROXY COMPANIES

A. Why it is Necessary to Select a Proxy Group

Since ROE is a market-based concept and given that neither FEI nor FBC are publicly traded, it is necessary to establish a group of companies that are both publicly traded and comparable to each company's business and financial characteristics to serve as its "proxy" for purposes of the ROE estimation process. Even if FEI's regulated gas utility operations or FBC's regulated electric utility operations made up the entirety of a publicly traded entity, transitory events could bias those entities' market value in one way or another over a given period of time. A significant benefit of using a proxy group is that it provides the ability to mitigate the effects of anomalous events that may be associated with any one company. The proxy companies used in my ROE analyses possess a set of business and financial characteristics that are similar to FEI's and FBC's regulated gas and electric utility operations, and thus provide a reasonable basis for ROE and capital structure estimates.

B. Precedent for Use of U.S. Data

Canadian regulators have adopted a pragmatic view of the use of U.S. data and proxy groups to estimate the allowed ROE for Canadian regulated utilities. The development of a proxy group comprised entirely of Canadian regulated gas or electric utilities is challenged by the small number of publicly-traded utilities in Canada and the fact that many of those Canadian companies derive a significant percentage of revenues and net income from operations other than regulated gas or electric utility service. The continuing trend toward mergers and acquisitions in the utility industry, both within Canada and across the border with U.S. utility holding companies, further blurs the distinction between a Canadian and U.S. utility company.

The BCUC has accepted the use of U.S. proxy group data in Canadian ROE analysis, primarily due to the lack of sufficient Canadian data, and in recognition of the need for Canadian utilities to compete for capital in a global marketplace.[48] In its August 2016 GCOC decision for FEI, the BCUC affirmed the reasonableness of using U.S. market data and proxy groups. Although the Panel found that the evidence was not persuasive in demonstrating that the U.S. proxy companies have

48 British Columbia Utilities Commission, In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., Return on Equity and Capital Structure, Decision G-158-09, December 16, 2009, at 15-16.

the same regulatory protections (deferral and variance accounts) as the Canadian proxy companies, the Panel did not make an explicit adjustment to the ROE results for the U.S. proxy group to reflect differences in risk between the two countries.[49] Other Canadian jurisdictions, including the CER, OEB and the Régie de L'Energie, have also accepted the use of U.S. data and proxy groups for purposes of establishing the allowed ROE and common equity ratio for Canadian electric and gas utilities.[50] In summary, multiple regulatory authorities in Canada have recognized that Canadian utility companies are competing for capital in global financial markets and that Canadian data are limited by the small number of publicly-traded utilities. Regulators have also recognized the integrated nature of Canadian and U.S. financial markets, and the similarity of the utility regulatory regimes. I will explicitly address the BCUC's expressed reservations regarding the comparability of regulatory environments in the risk section of this testimony.

C. Profile of FEI and FBC

FEI owns and operates a gas distribution utility serving approximately 1,059,200 customers[51] in 135 communities across British Columbia. In 2020, FEI had a gas rate base of approximately $5.1 billion and annual throughput of 219 PJs. FEI provides natural gas transmission and distribution to its customers and obtains natural gas supplies on behalf of most of its residential, commercial and industrial customers. According to FEI's 2020 Annual Information Form, residential customers make up 91 percent of customers, 57 percent of revenues and 37 percent of the sales volumes. Nine percent of customers are commercial customers and account for 29 percent of revenues and 25 percent of sales volumes. Industrial customers make up 7 percent of revenues and 8 percent of gas sales volumes. Transport and other customers make up approximately 7 percent of revenues and 30 percent of total throughput volumes. FEI has a senior unsecured debt rating of A3 (Outlook: Stable) from Moody's and an issuer rating of A (Trend: Stable) from DBRS

49 2016 FEI Decision (August 2016), at pp. 52-53.

50 National Energy Board, Reasons for Decision, TQM RH-1-2008 (March 2009), at 66-72; Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at 23; and English translation of Régie de l'Energie, Decision 2009-156 (R-3690-2009), Gaz Metro, December 7, 2009, at paragraph [249].

51 Moody's Investor's Service, Credit Opinion, FortisBC Energy Inc. Update to credit analysis, November 25, 2021, at 2.

Morningstar. FEI is not rated by S&P; however, Fortis Inc. has an S&P issuer rating of A- (Outlook: Stable) and a senior, unsecured debt rating of BBB+.

FBC is a vertically-integrated electric utility serving approximately 184,000[52] residential, commercial, industrial and wholesale customers in the cities and rural regions of southern BC. According to FBC's 2020 Annual Information Form, FBC sold 3,291 GWh of electricity to its customers, 560 GWh of which was purchased by FBC's six wholesale customers. FBC had a peak demand of 740 MW in 2020, 6 MW lower than the historical peak demand of 746 MW. FBC's regulated generation assets consist of four hydroelectric generating plants with a total capacity of 225 MW and an annual gross energy entitlement of approximately 1,609 GWh. FBC meets the remainder of its customers' energy and capacity requirements through a portfolio of long-term and short-term power purchase contracts. FBC has a senior unsecured debt rating of Baa1 (Outlook: Stable) from Moody's and an issuer rating of A (low) (Trend: Stable) from DBRS Morningstar. FBC is not rated by S&P; however, Fortis Inc. has an S&P issuer rating of A- (Outlook: Stable) and a senior, unsecured debt rating of BBB+.

D. Proxy Groups

I developed five proxy groups for the ROE analysis. The first proxy group is comprised of publicly traded, regulated Canadian electric and natural gas utility companies. Recognizing there are few publicly traded companies in the utility sector in Canada, the only screening criterion was an investment grade credit rating, which all companies in the sector have. Fortis Inc. has been excluded from the Canadian proxy group because it is the parent company of FEI and FBC. TC Energy (formerly TransCanada) has been excluded due to the risk profile of the TransCanada Mainline, which differs from gas distribution operations. The following six companies comprise the Canadian Proxy Group for both FEI and FBC:

[52] Moody's Investor's Service, Credit Opinion, FortisBC Inc. Update to credit analysis, November 25, 2021, at 2.

Figure 18: Canadian Proxy Group

Company	Ticker
Algonquin Power and Utilities Corp.	AQN
AltaGas Ltd.	ALA
Canadian Utilities Limited	CU
Emera Inc.	EMA
Enbridge, Inc.	ENB
Hydro One, Ltd.	H

The second proxy group is comprised of like-risk U.S. natural gas distribution companies. To obtain companies of like-risk, I performed a number of screens to determine a group of essentially pure-play gas utilities with similar risk profiles to FEI. I started with the ten companies Value Line classifies as Natural Gas Distribution Companies. From that group, I further screened for companies that:

a) Have credit ratings of at least BBB+ from S&P or Baa1 from Moody's;

b) Consistently pay quarterly cash dividends;

c) Have positive earnings growth rate projections from at least two sources;

d) Derived at least 65 percent[53] of operating income from regulated operations in the period from 2018-2020;

e) Derived at least 90 percent of regulated operating income from natural gas distribution utility service in the period from 2018-2020; and

f) Were not involved in a merger or other significant transformative transaction during the evaluation period.

The following four U.S. gas distribution utility companies met the screening criteria:

53 This screen was relaxed from 70% to 65% so that there would be a sufficient number of companies in the U.S. Gas proxy group. At 70% regulated operating income, the proxy group would only include three companies.

Figure 19: U.S. Gas Distribution Proxy Group

Company	Ticker
New Jersey Resources Corporation	NJR
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Spire, Inc.	SR

As shown in Figure 20, the third proxy group is comprised of the three Canadian regulated utilities that have significant natural gas operations (i.e., AltaGas Utilities, Inc., Canadian Utilities Ltd., and Enbridge, Inc.) plus the four U.S. gas distribution companies. This group is referred to as the North American Gas proxy group.

Figure 20: North American Gas Proxy Group

Company	Ticker
AltaGas Utilities, Inc.	ALA
Canadian Utilities Ltd.[54]	CU
Enbridge, Inc.	ENB
New Jersey Resources Corporation	NJR
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Spire, Inc.	SR

The fourth proxy group is comprised of like-risk U.S. electric utility companies. To obtain companies of like-risk, I performed a number of screens to determine a group of essentially pure-play electric utilities with similar risk profiles to FBC. I started with the 36 companies Value Line classifies as Electric Utility Companies. From that group, I further screened for companies that:

g) Have credit ratings of at least BBB+ from S&P or Baa1 from Moody's;

h) Consistently pay quarterly cash dividends;

i) Have positive earnings growth rate projections from at least two sources;

[54] Canadian Utilities Ltd. is a combination electric and gas utility. Earnings are 53.3% electric and 46.7% gas; Assets are 56.4% electric and 43.6 gas; and revenues are 47.1% electric and 52.9% gas.

j) Derived at least 70 percent of operating income from regulated operations in the period from 2018-2020;

k) Derived at least 90 percent of regulated operating income from electric utility service in the period from 2018-2020; and

l) Were not involved in a merger or other significant transformative transaction during the evaluation period.

As shown in Figure 21, the following ten U.S. electric utility companies met the screening criteria:

Figure 21: U.S. Electric Proxy Group

Company	Ticker
Alliant Energy Corp.	LNT
American Electric Power Company	AEP
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Exelon Corp	EXC
Evergy Inc.	EVRG
NextEra Energy, Inc.	NEE
OGE Energy Corporation	OGE
Pinnacle West Capital Corp.	PNW
Portland General Electric Company	POR

As shown in Figure 22, the fifth proxy group is comprised of the four Canadian regulated utilities that are primarily electric companies (i.e. Algonquin Power, Canadian Utilities, Emera, and Hydro One) plus the ten U.S. Electric utility companies. This group is referred to as the North American Electric proxy group.

Figure 22: North American Electric Proxy Group

Company	Ticker
Algonquin Power & Utilities Corp	AQN
Canadian Utilities Ltd.	CU
Emera Inc.	EMA
Hydro One, Ltd.	H
Alliant Energy Corp.	LNT
American Electric Power Company	AEP
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Exelon Corp.	EXC
Evergy Inc.	EVRG
NextEra Energy, Inc.	NEE
OGE Energy Corporation	OGE
Pinnacle West Capital Corp.	PNW
Portland General Electric Company	POR

Exhibits JMC-FEI-3 and JMC-FBC-3 provide additional information on the proxy group screening process.

I have selected these groups of gas and electric utilities to best align with the financial and operational characteristics of FEI and FBC, respectively. The proxy group screening criterion requiring an investment grade credit rating ensures that the proxy group companies, like FEI and FBC, are in sound financial condition. Because credit ratings take into account business and financial risks, the ratings provide a broad measure of investment risk for investors.[55] Additionally, I have screened my U.S. and North American proxy groups on the percent of net operating income from regulated operations to differentiate between utilities that are protected by regulation and those with substantial unregulated operations or market-related risks. Also, I have screened the U.S. and North American proxy group on the percentage contribution of the gas or electric utility segments to regulated consolidated financial results to select companies that, like FEI and FBC, derive the majority of their operating income from regulated gas or electric operations. These screens collectively reflect key risk factors that investors consider in making

[55] Credit ratings are commonly used as screens for companies of comparable business and financial risks in cost of capital analysis in regulatory proceedings. Credit ratings are exclusively focused on the risks for debt investors, but do not account for the risks for equity investors.

investments in gas and electric utilities. My conclusion is that my proxy groups adequately reflect the broad set of risks that investors consider when investing in regulated gas and electric utility companies such as FEI and FBC. Later in the report, I conduct more detailed risk analysis to determine if any adjustments are required to account for risks specific to FEI and FBC.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Question(s):

For each of CLD+ utilities, please provide:

a) Copies of all credit rating agency reports since 2009

b) Each year between 2009 and 2023, a table that shows approved (i.e. ROE include in base rates) vs actual regulated ROE. As part of that response, for i) Hydro One, please provide a further breakdown by regulated business (transmission and distribution), ii) OPG, please provide a breakdown by generating segment (nuclear and hydroelectric), iii) for Alectra, Elexicon, and Enbridge, who have been subject to major MAAD transactions since 2009, please provide information for predecessor utilities for the applicable years.

c) Details of all equity investments received since 2009, including the date, amount, and source (direct shareholder investment, indirect shareholder investment through holding company, and share sale).

d) A table that shows for all outstanding long-term debt, i) date of issuance, ii) term, iii) maturity date, iv) principal, v) interest rate, vi) type of debt instrument (e.g. public bond, private placement, loan, promissory note, swap, etc.) vii) source of debt (e.g. TD Bank, infrastructure Ontario, shareholder, etc.) and viii) indicate if the debt issued is at the LDC or holding company level.

e) For each year between 2009 and 2024, actual capital structure.

Response to a):

Enbridge Gas Inc.:

Please see N-M2-10-SEC-41 – Attachment 1 (Enbridge Gas Inc.) for all relevant Enbridge Gas Inc. credit rating agency reports from the past 5 years. The reports are provided in one file and are numerated below.

Appendix	Rating Agency	Title
1	DBRS	DBRS EGI RR Oct 2019
2	DBRS	DBRS EGI RR Sep 2020
3	DBRS	DBRS EGI RR Oct 2021
4	DBRS	DBRS EGI RR Sep 2022
5	DBRS	DBRS EGI RR Sep 2023
6	S&P	S&P EGI Apr 2020
7	S&P	S&P EGI Jan 2021
8	S&P	S&P EGI Feb 2022
9	S&P	S&P EGI Jul 2022
10	S&P	S&P EGI Jul 2023
11	S&P	S&P EGI Sep 2023 Research Update
12	S&P	S&P EGI Jun 2024 Research Update

OPG:

OPG's credit rating reports are provided in N-M2-10-SEC-41 – Attachment 2 (OPG).

Appendix	Rating Agency	Title
1	DBRS	DBRS 2019-2024
2	Moody's	Moody's 2019-2024
3	S&P	S&P 2019-2024

UCT 2:

Rating reports can be obtained from the links below and copies are also attached as N-M2-10-SEC-41 – Attachment 3 (UCT 2).

May 2024: https://dbrs.morningstar.com/research/432193/morningstar-dbrs-confirms-east-west-ties-ratings-at-a-low-with-stable-trends

May 2023: https://dbrs.morningstar.com/research/413338/dbrs-morningstar-finalizes-provisional-ratings-of-a-low-with-stable-trends-on-east-west-tie-limited-partnership

March 2023: https://dbrs.morningstar.com/research/411675/dbrs-morningstar-assigns-provisional-ratings-of-a-low-with-stable-trends-to-east-west-tie-limited-partnership

Hydro One:

Copies of the following credit rating agency reports since 2019 are attached as N-M2-10-SEC-41 – Attachment 4 (Hydro One).

Reference #	Ratings Agency	Title
1	DBRS	DSRS HOI April 15 2019
2	DBRS	DBRS HOI April 16 2020
3	DBRS	DBRS HOI May 3 2022
4	DBRS	DBRS HOI Nov 9 2022
5	DBRS	DBRS HOI Nov 20 2023
6	Moody’s	Moody’s HOI 20Dec10
7	Moody’s	Moody’s HOI Nov 25 2021
8	Moody’s	Moody’s HOI May 30 2023
9	Moody’s	Moody’s HOI 26Jul2024
10	S&P	S&P HOI Feb 24 2020
11	S&P	S&P HOI Mar 11 2021
12	S&P	S&P HOI Apr 15 2022
13	S&P	S&P HOI Mar 17 2023
14	S&P	S&P HOL June 10 2024

Hydro Ottawa Limited:

Hydro Ottawa Limited does not maintain a credit rating with a credit rating agency. Accordingly, there are no “distributor stand alone” credit rating agency reports to provide.

The following credit rating agency reports have been issued since 2019, pertaining to Hydro Ottawa Holding Inc., and are attached as N-M2-10-SEC-41 – Attachment 5 (Hydro Ottawa Holding):

- Standard & Poor’s RatingsDirect report for Hydro Ottawa Holding Inc. dated September 25, 2019
- Standard & Poor’s Research Update for Hydro Ottawa Holding Inc. dated January 13, 2020
- DBRS Rating Report for Hydro Ottawa Holding Inc. dated September 25, 2019
- DBRS Rating Report for Hydro Ottawa Holding Inc. dated September 30, 2020
- DBRS Rating Report for Hydro Ottawa Holding Inc. dated October 29, 2021

- DBRS Rating Report for Hydro Ottawa Holding Inc. dated October 19, 2022
- DBRS Rating Report for Hydro Ottawa Holding Inc. dated October 18, 2023

Toronto Hydro:

Please see N-M2-10-SEC-41 – Attachment 6 (Toronto Hydro) for all relevant Toronto Hydro credit rating agency reports from the past 5 years.

Reference	Rating Agency	Title
1	DBRS	Toronto Hydro – DBRS – 2019
2	DBRS	Toronto Hydro – DBRS – 2020
3	DBRS	Toronto Hydro – DBRS – 2021
4	DBRS	Toronto Hydro – DBRS – 2022
5	DBRS	Toronto Hydro – DBRS – 2023
6	DBRS	Toronto Hydro – DBRS – 2024
7	S&P	Toronto Hydro – S&P – 2019
8	S&P	Toronto Hydro – S&P – 2020
9	S&P	Toronto Hydro – S&P – 2021
10	S&P	Toronto Hydro – S&P – 2022_1
11	S&P	Toronto Hydro – S&P – 2022_2
12	S&P	Toronto Hydro – S&P – 2023
13	S&P	Toronto Hydro – S&P – 2024_1
14	S&P	Toronto Hydro – S&P – 2024_2

Alectra Inc.:

Please see N-M2-10-SEC-41 – Attachment 7 (Alectra) for all relevant Alectra credit rating agency reports from the past five years.

Reference	Rating Agency	Title
1	DBRS	Alectra Inc DBRS 2019
2	DBRS	Alectra Inc DBRS 2020
3	DBRS	Alectra Inc DBRS 2021
4	DBRS	Alectra Inc DBRS 2022
5	DBRS	Alectra Inc DBRS 2023
6	DBRS	Alectra Inc DBRS 2024
7	Fitch	Alectra Inc Fitch 2023
8	Fitch	Alectra Inc Fitch 2024

9	S&P	Alectra Inc S&P 2019
10	S&P	Alectra Inc S&P 2020
11	S&P	Alectra Inc S&P 2021
12	S&P	Alectra Inc S&P 2022
13	S&P	Alectra Inc S&P 2023
14	S&P	Alectra Inc S&P 2024

Elexicon Energy Inc:

Please see N-M2-10-SEC-41 – Attachment 8 (Elexicon) for all relevant Elexicon credit rating agency reports from the past five years.

1	DBRS	Elexicon Rating Report 2020 May 8
2	DBRS	Elexicon Rating Report 2021 May 10
3	DBRS	Elexicon Rating Report 2022 August 23
4	DBRS	Elexicon Rating Report 2023 July 5
5	DBRS	Elexicon Rating Report 2024 July 3

Response to b):

Elexicon Energy Inc:

	2019	2020	2021	2022	2023
Actual	7.61%	6.80%	6.87%	4.86%	5.15%
Deemed	9.43%	9.43%	9.43%	9.43%	9.43%

Toronto Hydro:

	2019	2020	2021	2022	2023
Actual	8.44%	5.90%	7.08%	7.44%	6.80%
Deemed	9.30%	8.52%	8.52%	8.52%	8.52%

Enbridge Gas Inc.:

Enbridge Gas Inc.'s 2019 – 2023 actual utility ROE's, and the ROE's included in rates, are provided in the table below.

		Col. 1	Col. 2
Line No.	Year	Actual Utility ROE	ROE in Base Rates
		%	%
			Union / EGD Rate Zones
1.	2019	10.47	8.93 / 9.00
2.	2020	8.72	8.93 / 9.00
3.	2021	9.17	8.93 / 9.00
4.	2022	9.52	8.93 / 9.00
5.	2023	6.35	8.93 / 9.00

Alectra:

Year	Approved ROE	Actual ROE
2019	8.95%	7.21%
2020	8.95%	4.80%
2021	8.95%	6.18%
2022	8.95%	6.70%
2023	8.95%	7.55%

UCT 2

Year	Actual ROE	Approved ROE
2022	9.42%	8.34%
2023	9.31%	8.34%

Hydro One:

Below is a table that outlines the OEB approved and achieved ROEs for Transmission and Distribution

Transmission

	2019*	2020	2021	2022	2023
Deemed ROE	N/A	8.52	8.52	8.52	9.36
Achieved ROE	9.53%	9.29%	9.30%	9.92%	10.80%

*2019 was an inflationary filing

Distribution

	2019	2020	2021	2022	2023
Deemed ROE	9.00	9.00	9.00	9.00	9.36
Achieved ROE	10.90%	10.56%	10.99%	10.10%	10.88%

Hydro Ottawa:

Year	**2019**	**2020**	**2021**	**2022**	**2023**
Hydro Ottawa ROE	8.98%	8.98%	8.34%	8.34%	8.34%
Hydro Ottawa ROE achieved	8.82%	7.24%	8.49%	6.94%	6.15%

OPG:

OPG operates as a single company, with a single management structure/corporate cost structure, and a single OEB-authorized cost of capital that covers both the hydroelectric and nuclear generating facilities, and obtains corporate financing as a single company. Accordingly, OPG reports achieved return on equity for its prescribed facilities as a whole.

OPG's Regulated ROE

	2019	2020	2021	2022	2023
Actual	15.61%	17.22%	10.79%	12.68%	13.80%
Nuclear Deemed	8.78%	8.78%	8.78%	8.66%	8.66%

Hydroelectric Deemed	9.33%	9.33%	9.33%	9.33%	9.33%

Response to c):

Toronto Hydro:

On June 28, 2017, Toronto Hydro Corporation issued 200 common shares to its shareholder for total proceeds of $250.0 million, net of share issue costs and expenses.

On June 28, 2024, Toronto Hydro Corporation filed the following Material Change Report related to shareholder equity: https://www.sedarplus.ca/csaparty/viewInstance/resource.html?node=W1580&drmKey=b87115a0c5ea1b95&drr=ss6b4650951600347cceb13bcd5b91b967b9ebdfe234b8bcde4c5e867b24c523e1c14901026484277ee266b1feddd5c7e7ux&id=0c11f8b7998bcd9668b76226759035c74a014ba8ed28aabf

Elexicon Energy: Elexicon Energy has not received any equity investment since the merger of its predecessor utilities in 2019.

Alectra: There have been no equity investments since 2019.

OPG: There were no shareholder equity injections in connection with OPG's regulated business since 2019.

Enbridge Gas Inc

Year	Date	Amount	Source
2019	**November 27, 2019**	**$800,000,000**	**Indirect Shareholder Investment through holding company**
2020	**December 10, 2020**	**$800,000,000**	**Indirect Shareholder Investment through holding company**
2021	**December 7, 2021**	**$975,000,000**	**Indirect Shareholder Investment through holding company**
2022	June 28, 2022	$500,000,000	**Indirect Shareholder Investment through holding company**
2022	September 26, 2022	$300,000,000	**Indirect Shareholder Investment through holding company**

2022 Total Contribution	**September 26, 2022**	**$800,000,000**	**Indirect Shareholder Investment through holding company**
2023 Total Contribution	-	None	-

UCT 2:

Equity investments were made in the form of direct shareholder investment.

Year	Amount ($ MMs)
2014	$19
2015	$7
2016	$8
2017	$15
2018	$23
2019	$111
2020	$275
2021	$231
2022	$196

Hydro Ottawa: No equity investments were received by Hydro Ottawa since 2019.

Hydro One: From 2019 to 2024, there have been no equity investments in the company.

Response to d):

Toronto Hydro:

Debenture Series	Date of Issuance	Terms (yrs)	Maturity Date	Principal	Interest Rate	Type of Debt Instrument	Source of Debt	Debt Issued is at the LDC or Holding Company Level
Series 14	12-Nov-2019	10	11-Dec-2029	$ 200,000,000	2.49%	Promissory Note	THC - Holding Company	Debentures issued at the holding company
Series 15	12-Nov-2019	30	10-Dec-2049	$ 200,000,000	3.04%	Promissory Note	THC - Holding Company	Debentures issued at the holding company

Series 16	15-Oct-2020	10	15-Oct-2030	$ 200,000,000	1.55%	Promissory Note	THC - Holding Company	Debentures issued at the holding company
Series 17	18-Oct-2021	10	20-Oct-2031	$ 150,000,000	2.52%	Promissory Note	THC - Holding Company	Debentures issued at the holding company
Series 18	18-Oct-2021	30	18-Oct-2051	$ 200,000,000	3.32%	Promissory Note	THC - Holding Company	Debentures issued at the holding company
Series 19	13-Oct-2022	30	13-Oct-2052	$ 300,000,000	5.00%	Promissory Note	THC - Holding Company	Debentures issued at the holding company
Series 20	14-Jun-2023	10	14-Jun-2033	$ 250,000,000	4.66%	Promissory Note	THC - Holding Company	Debentures issued at the holding company
Series 21	12-Oct-2023	5	12-Oct-2028	$ 200,000,000	5.18%	Promissory Note	THC - Holding Company	Debentures issued at the holding company

Elexicon Energy:

Type	Term	Issue date	Mature on	Rate	Amount (in thousands)	Debt Held By
Notes payable to the shareholders of the Corporation	Short Term	since merger	due on demand	4.13%	71,926	LDC
Notes payable to the Corporation	Long Term	since merger	December, 2034	5%	15,000	LDC
Notes payable to the Corporation	Long Term	since merger	December, 2039	OEB-deemed long-term debt rate, less 30bps	11,200	LDC
Loan payable to the Corporation	Long Term	September, 2016	September, 2031	5%	62	LDC
Loan payable to Town of Cobourg Holding Inc.	Long Term	February, 2019	February, 2044	6%	77	LDC
Long-term debt from TD Bank (SWAP Loan)	Long Term	November, 2023	November, 2028	5%	33,390	LDC
Long-term debt from TD Bank (SWAP Loan)	Long Term	August, 2023	August, 2028	5%	220,000	LDC
Notes payable to the shareholders,	Short Term	since merger	due on demand	4.13%	89,132	Corporation (Holding Company)

Alectra:

Description	Lender	Start Date	Term (years)	Maturity date	Principal ($)	Issue cost	Effective Rate (%)	Coupon rate (%)	Incremental (%)
Promissory Note Payable	Alectra Inc.	4/11/2019	30	4/12/2049	$200,000,000	$1,437,541	3.50%	3.46%	0.04%
Promissory Note Payable	Alectra Inc.	2/11/2021	10	2/11/2031	$300,000,000	$1,754,325	1.82%	1.75%	0.06%
Promissory Note Payable	Alectra Inc.	11/14/2022	30	11/14/2052	$250,000,000	$1,755,955	5.27%	5.23%	0.05%
Promissory Note Payable	Alectra Inc.	6/13/2024	10	6/13/2034	$200,000,000	$1,423,855	4.72%	4.63%	0.09%

Enbridge Gas Inc.

All long-term debt issuances by Enbridge Gas Inc. and its predecessor companies are public bonds issued in the Canadian debt capital markets. Investors primarily include pension funds, life insurance companies and asset managers.

Issuance Date	Maturity Date	Term (years)	Interest Rate	Currency	Notional
8/22/2014	8/22/2024	10	3.15%	CAD	$215,000,000
6/2/1995	12/2/2024	29	9.85%	CAD	$85,000,000
10/2/1995	10/2/2025	30	8.85%	CAD	$20,000,000
11/10/1995	11/10/2025	30	8.65%	CAD	$125,000,000
10/29/1996	10/29/2026	30	7.60%	CAD	$100,000,000
11/3/1997	11/3/2027	30	6.65%	CAD	$100,000,000
5/19/1998	5/19/2028	30	6.10%	CAD	$100,000,000
11/15/2002	11/15/2032	30	6.90%	CAD	$150,000,000
12/16/2003	12/16/2033	30	6.16%	CAD	$150,000,000
2/24/2006	2/25/2036	30	5.21%	CAD	$300,000,000
9/11/2006	9/11/2036	30	5.46%	CAD	$165,000,000
9/2/2008	9/2/2038	30	6.05%	CAD	$300,000,000
11/22/2010	11/22/2050	40	4.95%	CAD	$200,000,000
1/23/2011	7/23/2040	29	5.20%	CAD	$250,000,000
6/21/2011	6/21/2041	30	4.88%	CAD	$300,000,000
9/7/2011	11/22/2050	39	4.95%	CAD	$100,000,000
11/22/2013	11/22/2043	30	4.50%	CAD	$200,000,000
6/2/2014	6/2/2044	30	4.20%	CAD	$500,000,000
8/22/2014	8/22/2044	30	4.00%	CAD	$215,000,000
9/11/2015	9/11/2025	10	3.31%	CAD	$400,000,000
9/11/2015	8/22/2044	28	4.00%	CAD	$170,000,000
9/17/2015	9/17/2025	10	3.19%	CAD	$200,000,000
5/31/2016	6/1/2026	10	2.81%	CAD	$250,000,000
5/31/2016	6/1/2046	30	3.80%	CAD	$250,000,000
8/5/2016	8/5/2026	10	2.50%	CAD	$300,000,000
11/22/2017	11/22/2027	10	2.88%	CAD	$250,000,000
11/22/2017	11/22/2047	30	3.59%	CAD	$250,000,000
11/29/2017	11/29/2047	30	3.51%	CAD	$300,000,000
8/9/2019	8/9/2029	10	2.37%	CAD	$400,000,000
8/9/2019	8/9/2049	30	3.01%	CAD	$300,000,000
4/1/2020	4/1/2030	10	2.90%	CAD	$600,000,000
4/1/2020	4/1/2050	30	3.65%	CAD	$600,000,000
9/15/2021	9/15/2031	10	2.35%	CAD	$475,000,000
9/15/2021	9/15/2051	30	3.20%	CAD	$425,000,000
8/17/2022	8/17/2032	10	4.15%	CAD	$325,000,000
8/17/2022	8/17/2052	30	4.55%	CAD	$325,000,000
10/6/2023	10/6/2028	5	5.46%	CAD	$250,000,000

10/6/2023	10/6/2033	10	5.70%	CAD	$400,000,000
10/6/2023	10/6/2053	30	5.67%	CAD	$350,000,000
					$10,395,000,000

UCT 2:

As provided in EB-2023-0298, UCT 2's long-term debt is a 30-year $427,651,000 Senior Secured Fixed-Rate Partially Amortizing note with a 4.864% fixed interest rate. Long-term debt was issued on May 1, 2023.

Date of Issue	Term (yrs)	Maturity Date	Principal	Interest Rate	Type
May 1, 2023	30	May 1, 2053	$427,651,000	4.864 %	Senior Secured Fixed-Rate Partially Amortizing Note

Hydro Ottawa:

Date of Issuance	Term (Years)	Maturity Date	Principal ($)	Interest Rate	Type of Debt Instrument	Source of Debt (Creditor)[1]	Issuer (Debtor)[2]
9/Feb/15	10.0	3/Feb/25	138,667,000	2.614%	Promissory Note	Hydro Ottawa Holding Inc. ("HOHI")	Hydro Ottawa Limited ("HOL")
9/Feb/15	30.0	2/Feb/45	121,333,000	3.639%	Promissory Note	HOHI	HOL
14/May/13	30.0	14/May/43	107,185,000	3.991%	Promissory Note	HOHI	HOL
14/May/13	23.6	19/Dec/36	50,000,000	4.968%	Promissory Note	HOHI	HOL
25/Jun/15	10.0	25/Jun/25	15,999,000	2.614%	Promissory Note	HOHI	HOL
25/Jun/15	30.0	25/Jun/45	14,001,000	3.639%	Promissory Note	HOHI	HOL
16/Oct/19	10.0	16/Oct/29	87,500,000	2.660%	Promissory Note	HOHI	HOL

16/Oct/19	30.0	16/Oct/49	162,500,000	3.210%	Promissory Note	HOHI	HOL
5/Jul/21	on demand	on demand	80,000,000	3.570%	Grid Note	HOHI	HOL
9/Aug/22	on demand	on demand	30,000,000	4.940%	Grid Note	HOHI	HOL
7/Jul/23	on demand	on demand	30,000,000	4.560%	Grid Note	HOHI	HOL

Hydro One:

For Hydro One Inc.

Outstanding Debt as at August 20, 2024

Hydro One Inc.

Offering Date	Term (Years)	Maturity Date	Principal Amount ($Millions)	Coupon Rate	Yield
28-Feb-20	5.0	28-Feb-25	400.0	1.76%	1.77%
26-Jun-18	7.0	26-Jun-25	350.0	2.97%	2.97%
20-Oct-23	2.0	20-Oct-25	400.0	5.54%	5.54%
24-Feb-16	10.0	24-Feb-26	500.0	2.77%	2.77%
21-Sep-23	3.0	21-Sep-26	425.0	CORRA+0.5%	Variable
27-Oct-22	5.3	27-Jan-28	750.0	4.91%	4.91%
5-Apr-19	10.0	5-Apr-29	550.0	3.02%	3.02%
27-Jan-23	6.8	30-Nov-29	300.0	3.93%	3.93%
12-Jan-24	5.9	30-Nov-29	250.0	3.93%	4.09%
28-Feb-20	10.0	28-Feb-30	400.0	2.16%	2.16%
3-Jun-00	30.0	3-Jun-30	400.0	7.35%	7.36%
9-Oct-20	10.3	16-Jan-31	400.0	1.69%	1.70%
17-Sep-21	10.0	17-Sep-31	450.0	2.23%	2.24%
22-Jun-01	31.0	1-Jun-32	300.0	6.93%	6.94%
17-Sep-02	29.7	1-Jun-32	200.0	6.93%	6.60%
27-Jan-23	10.0	27-Jan-33	450.0	4.16%	4.16%
31-Jan-03	31.0	31-Jan-34	200.0	6.35%	6.36%
25-Jun-04	29.6	31-Jan-34	120.0	6.35%	6.29%
24-Aug-04	29.5	31-Jan-34	65.0	6.35%	6.05%
12-Jan-24	10.1	1-Mar-34	550.0	4.39%	4.40%
20-Aug-24	10.4	4-Jan-35	700.0	4.25%	4.25%
19-May-05	31.0	20-May-36	350.0	5.36%	5.37%
24-Apr-06	30.1	20-May-36	250.0	5.36%	5.41%

13-Mar-07	30.0	13-Mar-37	400.0	4.89%	4.89%
3-Mar-09	30.0	3-Mar-39	300.0	6.03%	6.03%
16-Jul-09	31.0	16-Jul-40	300.0	5.49%	5.50%
15-Mar-10	30.4	16-Jul-40	200.0	5.49%	5.42%
26-Sep-11	30.0	26-Sep-41	300.0	4.39%	4.40%
22-Apr-03	40.0	22-Apr-43	250.0	6.59%	6.59%
20-Aug-04	38.7	22-Apr-43	65.0	6.59%	6.03%
9-Oct-13	30.0	9-Oct-43	435.0	4.59%	4.59%
6-Jun-14	30.0	6-Jun-44	350.0	4.17%	4.18%
24-Feb-16	30.0	23-Feb-46	350.0	3.91%	3.92%
19-Oct-06	40.0	19-Oct-46	75.0	5.00%	5.01%
13-Sep-10	36.1	19-Oct-46	250.0	5.00%	4.95%
18-Nov-16	31.0	18-Nov-47	450.0	3.72%	3.72%
26-Jun-18	31.0	25-Jun-49	750.0	3.63%	3.63%
28-Feb-20	30.0	28-Feb-50	300.0	2.71%	2.71%
9-Oct-20	29.4	28-Feb-50	200.0	2.71%	2.70%
5-Apr-19	31.0	5-Apr-50	250.0	3.64%	3.64%
17-Sep-21	30.0	15-Sep-51	450.0	3.10%	3.10%
22-Dec-11	40.0	22-Dec-51	100.0	4.00%	4.00%
22-May-12	39.6	22-Dec-51	125.0	4.00%	4.00%
27-Jan-23	30.0	27-Jan-53	300.0	4.46%	4.46%
30-Nov-23	31.0	30-Nov-54	400.0	4.85%	4.86%
12-Dec-23	31.0	30-Nov-54	100.0	4.85%	4.56%
20-Aug-24	30.3	30-Nov-54	500.0	4.85%	4.64%
31-Jul-12	50.0	31-Jul-62	75.0	3.79%	3.79%
16-Aug-12	50.0	31-Jul-62	235.0	3.79%	3.80%
29-Jan-14	50.0	29-Jan-64	50.0	4.29%	4.29%

A portion of each debt issue listed above has been allocated to Hydro One Networks Inc. Distribution and Hydro One Networks Inc. Transmission

All debt listed above is public debt issued in the Canadian debt capital market

OPG:

OPG is filing its table confidentially due to commercially sensitive information. A redacted version is provided below.

List of Outstanding Debt Supporting Regulated Operations Issued since 2019($M)

Line No.	Issue	Issue Date	Term (years)	Maturity Date	Principal*	Interest Rate (%)	Type of Debt Instrument	Source of Debt	Debt issued at LDC/Holdco Level
	List of outstanding debt issued since 2019								
1	OEFC Debt	8/22/2019	20.0	8/22/2039	100.0	3.49%	Loan	OEFC Credit Facility	OPG
2	Green Bond	1/18/2019	30.0	1/18/2049	0.4	4.25%	Public Bond	Capital Market	OPG
3	Green Bond	7/18/2022	10.0	7/19/2032	297.9	4.92%	Public Bond	Capital Market	OPG
4	Green Bond	6/28/2024	10.0	6/28/2034	496.7	4.83%	Public Bond	Capital Market	OPG
5	Green Bond	6/28/2024	30.0	6/28/2054	496.2	4.99%	Public Bond	Capital Market	OPG
6	Insurance Linked Bond	1/5/2022	5.0	1/4/2027	25.0	9.19%	Insurance Linked Bond	Private Placement	OPG
7	CIB*	10/14/2022	[redacted]	[redacted]	78.0	[redacted]	Loan	CIB	OPG
8	CIB*	4/11/2023	[redacted]	[redacted]	85.0	[redacted]	Loan	CIB	OPG
9	CIB*	9/29/2023	[redacted]	[redacted]	91.0	[redacted]	Loan	CIB	OPG
10	CIB*	12/18/2023	[redacted]	[redacted]	68.0	[redacted]	Loan	CIB	OPG
11	CIB*	3/22/2024	[redacted]	[redacted]	77.0	[redacted]	Loan	CIB	OPG
12	CIB*	6/19/2024	[redacted]	[redacted]	87.0	[redacted]	Loan	CIB	OPG

*Term, Maturity Date and Interest Rate redacted for commercial sensitivity

Response to e):

Toronto Hydro:

	2019	2020	2021	2022	2023
Actual	55.1%	57.1%	57.8%	60.0%	61.5%

OPG

	2019	2020	2021	2022	2023
Actual Equity Ratio[1]	62.7%	71.2%	77.3%	78.3%	78.3%

[1] Given that OPG's regulated operations form part of OPG's overall business, and are not operated as a standalone entity, the percentages shown have been derived by adding the "Other Long-Term Debt Provision" in OPG's deemed capital structure for the regulated facilities, as shown in OPG's actual historical capitalization tables reported to the OEB, to the deemed equity.

Enbridge Gas Inc.

Enbridge Gas Inc.'s actual utility capital structure for each of 2019 – 2023 is provided in the table below.

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5 (col 1x col 3)
Line No.		Principal	Component	Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
EGI 2019 Actual Utility Capital Structure						
1.	Long and Medium-Term Debt	8,002.0	60.90	4.45	2.71	356.1
2.	Short-Term Debt	407.0	3.10	2.04	0.06	8.3
3.		8,409.0	64.00		2.77	364.4
4.	Common Equity	4,730.0	36.00	10.47	3.77	495.5
5.		13,139.0	100.00		6.54	859.9
EGI 2020 Actual Utility Capital Structure						
6.	Long and Medium-Term Debt	8,568.5	63.18	4.38	2.77	375.3
7.	Short-Term Debt	111.1	0.82	0.94	0.01	1.0
8.		8,679.7	64.00		2.78	376.3
9.	Common Equity	4,882.3	36.00	8.72	3.14	425.6
10.		13,562.0	100.00		5.91	801.9
EGI 2021 Actual Utility Capital Structure						
11.	Long and Medium-Term Debt	8,505.3	59.81	4.37	2.61	371.3
12.	Short-Term Debt	596.5	4.19	0.31	0.01	1.9
13.		9,101.8	64.00		2.63	373.2
14.	Common Equity	5,119.8	36.00	9.17	3.30	469.4

15.		14,221.6	100.00		5.93	842.6

EGI 2022 Actual Utility Capital Structure

16.	Long and Medium-Term Debt	9,049.8	58.84	4.25	2.50	384.9
17.	Short-Term Debt	794.3	5.16	2.31	0.12	18.4
18.		9,844.1	64.00		2.62	403.4
19.	Common Equity	5,537.3	36.00	9.52	3.43	526.9
20.		15,381.4	100.00		6.05	930.2

EGI 2023 Actual Utility Capital Structure

21.	Long and Medium-Term Debt	9,498.1	59.89	4.21	2.52	399.7
22.	Short-Term Debt	651.6	4.11	5.04	0.21	32.9
23.		10,149.7	64.00		2.73	432.6
24.	Common Equity	5,709.2	36.00	6.35	2.29	362.7
25.		15,858.9	100.00		5.02	795.4

Elexicon Energy:

	2019	2020	2021	2022	2023
Debt (%)	47.5%	51.8%	54.1%	57.1%	59.2%
Equity (%)	52.5%	48.2%	45.9%	42.9%	40.8%

Alectra:

Year	Actual Total Debt to Equity Ratio	Actual Equity Ratio
2023	1.24	44.7%
2022	1.21	45.3%
2021	1.13	47.0%
2020	1.20	45.4%
2019	1.16	46.4%

UCT 2

Year	Regulated Capital Structure
2022	56% LT/4% ST Debt – 40% Equity
2023	56% LT/4% ST Debt – 40% Equity
2024	56% LT/4% ST Debt – 40% Equity

Hydro One:

Hydro One Inc.	2019	2020	2021	2022	2023
Debt to capitalization ratio[1]	56.7%	55.0%	55.2%	55.1%	56.1%
Equity thickness[2]	43.3%	45.0%	44.8%	44.9%	43.9%

[1]Source: Hydro One Inc. Annual Management's Discussion and Analysis

- 2022 & 2023 pg 1 [link]
- 2020 & 2021 pg 1 [link]
- 2019 pg 1 [link]

[2]100% less Debt to capitalization ratio from preceding row

Hydro Ottawa:

Year	2019	2020	2021	2022	2023
HOL Total Debt (includes short-term and long-term debt) to Equity Ratio*	1.90	1.98	1.92	1.99	1.94
OEB Deemed Capital Structure*	1.50	1.50	1.50	1.50	1.50

*Represented using the OEB LDC scorecard format.

Ontario Energy Association (OEA)

Answer to Interrogatory from
Ontario Energy Board Staff (OEB Staff)

INTERROGATORY

Reference:

Concentric Report, pp. 152 & 155 & 156

Question(s):

Concentric agreed with LEI's recommendation for short-term DVAs (i.e., accounts that will clear within one year), but Concentric recommended that the OEB apply each utility's WACC to long-term DVAs.

Concentric suggested that long-term DVAs are balances that are to remain on utilities' balance sheets for more than one year. LEI did not differentiate between short-term and long-term DVAs.

Concentric recommended that the OEB apply the WACC to CWIP, for purposes of accruing carrying costs on construction balances. Concentric noted that from an implementation perspective, this approach is not burdensome because the WACC for each utility is readily available.

Concentric stated that the OEB's current approach to carrying charges on CWIP recognizes the long-term nature of construction projects by applying a long-term cost of debt but ignores that utilities also employ retained earnings and equity issuances to fund construction. Concentric stated that excluding the cost of equity borne by utilities during construction deprives the utilities of the opportunity to recover their full costs of financing, including the cost of equity over the life of the investment.

Concentric further stated that a long-term debt-only approach also places the Ontario utilities out of step with their U.S. and Canadian peers, placing them at a relative disadvantage in the ability to attract equity capital.

a) Please provide Concentric's views on how it would define short-term DVAs from long-term DVAs.

b) Would Concentric view all Group 1 DVAs as short-term and all Group 2 DVAs as long-term?

c) In Concentric's view, when the Group 1 DVAs are not disposed and carry more than one year's balance, do these DVAs become long-term DVAs?

d) Please provide Concentric's views on the potential increased regulatory burden on the OEB and stakeholders upon the separation of short-term DVAs from longterm DVAs.

e) Regarding Concentric's recommendations that the OEB apply each utility's WACC to long-term DVAs and CWIP, which WACC does Concentric propose to be used? For example:

   i. Regarding the balances approved for disposition in IRM proceedings, is Concentric suggesting that the WACC from the utilities' last rebasing proceeding be used?
   ii. Regarding the balances approved for disposition in cost-based proceedings, is Concentric suggesting that the WACC from the utilities' current cost-based proceeding be used?
   iii. Regarding the balances accumulated in the CWIP account and carried forward to rate base in a cost-based proceeding, is Concentric suggesting that the WACC from the utilities' last rebasing proceeding be used?

f) Please explain further why using a debt-only approach for CWIP places Ontario utilities "at a relative disadvantage in the ability to attract equity capital."

<u>Response:</u>

a) The short-term/long-term distinction relies on the length of time between when costs/customer refunds are incurred/deferred and when they are recovered from customers. Concentric considers short-term DVAs to be those for which costs are deferred and cleared within one year, with long-term DVAs being those for which the period between deferral and clearance is longer than one year. On page 153, Concentric referred to short-term DVAs as those that "cleared within one year," and clarified in footnote 168 that "DVAs that clear within one year would be those that are disposed within 12 months of the deferral of costs." From a practical perspective, Concentric believes that, where available, it would also be reasonable to use the accounting definition of short-term versus long-term, whereby short-term DVAs reported on a utility's balance sheet generally represent amounts to be cleared within 12 months of the balance sheet date and long-term DVAs generally represent amounts to be disposed of beyond one year.

b) Concentric's recommendation is based on regulatory and corporate finance principles, and the application of the WACC to DVAs is most consistent with those principles, regardless of the type or timing of the deferral. Concentric recognizes, however, that the timeframe over which a regulatory asset is accumulated and recovered is a historical consideration by the Board in assigning an appropriate carrying cost, and, as such, Concentric recommended that short-term DVAs be applied the prescribed interest rate. As such, Concentric's definition of short-term vs. long-term is not reliant on whether a DVA is a Group 1 or a Group 2 DVA.

Concentric recognizes, however, that for practical purposes few, if any, DVAs are accrued and recovered within one year. As such, under Concentric's recommendation, most, if not all DVAs would accrue carrying charges at the WACC, which would be most consistent with corporate finance and regulatory principles, as discussed in Concentric's report.

If the OEB, however, were to determine that it is appropriate to distinguish between DVAs that accrue carrying charges at the WACC versus at the prescribed interest rate, applying the prescribed interest rate to Group 1 DVAs and the WACC to Group 2 DVAs would provide a reasonable approximation of the short-term versus long-term distinction that Concentric has drawn in its report, and thus represent a reasonable alternative to Concentric's proposal. That approach, while not wholly consistent with the principles Concentric discussed in our report, would reflect better alignment with those principles as compared to the status quo.

c) See the response to part b).

d) Concentric does not believe there will be increased regulatory burden because under the status quo, utilities regularly update DVA carrying charge accruals based on changes in prescribed interest rates, changes in deferral balances, regulatory approvals or modifications, etc. Applying a different carrying charge rate to one set of DVAs versus another would only impact the inputting of the appropriate rate when determining the carrying charge amounts on that account. Both the prescribed interest rate and utility-specific WACC rates are readily available and auditable.

e) Concentric proposes that the most recently-approved WACC be used for calculating carrying charges on long-term DVAs and CWIP, and, when the WACC changes (whether through rebasing or in cost-based proceedings), that updated WACC be applied on a going-forward basis for future accruals, similar to the approach used for changes in prescribed interest rates.

f) Using a debt-only approach for CWIP places Ontario utilities at a relative disadvantage in the ability to attract equity capital because a debt-only approach puts Ontario utilities out of step with their U.S. and Canadian peers, with whom Ontario utilities compete for capital. Since a debt-only approach results in Ontario utilities not recovering their full costs of financing construction, jurisdictions that allow the accrual of financing costs at the WACC provide the opportunity to earn their actual cost of capital for financing these functions.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Question(s):

If Concentric's recommendations for capital structure and ROE were implemented for the 2025 rate year, for each of the CLD+ utilities, please provide an estimate in the increase of costs that would be recovered from customers.

Response:

The CLD Utilities have provided estimates using their most recently approved ROE and in most cases 2023 approved rate base. As Hydro Ottawa's ROE was most recently approved in 2024, the 2024 rate base was used. UCT2 utilizes a forecast 2025 rate base.

Toronto Hydro:

Using Toronto Hydro's 2023 approved rate base of $ 5,176.8M, the revenue requirement impact of adopting Concentric's recommendation for equity thickness (45% from 40%) and ROE (10% from the 2023 OEB-approved ROE of 9.36%) would be an increase of approximately $43.6M. The revenue requirement impact would be an increase in return on equity of $39.1M, the associated tax gross up of $14.1M, offset by a reduction in interest expense of $9.6M.

Enbridge Gas Inc.:

Leveraging EGI's 2023 actual rate base of $15,858.9 million to calculate cost of capital impacts, the revenue requirement impact of transitioning to an equity thickness of 45% (from 38% as was approved commencing in 2024 in EB-2022-0200) and an ROE of 10% (versus the current 2024 Board formula ROE of 9.21%) would be approximately $160 million. The revenue requirement impact would be comprised of an increase in return on equity of $159 million, plus the associated gross-up for income taxes of $57M, offset by a reduction in interest expense of $56 million.

UCT 2:

Utilizing the recommendations for capital structure and ROE, UCT 2's estimated increase in its revenue requirement is $8,005,220 (utilizing a forecast 2025 rate base and an increase in the ROE from the current 8.34% to 10%). However, this increase does not include any amount of additional risk premium that may be applied for and approved by the OEB under Concentric's proposal.

OPG:

Concentric has not recommended an ROE applicable to OPG in its report and has recommended that should OPG bring forward a proposal and evidence in its payment amounts application regarding whether and what amount of additional risk premium should be applied as part of its authorized ROE and that the OEB consider that proposal as part of that proceeding. Concentric also notes that OPG's current payment amounts are subject to the settlement agreement as part of its EB-2020-0290 proceeding, and its payment amounts should not be adjusted in the interim.

Alectra:

Using Alectra Utilities' 2023 actual rate base of $3,629.1 million to calculate cost of capital impacts, the revenue requirement impact of transitioning to an equity thickness of 45% and an ROE of 10% (increased from the current 8.95% weighted average across rate zones) would be approximately $39 million. The revenue requirement impact would be comprised of an increase in return on equity of $33 million, plus the associated gross-up for income taxes of $12M, offset by a reduction in interest expense of $6 million.

Hydro One:

Using Hydro One's OEB-approved rate base in 2023 of $23.99B, the revenue requirement impact of adopting Concentric's recommendation for equity thickness (45% from 40%) and ROE (10.0% from the 2023 OEB-approved ROE of 9.36%), would be an increase of approximately $194 million. This includes an increase in return on equity of $181 million, the associated gross-up for income taxes of $65, offset by a reduction in interest expense of $52 million.

Hydro Ottawa:

As part of Hydro Ottawa's 2024 annual update application the ROE parameter was updated. Using Hydro Ottawa's 2024 approved rate base and using the Concentric's recommended 10% return on equity (increase from the current 9.21% in rates), and using 45% equity thickness, the revenue requirement impact would be approximately $$12.7M. This includes an increase in return on equity of $11.2M, offset by a reduction in interest expense of $2.3M, plus a gross up Pils amount of $4.0M and offset Capital Stretch Factor impact of $0.2M.

Elexicon:

Using Elexicon's 2023 actual rate base of $473.8M, the revenue requirement impact of adopting Concentric's recommendation for equity thickness (from 40% to 45%) and ROE (10% from the current OEB-approved ROE of 9.43% underpinning Elexicon's rates) would be an increase of approximately $3.6M. The revenue requirement impact would be an increase in return on equity of $3.5M, the associated tax gross up of $1.2M, offset by a reduction of $1.1M in interest expense.

EB-2021-0110

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Hydro One Networks Inc. ("Hydro One") for an Order or Orders made pursuant to section 78 of the Act, approving or fixing just and reasonable rates for the transmission and distribution of electricity.

HYDRO ONE NETWORKS INC.

UPDATED ATTACHMENTS 1 AND 2

November 16, 2022

Hydro One Networks Inc.
Implementation of Decision in EB-2021-0110

Transmission Capital Structure and Return on Capital

	Hydro One Proposed					**OEB Decision Impact**					**OEB Approved**				
($ millions)	**2023**	**2024**	**2025**	**2026**	**2027**	**2023**	**2024**	**2025**	**2026**	**2027**	**2023**	**2024**	**2025**	**2026**	**2027**
Return on Rate Base															
Rate Base	$ 14,611.5	$ 15,516.6	$ 16,585.5	$ 17,602.6	$ 18,534.1	$ (77.1)	$ (174.2)	$ (314.5)	$ (454.1)	$ (594.0)	$ 14,534.4	$ 15,342.4	$ 16,271.0	$ 17,148.5	$ 17,940.2
Capital Structure:															
Third-Party long-term debt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Deemed long-term debt	56.0%	56.0%	56.0%	56.0%	56.0%	0.0%	0.0%	0.0%	0.0%	0.0%	56.0%	56.0%	56.0%	56.0%	56.0%
Short-term debt	4.0%	4.0%	4.0%	4.0%	4.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Common equity	40.0%	40.0%	40.0%	40.0%	40.0%	0.0%	0.0%	0.0%	0.0%	0.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Capital Structure:															
Third-Party long-term debt															
Deemed long-term debt	$ 8,182.5	$ 8,689.3	$ 9,287.9	$ 9,857.5	$ 10,379.1	(43.2)	(97.5)	(176.1)	(254.3)	(332.6)	$ 8,139.3	$ 8,591.7	$ 9,111.8	$ 9,603.1	$ 10,046.5
Short-term debt	584.5	620.7	663.4	704.1	741.4	(3.1)	(7.0)	(12.6)	(18.2)	(23.8)	581.4	613.7	650.8	685.9	717.6
Common equity	5,844.6	6,206.6	6,634.2	7,041.0	7,413.7	(30.9)	(69.7)	(125.8)	(181.7)	(237.6)	5,813.8	6,137.0	6,508.4	6,859.4	7,176.1
	$ 14,611.5	**$ 15,516.6**	**$ 16,585.5**	**$ 17,602.6**	**$ 18,534.1**	**(77.1)**	**(174.2)**	**(314.5)**	**(454.1)**	**(594.0)**	**$ 14,534.4**	**$ 15,342.4**	**$ 16,271.0**	**$ 17,148.5**	**$ 17,940.2**
Allowed Return:															
Third-Party long-term debt	4.04%	4.04%	4.04%	4.04%	4.04%	0.26%	0.26%	0.26%	0.26%	0.26%	4.30%	4.30%	4.30%	4.30%	4.30%
Deemed long-term debt	4.04%	4.04%	4.04%	4.04%	4.04%	0.26%	0.26%	0.26%	0.26%	0.26%	4.30%	4.30%	4.30%	4.30%	4.30%
Short-term debt	1.56%	1.56%	1.56%	1.56%	1.56%	3.23%	3.23%	3.23%	3.23%	3.23%	4.79%	4.79%	4.79%	4.79%	4.79%
Common equity	8.34%	8.34%	8.34%	8.34%	8.34%	1.02%	1.02%	1.02%	1.02%	1.02%	9.36%	9.36%	9.36%	9.36%	9.36%
Return on Capital:															
Third-Party long-term debt	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	$ -	$ -	$ -	$ -	$ -
Deemed long-term debt	$ 330.9	$ 351.3	$ 375.5	$ 398.6	$ 419.7	$ 19.3	$ 18.3	$ 16.5	$ 14.6	$ 12.6	$ 350.2	$ 369.7	$ 392.0	$ 413.2	$ 432.3
Short-term debt	$ 9.1	$ 9.7	$ 10.3	$ 11.0	$ 11.6	18.7	19.7	20.8	21.9	22.8	$ 27.8	$ 29.4	$ 31.2	$ 32.9	$ 34.4
Total return on debt	**$ 340.0**	**$ 361.0**	**$ 385.9**	**$ 409.6**	**$ 431.2**	**$ 38.1**	**$ 38.0**	**$ 37.3**	**$ 36.5**	**$ 35.4**	**$ 378.0**	**$ 399.1**	**$ 423.2**	**$ 446.0**	**$ 466.6**
Common equity	**$ 487.4**	**$ 517.6**	**$ 553.3**	**$ 587.2**	**$ 618.3**	**$ 56.7**	**$ 56.8**	**$ 55.9**	**$ 54.8**	**$ 53.4**	**$ 544.2**	**$ 574.4**	**$ 609.2**	**$ 642.0**	**$ 671.7**

Hydro One Networks Inc.
Implementation of Decision in EB-2021-0110

Distribution Capital Structure and Return on Capital

	Hydro One Proposed					OEB Decision Impact					OEB Approved				
($ millions)	**2023**	**2024**	**2025**	**2026**	**2027**	**2023**	**2024**	**2025**	**2026**	**2027**	**2023**	**2024**	**2025**	**2026**	**2027**
Return on Rate Base															
Rate Base	$ 9,394.7	$ 10,031.4	$ 10,764.2	$ 11,477.9	$ 12,104.7	$ 65.4	$ (52.4)	$ (191.7)	$ (325.3)	$ (448.9)	$ 9,460.0	$ 9,979.0	$ 10,572.5	$ 11,152.6	$ 11,655.7
Capital Structure:															
Third-Party long-term debt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Deemed long-term debt	56.0%	56.0%	56.0%	56.0%	56.0%	0.0%	0.0%	0.0%	0.0%	0.0%	56.0%	56.0%	56.0%	56.0%	56.0%
Short-term debt	4.0%	4.0%	4.0%	4.0%	4.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Common equity	40.0%	40.0%	40.0%	40.0%	40.0%	0.0%	0.0%	0.0%	0.0%	0.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Capital Structure:															
Third-Party long-term debt															
Deemed long-term debt	$ 5,261.0	$ 5,617.6	$ 6,027.9	$ 6,427.6	$ 6,778.6	36.6	(29.3)	(107.3)	(182.2)	(251.4)	$ 5,297.6	$ 5,588.3	$ 5,920.6	$ 6,245.4	$ 6,527.2
Short-term debt	375.8	401.3	430.6	459.1	484.2	2.6	(2.1)	(7.7)	(13.0)	(18.0)	378.4	399.2	422.9	446.1	466.2
Common equity	3,757.9	4,012.6	4,305.7	4,591.1	4,841.9	26.2	(21.0)	(76.7)	(130.1)	(179.6)	3,784.0	3,991.6	4,229.0	4,461.0	4,662.3
	$ 9,394.7	**$ 10,031.4**	**$ 10,764.2**	**$ 11,477.9**	**$ 12,104.7**	**65.4**	**(52.4)**	**(191.7)**	**(325.3)**	**(448.9)**	**$ 9,460.0**	**$ 9,979.0**	**$ 10,572.5**	**$ 11,152.6**	**$ 11,655.7**
Allowed Return:															
Third-Party long-term debt	4.07%	4.07%	4.07%	4.07%	4.07%	0.15%	0.15%	0.15%	0.15%	0.15%	4.22%	4.22%	4.22%	4.22%	4.22%
Deemed long-term debt	4.07%	4.07%	4.07%	4.07%	4.07%	0.15%	0.15%	0.15%	0.15%	0.15%	4.22%	4.22%	4.22%	4.22%	4.22%
Short-term debt	1.56%	1.56%	1.56%	1.56%	1.56%	3.23%	3.23%	3.23%	3.23%	3.23%	4.79%	4.79%	4.79%	4.79%	4.79%
Common equity	8.34%	8.34%	8.34%	8.34%	8.34%	1.02%	1.02%	1.02%	1.02%	1.02%	9.36%	9.36%	9.36%	9.36%	9.36%
Return on Capital:															
Third-Party long-term debt	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	$ -	$ -	$ -	$ -	$ -
Deemed long-term debt	$ 214.1	$ 228.6	$ 245.3	$ 261.6	$ 275.9	$ 9.4	$ 7.1	$ 4.5	$ 1.9	$ (0.5)	$ 223.5	$ 235.8	$ 249.8	$ 263.5	$ 275.4
Short-term debt	$ 5.9	$ 6.3	$ 6.7	$ 7.2	$ 7.6	12.3	12.9	13.5	14.2	14.8	$ 18.1	$ 19.1	$ 20.3	$ 21.4	$ 22.3
Total return on debt	**$ 220.0**	**$ 234.9**	**$ 252.0**	**$ 268.8**	**$ 283.4**	**$ 21.7**	**$ 20.0**	**$ 18.0**	**$ 16.1**	**$ 14.3**	**$ 241.6**	**$ 254.9**	**$ 270.1**	**$ 284.9**	**$ 297.7**
Common equity	**$ 313.4**	**$ 334.6**	**$ 359.1**	**$ 382.9**	**$ 403.8**	**$ 40.8**	**$ 39.0**	**$ 36.7**	**$ 34.7**	**$ 32.6**	**$ 354.2**	**$ 373.6**	**$ 395.8**	**$ 417.6**	**$ 436.4**

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.153]

Question(s):

Concentric recommends that “the Board apply the WACC to DVA balances that are to remain on utilities’ balance sheets for more than one year and retain a short-term rate for DVAs that are cleared within one year.” SEC seeks to understand how the one-year threshold would be measured.

a) As an illustrative example, if an amount is recorded in a DVA on September 1, 2024, when would the OEB need to clear the balance for the amount to attract the short-term debt rate?

b) How does Concentric’s approach work, considering the OEB’s policy for DVA accounts are generally not disposed of until after amounts are audited which results in a lag of at least one year (i.e. normally would not be recovered until January 1, 2027?

c) Does Concentric mean that the shorter-term rate is applied for DVAs cleared within one year or cleared and recovered within one year?

d) Does Concentric propose that this approach be applied to both Group 1 and Group 2 DVAs.

Response:

a) Please see the response to N-M2-21-OEB Staff-27.

b) Please see the response to N-M2-21-OEB Staff-27.

c) Please see the response to N-M2-21-OEB Staff-27.

d) Please see the response to N-M2-21-OEB Staff-27.

Ontario Energy Association (OEA)

Answer to Interrogatory from
Ontario Energy Board Staff (OEB Staff)

INTERROGATORY

Reference:

Concentric Report, Figure 19, p. 71

Question(s):

Note this interrogatory has been asked by LEI

It is common practice for Canadian regulators to approve an adjustment for flotation costs and financing flexibility, with 50 basis points being the norm.

a) Other than it being common practice, please provide the empirical basis (with examples of actual utility flotation costs) for recommending 50 basis points associated with floatation costs.

Response:

Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance of common stock, as well as price discounts and premiums. In his text, New Regulatory Finance, Dr. Roger Morin cited a 1996 study by Lee et. al., which found that the average flotation costs for regulated utilities are equal to approximately 5% of the gross proceeds of the equity issuance, with smaller issues tending to have a higher percentage.[1] This is consistent with recent research by the Enbridge Treasury team, which found that the average flotation costs for a sample of Canadian and U.S. utilities were also equal to slightly more than 5% of the gross proceeds. Based on Concentric's prior analysis of flotation costs, the empirical study cited by Dr. Morin, and the recent Enbridge analysis, our view is that flotation costs for utilities are within a range from 2% to 10%, with an average of around 5%. This can be translated into basis points of ROE by adjusting the dividend yield in the DCF model. Using this method, if f flotation costs are equal to 5% of the gross proceeds of the equity issuance, then the adjustment to ROE would be approximately 25 basis points for companies like those in Concentric's North American combined proxy group. Flotation costs at the higher end of the range (i.e., 10% of the gross proceeds), would equate to

[1] Dr. Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc. 2006, at 323.

an approximately 45 basis points adjustment. Concentric notes that the 50 basis point adjustment approved by Canadian regulators also includes financial flexibility.
In addition to an adjustment for flotation costs, Canadian regulators in most jurisdictions including Ontario have also typically included an adjustment for financial flexibility. This adjustment provides a small cushion so that the utility may continue to raise equity in challenging capital market conditions.

According to Dr. Roger Morin, utilities need the ability to attract capital even during “market breaks” because they have an ongoing obligation to serve. For that reason, he recommends providing the utility an additional allowance for financial flexibility during difficult market conditions, as follows:

> *The flotation cost allowance of 5% allows for both the direct flotation costs and market pressure component but does not contain an explicit allowance for market break.*
>
> ***
>
> *Such an allowance is desirable, however. If negative events should occur during the time period from announcement of a public issue to actual pricing, the price could fall below book value unless a sufficient margin is maintained. Compared to non-regulated companies, utilities do not possess the same latitude and discretion in accessing capital markets in view of their obligation to serve. They must access capital markets regardless of capital market conditions. Therefore, they have limited ability to time security issuances in order to avoid an adverse market break.*[2]

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[2] Dr. Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc. 2006, at 326.