Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Question(s):

Please provide Concentric's views on the recommendations and analysis contained in the expert report from Dr. Clearly on behalf of AMPCO/IGUA.

Response:

Pursuant to the OEB's August 14, 2024, letter providing guidance for the Presentation Day, Concentric will prepare a comparison and indicate areas of agreement and disagreement between the experts in that presentation which will be provided to the Registrar beforehand.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Question(s):

Please provide Concentric's views on the recommendations and analysis contained in the expert report from Nexus on behalf the EDA.

Response:

See the response to N-M2-0-SEC-28.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Question(s):

Please provide a copy of the retainer agreement and all the instructions provided to Concentric.

Response:

Please refer to pages 2-3 of the Concentric report, Exhibit M-2, Section 1B “Purpose of Report”, which contains Concentric’s mandate.

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.

This page is intentionally left blank. Due to size, this Attachment has not been included.

Please see Exhibit N-M2-0-SEC-31_Attachment 1.xlsx on the OEB's RDS.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Question(s):

Please provide copies of the documents contained in the Concentric report for the following footnotes: 3, 4, 28, 31, 129, 132, 138, 139, 146, 147, 150, 151, 152 and 162.

Response:

Please see N-M2-0-SEC-32, Attachments 1-13 for copies of the requested documents.

MORNINGSTAR | DBRS

Commentary

Losing Steam: Weakening Credit Metrics in the North American Utilities Sector

Morningstar DBRS
May 15, 2024

Contents

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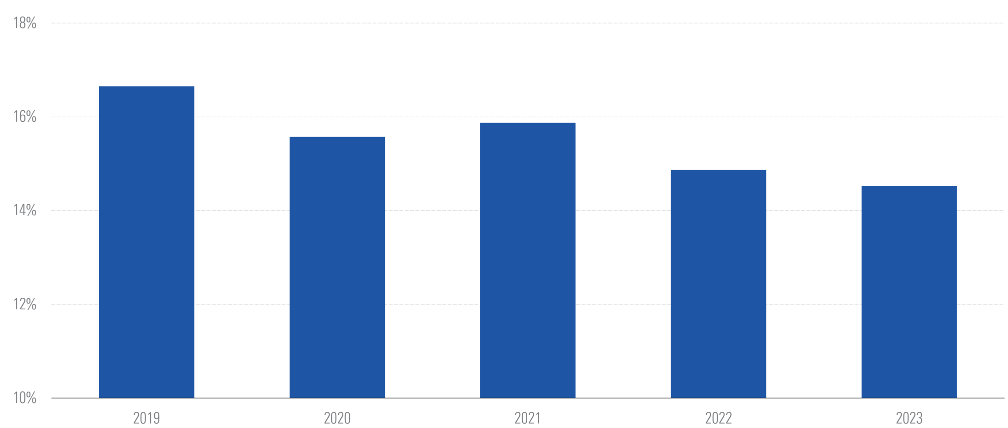
The North American utilities sector has navigated a remarkable set of macroeconomic and geopolitical challenges since the onset of the coronavirus pandemic in 2020. While the industry has demonstrated resilience in weathering these turbulent conditions, there are signs of an overall weakening in credit metrics across the sector and within our portfolio of rated issuers, largely driven by regulatory lag, significant capital needs, and macroeconomic pressures. As the chart below illustrates over the past five years the key cash flow to debt ratio on average for our rated issuers in the utilities sector has weakened from 16.6% in 2019 to 14.6% in 2023. The data for Exhibit 1 is based on a sample set of 31 of our rated issuers in the Utilities sector.

Exhibit 1 North American Utilities Cash Flow to Debt in Decline



Source: Morningstar DBRS
* The chart shows average cash flow/adjusted debt of North American gas and electric utilities rated by Morningstar DBRS.

Lagging Authorized Return of Equity

The regulatory process for updating the authorized Return of Equity (ROE) often moves slowly. Despite significant jumps in interest rates and inflation, the average authorized ROE for Canadian electric and gas utilities have seen a minimal increase (9.17% in 2023 from 8.77% in 2020). A similar situation is playing out for U.S. utilities, though their baseline ROEs tend to be higher than in Canada.

In North America, most rate designs and regulatory frameworks are structured to provide a stable, predictable ROE over time, rather than allowing the ROE to fluctuate with market conditions. ROE stability allows utilities to generate stable and predictable cash flows. However, at the same time, it can constrain the ability to promptly adjust returns in the event of upward pressure on ROE. Furthermore, as regulators seek to balance utility investment needs and consumer affordability because of the current economic condition, this often exerts downward pressure on the ROE. Having a relatively low ROE compared with the actual cost of capital can directly impact credit metrics.

Rising Capital Expenditure Requirements

The industry's ongoing allocation of substantial capital toward initiatives such as climate adaptation, modernization, and energy transition has reached unprecedented levels, with many utilities rolling out capital expenditure (capex) programs that are 10% to 20% greater compared with previous cycles. These investments have led, in many cases, to net free cash flow deficits and the need for funding.

We also note state-owned utilities, in particular, lack the access to equity markets because of their ownership structures, and are thus more reliant on debt financing for their capex needs. We anticipate the trend of elevated capex and reliance on debt financing will likely persist over the longer term, further adding stress on the sector's financial leverage ratios. Credit metrics are likely to weaken for companies that cannot maintain actual capital in-line with the approved regulatory capital structure.

Macroeconomic Pressures

Macroeconomic pressures related to inflation, interest rates, and bad debt write-offs from affordability concerns continue to have an impact on the credit profiles for utilities. The slower-than-expected moderation in inflation has resulted in revenue shortfalls for a number of utilities because of a lag in incorporating up-to-date inflation factors in rate case submissions. Without mechanisms in place for interim rate adjustments or timely regulatory approvals, some utilities may struggle to cover increasing costs over an extended period.

Furthermore, we have seen increasing accounts receivable collection periods and write-offs for some utilities since 2020. These pressures, combined with uncertainty around high interest rates, have driven up working capital requirements, contributing to greater utilization of credit facilities by utilities. Liquidity constraints could leave utilities more exposed to unexpected costs such as project cost overruns, extreme weather damage, and commodity price shocks if they cannot be passed through in a timely manner.

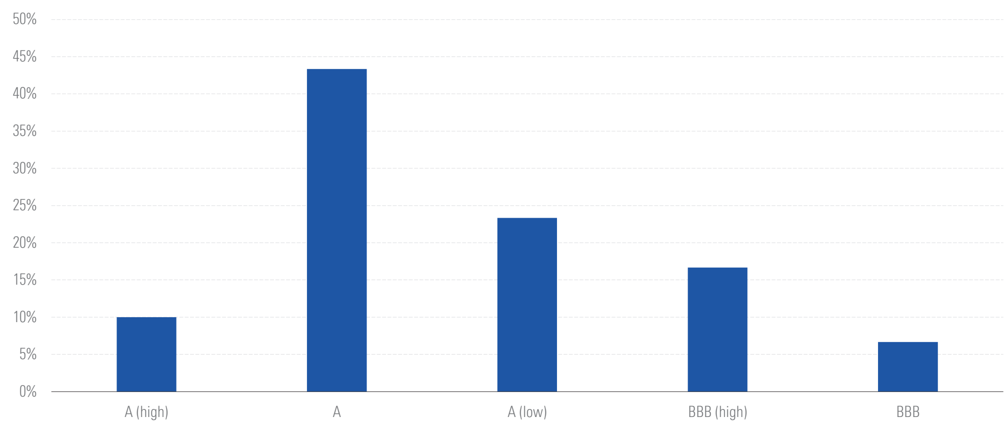
Some Relief in Sight

Despite these headwinds, there are some relief measures on the horizon for the utilities sector: (1) regulatory frameworks remain stable, providing utilities with a predictable operating environment without any material changes expected; (2) stabilizing or even declining interest rates could ease the cost of borrowing; (3) utilities in many jurisdictions are finally rebasing with their actual costs, in part by the significant rate base built over the past few years, which should help offset rising costs; and (4) government initiatives and subsidies aimed at supporting electrification and grid upgrades are expected to offset some of the capex burdens.

Conclusion

Among all the gas and electric utilities we rate, the average cash flow to debt ratio stands at approximately 15%, which is consistent with the sector's "A" rating category (see Exhibit 2 for the distribution of our rated North American Utilities). Nonetheless, factors such as regulatory lag, elevated capex, and macroeconomic pressures have collectively weakened the sector's credit metrics. About 33% of our rated utilities have minimal financial cushions in the "A" rating category and could become more susceptible to negative rating actions. We anticipate most of these companies will be able to maintain their bottom line and benefit from some potential tailwinds, allowing them to sustain their credit metrics in the near to medium term.

Exhibit 2 Rating distribution of North American Utilities



Source: Morningstar DBRS.

About Morningstar DBRS
Morningstar DBRS is a full-service global credit ratings business with approximately 700 employees around the world. We're a market leader in Canada, and in multiple asset classes across the U.S. and Europe.

We rate more than 4,000 issuers and nearly 60,000 securities worldwide, providing independent credit ratings for financial institutions, corporate and sovereign entities, and structured finance products and instruments. Market innovators choose to work with us because of our agility, transparency, and tech-forward approach.

Morningstar DBRS is empowering investor success as the go-to source for independent credit ratings. And we are bringing transparency, responsiveness, and leading-edge technology to the industry.

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19 Apr, 2023

Utility execs prepare for 'tripling' of electricity demand by 2050

Author **Darren Sweeney**
Theme **Energy**

As policies and economics combine to push the nation toward full decarbonization, the heads of two large US investor-owned utilities predict a significant increase in electricity demand.

Xcel Energy Inc. Chairman, President and CEO Bob Frenzel and Entergy Corp. Chairman and CEO Drew Marsh both acknowledged a potential "tripling" of electricity demand by 2050.

"Everything is going to need to electrify in some way," Marsh said during an executive roundtable April 18 at the Platts Global Power Markets Conference in Las Vegas.

New Orleans-headquartered Ente … d X Energy also are among the energy … lo such as hydrogen and energy storage, as they navigate the decarbonization of the economy.

The executives pointed out the potential to utilize assets and infrastructure in place today to help ease the transition. "A lot of the opportunity is built off the foundation that already existed," Marsh said.

Frenzel said it is important to "clean up" the nation's existing electric system through investing in hydrogen and other carbon-free fuels as part of the process of pursuing electrification.

"I do believe there is real value in the pursuit of the clean molecule," Frenzel said, adding that direct air capture technology will likely rely on a significant amount of wind and solar generation.

Xcel Energy in late January entered into a partnership with Form Energy Inc. to build long-duration storage projects at two of the utility's coal plants in Minnesota and Colorado that are to be retired. The 10-MW, multiday iron-air batteries are scheduled to be connected in 2025.

In addition, Xcel Energy has received a $12 million grant from the US Energy Department to pilot high-temperature hydrogen production using excess steam and electric power from its 1,092-MW Prairie Island nuclear plant in Minnesota.

The Inflation Reduction Act (IRA) of 2022 also opens up new avenues for cleaner growth, the executives said. The IRA contains $370 billion in energy climate spending, including about $270 billion in tax incentives for solar, wind, hydrogen and energy storage projects.

Companies, however, are seeking more certainty around how to qualify and take advantage of the tax provisions in the new law. In addition, utilities face permitting challenges when it comes to building out the infrastructure needed to support a cleaner energy future.

"That is a tough nut to crack [but] we do need to crack it," Marsh said.

Balancing act

The CEOs also pointed out the importance of balancing reliability and affordability when working to achieve sustainability.

"You can't sacrifice the first two legs of the stool for the third," Marsh said.

"We are in a different world today from an electricity perspective," he added. "The cost to society of not having electricity is a lot bigger."

Entergy plans to add as much as 17 GW of renewable resources by the end of 2031 as part of its goal of reaching net-zero carbon emissions by 2050.

Certain technologies, such as batteries, are seen as complementing this transition but may not achieve the scale needed for balancing the grid.

"The scale of what we are talking about across the country is enormous," Marsh said, adding "there is a place for batteries," but other resources will need to support the system.

As an example, Entergy has announced plans to explore offshore wind potential in the Gulf of Mexico.

Xcel Energy has been "preserving our gas fleet" as it shuts down coal plants and targets cutting carbon emissions 80% by 2030, Frenzel said. The company does see opportunities in long-duration storage as it eventually moves away from traditional gas-fired generation and hits carbon-free power by 2050.

"There are lots of tools in the tool chest and as a company we are focused on utilizing all of it," Frenzel said.

S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro.

S&P GLOBAL — 24 Feb, 2020

What is Energy Transition?

Theme **ESG**
Tags **Global**

HIGHLIGHTS

Energy transition refers to the global energy sector's shift from fossil-based systems of energy production and consumption — including oil, natural gas and coal — to renewable energy sources like wind and solar, as well as lithium-ion batteries.

The increasing penetration of renewable energy into the energy supply mix, the onset of electrification and improvements in energy storage are all key drivers of the energy transition.

Regulation and commitment to decarbonization has been mixed, but the energy transition will continue to increase in importance as investors prioritize environmental, social and governance (ESG) factors.

As more investors and companies seek greater clarity and confidence in accounting for long-term **climate risks and opportunities**, businesses are adapting to the "energy transition" — a transformation of the global energy sector from fossil-based systems of energy production and consumption to renewable energy sources. Switching from nonrenewable energy sources like oil, natural gas, and coal to renewable energy is made possible by technological advancements and a societal push toward sustainability. Spurred by structural, permanent changes to energy supply, demand, and prices, the energy transition also aims to reduce energy-related greenhouse gas emissions through various forms of **decarbonization**.

After years of depending on regulation for growth in the sector, renewable energy sources have become a powerful and cost-effective source of electricity. The costs of both solar and wind have fallen so drastically that in some regions of the **U.S.**, as well as in the **U.K. and Europe**, wind power has become cheaper than traditional high-carbon energy resources. As costs continue to fall and wind and solar become mainstream, the renewable energy sector will only keep growing and solidify as a strong investment opportunity.

The International Energy Agency forecasts the world's total renewable-based power capacity to increase 50% between 2019 and 2024. In response to this shift, utilities have begun a rapid energy transition **away from coal**. While some market observers expect that transition to slow, pressure is mounting on **power generators to retire** existing assets that depend on coal supplies and build out other forms of power generation. Many major oil companies are **accelerating spending** on and **diversifying** into renewable and low carbon energy in response to growing concerns over climate change. As the movement continues to expand, **S&P Global's ESG Solutions** provide a holistic perspective on the energy transition.

Although federal subsidies for wind and solar energy are set to expire, the demand for renewable energy, **driven primarily by corporations'** large-scale renewable energy purchases, will likely remain high. The corporate renewables market is expected to continue to grow in 2019 after more than doubling the previous peak of annual corporate renewable capacity since

2015. Demand has already been secured through initiatives such as the **RE100 coalition**, under which large companies have committed to source 100% of their power from renewable sources, and the Renewable Energy Buyers Alliance, which was launched by **over 300 companies** including Facebook Inc., Google LLC, Walmart Inc., and General Motors Co.

Generating power from renewables is only part of the energy transition. Mass introduction of **electric transportation infrastructure** and energy storage, coupled with greater usage of technologies to improve energy efficiency, are also driving this movement. As the average cost of **lithium-ion batteries** has fallen drastically on a mixture of manufacturing economies of scale and technology improvements, companies and consumers alike are increasingly turning to electrification for power transportation, making the transition to electric vehicles (EVs) one of the largest potential areas for electrification. The **global EV adoption rate** could reach 10%-12.5% by 2025.

Another central factor for renewable energy and electrification (and the energy transition overall) is renewable energy storage, which could solve the production problems many renewable energy technologies face. Though long seen as the missing link between intermittent renewable power and constant reliability, energy storage has begun playing a broader role in the energy transition, with the potential to enable the eventual decarbonization of energy systems. As costs fall, renewable energy storage has the potential for broad use beyond the niche markets in which it is currently employed. Some commercial uses for **energy storage** are already more economical.

Global regulatory structures in the realm of energy transition have been fairly uneven. In Europe, regulators have taken a leading role in pushing toward a a review on how to reach the **carbon-neutral economy** by launching **EU's net-zero greenhouse gas emissions** target for 2050. Many EU countries have been outspoken about their energy and electrification priorities by publicly setting **related targets.** Led in large part by China, **emerging economies** are also trying to determine how to increase energy access and sustain development while also transitioning toward cleaner energy sources. In the U.S., there is growing political momentum around lower greenhouse gas-emitting power generation and a clean energy economy.

Together, almost 200 nations have committed to curbing global warming by substantially reducing greenhouse gas emissions; however, the fulfillment of those commitments has varied. Regulation and commitment have been uneven across the global economy, with some nations continuing to grow their emissions despite promises of further decarbonization.

Accounting for the various components of the energy transition and evaluating companies' preparedness for this shift requires ESG-centric tools. S&P Global's **S&P 500 ESG Index**, **Risk Atlas** and **ESG Evaluations**, among other ESG solutions, provide investors with the essential intelligence needed to better understand the risks and opportunities related to the energy transition and environmental risk. Overall, the energy transition is central to ESG investing by pushing toward a carbon-neutral economy.

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY
13 April 2022

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Rating Methodology

Regulated Electric and Gas Networks

This rating methodology replaces the *Regulated Electric and Gas Networks* methodology published in March 2017. We have differentiated the Leverage and Coverage sub-factors for project-financed and corporate issuers. We have also reordered and have made editorial updates to various sections of the methodology, and we have changed the presentation of the scorecard.

Scope

This methodology applies to companies globally that are primarily* engaged in the transmission or distribution of electricity or natural gas or both. The companies rated using this methodology provide their services primarily to non-retail customers. They operate as monopolies within their service territory with tariffs regulated at the regional, national or sovereign level. This methodology also applies to oil pipelines that are national monopoly businesses and that are subject to tariff regulation.

Transmission companies rated using this methodology are engaged in the high-voltage/ high-pressure transportation of electricity and gas. Distribution companies rated using this methodology provide low-voltage/low-pressure transportation of electricity and gas.

Regulated electric and gas networks, which we also refer to as regulated networks, predominantly operate infrastructure assets with no significant ownership of upstream activities, e.g., electricity generation or gas production, or downstream activities. While they may physically transmit electricity or gas to end-users on behalf of retail energy suppliers, regulated networks are generally not responsible for providing utility services to the final consumer. Instead, the customers of regulated networks are other energy companies, including retail energy suppliers, which procure electricity and gas on behalf of the end consumer and are themselves responsible for providing utility services, including billing and metering. As monopolies, the charges that networks can levy are determined by a regulatory authority at the regional, national or sovereign level, with tariffs typically reviewed periodically.

While many companies rated using this methodology are regulated networks financed on a corporate basis, this methodology also applies to project-financed entities that are primarily

*The determination of a company's primary business is generally based on the preponderance of the company's business risks, which are usually proportionate to the company's revenues, earnings and cash flows.

engaged in the ownership and operation of electric and gas network infrastructure and whose debt fully amortizes by its final legal maturity date.

Companies that are engaged in the transmission or distribution of electricity or natural gas or both but that also provide regulated utility services to a retail customer base; that, in many cases, also own regulated electricity generation assets are rated using our regulated electric and gas utilities methodology. Unregulated utilities and power companies, US public power utilities with generation ownership (including US municipal utilities) and US electric generation and transmission cooperatives are rated using separate methodologies. Natural gas pipeline owners and operators that typically do not hold a monopoly franchise, could be subject to some competition, and whose revenues are determined primarily by commercial contracts, albeit with some regulatory oversight, are rated using our natural gas pipelines methodology.[1]

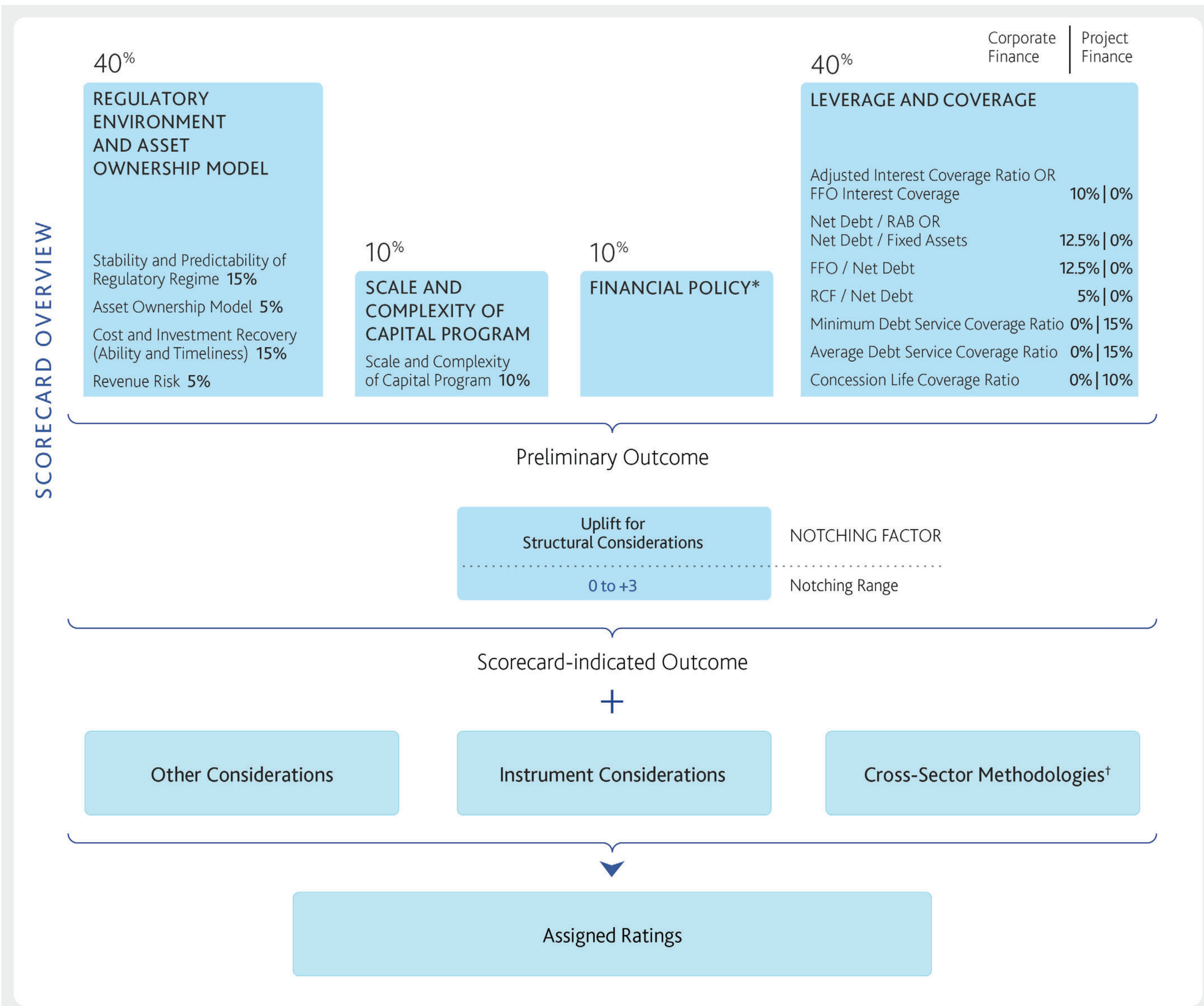
Rating approach

In this rating methodology, we explain our general approach to assessing credit risk of issuers in the regulated electric and gas network sector globally, including the qualitative and quantitative factors that are likely to affect rating outcomes in this sector. We seek to incorporate all material credit considerations in ratings and to take the most forward-looking perspective that visibility into these risks and mitigants permits.

The following schematic illustrates our general framework for the analysis of regulated electric and gas networks, which includes the use of a scorecard.[2] The scorecard-indicated outcome is not expected to match the actual rating for each company. For more information, see the "Other considerations" and "Limitations" sections.

Exhibit

Illustration of the regulated electric and gas networks methodology framework



* This factor has no sub-factors.

† Some of the methodological considerations described in one or more cross-sector rating methodologies may be relevant to ratings in this sector. A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

Source: Moody's Investors Service

Regulated electric and gas networks scorecard

For general information about how we use the scorecard and for a discussion of scorecard mechanics, please see the "Using the scorecard to arrive at a scorecard-indicated outcome" section. The scorecard does not include or address every factor that a rating committee may consider in assigning ratings in this sector. Please see the "Other considerations" and "Limitations" sections.

Exhibit 2

Regulated electric and gas networks scorecard

	REGULATORY ENVIRONMENT AND ASSET OWNERSHIP MODEL (40%)				SCALE AND COMPLEXITY OF CAPITAL PROGRAM (10%)	FINANCIAL POLICY (10%)	LEVERAGE AND COVERAGE (40%)								
							Corporate Issuers						Project-financed Issuers		
	Stability and Predictability of Regulatory Regime (15%)	Asset Ownership Model (5%)	Cost and Investment Recovery (Ability and Timeliness) (15%)	Revenue Risk (5%)	Scale and Complexity of Capital Program (10%)	Financial Policy (10%)	Adjusted Interest Coverage Ratio (3-Year Avg)	OR (10%)	FFO Interest Coverage (3-Year Avg)	Net Debt / RAB OR Net Debt / Fixed Assets (3-Year Avg) (12.5%)	FFO / Net Debt (3-Year Avg)[1] (12.5%)	RCF / Net Debt (3-Year Avg)[2] (5%)	Minimum Debt Service Coverage Ratio (15%)	Average Debt Service Coverage Ratio (15%)	Concession Life Coverage Ratio (10%)
Aaa	Regulation is independent, well established (> 15 years of being predictable and stable) and transparent (well-established regulatory principles clearly define risk allocation between companies and customers and are consistently applied, with public or shared financial models). These conditions are expected to continue.	All key T&D assets held outright in perpetuity AND no risk that a change in ownership would negatively affect creditor rights.	No regulatory or contractual impediment to adjust tariffs (no approval or reviews required).	No exposure to volume risk. Collected revenues based on capacity charges.	Capex program is extremely limited in scale, reflecting a modern, highly developed asset base that requires only simple maintenance expenditure (e.g. total annual capex < 4% of total fixed assets or regulated asset base).	Long track record and expected maintenance of extremely conservative financial policy; very stable metrics; low debt levels for the industry; AND Public commitment to the highest credit quality over the long-term.	≥ 5.5x		≥ 7.5x	< 30%	≥ 35%	≥ 30%	≥ 3.00x	≥ 3.00x	≥ 4.50x
Aa	Regulation is independent, well established (> 10 years of being predictable and stable) and transparent (well-established regulatory principles clearly define risk allocation between companies and customers and are generally consistently applied). These conditions are expected to continue.	All key T&D assets held outright under licence which can be terminated for underperformance, failure to meet certain financial parameters or insolvency OR held under long term concession with clearly defined right to timely recovery of residual asset value at termination/end of concession underpinned by highly rated entity AND no risk that a change in ownership would negatively affect creditor rights.	Tariff formula is expected to allow for timely recovery of operating expenditure including depreciation, electricity losses and balancing costs/shrinkage gas and a fair return on all investment. All capital expenditure is included in asset base as incurred. Unanticipated expenditure quickly reflected in allowed revenue with low, if any, efficiency assessment.	Very low exposure to volume risk. Collected revenues based on volume charges with stable volumes expected. Revenue cap mechanism with timely recovery in place.	Capex program is limited in scale, reflecting a well developed asset base that requires only maintenance expenditure (e.g. total annual capex is 4-6% of total fixed assets or regulated asset base).	Long track record and expected maintenance of a conservative financial policy; stable metrics; lower than average debt levels for the industry; AND Public commitment to a very high credit quality over the long-term.	3.5x - 5.5x		5.5x - 7.5x	30% - 45%	26% - 35%	21% - 30%	1.55x - 3.00x	2.00x - 3.00x	3.00x - 4.50x

	REGULATORY ENVIRONMENT AND ASSET OWNERSHIP MODEL (40%)				SCALE AND COMPLEXITY OF CAPITAL PROGRAM (10%)	FINANCIAL POLICY (10%)	LEVERAGE AND COVERAGE (40%)								
							Corporate Issuers						Project-financed Issuers		
	Stability and Predictability of Regulatory Regime (15%)	Asset Ownership Model (5%)	Cost and Investment Recovery (Ability and Timeliness) (15%)	Revenue Risk (5%)	Scale and Complexity of Capital Program (10%)	Financial Policy (10%)	Adjusted Interest Coverage Ratio (3-Year Avg)	OR (10%)	FFO Interest Coverage (3-Year Avg)	Net Debt / RAB OR Net Debt / Fixed Assets (3-Year Avg) (12.5%)	FFO / Net Debt (3-Year Avg)[1] (12.5%)	RCF / Net Debt (3-Year Avg)[2] (5%)	Minimum Debt Service Coverage Ratio (15%)	Average Debt Service Coverage Ratio (15%)	Concession Life Coverage Ratio (10%)
A	Regulation is generally independent and developed (regulatory principles define risk allocation between companies and customers and are based on established precedents in the same jurisdiction). These conditions are expected to continue.	All key T&D assets held under long-term concession with clearly defined right to recover value of residual assets at termination/end of concession underpinned by highly rated entity but with undefined timeframe OR held under medium/long-term operating leases or management contracts with very substantial portfolio diversification, very established market position and very high renewal rate (>95%) AND no risk that a change in ownership would negatively affect creditor rights.	Tariff formula is expected to allow for recovery of operating expenditure including depreciation based on allowances set at frequent price reviews (5-yearly intervals or shorter) and a fair return on all efficient investment. Capital expenditure is included in asset base as incurred. Opex and capex subject to efficiency tests; electricity losses and balancing costs/shrinkage gas subject to efficiency test on volumes only (price is a pass through). Unanticipated expenditure generally quickly reflected in allowed revenue although this may not be until the following regulatory period and may be subject to a degree of regulatory scrutiny or sharing factor with customers. Performance is likely to be in line with regulatory expectations.	Limited exposure to volume risk. Collected revenues based on volume charges with some volatility in volumes expected. Revenue cap mechanism in place; OR Hybrid price/revenue cap with low volatility in volumes.	Capex program is modest in size, reflecting a well developed asset base. Expenditure primarily relates to maintenance although some projects may be larger (e.g. total annual capex is 6-8% of total fixed assets or regulated asset base) or more complicated.	Extended track record and expected maintenance of a conservative financial policy; moderate debt leverage and a balance between shareholders and creditors; Not likely to increase shareholder distributions and/or make acquisitions which could lead to a weaker credit profile; Solid commitment to high credit quality.	2.0x - 3.5x		4.0x - 5.5x	45% - 60%	18% - 26%	14% - 21%	1.35x - 1.55x	1.50x - 2.00x	2.00x - 3.00x

	REGULATORY ENVIRONMENT AND ASSET OWNERSHIP MODEL (40%)				SCALE AND COMPLEXITY OF CAPITAL PROGRAM (10%)	FINANCIAL POLICY (10%)	LEVERAGE AND COVERAGE (40%)								
							Corporate Issuers						Project-financed Issuers		
	Stability and Predictability of Regulatory Regime (15%)	Asset Ownership Model (5%)	Cost and Investment Recovery (Ability and Timeliness) (15%)	Revenue Risk (5%)	Scale and Complexity of Capital Program (10%)	Financial Policy (10%)	Adjusted Interest Coverage Ratio (3-Year Avg)	OR (10%)	FFO Interest Coverage (3-Year Avg)	Net Debt / RAB OR Net Debt / Fixed Assets (3-Year Avg) (12.5%)	FFO / Net Debt (3-Year Avg)[1] (12.5%)	RCF / Net Debt (3-Year Avg)[2] (5%)	Minimum Debt Service Coverage Ratio (15%)	Average Debt Service Coverage Ratio (15%)	Concession Life Coverage Ratio (10%)
Baa	Regulatory framework is relatively new and untested, although regulatory principles are based on established precedents. Jurisdiction has a history of independent and transparent regulation for other utility services. These conditions are expected to continue.	All key T&D assets held under long-term concession with some entitlement to recover value of residual assets at termination/end of concession but procedures untested/undefined OR held under medium-term operating leases or management contracts with substantial portfolio diversification, established market position and high renewal rate (>90%) AND/OR jurisdiction has reasonably strong property rights although there is some, albeit low risk a that a change in ownership would negatively affect creditor rights.	Tariff formula is expected to allow for recovery of operating expenditure including depreciation and return on investment but subject to retrospective regulatory approval or infrequent price reviews (> 5-yearly intervals); recovery of electricity losses and balancing costs/shrinkage gas is somewhat exposed to price. Some instances of revenue backloading expected (e.g. depreciation allowance set below asset consumption or operating expenditure is capitalized). Unanticipated expenditure slow to be reflected in allowed revenue or may be subject to a stringent efficiency assessment / low sharing factor. Performance may be below regulatory expectations.	Moderate exposure to volume risk. Hybrid price/revenue cap with moderate volatility in volumes; OR Some reliance on connection revenues.	Capex program is manageable in size (e.g. total annual capex is 8-12% of total fixed assets or regulated asset base) or is generally straightforward (expenditure consists of a combination of replacement plus a number of development projects albeit with limited execution risk).	Track record and expected maintenance of a conservative financial policy; an average level of debt for the industry and a balance between shareholders and creditors; Some risk that shareholder distributions and/or acquisitions could lead to a weaker credit profile; Solid commitment to targeted metrics.	1.4x - 2.0x		2.8x - 4.0x	60% - 75%	11% - 18%	7% - 14%	1.20x - 1.35x	1.30x - 1.50x	1.35x - 2.00x

	REGULATORY ENVIRONMENT AND ASSET OWNERSHIP MODEL (40%)				SCALE AND COMPLEXITY OF CAPITAL PROGRAM (10%)	FINANCIAL POLICY (10%)	LEVERAGE AND COVERAGE (40%)								
							Corporate Issuers						Project-financed Issuers		
	Stability and Predictability of Regulatory Regime (15%)	Asset Ownership Model (5%)	Cost and Investment Recovery (Ability and Timeliness) (15%)	Revenue Risk (5%)	Scale and Complexity of Capital Program (10%)	Financial Policy (10%)	Adjusted Interest Coverage Ratio (3-Year Avg)	OR (10%)	FFO Interest Coverage (3-Year Avg)	Net Debt / RAB OR Net Debt / Fixed Assets (3-Year Avg) (12.5%)	FFO / Net Debt (3-Year Avg)[1] (12.5%)	RCF / Net Debt (3-Year Avg)[2] (5%)	Minimum Debt Service Coverage Ratio (15%)	Average Debt Service Coverage Ratio (15%)	Concession Life Coverage Ratio (10%)
Ba	Regulatory framework is defined but not consistently applied; tariff setting is subject to negotiation and political interference; some precedents in the country of predictable regulation for other utility services. These conditions are expected to continue.	All key T&D assets held under concession with recovery of residual asset value at termination/end of concession subject to negotiation OR held under short-term operating leases or management contracts with good degree of portfolio diversification and renewal rate (>80%) AND/OR jurisdiction may have some laws detailing property rights although these may be untested. A change of ownership would likely result in a loss for creditors.	Tariff formula is not expected to take into account all cost components and depreciation is set below asset consumption; recovery of electricity losses and balancing costs/shrinkage gas has large exposure to price. Revenues expected to cover most operating expenditure but investment is not clearly or fairly remunerated. Overspend either not recognized in allowed revenue or there is high uncertainty about its future recognition. Operational underperformance likely to be significantly impacting the returns achieved by the business.	Material exposure to volume risk: price cap with significant volatility in volumes; OR Material reliance on connection revenues.	Capex program is large in size (e.g. total annual capex is 12-20% of total fixed assets or regulated asset base) or is challenging in scope (small number of large and complex development projects account for the majority of capital expenditure and carry a degree of execution risk). Obligation to invest poses a financing challenge.	Track record or expectation of maintenance of a financial policy that is likely to favour shareholders over creditors; higher than average, but not excessive, level of leverage; Owners are likely to focus on extracting distributions and acquisitions but not at the expense of financial stability.	1.1x - 1.4x		1.8x - 2.8x	75% - 90%	5% - 11%	1% - 7%	1.10x - 1.20x	1.15x - 1.30x	1.20x - 1.35x
B	Regulatory framework is unclear, untested or undergoing significant change, with a history of political interference. These conditions are expected to continue.	Key T&D assets held under short-term operating leases or management contracts (limited portfolio diversification) with limited clarity on renewal and/or compensation AND/OR probability of termination / expropriation is elevated. Compensation likely to be minimal and could be subject to significant delays in payment.	Tariff formula is not expected to take into account all cost components and depreciation is set below asset consumption; recovery of electricity losses and balancing costs/shrinkage gas is fully exposed to price. Revenues expected to cover cash operating expenditure.	High exposure to volume risk: price cap with substantial volatility in volumes; OR Very high reliance on connection revenues.	Capex program is very large in size (e.g. total annual capex is 20-30% of total fixed assets or regulated asset base) or highly complex in scope (one large or complex project accounts for majority of expenditure and carries a high execution risk). Capex obligation likely to pose a significant financing challenge.	Track record of aggressive financial policies or expected to have a financial policy that favours shareholders through high levels of leverage with only a modest cushion for creditors; OR High financial risk resulting from shareholder distributions or acquisitions.	0.9x - 1.1x		1.1x - 1.8x	90% - 100%	0% - 5%	(4%) - 1%	1.00x - 1.10x	1.00x - 1.15x	1.10x - 1.20x

	REGULATORY ENVIRONMENT AND ASSET OWNERSHIP MODEL (40%)				SCALE AND COMPLEXITY OF CAPITAL PROGRAM (10%)	FINANCIAL POLICY (10%)	LEVERAGE AND COVERAGE (40%)								
							Corporate Issuers						Project-financed Issuers		
	Stability and Predictability of Regulatory Regime	Asset Ownership Model	Cost and Investment Recovery (Ability and Timeliness)	Revenue Risk	Scale and Complexity of Capital Program	Financial Policy	Adjusted Interest Coverage Ratio (3-Year Avg)	OR	FFO Interest Coverage (3-Year Avg)	Net Debt / RAB OR Net Debt / Fixed Assets (3-Year Avg)	FFO / Net Debt (3-Year Avg)[1]	RCF / Net Debt (3-Year Avg)[2]	Minimum Debt Service Coverage Ratio	Average Debt Service Coverage Ratio	Concession Life Coverage Ratio
Caa	Regulatory framework is not defined, is unpredictable or politically driven with significant adverse consequences for the utility. These conditions are expected to continue.	Company is in default of its licence, concession or lease/contract and is likely to lead to termination AND/OR expropriation very likely, no prospect of compensation.	Revenues expected to only partially cover cash operating costs.	Very high exposure to volume risk: price cap with high concentration of volumes to one particular customer or sector; OR Revenues mainly driven by connections.	Capex program is extremely large in size (e.g. total annual capex is ≥ 30% total fixed assets or regulated asset base) or is highly technically complex (one or more large projects account for the majority of expenditure and together carry a very high execution risk). Capex obligation likely to undermine the ongoing financial stability of the company.	Expected to have a financial policy unfavourable to creditors with a track record of or expected policy of maintaining excessively high debt leverage; OR Elevated risk of debt restructuring.	< 0.9x		< 1.1x	≥ 100%	< 0%	< (4%)	< 1.00x	< 1.00x	< 1.10x

Notching Factor
Uplift for Structural Considerations
(0 to +3 notches)

[1] When net debt is negative and FFO is positive, the score is Aaa. When net debt is negative and FFO is negative, the score is B.
[2] When net debt is negative and RCF is positive, the score is Aaa. When net debt is negative and RCF is negative, the score is B.
Source: Moody's Investors Service

Discussion of the scorecard factors

In this section, we explain our general approach for scoring each scorecard factor or sub-factor, and we describe why they are meaningful as credit indicators.

Factor: Regulatory Environment and Asset Ownership Model (40% weight)

Why it matters

A regulated electric and gas network's regulatory environment and its asset ownership model greatly influence the stability and predictability of its cash flows.

As monopoly providers of essential transmission and distribution services, electric and gas networks are regulated, i.e., their revenues (or tariffs) are subject to price control limits that are typically reset periodically. Price-setting mechanisms are generally structured to limit volatility and tend to be highly predictable. In addition to price-setting, there are a number of ways that regulatory decisions can affect a network's business position, including a regulator's ability to agree on a capital expenditure program or to set efficiency targets to reduce operating costs. The ability to recover prudently incurred costs in a timely manner is extremely important because a delay in cost recovery may cause financial stress. Therefore, the predictability and supportiveness of the regulatory framework in which a network operates, as well as the legal and political framework that underpins it, are key credit considerations.

The asset ownership model of one network can be significantly different from other networks serving similar regions (in terms of size or population) elsewhere in the world. The nature of the ownership of the network and/or the rights to charge customers for its use can vary from full ownership and control of all key assets, through some form of concession arrangement, to a short-term lease or license arrangement that can be terminated relatively easily by the regulator or the licensing authority, hence giving only a short period to benefit from the revenue capacity of the network. Termination risk may be further elevated in jurisdictions where there is an increased likelihood of expropriation, or where the laws detailing property rights are weaker or less established. The ability of a company to sell, if necessary, its network without constraint is also a key consideration and allows substantial operational and capital flexibility. This is most easily achieved where assets are owned outright in jurisdictions with strong property rights.

How we assess it for the scorecard

Scoring for this factor is based on four sub-factors: Stability and Predictability of Regulatory Regime; Asset Ownership Model; Cost and Investment Recovery (Ability and Timeliness); and Revenue Risk.

STABILITY AND PREDICTABILITY OF REGULATORY REGIME:

We consider the characteristics of the regulatory environment in which a network operates. These include how developed and transparent the regulatory framework is; the strength of the political and legal underpinnings of the regulatory framework; the regulator's track record for predictability and stability in terms of decision making; its independence from political interference; and our forward-looking view of these conditions. In addition, we also consider the effectiveness of the independent body or legal system that can arbitrate disputes between a regulator and a regulated company in a timely fashion.

A network operating in a stable, reliable and highly predictable regulatory environment typically receives a higher score for this sub-factor than a network operating in a less developed regulatory environment or one characterized by a high level of political intervention. The way in which changes to the regulatory framework or to existing utility law are implemented can vary. Where regulatory or legislative change occurs, a network may receive a high score for this sub-factor if there was sufficient consultation with the affected companies during the process and the changes are supportive of the network's credit quality. In contrast, a network may receive a lower score for this sub-factor if changes to the regulatory framework have been implemented without consultation, are unclear or are detrimental to credit quality.

ASSET OWNERSHIP MODEL:

Where an issuer does not own the network assets, we consider the risk that a license or concession may be terminated. We also consider whether the right to charge customers for their use of the network assets effectively may be short-to-medium term and therefore transitory. Ownership of what are, in many cases, assets of national importance is commonly subject to a license. It is less common to see private sector companies own assets outright in perpetuity, although this ownership model may be seen in certain countries or in cases where alternative transportation systems exist (e.g., transit pipeline or interconnector systems).

A company that owns all key network assets outright in perpetuity and has control over them would typically receive a higher score for this sub-factor, and a company that holds its key assets under a short-term operating lease or license-type arrangement would typically receive a lower score. Scoring for this sub-factor in the case of issuers with concession agreements or more permanent licenses would typically be somewhere in the middle of the range and would depend on (i) the nature of events that could cause a loss of concession or license; (ii) the time frame thereof; and (iii) the entitlement to compensation upon termination.

We also consider the general rule of law and the value and enforcement of asset property rights. A network that operates in a jurisdiction with no perceived risk of expropriation and where the laws pertaining to property rights are well established typically receives a higher score for this sub-factor. A lack of well-established laws pertaining to property rights may be mitigated by other considerations, such as government ownership. The regulatory framework of networks that score A and above for this sub-factor needs to include well-established creditor and property rights, such that we do not perceive any risk that a change in ownership (including by expropriation) would negatively affect creditors, which can often be mitigated where the government owns the network. Where there is a heightened risk of expropriation of sector assets with limited potential for compensation, a company would typically receive a lower score for this sub-factor, even if it owns its assets outright.

COST AND INVESTMENT RECOVERY:

In assessing this sub-factor, we consider the supportiveness of the regulatory framework, i.e., the extent to which the regulatory formula is supportive of cost recovery, including the mechanism by which one-off costs or over-spends are recovered, if at all. In other words, it focuses on the risk allocation between the network operator and its customers. Prevalent regulatory models for unbundled networks across the world are “ex-ante,” “ex-post” or “cost-plus.” While in theory ex-ante regulation provides the greatest certainty for the recovery of capital investment, each type of regulatory model may have greater or lesser predictability in cost recovery, depending on the details of the framework and the manner in which it is applied by regulators.

We assess whether the regulator seeks to insulate consumers from the volatility and the uncertainty associated with operating and financial costs, whether there is risk-sharing between the network and its consumers, and whether the network is able to pass through its incurred costs, including financial costs, easily. A network that has complete flexibility to set tariffs so that it can meet current and future operating and capital costs without impediment would typically receive a higher score for this sub-factor. A network that benefits from fair and timely cost and investment recovery but is subject to efficiency targets or high regulatory scrutiny would likely score in the middle of the range. Where there is a significant deferral of allowed revenue, e.g., for a greenfield development where the current number of customers is very low but expected to grow, or where a company has been significantly over-spending on its investments, the score for this sub-factor would typically be lower.

REVENUE RISK:

We consider the ability of a network to generate the revenue allowed to it by the regulator. In general, a network’s revenue can vary from this pre-determined level based on differences between actual volumes and those forecast when charges were initially set. However, the extent to which networks are affected by volume risk depends on the structure of the regulatory charge, which can include both a fixed and a variable element. The greater the proportion of the end-user charge that is fixed, the lower the potential revenue variability.

Gas and electricity transmission tends to be less volatile than distribution due to its wider geographic reach (e.g., volumes are arguably more stable and predictable where exposed to a country’s entire economy than to a subset thereof). From a commodity perspective, gas volumes are likely to be more exposed to weather conditions than electricity volumes, given the role of gas as a heating fuel source in many jurisdictions. However, there may ultimately be no direct link between volume volatility and revenue generation as some regulators de-couple the two, given that volumes are outside of a network company’s control. In such cases, a regulator may choose to eliminate volume risk entirely (e.g., by setting a fully fixed charge for transmission and distribution activities) or may allow a true-up mechanism that allows networks to reset their charges in a timely fashion to recover any lost revenue.

A network whose revenues are entirely de-linked from volumes transported typically receives a higher score for this sub-factor. A network that has some exposure to volume risk but that benefits from a regulatory formula that allows for the recovery of any lost revenue typically scores in the middle of the range. In contrast, a network that has higher exposure to volumes or where volumes are expected to be particularly volatile typically receives a lower score for this sub-factor. We also take into account a network's reliance on revenue associated with new connections. While the costs incurred in connecting new customers are normally a pass-through under most developed regulatory frameworks, such activity may generate significant cash flows if the network is allowed to make a margin, thereby raising the overall volatility of the business.

Factor: Scale and Complexity of Capital Program (10% weight)

Why it matters

The scale and complexity of a network's capital investment plan provide important indications of execution risk. Given the global trend of population growth, renewable generation deployment and decarbonization requirements, and the increased roll-out of innovative technologies (such as smart grids and electric cars), many networks have large and ongoing capital investment programs.

Many companies also may need to replace aging grids, or improve their reliability. For most networks, a sizable capital expenditure program is a permanent feature of their business model. While networks are generally experienced in carrying out large construction programs, such programs nonetheless introduce execution risk to the enterprise. The program may take longer than envisaged to complete or could cost more than expected. Furthermore, cost overruns may not be recoverable from future revenue or may be subject to an efficiency review by the regulator. In addition to the direct financial impact, a large or complex capital program may prove a distraction for management, which could lead to underperformance in other areas of the business.

How we assess it for the scorecard

We assess a regulated network's capital expenditure program by considering (i) its size and scope; (ii) its complexity, i.e., the type of assets to be built and associated technical issues as well as the relative concentration of challenging projects within an issuer's total capital expenditure program; (iii) management's ability to deliver the plan without material cost over-runs; and (iv) whether the program will introduce financing challenges.

The size of a network's capital expenditure plans may, to some extent, be correlated with the complexity of the program, particularly for material capacity increases or technically challenging projects. We consider the annual amount of the capital expenditure plan as a percentage of the regulatory asset base or total fixed assets. However, this percentage may not directly correlate to risk in all scenarios. For example, a replacement program such as the laying of polyethylene gas pipe may be large in scope but present only limited execution risk. Here the technology is relatively simple and well established. Another example where the size of a capital program may not be correlated to risk is a large capital expenditure program comprising a significant number of individual projects where overall execution risk is reduced through diversification.

A network undertaking a relatively small but specific or complex investment program would typically receive a lower score for this factor than a network involved in a number of small and simple projects. We consider total capital expenditure, including those outside of the core regulated activity. Although such activities would generally not negatively impact core regulated operations directly, material investments outside of the core regulated business may weaken a network's ability to service debt or cause a significant drain on management's time and resources.

Issuers with large, modern asset bases requiring a limited amount of simple maintenance (with capital expenditure representing a low percentage of fixed assets) typically receive higher scores for this factor. In contrast, networks that need to modernize their systems and engage in complex, concentrated programs that are challenging to finance (and where annual capital expenditure represents a high percentage of fixed assets) generally receive lower scores for this factor.

Factor: Financial Policy (10% weight)

Why it matters

Management and board tolerance for financial risk is an important rating factor because it directly affects debt levels, credit quality and risk in the capital structure (e.g., refinancing risk, counterparty risk or exposure to interest rates or foreign exchange movements).

The generally stable and predictable cash flows of a regulated network create significant capacity to incur debt financing and, potentially, to invest in related businesses. While debt financing may be considered essential to the efficient capital structure of a network, a desire to enhance shareholder returns may lead to the pursuit of higher leverage, which increases credit risk. The way in which a network owner uses its debt capacity, therefore, is a key rating consideration.

In our assessment of this factor, we consider the likelihood that financial policy decisions, in their totality, could add uncertainty to future cash flow levels and divert resources that may otherwise be available to service debt. In this regard, management's track record and its public commitment to maintaining the issuer's credit quality are key considerations.

How we assess it for the scorecard

We consider the company's approach to financing its activities, especially the balance it strikes in apportioning risk between shareholders and creditors. We assess both the company's track record and its stated objectives with respect to leverage and financing decisions, as well as the investment return requirements of its owners. The behavior of owners can be a key differentiating credit consideration – where owners' objectives are short-term or opaque, or where there is a lack of track record, the regulated network typically receives a lower score than if its shareholders have longer-term return requirements and may be willing to forgo near-term distributions to maintain flexibility.

Issuers typically receive a higher score for this factor if they have an extended track record of low levels of leverage and a public commitment to maintaining high credit quality. A network that employs an average level of leverage for the industry (e.g., to a level implied within the regulator's allowed rate return) and that has a solid record of commitment to maintaining its targeted financial metrics typically receives a score in the middle of the range. However, scores of Baa and higher are generally only assigned where there are no (or only very limited) concerns regarding owners' behavior – e.g., listed companies, government majority-owned companies or those owned by industrial shareholders. Issuers with consistently higher levels of leverage or those with a less transparent financial policy typically receive a score of Ba or lower for this factor.

This factor is scored separately from the Uplift for Structural Considerations notching factor, which is used to assess structural features and sources of rating uplift from creditor protection. However, where they exist, such enhancements are considered in our assessment of the Financial Policy factor to the extent they define or clarify the issuer's overall financial policy.

Factor: Leverage and Coverage (40% weight)

Why it matters

Leverage and coverage measures are critical indicators of a regulated network's financial flexibility and long-term viability, including the ability to adapt to changes in the economic and regulatory environments in which it operates.

We distinguish between networks that use a corporate financing structure and those that use a project financing structure. The financing structure is important because corporate-financed networks typically have greater flexibility, e.g., a wide latitude to transform their business, buy and sell assets, take on additional leverage and refinance their debt. Project financing structures typically limit the scope of the issuer's business activities and its ability to incur additional debt.

Corporate-financed Networks

For corporate-financed issuers, this factor comprises four sub-factors: Adjusted Interest Coverage Ratio or Funds From Operations Interest Coverage; Net Debt/Regulatory Asset Base or Net Debt/Fixed Assets; FFO/Net Debt; and Retained Cash Flow/Net Debt.

Adjusted Interest Coverage Ratio or Funds from Operations Interest Coverage

The Adjusted Interest Coverage Ratio (AICR) and Funds from Operations (FFO) Interest Coverage are indicators of a regulated network's ability to meet its interest obligations.

We use the AICR for regulated networks where allowed revenues/tariffs are determined using a "building block approach" and where the components of allowed revenues/tariffs are routinely published and can be verified by an independent source, which in most cases is the regulatory authority. The AICR adjusts FFO by an amount of money (Capital Charges) that the regulator includes within current revenue at the expense or benefit of future revenue. The removal of capital charges from FFO allows for greater comparability of interest coverage for networks within a regulatory regime and for networks across different regulatory regimes. See appendix B for examples.

We use FFO Interest Coverage for regulated networks in jurisdictions where regulatory revenues/tariffs are not determined with a building block approach or where the regulatory information needed to calculate capital charges may not be consistently available.

Net Debt / Regulatory Asset Base (RAB) or Net Debt / Fixed Assets

The ratio of net debt to regulated asset base (Net Debt/RAB) and the ratio of net debt to fixed assets (Net Debt/Fixed Assets) are indicators of debt serviceability and financial leverage. These ratios provide a basis for comparing the size of an issuer's debt relative to that of its peers.

We use Net Debt/RAB for regulated networks where the RAB serves as a proxy for the long-term average enterprise value of a regulated business. The RAB is analogous to the rate base in the US, albeit with some differences.

Under some regulatory regimes, RAB may not accurately represent the invested capital on which a network earns a return over time (e.g., because of ex-post rate-setting), or the information may not be publicly available. In these cases, we use Net Debt/Fixed Assets. For example, a network may be allowed to earn a return on construction work-in-progress, but the amount is not part of RAB until the asset is completed. Alternatively, a regulator may designate certain assets (e.g., receivables, deferred charges or regulatory assets) outside of RAB but permit the network to earn a regulated return on them.

FFO / Net Debt

The ratio of FFO to net debt (FFO/Net Debt) is more useful in comparing the ability of a network (or a peer group of networks operating under similar regulatory financial models) to generate sufficient cash flow to cover future debt repayments than in comparing networks operating under very different regulatory financial models (see Appendix A). More specifically, a higher FFO/ Net Debt ratio may not be a sign of financial strength where it is driven by a higher level of regulatory depreciation. Nevertheless, in comparing two companies that maintain a similar Net Debt/RAB ratio over time, a higher FFO/Net Debt ratio is usually indicative of greater financial strength.

RCF / Net Debt

The ratio of retained cash flow to net debt (RCF/Net Debt) is an indicator of a network's cash generation (before working capital movements and capital expenditures, and after dividend payments) relative to its net debt (total debt minus cash and cash equivalents). Dividend obligations of networks are often substantial, quasi-permanent outflows that can affect the ability of a network to cover its debt obligations. This ratio can also provide insight into a regulated network's financial policies. The higher the level of retained cash flow relative to debt, the more cash the network has to support its capital expenditure program.

Project-financed Networks

For project-financed issuers, this factor comprises three sub-factors: Minimum Debt Service Coverage Ratio (DSCR), Average DSCR and Concession Life Coverage Ratio (CLCR).

Debt Service Coverage Ratio

The minimum DSCR and average DSCR are measures of financial leverage and debt repayment capacity. Project-financed electric and gas networks' net cash flows can be more stable and predictable than project-financed issuers in other sectors, resulting in both the minimum and average DSCRs providing indications of an issuer's ability to sustain lower cash flows from unexpected events before debt service is impaired and its ability to pay its debt service from available cash flow within the remaining tenor of its license or concession. An issuer that maintains high minimum and average DSCRs with a comfortable excess coverage margin is typically better able to withstand short-term cash flow disruptions.

Concession Life Coverage Ratio

The concession life coverage ratio (CLCR) provides an important indication of an issuer's capacity to pay its debt service over the remaining tenor of the license or concession.

How we assess it for the scorecard

In assessing regulated electric and gas networks, we use project finance metrics where (i) the debt is fully amortizing; and (ii) the financing contains many of the structural features that may provide protection to creditors listed in the "Uplift for Structural

Considerations" notching factor section. Networks that do not have fully amortizing debt and many of these structural features are assessed using corporate financing metrics.

Corporate-financed Networks

ADJUSTED INTEREST COVERAGE RATIO:

The numerator is FFO plus interest expense minus non-cash accretion minus capital charges. For clarity, we calculate interest expense minus non-cash accretion and add this number back to FFO. To the extent FFO is calculated after interest expense but without deducting non-cash accretion, we typically add this non-cash accretion to FFO.

$$\frac{\text{FFO} + (\text{Interest Expense} - \text{Non-Cash Accretion}) - \text{Capital Charges}}{\text{Interest Expense} - \text{Non-Cash Accretion}}$$

The denominator is interest expense minus non-cash accretion.

For regulated networks that use unconventional debt funding, such as zero-coupon, capital accretion, index-linked bonds or swap arrangements, we may make adjustments to the ratio calculations to improve consistency and comparability to the peer portfolio.

FFO INTEREST COVERAGE:

The numerator is FFO plus interest expense, and the denominator is interest expense.

NET DEBT / RAB:

The numerator is net debt (total debt minus cash and cash equivalents), and the denominator is the regulated asset base.

NET DEBT / FIXED ASSETS:

The numerator is net debt (total debt minus cash and cash equivalents), and the denominator is fixed assets. Fixed assets is used as a proxy for the network assets necessary to fulfil the regulatory obligations. The denominator is typically net property, plant and equipment (PP&E). However, where companies report network assets operated under concession contracts as intangible assets (e.g., under IFRIC 12), we make an adjustment to include such assets in the denominator.

FFO / NET DEBT:

The numerator is FFO, and the denominator is net debt (total debt minus cash and cash equivalents).

RCF / NET DEBT:

The numerator is RCF, and the denominator is net debt (total debt minus cash and cash equivalents).

Project-financed Networks

For project-financed networks, we use three sub-factors: the minimum DSCR, the average DSCR and the CLCR.

In general, the focus of our assessment of project finance leverage and coverage financial metrics is forward-looking. We generally use cash flow projections based on our own assessment of the most likely financial and operating parameters and sensitivities. We also typically consider a number of downside or sensitivity scenarios to test the resiliency of the project's cash flows. Our central scenario and sensitivities may be informed by third-party technical or market consultants, and they may be different from the owner's or sponsor's projections. For projects that have a track record, historical performance generally has a strong influence on our view of likely future results, unless there is a material change in the project's operating parameters or market dynamics. As a result, historical results are among the drivers that can cause changes to our central scenario and downside or sensitivity scenarios over time.

DEBT SERVICE COVERAGE RATIO:

The DSCR is typically calculated based on the projections, through the scheduled maturity of the issuer's debt. The minimum DSCR is the lowest of the future periodic coverage ratios, while the average DSCR is the average of the future periodic coverage ratios.

To calculate the DSCR for any 12-month period, the numerator is cash flow available for debt service (CFADS), and the denominator is scheduled interest and principal as defined in the finance documents, excluding cash sweeps.

CFADS equals cash flow from operations (before interest) minus maintenance capital expenditure plus (or minus) transfers from (or to) timing reserves, if relevant. We do not include movements in the debt service reserve account. Because the calculation of CFADS is based on operating cash flow, this numerator incorporates movements in working capital.

Interest and principal equals cash interest and principal in the relevant period. Interest excludes interest income (which is included in the numerator).

CONCESSION LIFE COVERAGE RATIO:

The numerator is the sum of (i) the net present value of future CFADS through the revenue entitlement period of the license or concession and (ii) the debt service reserve account. The denominator is total debt. We use the weighted average cost of the senior secured debt as the discount rate.

For concessions held in perpetuity, future CFADS includes any fixed tariff period and may include CFADS for a longer period if there is visibility over regulated revenue beyond the fixed tariff period.

Notching factor

Our assessment of the Uplift for Structural Considerations notching factor may result in an upward adjustment to the preliminary outcome that results from the four weighted scorecard factors. Adjustments may be made in half-notch or whole-notch increments.

In aggregate, structural features that we consider effective may result in up to three upward notches from the preliminary outcome to arrive at the scorecard-indicated outcome. However, typical uplift is between a half notch and one and a half notches. In cases where we consider that the credit weakness or credit strength represented by this notching factor is greater than the scorecard range, we incorporate this view into the rating, which may be different from the scorecard-indicated outcome.

Uplift for Structural Considerations

Why It matters

A regulated electric and gas network's debt structure may contain structural features that can provide creditors meaningful protection against losses. Such enhancements may be incorporated into the terms and conditions of financing agreements pertaining to essentially all of a network's securities holders, or they may be a feature within the networks' regulatory license, and include requirements such as maintaining a certain credit rating and demonstrating sufficient operating and financial resources. These features are important because they can restrict the issuer's ability to take actions that could increase credit risk, thereby reducing the likelihood of default or increasing the likelihood of higher recovery in the event of default, or both.

How we assess it for the scorecard

We typically consider the extent to which structural features and regulatory ring-fence provisions (i) reduce the likelihood of default; and (ii) give creditors either the right, or ability, to influence a network's decision to take corrective action to stop or reverse credit deterioration. The impact of these structural features on notching is based on a holistic assessment of their effectiveness.

STRUCTURAL FEATURES THAT REDUCE THE LIKELIHOOD OF DEFAULT:

In assessing structural features that reduce the likelihood of default, we typically assess the following:

Restriction on business activities

» The extent to which an issuer is prohibited from engaging in new activities or making acquisitions.

Restrictions on raising additional debt

» Whether restrictions on additional indebtedness reduce the risk that additional obligations could cause a payment default.

Distribution lock-up tests

» The extent to which an issuer is prohibited from distributing cash to shareholders in periods of financial stress.

Limits on debt structure

» Whether the issuer is required to remove or mitigate certain financial risks, such as interest rate, currency or refinancing risk. Structural features that can reduce refinancing risk include restrictions on debt maturity concentration and the implementation of a fully amortizing debt structure, which by itself can result in one notch of ratings uplift. Covenants can also restrict the issuer's use of derivative products, thus reducing the likelihood of additional or sizeable claims on the business.

Reserves to cover large future or unforeseen costs

» The presence of dedicated timing reserves for large-cost items, e.g., a one-off capital expenditure.

STRUCTURAL FEATURES THAT GIVE CREDITORS THE RIGHT, OR ABILITY, TO INFLUENCE AN OPERATOR'S DECISION TO TAKE CORRECTIVE ACTION:

We assess the ability of debtholders to force owners to reduce debt before equity value is lost and debt is impaired, and to take action to repay debt through the enforcement of security provisions if this is not achieved. Financing document events of default or other events giving rise to debtholder controls, and the consequences of their breach or trigger, are key elements of this protection. To provide effective protection to creditors, these features work within the context of the business being financed, in most cases to allow the operating businesses to continue as going concerns and to allow debt service to be paid through available liquidity facilities while action is being taken.

In assessing structural features that provide control rights, we typically consider the following:

Effectiveness of control rights

» The extent to which the exercise of control rights may be impeded (e.g., local jurisdiction laws or certain regulatory restrictions).

» The proposed terms and conditions, in conjunction with opinions of counsel, to ascertain whether the proposed control rights are likely to operate as intended.

Length of the control period

» The length of time creditors have to exercise control rights before the issuer loses the right to generate cash flow from the assets (e.g., before an insolvency process or before a concession/regulatory license is terminated).

Dedicated liquidity support

» The extent to which dedicated liquidity support covers ongoing debt service while control rights are exercised. To be considered effective, such dedicated liquidity would need to be available for use in circumstances where control rights are exercised.

To be considered effective, structural features typically include the following:

» The entity subject to the financing and the restrictions is separated from the wider ownership group and any wider business group. The separation is achieved through legal means related to the creation of the issuer or restrictions in the financial structure.

» All creditors are subject to common terms that ensure that an individual creditor or a group of creditors cannot take unilateral action to destabilize the financing.

» Creditor step-in rights are specifically permitted under the concession, regulatory license or legal framework, as well as the financing documents. In our assessment, we consider security arrangements to be one element, albeit usually a critical element, of a wider package of features designed to improve creditors' ability to detect early potential problems and rectify them if possible (in the first instance by retaining cash surpluses within the company). In addition, if remedial action is not possible or fails, the security arrangements are used to maximize recovery prospects.

We also consider the quality of security arrangements on material collateral. Security is sometimes not allowed or is not enforceable on certain assets, the title of which may be retained by the state or other granting authority, or where the company is restricted from giving security over its assets by a pre-existing statute.

Ratings fully incorporate our view of the actual structural or contractual features in a particular transaction. In rare cases, contractual features may provide greater uplift to the issuer's credit quality than what is reflected in the scorecard.

Other considerations

Ratings may reflect consideration of additional factors that are not in the scorecard, usually because the factor's credit importance varies widely among the issuers in the sector or because the factor may be important only under certain circumstances or for a subset of issuers. Such factors include financial controls and the quality of financial reporting; corporate legal structure; the quality and experience of management; assessments of corporate governance as well as environmental and social considerations; exposure to uncertain licensing regimes and possible government interference in some countries. Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns and macroeconomic trends also affect ratings.

Following are some examples of additional considerations that may be reflected in our ratings and that may cause ratings to be different from scorecard-indicated outcomes.

Non-Core Businesses

As described in the "Scope" section, this methodology applies to issuers whose primary activity is the ownership and operation of regulated electric and gas networks. Where an issuer has diversified or may diversify a portion of its operations towards other business types, we assess the impact on credit quality. In particular, the ownership of material businesses with higher credit risk than electric and gas networks would likely result in an assigned rating that is lower than the scorecard-indicated outcome.

Liquidity and Access to Capital Markets

Liquidity is an important rating consideration for all electric and gas networks, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Network assets frequently have a very long useful life —- 30, 40 or even 60 years is not uncommon — as well as high development or acquisition costs. Furthermore, the sector has historically experienced prolonged periods of negative free cash flow, such that a portion of capital expenditure must be debt-financed. Dividends are also a quasi-permanent outlay, as networks rarely lower their dividend. Liquidity is also important to meet maturing debt obligations, which can be large, and to meet collateral calls under hedging agreements.

We assess liquidity for regulated networks through analysis of the sources and uses of cash over the next 12 months or more. Through analysis of an issuer's available sources of liquidity (including our financial projections and assessment of the quality and reliability of alternative sources of liquidity, such as committed credit facilities), we evaluate how projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, potential liquidity calls on financial hedges, and issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no dividend reduction. We also assess a company's ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability. Please see our liquidity cross-sector methodology.[3]

Management Strategy

The quality of management is an important factor supporting a company's credit strength. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and evaluates management performance relative to performance of competitors and our projections. Management's track record of adhering to stated plans, commitments and guidelines provides insight into management's likely future performance, including in stressed situations.

Size

The size and scale of a regulated network has generally not been a major determinant of its credit strength in the same way that it has been for many other sectors. However, size can still be a very important consideration in our assessment of certain credit risks, including event risk, construction risk and access to external funding. While the Scale and Complexity of Capital Program factor seeks to incorporate some of the execution risk involving large or complex projects, these considerations may be sufficiently important that the rating reflects a greater weight for these risks.

Interaction of Ratings with Government Policies and Sovereign Ratings

Regulated networks are more likely to be affected by government actions than companies in most other sectors. Credit impacts can occur directly through regulation, and indirectly through energy, environmental and tax policies. While the Regulatory Environment and Asset Ownership Model factor seeks to capture many of these risks, a greater weighting may be appropriate in assessing some issuers' ratings.

Environmental, Social and Governance Considerations

Environmental, social and governance (ESG) considerations may affect the ratings of issuers in the regulated electric and gas networks sector. For information about our approach to assessing ESG issues, please see our methodology that describes our general principles for assessing these risks.[4]

Increasing environmental requirements and efforts to reduce greenhouse gas emissions (known as carbon transition risk) may lead to higher costs for many industries. Key considerations for regulated networks include the impact of carbon transition policies on tariffs and cost recovery mechanisms as well as access to capital. Electricity networks will remain essential as economies decarbonize, leaving most of them with neutral to low carbon transition exposure despite significant investment requirements. In contrast, gas networks in many markets will be adversely affected by decarbonization, particularly of residential heating, although this risk is mitigated by the likelihood that their assets will remain in use for decades, providing the opportunity to recover their investments and amortize debt under well-defined regulatory frameworks, or potentially to adapt their networks to transport lower carbon gases.

Storms, hurricanes, floods and wildfires have the potential to damage electricity networks, causing operational disruptions and necessitating expensive repairs. These risks can be mitigated by reinforcing networks and ensuring that nodes can be supplied from multiple entry points. The cost of doing so may be significant, particularly if climate change accelerates. Insurance and specific cost-recovery mechanisms for regulated networks may reduce but not eliminate the risk, as can broad geographic diversification.

Social issues, including concerns about clean and affordable energy, are important considerations. Networks are highly exposed to socially driven policy agendas resulting from public concern about affordable energy and environmental issues, combined with the direct involvement of governments and regulators in setting energy policy. Typically, this risk is lower in markets with transparent regulatory frameworks, where independent regulators follow well-established principles that clearly define risk allocation between companies and customers. Public interest in reducing carbon emissions and addressing global warming can influence public policy. Gas networks' exposure to responsible production issues is typically greater than for electricity networks and includes public safety risks related to possible gas leaks and explosions and the operating costs incurred to mitigate these risks.

For corporate networks, regulatory frameworks have typically required a fairly high level of transparency in financial reporting, in addition to review of capital spending programs, which has tended to have a positive impact on governance. Where regulated networks are owned by government shareholders, we typically assess the risk that credit quality will be sacrificed to achieve public policy goals. We would typically also assess owners' track record in preserving long-term viability and providing additional governance oversight, and the potential for ongoing support. For government-related issuers, we also consider the likelihood of extraordinary support. Please see the Parental Support consideration in this section.

Our assessment of the financial structure of project-financed regulated networks provides meaningful insights into governance risks. For example, covenants typically explicitly limit debt leverage and require hedging or insuring against key risks. Well structured project financings that provide for a clear contractual allocation of risks among lenders, owners and contractors also limit risk associated with organizational structure.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. The quality of financial statements may be influenced by internal controls, including the proper tone at the top, centralized operations, and consistency in accounting policies and procedures. Auditors' reports on the effectiveness of internal controls, auditors' comments in financial reports and unusual restatements of financial statement or delays in regulatory filings may indicate weaknesses in internal controls.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness which may cause actual ratings to be lower than the scorecard-indicated outcome. Event risks — which are varied and can range from leveraged recapitalizations to sudden regulatory changes or liabilities from an accident — can overwhelm even a stable, well-capitalized firm. Some other types of event risks include M&A, asset sales, spin-offs, litigation, pandemics, geopolitical conflict, significant cyber-crime events and shareholder distributions.

Additional Metrics

The metrics included in the scorecard are those that are generally most important in assigning ratings to issuers in this sector; however, we may use additional metrics to inform our analysis of specific companies. These additional metrics may be important to our forward view of metrics that are in the scorecard or other rating factors.

For example, free cash flow is not always an important differentiator of credit profiles. Strong companies with excellent investment opportunities may demonstrate multiyear periods of negative free cash flow while retaining solid access to capital and credit, because these investments will yield stable cash flows in future years. Weaker companies with limited access to credit may have positive free cash flow for a period of time because they have curtailed the investments necessary to maintain their assets and future cash-generating prospects. However, in some cases, free cash flow can be an important driver of the future liquidity profile of an issuer, which, as noted above, can have a meaningful impact on ratings.

Parental Support

Ownership can provide ratings lift for a particular company in the regulated electric and gas networks sector if it is owned by a highly rated owner(s) and is viewed to be of strategic importance to those owners. In our analysis of parental support, we consider whether the parent has the financial capacity and strategic incentives to provide support to the issuer in times of stress or financial need (e.g., a major capital investment or advantaged operating agreement), or has already done so in the past. Conversely, if the parent puts a high dividend burden on the issuer, which in turn reduces its flexibility, the ratings would reflect this risk.

Government-related issuers may receive ratings uplift due to expected government support. However, for certain issuers, government ownership can have a negative impact on the underlying Baseline Credit Assessment.[5] For example, price controls, onerous taxation and high distributions can have a negative effect on an issuer's underlying credit profile.

Structural Subordination

An energy utility may finance itself in many different ways, including using a regulated network operating company (OpCo) and a holding company (HoldCo) structure, with debt at different levels. Given that creditors of the HoldCo usually have a secondary claim on the group's cash flows and assets after OpCo creditors, this leads to structural subordination. Our ratings of HoldCo debt are usually notched downward from our assessment of group credit quality (which ignores priority of claim) but takes into account a number of other considerations including the following:

» Regulatory or other barriers to cash movement from OpCos to HoldCos.

» Specific ring-fencing provisions or financial covenants at the OpCo level.

» HoldCo exposure to subsidiaries with high business risk or volatile cash flows.

» Strained liquidity at the HoldCo level.

Using the scorecard to arrive at a scorecard-indicated outcome

1. Measurement or estimation of factors in the scorecard

In the "Discussion of the scorecard factors" section, we explain our analytical approach for scoring each scorecard factor or sub-factor,[6] and we describe why they are meaningful as credit indicators.

The information used in assessing the sub-factors is generally found in or calculated from information in the company's financial statements or regulatory filings, derived from other observations or estimated by Moody's analysts. We may also incorporate non-public information.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. Financial ratios,[7] unless otherwise indicated, are typically calculated based on the average of the last three years of reported results. As described in the "Discussion of the Scorecard Factors" section, the debt service coverage and concession life coverage ratios are typically calculated on a forward-looking basis. However, the factors in the scorecard can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historical and expected future performance for periods of several years or more.

All of the quantitative credit metrics for corporate regulated networks incorporate our standard adjustments[8] to income statement, cash flow statement and balance sheet amounts for items such as underfunded pension obligations and operating leases. We may also make other analytical adjustments that are specific to a particular corporate or project-financed network.

2. Mapping scorecard factors to a numeric score

After estimating or calculating each factor or sub-factor, each outcome is mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, Caa or Ca, also called alpha categories) and to a numeric score.

Scorecard factors are scored based on the description by broad rating category in the scorecard. The numeric value of each alpha score is based on the scale below.

Exhibit 3

Aaa	Aa	A	Baa	Ba	B	Caa
1	3	6	9	12	15	18

Source: Moody's Investors Service

3. Determining the overall scorecard-indicated outcome

The numeric score for each sub-factor (or each factor, when the factor has no sub-factors) is multiplied by the weight for that sub-factor (or factor), with the results then summed to produce an aggregate numeric score.

A further weighting is then applied by rating category as shown in the table below:

Exhibit 4

Aaa	Aa	A	Baa	Ba	B	Caa
1	1	1	1.15	2	3	5

Source: Moody's Investors Service

We weight lower scores more heavily than higher scores in the scorecard because a serious weakness in one area often cannot be completely offset by strength in another.

The actual weighting applied to each sub-factor is the product of that sub-factor's standard weighting and its over-weighting, divided by the sum of these products for all the sub-factors (an adjustment that brings the sum of all the sub-factor weightings back to 100%).

The numeric score for each sub-factor is multiplied by the adjusted weight for that sub-factor, with the results then summed to produce an aggregate numeric score before notching factors (the preliminary outcome). We then consider whether the preliminary outcome that results from the weighted factors should be notched upward or downward[9] in order to arrive at an aggregate numeric score after notching factors. The Uplift for Structural Considerations notching factor can result in a total of up to three upward notches from the preliminary outcome to arrive at the scorecard-indicated outcome.

The aggregate numeric score before and after the notching factor is mapped to an alphanumeric. For example, an issuer with an aggregate numeric score before notching factors of 11.7 would have a Ba2 preliminary outcome, based on the ranges in the table below. If the combined notching factors totaled two upward notches, the aggregate numeric score after notching factors would be 9.7, which would map to a Baa3 scorecard-indicated outcome.

Exhibit 5

Scorecard-indicated outcome

Scorecard-Indicated Outcome	Aggregate Numeric Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5

Source: Moody's Investors Service

In general, the scorecard-indicated outcome is oriented to the corporate family rating (CFR) or senior unsecured rating for corporate issuers and to the senior secured rating for project finance issuers. For issuers that benefit from rating uplift from parental support, government ownership or other institutional support, we consider the underlying credit strength or Baseline Credit Assessment for comparison to the scorecard-indicated outcome. For an explanation of the Baseline Credit Assessment, please refer to *Rating Symbols and Definitions* and to our cross-sector methodology for government-related issuers.[10]

Assigning issuer-level and instrument-level ratings

After considering the scorecard-indicated outcome, other considerations and relevant cross-sector methodologies, for corporate issuers we typically assign a CFR to speculative grade issuers or a senior unsecured rating for investment-grade issuers and for project-financed issuers we typically assign a senior secured rating. For issuers that benefit from rating uplift from government ownership, we may assign a Baseline Credit Assessment.[11]

Individual debt instrument ratings may be notched up or down from the CFR, the senior secured rating or the senior unsecured rating to reflect our assessment of differences in expected loss related to an instrument's seniority level and collateral. The documents that provide broad guidance for such notching decisions are the rating methodology on loss given default for speculative grade non-financial companies, the methodology for notching corporate instrument ratings based on differences in security and priority of claim, and the methodology for assigning short-term ratings.[12]

Key rating assumptions

For information about key rating assumptions that apply to methodologies generally, please see *Rating Symbols and Definitions*.[13]

Limitations

In the preceding sections, we have discussed the scorecard factors and many of the other considerations that may be important in assigning ratings. In this section, we discuss limitations that pertain to the scorecard and to the overall rating methodology.

Limitations of the scorecard

There are various reasons why scorecard-indicated outcomes may not map closely to actual ratings.

The scorecard in this rating methodology is a relatively simple reference tool that can be used in most cases to approximate credit profiles of issuers in this sector and to explain, in summary form, many of the factors that are generally most important in assigning ratings to these issuers. Credit loss and recovery considerations, which are typically more important as an issuer gets closer to default, may not be fully captured in the scorecard. The scorecard is also limited by its upper and lower bounds, causing scorecard-indicated outcomes to be less likely to align with ratings for issuers at the upper and lower ends of the rating scale.

The weights for each factor and sub-factor in the scorecard represent an approximation of their importance for rating decisions across the sector, but the actual importance of a particular factor may vary substantially based on an individual company's circumstances.

Factors that are outside the scorecard, including those discussed above in the "Other Considerations" section, may be important for ratings, and their relative importance may also vary from company to company. In addition, certain broad methodological considerations described in one or more cross-sector rating methodologies may be relevant to ratings in this sector.[14] Examples of such considerations include the following: how sovereign credit quality affects non-sovereign issuers, the assessment of credit support from other entities, the relative ranking of different classes of debt and hybrid securities, and the assignment of short-term ratings.

We may use the scorecard over various historical or forward-looking time periods. Furthermore, in our ratings we often incorporate directional views of risks and mitigants in a qualitative way.

General limitations of the methodology

This methodology document does not include an exhaustive description of all factors that we may consider in assigning ratings in this sector. Companies in the sector may face new risks or new combinations of risks, and they may develop new strategies to mitigate risk. We seek to incorporate all material credit considerations into ratings and to take the most forward-looking perspective that visibility into these risks and mitigants permits.

Ratings reflect our expectations for an issuer's future performance; however, as the forward horizon lengthens, uncertainty increases and the utility of precise estimates, as scorecard inputs or in other considerations, typically diminishes. Our forward-looking opinions are based on assumptions that may prove, in hindsight, to have been incorrect. Reasons for this could include unanticipated changes in any of the following: the macroeconomic environment, general financial market conditions, industry competition, disruptive technology, or regulatory and legal actions. In any case, predicting the future is subject to substantial uncertainty.

Appendix A: Calculating the Adjusted Interest Coverage Ratio for the Regulated Electric and Gas Networks Scorecard

As described in the Leverage and Coverage factor discussion, a regulator may seek to alter the timing of a network's cost recovery by changing specific parts of the regulatory formula through, for example, the following:

1. **Regulatory asset life/regulatory depreciation:** A regulator may change the rate at which capital is returned to a network through adjustment of the rate of depreciation of the regulated asset base (RAB). Reducing asset life in order to increase the rate of depreciation results in an increase in a networks' regulatory revenue and FFO in the short term but results in a decrease in the RAB and long-term cash flow.

2. **Speed of money:** Under ex-ante regulatory frameworks, a regulator may change the rate at which allowed total expenditure (operating + capital) is capitalized into the RAB. In the UK, the regulatory allowances for operating expenditure are known as "fast money" whereas the allowances for capital expenditure are known as "slow money." If the elected regulatory capitalization into the RAB is lower than is implied in a company's financial accounts, "fast money" will be higher than statutory operating expenditure, which increases a network's regulatory revenue and FFO in the short-term. In the long term, the situation may reverse, decreasing FFO.

3. **Revenue profiling:** A regulator may smooth the impact of revenue changes on consumers by profiling the trajectory of tariffs over a control period. Cash flow volatility that may result from a network's investment program, which could be lumpy, may be undesirable to a regulator. The regulator may choose to address this volatility by profiling allowed revenue such that all costs are recovered and the impact on the consumer is reduced.

The AICR ratio seeks to normalize for these regulatory levers by adding or subtracting amounts (capital charges) to FFO related to regulatory decision-making in the allowed revenue calculation. Capital charges may include:

» Regulatory depreciation (for many regulated networks this is the only Capital Charge)

» The excess of "fast money" over operating expenditure

» The excess of profiled revenue over unprofiled revenue

In eliminating the effects of regulatory timing differences, the AICR ratio instead seeks to capture normalized cost outperformance and provide better comparability among networks.

To illustrate these points, we consider four hypothetical regulated networks – company A, B, C and D, which have the same RAB. For all four companies, the regulator calculates allowed revenue using a "building block" approach, i.e., revenue to cover operating expenditure (i.e., fast money), an allowed return to cover debt and equity costs plus regulatory depreciation, i.e., the portion of the RAB that has been allowed by the regulator to reward historical investment.

Company A has revenue of 200, of which 40 reflects regulatory depreciation, while company B has revenue of 240 and regulatory depreciation of 80. This reflects adoption by the regulator of a policy of "accelerated depreciation" for company B, effectively accelerating cash flow in the short term to the detriment of long-term cash flow. This change results in an increase of revenue and FFO of 40 for company B, which significantly boosts its FFO-based financial ratios. In this example, FFO/Net Debt increases to 18% from 12% and FFO Interest Coverage increases to 4.7x from 3.3x. In contrast, the AICR remains stable at 2.0x as the higher regulatory depreciation is deducted from FFO for the purpose of the interest coverage ratio calculation. Our point-in-time example does not illustrate the effect of accelerated depreciation on Net Debt/RAB, which for Company B would be expected to increase over time unless debt was commensurately reduced or capital expenditure was commensurately higher.

Company C has revenue of 220, which is 20 higher than that of company A; the difference due to the regulator allowing Company C a higher level of "fast money" than their statutory amount of operating expenditure. In contrast, the level of "slow money" capitalized into the RAB (not illustrated) is 20 lower than the statutory level of capital expenditure, which leads to either less growth or a depletion of the RAB. We consider this regulatory lever to be equivalent to the way revenue is impacted by changes to regulatory depreciation. We therefore view this 20 as a further capital charge that we deduct from FFO in calculating the AICR Ratio. While FFO-based financial ratios are improved by increasing the speed of money, the AICR Ratio remains the same.

Company D has revenue of 210, which is 10 higher than that of company A. The difference reflects that the regulator has profiled the allowed revenue over the period of a price control in a way that is different from that implied by the company's expected evolution of costs (which may be volatile) but is preferred by the regulator due to the reduced impact on consumers. The Net Present Value of allowed revenue should be the same irrespective of the profiling method employed. In this example, we treat the revenue benefit of 10 as a capital charge and deduct it from FFO for the purpose of calculating the AICR Ratio. In contrast, in other periods within the price control the profiling adjustment will be a negative amount, but we would adjust for it in a similar way (the negative amount would increase FFO net of capital charges).

Exhibit 6

		Company A (Conventional approach)	Company B (Accelerated regulatory depreciation)	Company C (Fast speed of money)	Company D (Revenue profile adjusted)
Regulatory Asset Base (RAB)	[a]	1000	1000	1000	1000
Regulatory depreciation as a % of RAB	[b]	4%	8%	4%	4%
Net debt	[c]	600	600	600	600
Total debt	[d]	600	600	600	600
Allowed rate of return	[e]	6%	6%	6%	6%
Actual cost of debt	[f]	5%	5%	5%	5%
Actual interest expense	[g] = [d] x [f]	30	30	30	30
Regulatory capitalization rate (slow money as a % of total expenditure)	[h]	75%	75%	70%	75%
Statutory capitalization rate (capital expenditure as a % of total expenditure)	[i]	75%	75%	75%	75%
Total expenditure	[j]	400	400	400	400
Statutory operating expenditure	[k] = [1 – [i]] x [j]	100	100	100	100
Speed of money adjustment	[l] = [[i] – [h]] * [j]	0	0	20	0
Revenue Building Block					
Fast money	[m] = [k] + [l]	100	100	120	100
Regulatory depreciation	[n] = [a] x [b]	40	80	40	40
Allowed return	[o] = [a] x [e]	60	60	60	60
Revenue profiling adjustment	[p]	0	0	0	10
Revenue allowance	[q] = [m] + [n] + [o] + [p]	200	240	220	210
FFO	[r] = [[q] – [k] – [g]]	70	110	90	80
Capital charges					
-regulatory depreciation	[n]	40	80	40	40
-excess fast money over opex	[s] = [m] – [k]	0	0	20	0
-profiled revenue over unprofiled revenue	[p]	0	0	0	10
Total capital charges	[t] = [n] + [s] + [p]	40	80	60	50
FFO net of Capital Charges	[y] = [r] – [t]	30	30	30	30
Ratios					
- Net Debt / RAB	[u] = [c] / [a]	60%	60%	60%	60%
- FFO / Net debt	[v] = [r] / [c]	12%	18%	15%	13%
- (FFO + Interest Expense) / Interest Expense	[w] = [[r] + [g]] / [g]	3.3x	4.7x	4.0x	3.7x
- Adjusted Interest Coverage Ratio	[x] = [[y] + [g]] / [g]	2.0x	2.0x	2.0x	2.0x

Source: Moody's Investors Service

Appendix B: Considerations for Ratings Within a Corporate Family

Our assessment of entities within a network's corporate family includes the extent to which the credit quality of each legal entity is interlinked or insulated from other entities within the family. We perform a holistic assessment in determining whether the probability of default is similar for each family entity, differentiated but tightly banded around an overall family credit quality, or differentiated with a wider banding. We assess the credit-insulating elements in the family as well as their effectiveness. Major considerations include:

Regulatory framework

» Requirement that a network maintain a minimum financial profile (e.g., to comply with its regulatory license)

» Requirement that a network maintain a particular capital structure to earn its allowed revenues/tariffs (compared to a network whose tariffs are set based on an assumed capital structure)

» Prohibition on pooling cash with a parent or affiliates or on making loan advances to those entities (compared to an ability of the parent company to pool the cash of all family entities)

» Requirement that the regulator pre-approve debt issuance and liquidity arrangements (compared to a network's unrestricted ability to make financing decisions)

» A regulator's ability and willingness to limit or prohibit a network from making dividend distributions to its parent

Financing structure

» Strength or weakness of financial covenants and other structural features

» The relative debt levels at each network and at holding companies (networks may have leverage at intermediate holding companies and at the parent company)

» For a holding company, the extent to which it is dependent on the distributions of a particular network in order to meet its own obligations

» Ability of each entity to meet its own liquidity needs (e.g., its dependence on external sources of support)

Corporate structure

» A network subsidiary may have independent board members whose affirmative votes are required for major corporate actions, including voluntary bankruptcy (compared to a corporate family where the board members of each subsidiary are all parent company board members or managers)

» Network subsidiaries may have minority (or blocking) shareholders that must be consulted for major corporate actions

In many circumstances, the rating of a regulated network subsidiary is constrained by the overall credit quality of the group , because the regulatory treatment of its activities provides limited credit insulation between entities, and the corporate and financing documents provide limited restriction in the movement of cash between entities. The absence of such credit insulation tends to result in an alignment of the credit quality of a network with its family and parent. In these circumstances, our analysis considers the consolidated group's credit quality, and the ratings of the family members are likely to be the same as or very closely aligned to the consolidated group's credit quality. A certain amount of credit deterioration at a weaker subsidiary within the same group would typically be counterbalanced by stronger subsidiary(ies) and an expectation that the parent would find a way to direct support to the weak entity. However, if the deterioration at a network subsidiary was severe (e.g., due to material regulatory challenges) and parent support was not assured, ratings within the group could be more differentiated and the rating of the distressed regulated network could be well below that of the parent.

Certain aspects of the UK regulatory framework have led to a partial de-linkage of ratings for group members. UK networks typically must: (i) maintain an investment grade credit rating; (ii) not participate in sizeable unregulated business activities; (iii) maintain at least 12 months of operating and financial resources; and (iv) not pledge any of the network assets as collateral. Nevertheless, our approach for assessing these groups typically starts with the group's consolidated credit quality and incorporates our view of the parent's activities because, until one of these triggers is breached, networks are mostly unimpeded from making distributions or maintaining a capital structure that is different from the one regulators assume when revenues/tariffs are set. However, if a trigger occurred, e.g., the credit quality of the consolidated group fell below a certain level, the ratings of regulated networks within the group that have sufficiently protective arrangements may deviate more widely from the consolidated credit profile. Even in a situation of distress at the parent, regulated networks that are subject to these provisions could retain a relatively high credit rating that may be significantly higher than the consolidated credit quality of the group. In addition, notching within the family may be more extensive when debt structural features are present; these have been more widely used in the UK than in other markets.

Even where meaningful regulatory barriers exist such that ratings of individual regulated entities vary more widely from the consolidated credit profile, the credit quality of the parent still impacts an individual network's ratings in most circumstances. Therefore, while the credit analysis of individual regulated networks may have greater weight in our ratings, our assessment of parent credit quality is also important. Nevertheless, in some jurisdictions there may be significant barriers to cash movement between group entities. In the US, for example, some state regulators oversee the financing arrangements of regulated entities. State level oversight can include: (i) regulatory pre-approval to increase indebtedness; (ii) leverage restrictions for the regulated entity and, potentially, for its immediate parent; (iii) an expectation that the regulated entity will maintain the capital structure utilized for rate-setting; (iv) limitations on the exposure of a regulated entity to its affiliates via, for example, a regulated money pool arrangement; and (v) regulatory pressure to restrict dividends. Nevertheless, the benefit to creditors of these arrangements can vary significantly among states, resulting in a spectrum of barriers to cash movement between regulated companies and related entities. US networks are regulated primarily by the Federal Energy Regulatory Commission (FERC), which has tended to exercise less pervasive oversight than most state regulators with respect to financing arrangements. A change in approach by regulators may change our approach to assessing the ratings of networks in affected corporate families.

Moody's related publications

Credit ratings are primarily determined through the application of sector credit rating methodologies. Certain broad methodological considerations (described in one or more cross-sector rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments. A list of sector and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings, please click here.

For further information, please refer to *Rating Symbols and Definitions*, which is available here.

Moody's Basic Definitions for Credit Statistics (User's Guide) can be found here.

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Endnotes

1 A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

2 In our methodologies and research, the terms "scorecard" and "grid" are used interchangeably.

3 A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

4 A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

5 For an explanation of the Baseline Credit Assessment, please refer to *Rating Symbols and Definitions* and to our cross-sector methodology that describes our approach for assessing government-related issuers. A link to a list of our sector and cross-sector methodologies and a link to *Rating Symbols and Definitions* can be found in the "Moody's related publications" section.

6 Some factors do not have sub-factors, in which case we score at the factor level. When a factor comprises sub-factors, we score at the sub-factor level.

7 For definitions of our most common ratio terms, please see *Moody's Basic Definitions for Credit Statistics (User's Guide)*. A link can be found in the "Moody's related publications" section.

8 For an explanation of our standard adjustments, please see the cross-sector methodology that describes our financial statement adjustments in the analysis of non-financial corporations.

9 Numerically, a downward notch adds 1 to the score, and an upward notch subtracts 1 from the score.

10 A link to a list of our sector and cross-sector methodologies and a link to *Rating Symbols and Definitions* can be found in the "Moody's related publications" section.

11 For an explanation of the Baseline Credit Assessment, please refer to *Rating Symbols and Definitions* and to our cross-sector methodology for government-related issuers. A link to a list of our sector and cross-sector methodologies and a link to *Rating Symbols and Definitions* can be found in the "Moody's related publications" section.

12 A link to a list of our sector and cross-sector rating methodologies can be found in the "Moody's related publications" section.

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14 A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

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Regulated Electric & Gas Utilities – North America

Shifting environmental agendas raise long-term credit risk for natural gas investments

» **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. As carbon transition efforts gain ground, natural gas consumption may see a measured reduction in order to meet 2040 and 2050 GHG goals.

» **Low prices and key role in transition to cleaner energy mix will drive continued near-term investment.** Investment in natural gas infrastructure will continue thanks to low gas prices and far lower carbon intensity than coal when used to generate electricity. We project that coal-fired generation to fall to about 10% of generation supply in 2030, with a large portion being replaced with natural gas generation.

» **Patchwork of regulations and agendas will affect timing and magnitude of the incremental risk.** States and local governments pursue their own agendas, which have varied implications for utility companies that serve large, diversified regions. States with more aggressive emission restrictions, such as New York, California and Hawaii, have commitments for a net-zero carbon economy, including methane reduction goals. Other states are passing legislation aimed at decarbonizing power generation. Oregon is the first state to pass legislation incorporating the use of renewable natural gas, providing incremental growth opportunities for the gas industry. That said, long-term regulations or legislation without financial or regulatory consequences are not a credit driver.

» **Long-term horizons allow companies to shift strategies and pursue technological advancements.** The longer-term nature of emission targets allows companies to adjust their strategic plans. Geographic influences, local politics, weather characteristics and electricity prices can also impact the energy transition timing, and resulting credit implications.

» **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. There is less protection for assets that operate in a competitive landscape, such as independent power production and contracted pipelines.

» **Pace of transition depends on technology, related costs and ultimately public policy.** Certain technological advancements, including the prolific use of renewable natural gas or even hydrogen gas, could help to support the use of existing natural gas infrastructure. At the same time, competing technologies such as battery storage for electric generation could accelerate the decline of gas assets. In either case, the ability of consumers to absorb the cost of implementing such changes and public policy decisions will dictate the pace and profile of the carbon transition.

Long-term challenges to natural gas infrastructure are increasing

Environmental concerns over carbon and methane emissions from natural gas are prompting energy companies to pivot away from developing natural gas infrastructure and toward clean alternatives. This transition is being spurred in part by mounting pressure from advocacy groups, indigenous communities and politicians, as well as the companies' own green initiatives.

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

At the same time, we recognize that natural gas continues to be used as a “bridge fuel” to help accelerate regional and global decarbonization efforts and that electrification of an economy can be difficult and expensive. Furthermore, the sector continues to make investments to improve infrastructure safety and to reduce carbon and methane emissions of its infrastructure and product; trends that will continue in the coming decades. As such, we expect that investments will still be made in natural gas infrastructure, particularly among regulated utilities where there is visibility into rate base treatment and rider recovery to accelerate cash returns.

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.

New pipeline development faces the most challenges

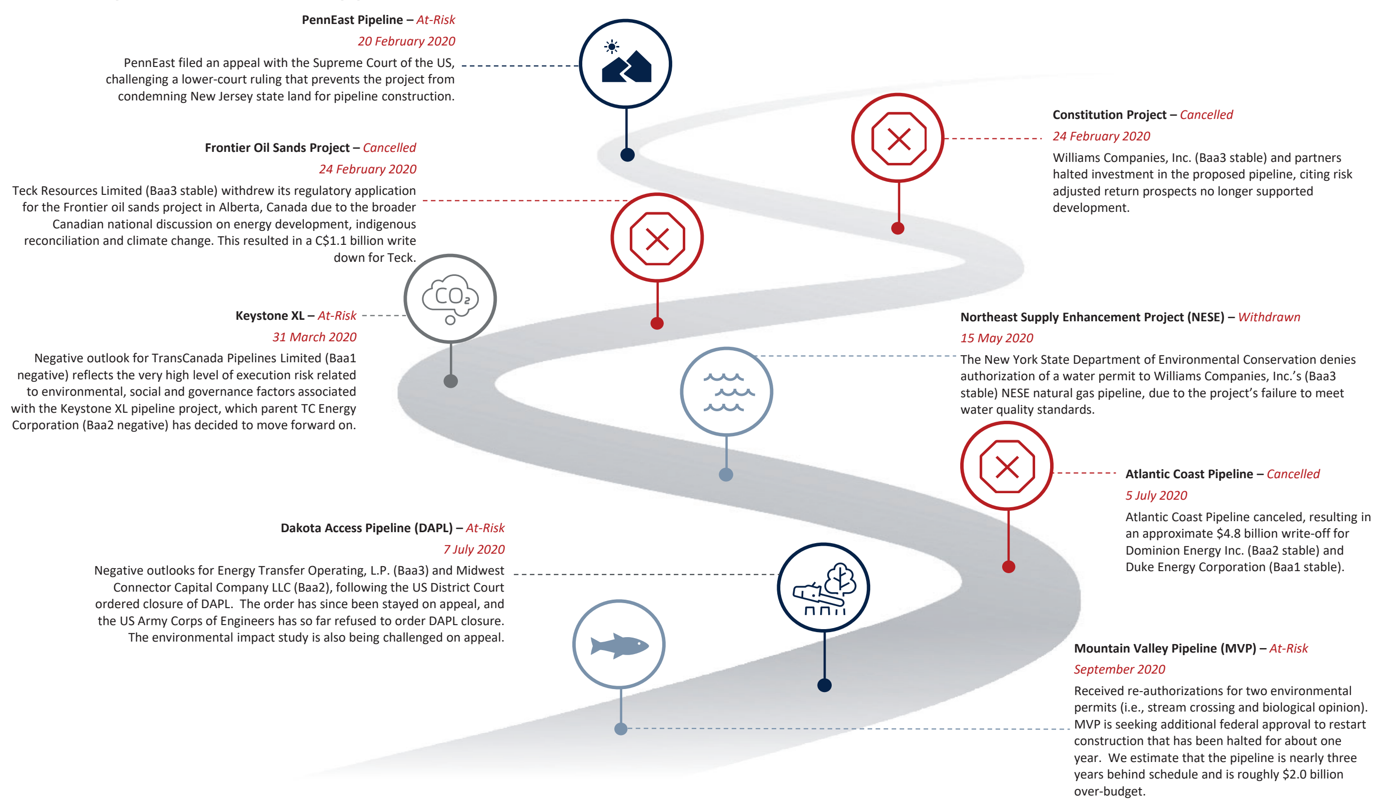
Development of oil and gas transmission infrastructure, in particular, continues to face legal challenges from environmental groups, which are succeeding in delaying pipeline development by opposing efforts by project developers to secure needed permits, highlighting the potential effect of pipeline construction or leaks on protected land and water resources and urging the completion of more comprehensive biological impact studies. Environmentalists and indigenous communities have opposed both oil and gas pipelines as well as broader development projects, such as the Frontier oil sands project in Alberta, Canada.

Moreover, even existing pipeline facilities have come under fire, such as the Dakota Access Pipeline and an Enbridge Inc. (Baa2 positive) compressor station that will increase pipeline capacity in Massachusetts.

Exhibit 1

Negative credit implications are associated with pipeline challenges

Recent examples of derailed or at-risk pipeline investments



Source: Company disclosures and Moody's Investors Service

Because of growing uncertainties about whether new projects will be completed, we generally do not incorporate any revenue from such pipelines in our base case financial projections for a company. Instead, cash contribution will occur when construction has been completed and the pipeline is in operation. The debt used to finance a given project is, however, on-credit and will depress financial metrics during the construction period, all else being equal.

Political and strategic agendas impact LDC growth in some areas

The political and legislative push for lower carbon emissions will impact more than just the fuel source of electric generation units. For the gas sector, decarbonization goals are more disruptive than renewable portfolio standards because the latter typically affects only power generation, whereas mandates to reduce emissions affect all fossil-fuel infrastructure. In some pockets of the US, even local distribution companies (LDCs) are facing early-stage challenges to sales growth, where limited upstream expansion for supply or local restrictions on new gas services will have a greater impact on the business in the coming years.

New York offers one of the more dramatic examples of how political agendas can have an immediate effect on the midstream and gas utility sector. The state is in the process of transitioning away from natural gas use, following the 2019 passage of the state's Climate Leadership and Community Protection Act (CLCPA), which aims to reduce 85% of human-made greenhouse gas (GHG) emissions below 1990 levels by 2050, with special projects helping to offset the remaining 15%.

The state's climate policy has blocked some pipeline infrastructure projects despite the fact that three separate utilities across the state have stopped providing natural gas hookups to new customers because of inadequate supply to meet location-specific customer demand. The CLCPA was also prominently cited in a 22 June 2020 rate filing by New York State Electric & Gas Corporation (NYSEG, A3 negative) and Rochester Gas & Electric Corporation (RG&E, A3 negative), in which the two Avangrid Inc. (Baa1 negative) subsidiaries committed to a zero-net increase in natural gas volumes through the end of the rate plan, in April 2023.

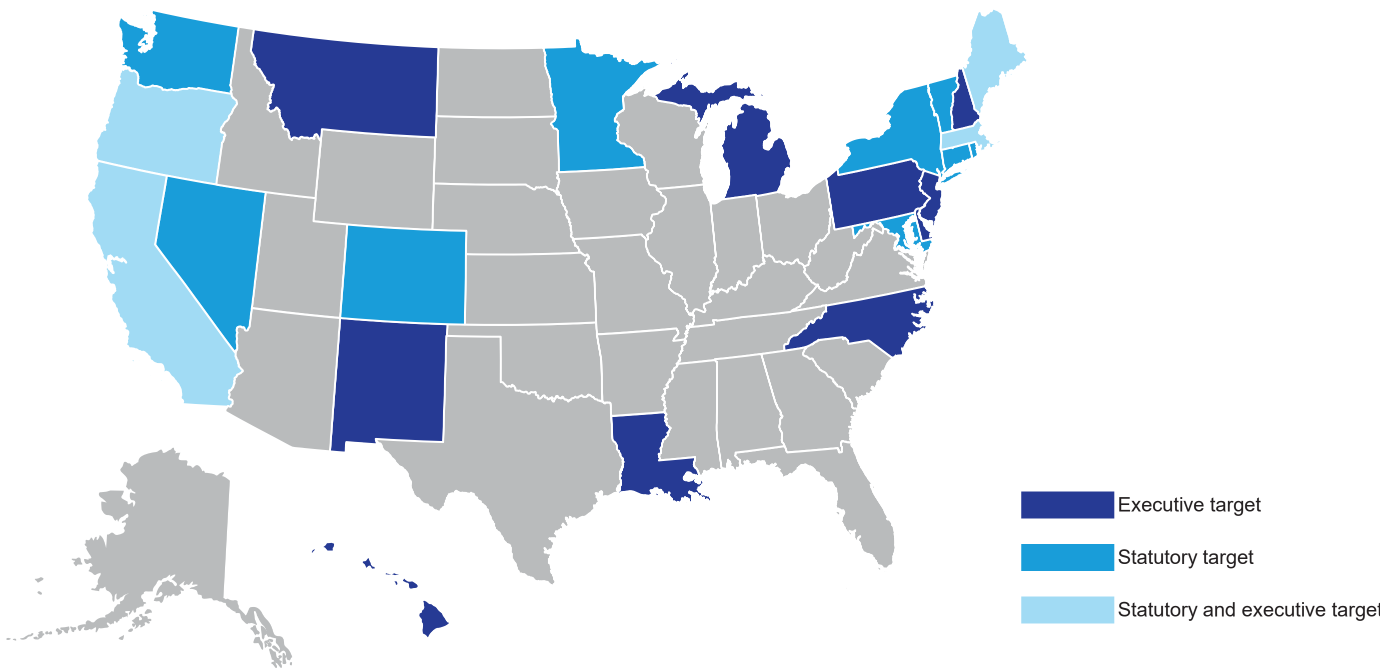
California and Hawaii have passed similar GHG legislation, targeting a carbon-neutral economy by 2045. Like New York, California has opened a regulatory docket to facilitate a public discussion about the steps necessary to make the economy-wide transition, while Hawaii is taking initial steps by including a life cycle GHG emissions analysis when making decisions on energy projects going forward.

The map in Exhibit 2 shows other states with clean energy goals, including Colorado, which is requiring a statewide emissions reduction of 90% below 2005 levels by 2050 and Maine, which has plans to reduce GHG emissions by 45% by 2030 and 80% by 2050.

Exhibit 2

Some states have greenhouse gas emission reduction targets

States with executive and/or statutory-based emission reduction targets



Source: Center for Climate and Energy Solutions

Large, diverse utility companies are beginning to make strategic decisions to limit gas investment

Corporate sustainability strategies continue to evolve as well, with nearly dozens of holding companies expanding their environmental goals to include net-zero carbon emissions, including industry bellwethers like Duke Energy Corporation (Baa1 stable), The Southern Company (Baa2 stable) and Dominion Energy Inc. (Baa2 stable). We view this trend as noteworthy because each of these three companies have material operations in gas distribution and such corporate-wide targets will affect all of their asset classes. In a similar vein, Consolidated Edison, Inc. (Baa2 stable) has expressed their bearish view of gas transmission assets made over the past five years, capped their investment in the Mountain Valley Pipeline at $530 million in November 2019 and provided commentary around their willingness to sell their midstream assets for an adequate price.

Moreover, environmental strategies can also include methane reductions, such as Dominion's 2019 goal to reduce methane emissions by 65% by 2030 and 80% by 2040 (both relative to 2010 emissions and excluding its Southeast Energy Group). We believe that this trend will grow among other large energy companies.

Exhibit 3 shows tactical strategies taken by large, diverse utility companies, regarding natural gas assets over the past three months. Only Berkshire Hathaway Energy Company (Berkshire, A3 stable) has made material investment, by agreeing to pay nearly $10 billion for Dominion's transmission and storage business. We note that Berkshire has strong operational practices and methane leak detection programs and are committed to reducing methane emissions across the natural gas supply chain.

Exhibit 3

Some bellwether energy companies have made moves to limit natural gas exposure over the past three months

Company	Date	Event	Comments
Dominion Energy	July 5	$10 billion sale of gas transportation and storage business and focus on regulated clean energy	Lowers Dominion's business risk
Berkshire Hathaway Energy	July 5	Purchase of Dominion's gas transportation and storage business	Increases BHE's business risk
Dominion Energy	July 5	Cancellation of Atlantic Coast Pipeline	$2.8 billion write-off
Duke Energy	July 5	Cancellation of Atlantic Coast Pipeline	$2.0 billion write-off
Public Service Enterprise Group	July 31	Intent to sell about 6.8 GW of merchant fossil generation assets and focus on regulated clean energy	Lowers PSEG's business risk

Source: Company press releases

As these carbon and methane transition efforts gain momentum, including other states and companies that have not yet committed to broad emission reduction targets, there will be a measured reduction in natural gas use as stakeholders ramp-up use of alternative sources of energy to meet carbon and methane reduction goals through 2050.

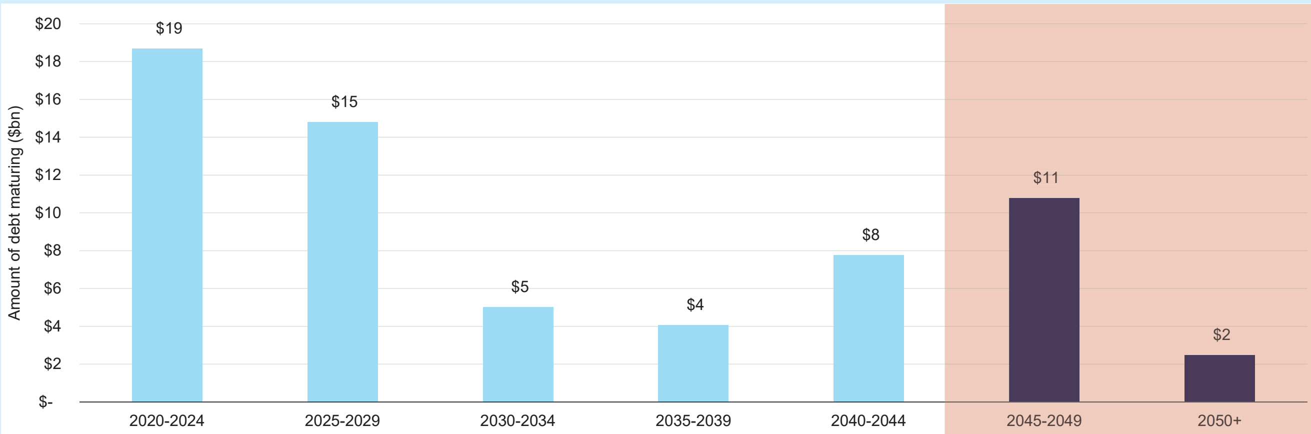
Why does this matter now?

The utility sector is accustomed to issuing long-dated debt to match the useful life of its assets, including 30-year bonds. The LDC sector has roughly $18 billion in 30-year bonds outstanding and a weighted average long-term debt tenor of 14 years on roughly $64 billion of total debt outstanding as of 30 June 2020. This means that most existing debt will retire prior to the 2045-50 target dates that some states, cities and companies have identified for the elimination of GHG emissions.

Exhibit 4

Around $13 billion of long-term debt will mature beyond 2045 when some assets may not be producing the cash to service or repay debt

Local distribution company (LDC) sector's long-term debt maturity profile as of 30 June 2020



Sources: FactSet and Moody's Investors Service

Low prices and key role in transition to cleaner energy mix will drive continued near-term investment

Despite pressures to reduce natural gas growth over the long term, investment in natural gas infrastructure will continue over the next decade because the commodity is cheap, plentiful, less carbon intensive than coal- and oil-fired electric generation and heating and is efficiently transported from production sources to customer. Enhancing the safety of existing transportation and distribution networks will also be a reason for investment, as will blossoming opportunities in renewable natural gas (RNG), methane captured from such sources as landfills, farms and wastewater treatment plants.

New gas-fired electric generation to remain part of the transition from carbon

Given that price levels are low by historical standards and the fact that natural gas emits roughly half of the carbon that coal does, much of the power sector will be using combined-cycle gas units in tandem with a build-out of solar and wind resources. Most vertically integrated electric generators have used gas fired generation as the technology of choice to provide firm generation that is available regardless of wind and solar conditions.

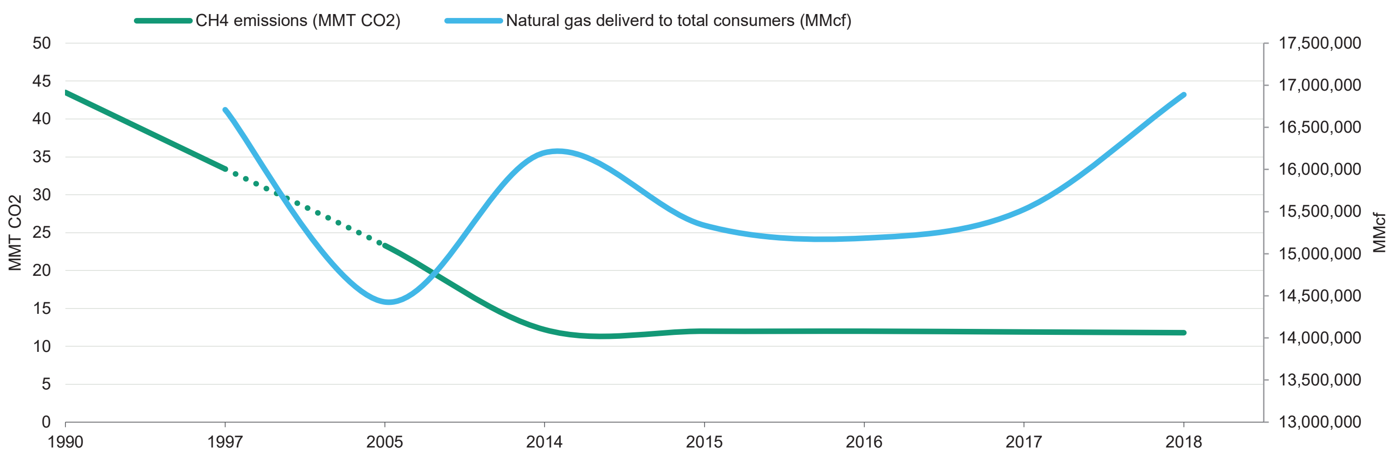
For example, companies like Entergy Corporation (Baa2 stable) and American Electric Power Company Inc. (AEP, Baa2 stable) are planning to construct multiple gas-fired generating units to help meet customer demand with more efficient and lower emission plants. These investments are being accompanied by a sharp increase in planned renewable investments over the next decade. Entergy and AEP expect that the collective impact will reduce overall emissions to 50% by 2030 and 70% by 2030, respectively, from year 2000 levels.

Pipeline replacement programs improve safety and help reduce methane emissions

Over the past 10 years, most of the gas distribution sector's capital has been deployed for system improvements, which replace high-risk pipeline material, like cast iron or bare steel, at the same time as reducing methane emissions. These efforts have helped the sector lower emissions by about 49% since 2005, despite greater delivered volumes, according to the American Gas Association (AGA) and the US Environmental Protection Agency (EPA).

Exhibit 5

Methane (CH4) emissions from natural gas distribution systems have been reduced by almost 50% since 2005 despite the rise in natural gas production



Dotted line represents trend decrease in methane emissions during the period 1990 to 2005.
Source: EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2018, US Energy Information Administration

Utility companies will continue to make these investments over the next decade because there is strong regulatory support for the improvements, ample investment opportunity and timely cost recovery mechanisms for the expenditures. For example, 41 states have some type of infrastructure investment rider that tracks qualifying investments in the replacement of high-risk pipeline material. These costs are generally placed into customer rates on an annual basis with very little, if any, disallowance. The mechanisms are provided through state regulatory commissions or legislatures in order to accelerate the replacement of old and at-risk pipe. The Pipeline and Hazardous Materials Safety Administration (PHMSA) estimates that at the end of 2019, there were roughly 21,300 main miles of cast/wrought iron and 42,400 main miles of bare steel gas distribution pipes to be replaced across the US. Based on average annual mileage of pipe replaced since 2005, we expect another three years of investment for cast iron to be eradicated and over 20 years for bare steel to be completely replaced.

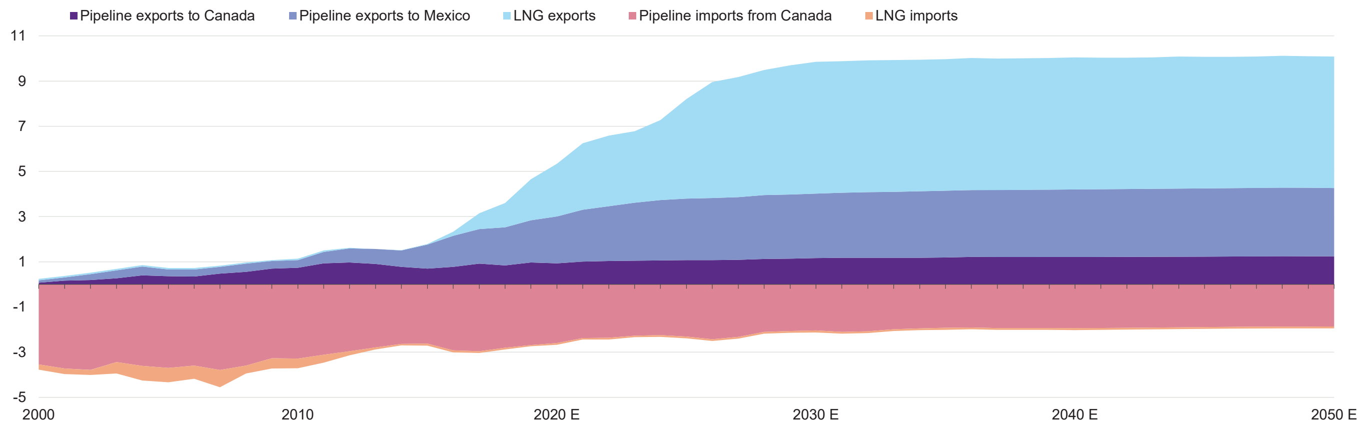
Exports through LNG facilities and to Mexico offer growth opportunities for some pipelines

The EIA expects natural gas exports to Mexico to increase moderately through 2025 and LNG exports to rise through 2030 before flattening out, as seen in Exhibit 6. These opportunities should help support pipelines in the region; however, they also depend on adequate connectivity in Mexico (the country has experienced some delays in pipeline construction in recent years) and incremental LNG export capacity to be in-service by 2025.

Exhibit 6

Natural gas exports are expected to ramp-up significantly in the coming years

The EIA projects that the US will export roughly 10 trillion cubic feet of gas, mostly from LNG exports and pipeline exports to Mexico, in the years 2030 through 2050.



Source: US Energy Information Administration

NGPL PipeCo. LLC (Baa3 stable) is one example of a system that stands to benefit from this growth, since demand from LNG export facilities and exports to Mexico will likely lead to further expansion of the southern part of the pipeline's system over the next few years. The LNG demand, in particular, includes long-dated agreements that will continue to extend the average life of NGPL's contract portfolio from an existing eight years.

Assets already in operation have staying power

The low price of natural gas, the efficiency of its delivery system and the difficulties faced by new natural gas construction projects mean that existing assets will continue to be important. This will likely be especially so in the colder regions of the US, which rely heavily on natural gas and will find it more difficult to replace.

Because of the permitting obstacles for greenfield pipelines, existing transportation infrastructure will continue to play a critical role in today's energy landscape. As a result, we see continued pipeline capital spending for in-corridor and low-profile system enhancements, such as modernizing compression stations or new connections for discrete industrial customers.

This environment theoretically increases the value of assets already in operation, which was part of Berkshire's rationale for purchasing Dominion's gas business. Berkshire views the $10 billion asset acquisition as complementary to its existing gas pipeline infrastructure, which will be a source of stable and predictable revenue for the company for years to come.

At the same time, in order to more effectively use existing infrastructure, companies like Northwest Natural Gas Company (NW Natural, Baa1 stable) and Sempra Energy (Baa2 stable) subsidiary Southern California Gas Company (SoCalGas, A2 stable) have committed to adding RNG as a significant component of their gas supply over the next decade. NW Natural has legal authority to incorporate RNG into its gas supply up to 15% by 2030, 20% by 2035 and 30% by 2050. SoCalGas has committed to obtaining 5% of its 2022 core customer deliveries from RNG and 20% by 2030. RNG is a compelling investment for the sector because it contributes zero net carbon emissions and is readily compatible with existing pipeline infrastructure.

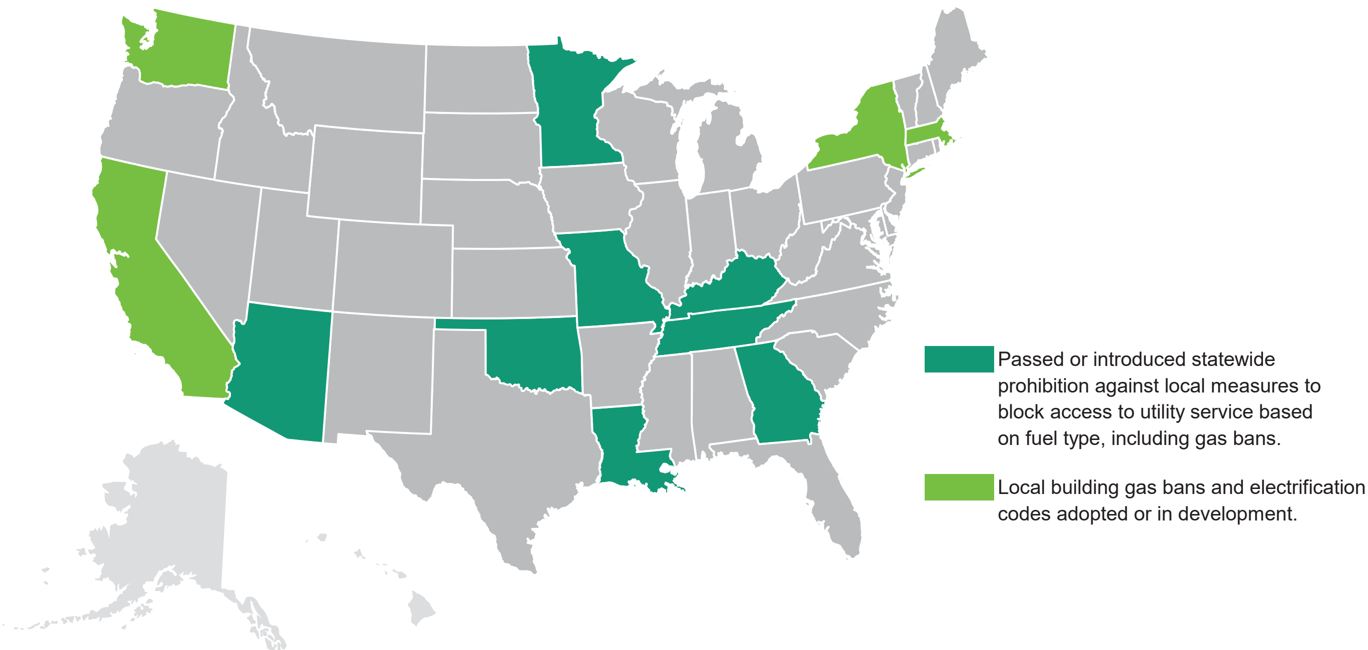
Patchwork of regulations and agendas will affect timing and magnitude of the incremental risk

No federal policy currently exists to provide a cohesive carbon transition across the US. Therefore, states and even local municipalities are pursuing their own diverse agendas, which have varied implications for the industry's utility companies. Gas assets are more threatened in states like New York and California, where policies will strongly pursue electrification versus gas assets in states that have only sporadic municipal goals, or neutral-to-supportive gas policies, such as Oregon and its support of RNG use.

One of the more recent and high-profile areas where a philosophical divergence has emerged is whether to incorporate gas or electric heating in new buildings. Certain municipalities in California, Massachusetts, New York and Washington have implemented gas bans or electrification codes in new buildings, because the building segment typically accounts for a large percentage of state emissions.

At the same time, some states have passed or introduced legislation that supports the use of natural gas by prohibiting gas bans on new buildings (see Exhibit 7), while other states like Texas, Louisiana and Pennsylvania are likely to promote its use because of the role the commodity plays in their economy.

Exhibit 7
States advancing or prohibiting gas bans and electrification codes in buildings

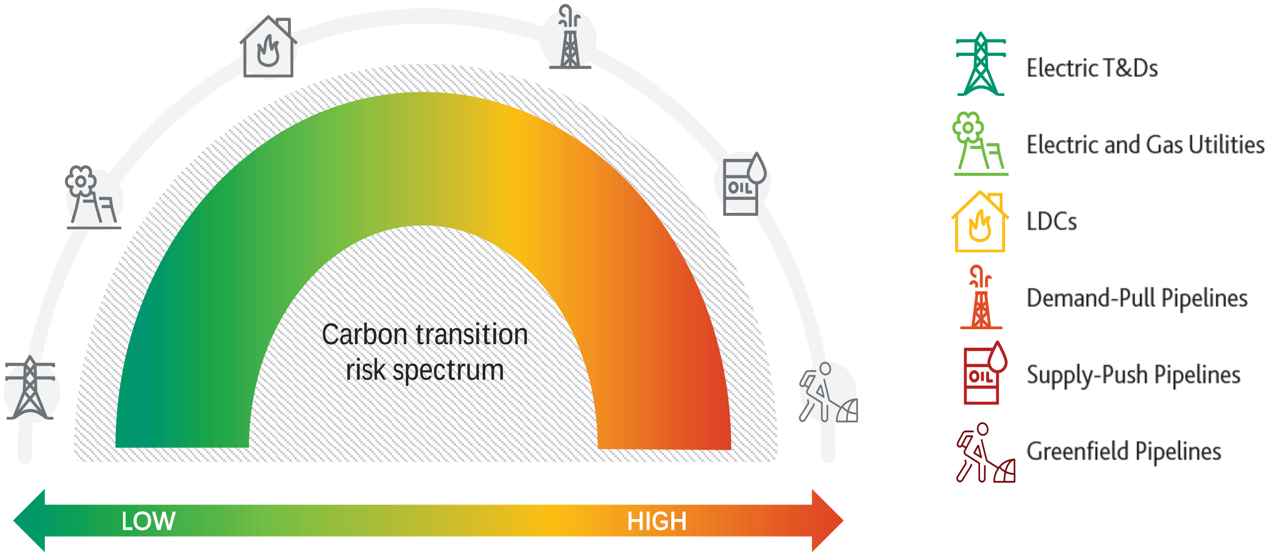


Source: S&P Global Market Intelligence

Company-specific factors to determine credit impact

Factors such as weather and the cost of transitioning away from widespread natural gas use will mean that the credit implications of the carbon transition will differ by company. For now, we see natural gas pipelines with a supply-push customer base as most at-risk because their business is already exposed to competitive market dynamics (such as price and volume fluctuations or counterparty risks) and do not benefit from a monopoly position. By contrast, combination electric and gas distribution utilities are best positioned to absorb a decline in gas use because they can also benefit from the upside of electrification. Demand-pull pipelines and LDCs will be most sensitive to the aforementioned geographical influences, such as local and state politics, weather characteristics and relative consumer costs.

Exhibit 8
The degree of carbon transition exposure depends on a company's asset profile and business mix

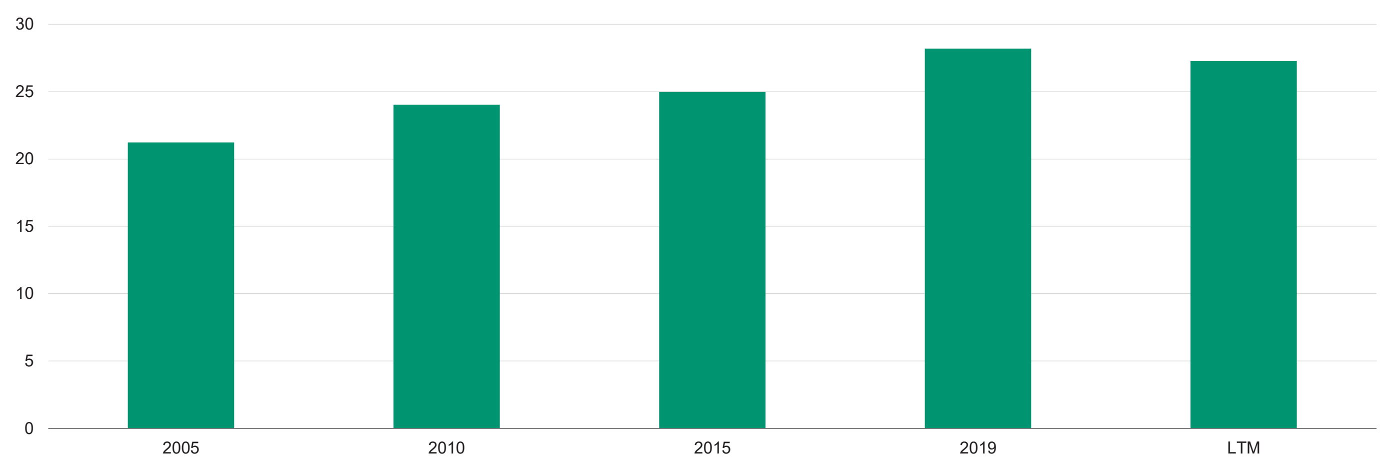


Source: Moody's Investors Service

Supportive regulation likely to help companies avoid stranded asset risk

Based on GAAP-reported property, plant and equipment numbers for the LDC sector, the average depreciation rate is around 3% per year and it has an average remaining depreciable life of about 27 years. As such, stranded asset exposure will likely be manageable for today's gas network if electrification renders gas assets obsolete by 2050. However, the useful life has been increasing over the past 15 years, as shown by the LDC averages shown in Exhibit 9. This trend would need to reverse if gas distribution infrastructure becomes threatened or phased out as part of electrification.

Exhibit 9
Remaining average useful life of LDC property, plant and equipment
GAAP reported figures



Remaining average useful life = net PP&E/D&A
Source: Moody's Investors Service

Even as new investments are made, we expect that state regulators will work with affected utilities and stakeholders to avoid stranded asset risk. US regulators have a strong track record of allowing utilities to recover the cost of any stranded assets once they are authorized in rate base (see "[Regulated Electric and Gas Utilities - US: Renewable generation transition unlikely to create significant stranded asset risk]").

As we have seen with the early retirement of coal-fired electric generation assets, adjusting the useful life of new assets, accelerating depreciation rates of existing assets and securitizing the asset value of at-risk property, plant and equipment are all ways that regulators could ensure full investment recovery or support utility credit quality.

Pace of transition depends on technology, related costs and ultimately public policy

Certain technological advancements, including the prolific use of RNG or hydrogen gas blending, could help to support the use of existing natural gas infrastructure, whereas competing technologies such as battery storage and hydrogen gas storage for electric generation could accelerate electrification efforts and the decline of gas assets.

In either case, the ability of consumers to absorb the cost of implementing any such changes will likely be a key factor in determining the pace and magnitude of asset replacement. Full decarbonization efforts aimed at achieving net-zero emissions will likely come at a hefty cost, ultimately to be borne by utility customers.

Energy prices will be affected by the pace of technological advancement and associated declining cost curves, as well as political efforts to incentivize certain investments (e.g., by way of tax credits). As such, we believe that public policy will be necessary to help achieve the most ambitious of carbon and methane reduction targets and will therefore be a distinguishing factor for the path of energy transition.

Appendix

Rated LDC peer group

Exhibit 10

Rated local distribution company (LDC) peers and selected financial data

$ millions

Company	Rating	Outlook	Revenue	EBITDA	CFO pre-WC	Net PP&E	Total Debt	Capex	Dividends	CFO pre-WC / debt
Atmos Energy Corporation	A1	Stable	2,790	1,286	1,176	12,881	4,850	1,934	274	24.3%
North Shore Gas Company	A2	Stable	165	51	33	479	188	42	16	17.5%
Northern Illinois Gas Company	A2	Stable	1,799	508	502	5,705	1,672	857	-	30.0%
ONE Gas, Inc	A2	Stable	1,503	501	336	4,703	1,954	481	110	17.2%
Peoples Gas Light and Coke Company	A2	Stable	1,121	500	333	4,436	1,628	667	100	20.5%
Southern California Gas Company	A2	Stable	4,763	1,948	1,286	13,915	5,391	1,685	150	23.9%
Spire Alabama Inc.	A2	Stable	454	173	163	1,329	626	174	20	26.1%
UGI Utilities, Inc.	A2	Stable	1,033	340	305	2,951	1,345	346	43	22.7%
Connecticut Natural Gas Corporation	A3	Positive	375	94	97	737	263	52	60	36.7%
Berkshire Gas Company	A3	Stable	78	21	23	192	75	15	-	30.2%
CenterPoint Energy Resources Corp.	A3	Stable	6,326	748	520	6,046	2,468	833	-	21.1%
DTE Gas Company	A3	Stable	1,368	436	373	4,173	1,903	521	129	19.6%
New Jersey Natural Gas Company	A1*	Stable	734	244	189	2,514	1,051	335	-	18.0%
Piedmont Natural Gas Company, Inc.	A3	Stable	1,302	564	484	6,960	3,019	989	-	16.0%
Questar Gas Company	A3	Stable	904	219	196	2,446	887	195	-	22.1%
Southern Connecticut Gas Company	A3	Stable	362	96	133	843	321	77	30	41.4%
Spire Missouri Inc.	A1*	Stable	1,166	325	278	3,048	1,476	356	54	18.8%
UNS Gas, Inc.	A3	Stable	114	32	28	315	101	26	-	27.5%
Washington Gas Light Company	A3	Stable	1,251	362	277	4,506	1,662	392	100	16.7%
Wisconsin Gas LLC	A3	Stable	580	190	135	1,888	706	198	30	19.1%
Boston Gas Company	A3	Negative	1,557	410	407	5,075	2,105	591	-	19.3%
KeySpan Gas East Corporation	A3	Negative	1,115	353	288	3,949	1,456	435	-	19.8%
South Jersey Gas Company	A3	Negative	563	263	152	2,647	1,257	248	-	12.1%
Southwest Gas Corporation	A3	Negative	1,355	530	346	5,936	2,836	769	101	12.2%
Colonial Gas Company	A3	No Outlook	268	69	34	405	124	24	-	27.8%
Brooklyn Union Gas Company, The	A3	RUR-Down**	1,770	498	323	5,972	2,819	900	-	11.5%
Northwest Natural Gas Company	Baa1	Stable	747	237	175	2,505	1,367	252	55	12.8%
PNG Companies LLC	Baa1	Stable	909	308	264	2,422	1,517	280	75	17.4%
Public Service Co. of North Carolina, Inc.	Baa1	Stable	521	222	111	2,282	892	190	-	12.4%
SEMCO Energy, Inc.	Baa1	Stable	658	154	122	1,214	557	162	60	21.9%
Southern Company Gas Capital	Baa1	Stable	3,514	1,533	1,275	12,784	5,836	1,467	502	21.8%
Yankee Gas Services Company	Baa1	Stable	536	142	104	1,818	725	221	38	14.4%

All financial measures are Moody's adjusted as of latest available last twelve months.
*Senior Secured Rating
**RUR-Down = Rating(s) Under Review for Downgrade

Moody's related publications

Issuer Comments

- Public Service Enterprise Group Incorporated: Non-nuclear generation asset sale accelerates transition to more regulated utility holding company, 12 August 2020
- Dominion Energy, Inc.: Dominion will sell around $10 billion of natural gas assets and cancels Atlantic Coast Pipeline, credit positive, 6 July 2020
- CenterPoint Energy Resources Corp.: CenterPoint's sale of its energy services business will reduce business risk and debt, a credit positive, 25 February 2020
- Spire Missouri Inc.: Court orders Spire Missouri to partially refund disallowed portion of pipeline replacement surcharge, a credit negative, 26 November 2019

Sector In-Depth

- ESG - Canada: Focus on Indigenous rights increasingly vital for project execution, corporate activities, 22 June 2020
- Electric and gas – US: Pipeline cybersecurity standards help plug security loophole in utility supply chain, 10 July 2019
- Regulated Electric and Gas Utilities - US: Renewable generation transition unlikely to create significant stranded asset risk, 5 November 2018

Sector Comment

- Regulated electric and gas utilities – New York: Threat to revoke National Grid's operating license is credit negative for utilities, 18 November 2019

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CREDIT OPINION
24 June 2024

Update

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RATINGS

Ontario Power Generation Inc.

Domicile	Ontario, Canada
Long Term Rating	A3
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Ontario Power Generation Inc.

Update to credit analysis

Summary

Ontario Power Generation's (OPG) credit profile reflects a Baseline Credit Assessment (BCA) of baa3 with a 3 notch uplift based on its high dependence on and a high probability of extraordinary support from the Province of Ontario (Aa3 positive).

OPG's credit profile benefits from its substantial regulated nuclear and hydroelectric operations that are expected to generate the vast majority of its relatively stable cash flow. OPG's contracted assets generally exhibit long contract tenors and have a strong counterparty in the Ontario Independent Electricity System Operator (IESO, Aa3 positive) to which most assets are contracted and to which they pass through most of their costs. The company also has diversification benefits across its extensive fleet.

Offsetting these credit strengths, OPG has a large capital program that has very high levels of execution risk associated with some nuclear capital expenditures. OPG has exceeded our expectations on its Darlington nuclear refurbishment by completing its most recent unit 169 days ahead of schedule. The company's success at Darlington may carry over as it embarks on the refurbishment of units 5-8 of the Pickering nuclear generating station as well.

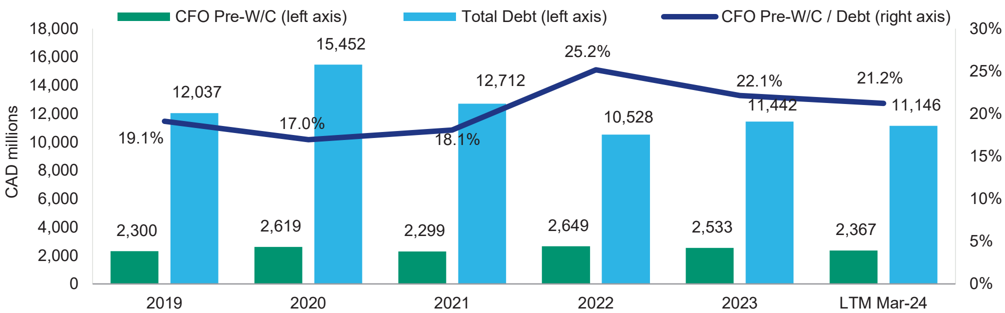
The company is also moving forward with a small modular reactor (SMR) program at Darlington which carries very high levels of execution risk. OPG expects the first of four potential units to be in commercial operation in 2029. While we expect these units to form part of its regulated fleet, at this time it is unclear what the extent of the regulatory support, if any, the company will have for the Pickering refurbishment and the SMR program during construction.

We expect the company's CFO pre-W/C to debt ratio to be sustained in the 17%-22% range over the next few years. OPG does not pay a dividend and reinvests all of its cash flow into maintaining and growing its asset base, although we expect debt to grow to fund its capital program. The company is exposed to availability risk across its fleet of generation assets and some hydrology risk. While small, its merchant generation segment has grown as a result of several 100% debt financed acquisitions and we think OPG's large capital program lessens the probability of additional, material debt financed M&A transactions.

OPG is 100% owned by the Province of Ontario and is considered a government related issuer (GRI) under our GRI methodology. The three notch uplift attributed to OPG as a GRI incorporates our expectation of an enduring link between OPG and the Province. Our high support assumption considers that OPG produces more than half of the power generated in the Province at a comparatively low cost, making its infrastructure essential to the Ontario economy. OPG also implements government policy, its board is appointed by the Province

and the Ontario Electricity Financial Corporation (OEFC, Aa3 positive), a crown corporation, is a source of debt capital for OPG. Our assessment of high dependence reflects that both OPG and the Province largely rely on the same revenue base and share some political risks.

Exhibit 1
Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt



All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Credit strengths

» Primarily regulated generation facilities support stable cash flow generation

» Non-regulated generation segment dominated by long term contracts

» Our expectation of support from the Province of Ontario given its 100% ownership

» Diversification benefits by power generation site and units, as well as fuel source

Credit challenges

» Large capital program, which has very high levels of execution risk associated with some nuclear capital expenditures

» Uncertain regulatory support for large capital projects during construction

» Merchant cash flow entails more risk

» Availability risk across the fleet, including potential weak hydro conditions

Rating outlook

The stable outlook incorporates the following expectations:

» The company will continue to execute the Darlington nuclear refurbishment on time and budget

» It will maintain a CFO pre-WC/debt ratio in the 17-22% range over the next few years

» The relationship with the Province will remain stable and supportive

Factors that could lead to upgrade

» An upgrade is unlikely given the very high levels of execution risk associated with some of its upcoming nuclear capital expenditures

» CFO pre-WC/debt sustained above 20%

» An improvement in regulatory outcomes

» An upgrade of the Province to Aa1

Factors that could lead to downgrade

» Challenges, delays or cost overruns related to its capital program

» A reduction in the probability of support from the Province

» A deterioration in financial metrics such that CFO pre-WC/debt is forecast to fall below 15% on a sustained basis

» A weakening of the business risk profile by, for example, by further growing the merchant segment

Key indicators

Exhibit 2

Ontario Power Generation Inc.

	2019	2020	2021	2022	2023	LTM Mar-24
C O re W C Interest Interest						
C O re W C ebt						
CFO Pre-W/C – Dividends / Debt						
ebt Capita i ation						

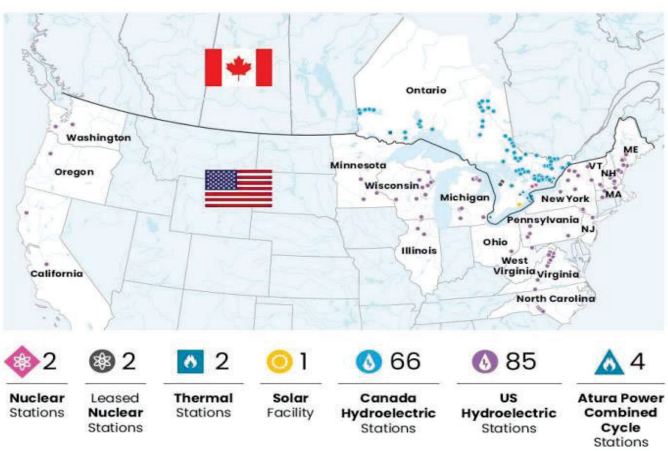
All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Profile

Headquartered in Toronto, Ontario, OPG is an electricity generation company wholly owned by the Province with an in-service generating capacity of 18,236 MW at March 31, 2024. OPG owns and operates 75 generating stations, 2 of which are nuclear, 66 hydroelectric, 2 thermal, 1 solar and 4 combined-cycle natural gas-fired plants in Ontario, Canada. In the US, OPG also wholly or jointly owns and operates 85 hydroelectric stations and has interests in 14 other hydroelectric and 2 solar facilities. OPG's nuclear and most of its hydroelectric facilities are regulated by the Ontario Energy Board (OEB).

Exhibit 3

OPG's service territory



Source: Company filings

Detailed credit considerations

Primarily regulated and contracted assets generate predictable cash flow

OPG's strong business risk profile is driven by its high proportion of regulated and contracted cash flow. Regulated earnings from OEB's rate regulated assets accounted for 75% of the EBITDA (all figures rounded) from its generating business segments during last twelve months end 31 March 2024, including 48% from the regulated nuclear generation segment and 27% from the regulated hydroelectric generation segment. The Atura Power combined cycle plants generated 18% of EBITDA and contracted hydroelectric and other, which has more contracted cash flow than merchant, generated 7% of EBITDA.

The company has extensive diversity by generation station and unit within each segment, reducing volatility. It also has some hydro risk, albeit low, and negligible levels of commodity price risk, a key credit positive. Unlike most other regulated utilities, OPG owns generating assets only and does not have any lower risk transmission and distribution assets. As a result, as a higher risk generation company, OPG is exposed to availability risks on all of its assets which drives more variability in its financial results compared to most T&D companies.

The company's regulated assets should provide predictable cash flow going forward. A multiyear rate plan in place from 2022-2026 establishes volumetric prices for the regulated nuclear segment and a change in Ontario Regulation 53/05 undertaken by the Province provides pricing for regulated hydroelectric assets over this period.

The nuclear generation segment benefits from diversification across 2 nuclear generating stations, with 6 (Pickering) and 4 (Darlington) operating reactors respectively, that enable the company to maintain high levels of generation and cash flow while undertaking nuclear refurbishment. Pickering Units 1 and 4 are set to be shut down in the second half of 2024.

In the second half of 2021, OPG reached a settlement with its intervenors that was subsequently approved by the OEB. The settlement led to a 2022-2026 nuclear generation revenue requirement of CAD16 billion, compared to CAD16.7 billion in the company's rate case application. Regulated prices are designed to support an allowed level of operating costs and earn a return on its capital costs for a forecast amount of generation. Significantly, the settlement supports growth in rate base over the period as the company continues to make progress on the Darlington refurbishment.

Nuclear rate base for the period 2022-2026 is allowed an ROE of 8.66% and hydroelectric 9.33% and both have equity capital of 45%. Performance that deviates by more than 300 bps in any given year may lead to a regulatory review. Regulatory lag has improved considerably with the most recent rate case, where a payments order was issued in January 2022 with new rates effective that month, although the extensive use of deferral accounts that reduce cash flow is a credit negative. Nuclear rates have significantly increased over the past several years. As recently as the first half of 2017, nuclear rates were CAD 59.29 MWh, a price that, like the table below, incorporates rates riders for variance and deferral accounts. The table below includes rates increases to both nuclear and hydroelectric rates following a 13 June 2024 OEB decision that addressed several issues, including multiple variance accounts.

Exhibit 4

	2023	2024	2025	2026
Regulated Nuclear Generation Total price ($/MWh)	109.0	107.8	111.6	123.8
Approved Nuclear Rate Base (CAD million)	8,615.0	11,033.0	12,189.0	12,992.0
Forecast Nuclear Production (TWh)	31.2	34.0	31.1	21.9
Regulated Hydroelectric Generation price ($/MWh)	44.9	47.5	47.2	47.2

Rates for 2024-2026 effective 1 July 2024
Source: Ontario Energy Board

The regulated hydroelectric facilities include 54 generating stations in Ontario across a number of river systems with prices established by an incentive rate mechanism. On 10 November 2020, the Province took steps to establish the hydroelectric base regulated price for the period 2022-2026 at the 2021 regulated price. While this provides price certainty for the period, it may be challenging at times for OPG to earn its allowed returns over the period given ongoing investments in rate base assets that exceed depreciation. Mitigating this challenge is the increase in production that will directly result from some of these investments.

The contracted hydroelectric and other generation segment consists of lower risk contracted assets in Ontario and higher risk, primarily merchant US based assets. Ontario based assets are all under contract on generally favorable terms and almost all of the contracts are with the IESO. The largest of these is the project financed Lower Mattagami Energy Limited Partnership (A1 stable). It, and other contracted hydro facilities like it, including UMH Energy Partnership (A2 stable), have strong contract terms which include limited hydro risk and contract expiries over the 2059-2067 period. The two Ontario thermal plants in this segment have substantial capacity, but are largely peaking facilities and typically have low levels of generation. They are primarily compensated based on their availability and have cost pass through provisions, however they have shorter contract tenors compared to the contracted hydro facilities.

OPG has grown its US presence and its Atura business segment through acquisitions in the past few years. The Atura Power business consists of 4 combined cycle gas plants that operate under contract with the IESO or other long term contracts on similar terms to the above mentioned thermal plants. The latest contract expiry is the 900 MW Napanee plant that operates under a 20 year contract that expires in 2040. This segment is also pursuing opportunities in battery storage and hydrogen production, including the construction of a 250MW four hour battery storage system at the site of one of its gas plants. It expects to complete construction in 2026 and the investment is supported by a 21 year capacity agreement with the IESO. The US assets have some contracts, but are primarily merchant assets with substantially more risk than the rest of the portfolio.

Large, nuclear focused capital program with varying degrees of execution risk

We expect OPG's large capital program to grow rapidly to about CAD5-6 billion a year with varying degrees of execution risk. Weighing on the company's business risk profile in particular is the risk associated with nuclear capex with the company's small modular reactor program at the very high end of the risk spectrum, with less risk associated with Pickering refurbishment and lower risk associated with Darlington refurbishment. At this time, it is unclear what regulatory support, if any, the company will have for Pickering refurbishment and the SMR program during construction. For example the company may capitalize an allowance for funds used during construction which would provide no cash flow support or it may receive cash construction work in progress which would provide comparably more support. We expect the company will publish a cost estimate associated with the SMR program within the next year. Moving forward with large projects without a public cost estimate and certainty on the degree of regulatory support during construction differentiates OPG from investor owned utilities.

Darlington refurbishment execution risk is diminishing

Execution risk associated with nuclear refurbishment at the Darlington Generation Station is diminishing given the company's strong track record of execution on the first 2 units. Unit 3 connected to the grid 169 days ahead of schedule, resulting in the production of an incremental 3TWh of electricity. The company applied more than 1000 lessons learned from Unit 2's refurbishment and applied that to Unit 3 and management continues to incorporate learnings into subsequent units. The refurbishment is tracking to its forecast cost of CAD12.8 billion with the exception of cost increases driven by COVID.

Given the success at Unit 3, management now expects Unit 1 to complete refurbishment and return to service in Q4 of 2024, well ahead of its prior projected in service date of Q2 2025. The time table for Unit 4 is the second half of 2026, although we think there is a high probability that this unit will also return to service well ahead of schedule. The regulatory framework continues to incorporate the forecasted capex to bring the units in service, so it is already reflected in both rate base and revenues without the need for OPG to file a rate case.

Exhibit 5

Darlington refurbishment timeline

Darlington	Capacity	Refurbishment start date	Refurbishment completion date
Unit 2	878	Oct-16	Jun-20
Unit 3	878	Sep-20	Jul-23
Unit 1	878	Feb-22	Q4-2024
Unit 4	878	Jul-23	H2-2026

Source: Company filings

Pickering refurbishment also moving forward but awaiting nuclear regulatory approval

Following a request from the Provincial government, OPG updated the feasibility assessment for the refurbishment of Pickering Units 5 to 8, which had been scheduled for shutdown in the coming years. Subsequently, the Provincial government requested that OPG proceed with the refurbishment of these units. In response, the company has sanctioned CAD2 billion in capital expenditure to advance the project. The refurbishment plan is contingent on receiving approvals from the Canadian Nuclear Safety Commission (CNSC). The company's schedule involves shutting down Units 5 to 8 in 2026, with a phased plan to return units to service by the mid 2030's. Units 1 and 4 are slated for shutdown in the latter half of 2024, while Units 2 and 3 were placed in safe storage more than a decade ago.

Small modular reactors entail high execution risk

The company is also planning to build four 300 MW SMR's adjacent to the Darlington station, that we view as new nuclear construction entailing very high execution risk. The company expects the first unit to be in commercial operation in 2029, and will start construction on subsequent units only after the first one is complete, with the remaining units in service in the mid-2030's. Each SMR will be a GE Hitachi BWRX-300 reactor and the company expects to yield benefits from a fleet approach.

The OEB has determined that SMR related costs may be recorded in a nuclear development variance account (NDVA). The NDVA does not have a limit but is subject to prudence review. A 13 June 2024 OEB decision approved the recovery of CAD108 million over the period 1 July 2024 through the end of 2026. These costs were associated with the non-capital preliminary planning and preparation costs that were incurred between 2020 and 2022. The company did not incorporate any SMR related spending into its 2022-2026 rate case application. With significant spending likely in the next few years and uncertainty around regulatory support during construction, the burden on the company's balance sheet is likely to grow over time. The company has not yet provided an SMR cost forecast, but we believe a cost estimate is likely following the receipt of a license to construct from the CNSC in early 2025. We believe execution risk will be highest with the first unit, with diminishing risk on subsequent units.

Financial metrics to remain reasonably predictable

We expect CFO pre-WC/debt to be in the range of 17-22% over the next few years with cash flow to remain reasonably predictable, although generation levels will drive some variability. These variations in generation result in a wider range in forecast financial metrics compared to transmission and distribution companies. We expect the remaining units at Darlington to be completed ahead of schedule, providing some support to financial metrics. Nonetheless, pressure on metrics may build in the latter part of the decade as the company progresses with both the Pickering refurbishment and the SMR's since they do not currently have any form of cash flow recovery during construction and will result in significant debt issuances.

We expect both internally generated cash flow and debt issuances to fund the capital program, which is focused primarily on nuclear capex, sustaining capital and other smaller projects that have relatively low levels of execution risk. The company exhibits credit supportive financial policies and OPG seldom pays a dividend. However, the offset to this is that, unlike public companies, we think it could be challenging to issue equity if required, limiting OPG's financial flexibility.

Further debt financed M&A remains a risk, although management has indicated that they plan to focus on their existing assets and, given the planned nuclear projects, the company has ample organic growth opportunities.

There is some structural subordination stemming from project finance debt at Canadian contracted assets totaling about CAD2.4 billion at 31 March 2024 and about CAD486 million of debt on US assets. However, unlike the vast majority of regulated utilities, there is no debt outstanding at the key regulated businesses that generated about 72% of EBITDA in 2023. That, in conjunction with primarily centralized funding at OPG, results in no notching for structural subordination.

A driver of improving financial metrics over the past few years has been the significant change in the company's pension plan, which had led to a decline in our pension driven debt adjustment to CAD900 million at 31 March 2024 from a high of CAD5 billion at FYE2020, supporting financial metrics. The company is also eligible for different types of investment tax credits, and these will likely provide incremental support to the company's financial profile over time.

High probability of support from the Province provides an uplift to OPG's credit profile

Given the 100% ownership interest of the Province, OPG is considered a government related issuer (GRI) under our GRI methodology. Based on our estimate of a high probability of extraordinary support in case of financial distress, the A3 credit profile incorporates 3 notches of uplift from OPG's BCA of baa3.

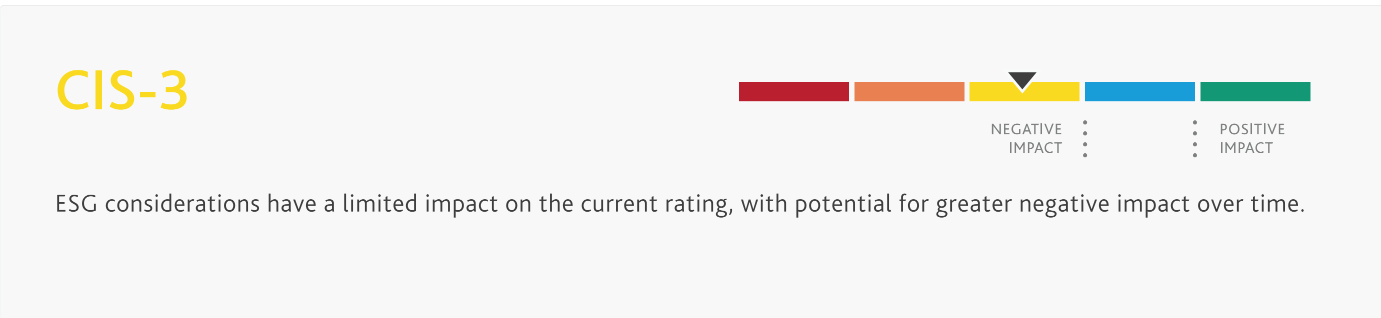
The company's ratings incorporate our expectation that extraordinary financial support to OPG would be forthcoming from the Province if needed. Our high support assumption considers that OPG produces more than half of the power in the Province at a comparatively low cost, making its infrastructure essential to the Ontario economy. OPG also implements government policy which can have negative credit implications. For example, in an effort to reduce and smooth rate increases for customers, Ontario Regulation 53/05 mandated the creation of the rate smoothing and deferral account (RSDA), including the financing of the RSDA at the long term debt rate and recovery over a 10 year period after the Darlington refurbishment is complete. The Province also appoints OPG's board, reviews its business plans and is a source of debt financing through the OEFC. We do not believe there are any barriers that would prevent the Province from providing timely support.

Our assessment of high dependence reflects that both OPG and the Province largely rely on the same revenue base and share some political risks. While the OEFC is a source of financing, OPG has been increasing the level of its borrowing from public debt capital markets.

ESG considerations

Ontario Power Generation Inc.'s ESG credit impact score is CIS-3

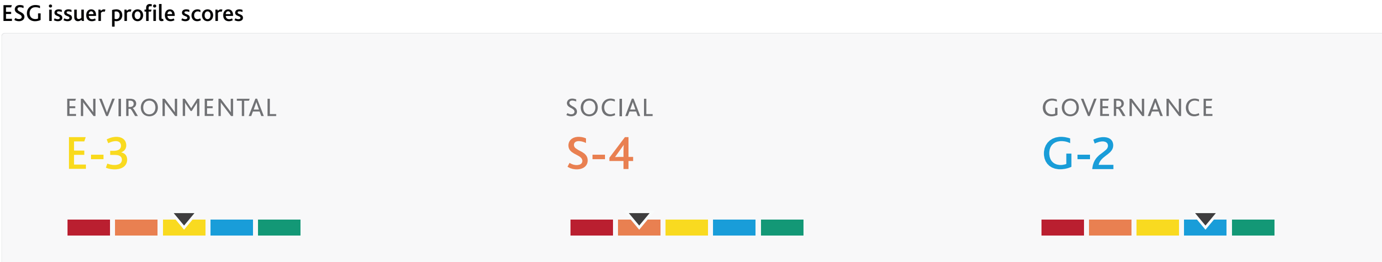
Exhibit 6
ESG credit impact score



Source: Moody's Ratings

OPG's **CIS-3** indicates that ESG considerations have a limited impact on the current credit rating with potential for greater negative impact over time as a result of physical climate risks and demographic and social trends related primarily to affordability.

Exhibit 7
ESG issuer profile scores



Source: Moody's Ratings

Environmental

OPG's **E-3** score reflects exposure to physical climate risks mostly due to extreme weather patterns which is a challenge for the sector. OPG's nuclear generation assets also have exposure to waste management and pollution risks. While the company has not had any issues with its nuclear fleet or nuclear waste, it remains an inherent risk for nuclear operators. The company has limited exposure to carbon transition risks owing to its portfolio of primarily nuclear and renewable assets.

Social

OPG's **S-4** score reflects the high risk related to demographic and societal trends associated with rate pressures as evidenced by some lengthy delays associated with recovering some costs. Factors contributing to rate pressures include more expensive sources of energy in the Province, particularly some high priced legacy renewable contracts.

Governance

OPG's **G-2** score is a function of its governance that is established by its sole owner. The company has some exposure to board structure, policies, & procedure risks resulting from its sole ownership by the Province of Ontario.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

OPG has an adequate liquidity profile driven by about CAD3.3 billion of available credit facilities, unrestricted cash and expected cash flow that together are sufficient to cover its uses for the next 12 months.

As of March 31, 2024, OPG had a CAD1 billion committed credit facility that expires in May 2028 and a USD750 million 364 day revolving committed facility that expires in November 2024 with a one year term out provision at the company's option. Both of these facilities backstop CAD1 billion and USD750 million commercial paper programs that had no commercial paper outstanding at December 2023. In addition, the company has drawings of CAD571 million available on a facility from the Canada Infrastructure Bank to support SMR investments that expires in Sept 2027 and CAD750 million undrawn on a facility with the OEFC that expires in December 2026.

The company has asset level facilities of CAD460 million committed at Lower Mattagami Energy Limited Partnership that expires in August 2028 and a USD20 million committed facility at OPG Eagle Creek Holdings LLC and subsidiaries that combined supported letters of credit of about CAD85 million. We have conservatively assumed that letters of credit of CAD445 million that are not allocated to above listed credit facilities are supported by corporate facilities and are not reflected in our calculations of available credit facilities.

Moody's forecasts cash flow from operations over the next twelve months to be close to the CAD2.4 billion it generated over the last twelve months. In addition to the available credit facilities of CAD3.3 billion and cash and cash equivalents (including restricted cash of CAD22 million at 31 December 2023) of CAD0.9 billion as of 31 March 2024, these sources should be sufficient to cover uses comprising CAD5-6 billion of expected capital expenditures and around CAD203 million of debt maturities in the next 12 months. We expect OPG will rely in part on debt to finance its ongoing capex and refinance its upcoming debt maturities. The company's liquidity position benefits from the lack of regular dividends payable to the Province.

There are material adverse change clauses in its credit facilities that could prevent borrowings under certain circumstances, a credit and liquidity negative. Moody's expects the company to manage its program maturities, cash on hand and its swing lines in a prudent fashion.

Rating methodology and scorecard factors

The principal methodology used for this rating is the Regulated Electric and Gas Utilities rating methodology. The scorecard- indicated outcome for our 12-18 months forward view is Baa1, two notches above the BCA of baa3 with the difference attributable to elevated capex risk and OPG's generation asset base compared to all peers having at least some lower risk transmission and distribution assets.

Exhibit 8
Methodology scorecard factors
Ontario Power Generation Inc.

Regulated Electric and Gas Utilities Industry Scorecard	Current LTM 3/31/2024		Moody's 12-18 Month Forward View	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	Baa	Baa	Baa	Baa
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	Ba	Ba	Ba	Ba
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	A	A	A	A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.5x	Aa	6x - 8x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	21.7%	Baa	17% - 22%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	21.6%	A	17% - 22%	A
d) Debt / Capitalization (3 Year Avg)	35.2%	A	35% - 40%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		Baa1		Baa1
b) Actual Rating Assigned		A3		A3
Government-Related Issuer	**Factor**			
a) Baseline Credit Assessment	baa3			
b) Government Local Currency Rating	Aa3			
c) Default Dependence	High			
d) Support	High			
e) Actual Rating Assigned	A3			

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Sources: Moody's Financial Metrics™ and Moody's Ratings forecasts

Appendix

Exhibit 9

Peer comparison

Ontario Power Generation Inc.

	Ontario Power Generation Inc. A3 Stable			Constellation Energy Generation, LLC Baa1 Stable			NextEra Energy, Inc. Baa1 Stable		
(in $ millions)	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-21	FY Dec-22	FY Dec-23	FY Dec-22	FY Dec-23	LTM Mar-24
e enue									
C O re W C									
ota ebt									
C O re W C Interest Interest									
C O re W C ebt									
CFO Pre-W/C – Dividends / Debt									
ebt Capita i ation									

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

Source: Moody's Financial Metrics™

Exhibit 10

Moody's – adjusted cash flow metrics

Ontario Power Generation Inc.

(in CAD millions)	2019	2020	2021	2022	2023	LTM Mar-24
FFO	1,828.2	2,538.3	2,231.0	2,471.0	2,590.0	2,409.0
Ot er						
CFO Pre-WC	2,300.2	2,619.3	2,299.0	2,649.0	2,533.0	2,367.0
+/- ΔWC						
CFO	2,399.2	2,722.3	2,358.0	2,872.0	2,419.0	2,481.0
i						
Cape						
FCF	531.0	1,040.0	396.0	423.0	(382.0)	(402.0)
C O re W C ebt						
C O re W C i i en s ebt						
O ebt						
C ebt						
e enue						
Interest pense						
et Income						
ota ssets						
ota Liabi ities						
ota uit						

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

Periods are fiscal year-end unless indicated.

Source: Moody's Financial Metrics™

Exhibit 11

Moody's – adjusted Debt reconciliation

Ontario Power Generation Inc.

(in CAD millions)	2019	2020	2021	2022	2023	LTM Mar-24
As reported debt	8.4	10.4	9.8	10.2	10.5	10.2
ensions						
Operatin Leases						
on tan ar ustments						
Moody's – adjusted debt	12.0	15.5	12.7	10.5	11.4	11.1

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

Periods are fiscal year-end unless indicated.

Source: Moody's Financial Metrics™

Exhibit 12

Moody's – adjusted EBITDA reconciliation

Ontario Power Generation Inc.

(in CAD millions)	2019	2020	2021	2022	2023	LTM Mar-24
As reported EBITDA	2.2	3.0	2.9	3.4	3.6	3.4
ensions						
Operatin Leases						
nusua						
Moody's – adjusted EBITDA	2.1	2.9	2.7	3.0	3.4	3.2

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Ratings

Exhibit 13

Category	Moody's Rating
ONTARIO POWER GENERATION INC.	
Outlook	Stable
Senior Unsecured -Dom Curr	A3
Commercial Paper	P-2

Source: Moody's Ratings

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CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

COMMENTS — 14 Feb, 2024 | 15:04 —
APAC, United States of America, Latin America, Canada, EMEA, APAC

Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens

Primary Credit Analyst:	**Gabe Grosberg**
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Sector	Utilities & Power, Oil & Gas, Infrastructure & Utilities, Utilities & Power, Midstream
Tags	Americas, Latin America, APAC, EMEA
Topic	Confronting Credit Headwinds , Seeking Energy & Climate Resilience , Outlook 2024

View Analyst Contact Information

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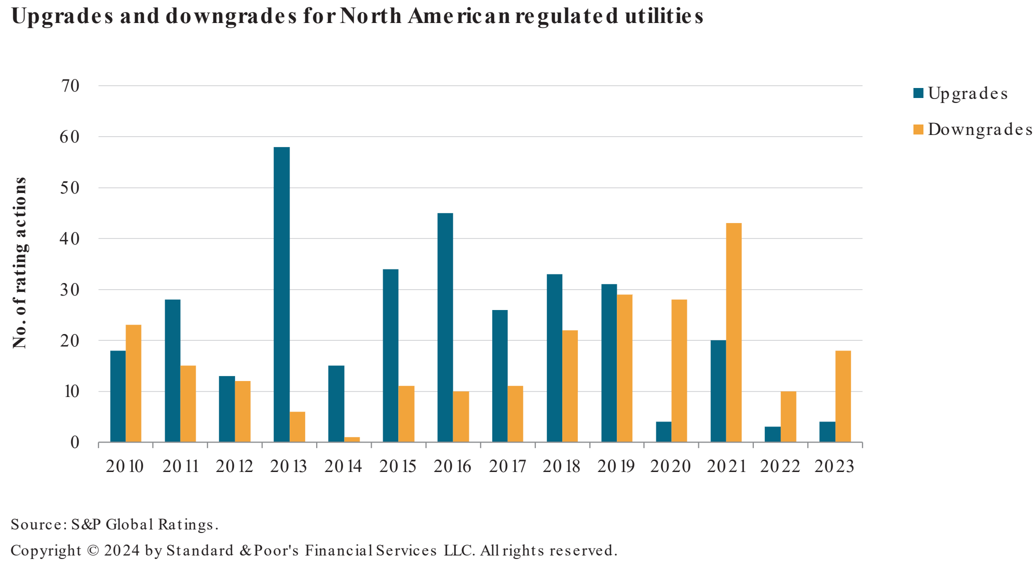
Key Takeaways

- We are updating our 2024 outlook on the investor-owned North American regulated utility industry to negative.
- Given the relatively high percentage of companies with negative outlooks, we expect that 2024 will likely be the fifth consecutive year that downgrades outpace upgrades.
- The industry faces rising physical risks and high cash flow deficits that may not be sufficiently funded in a credit-supportive manner.
- Still, we expect that the utility industry will maintain a median investment-grade rating of 'BBB+'.
- We also expect that a smaller percentage of companies rated 'BBB' or lower are more likely to implement measures to maintain or even improve credit quality.

Credit quality for North American investor-owned regulated utilities has weakened over the past four years, with downgrades outpacing upgrades by more than three times. We expect downgrades to again surpass upgrades in 2024 for the fifth consecutive year. In the decade prior to 2020, upgrades generally outpaced downgrades in the industry.

Chart 1

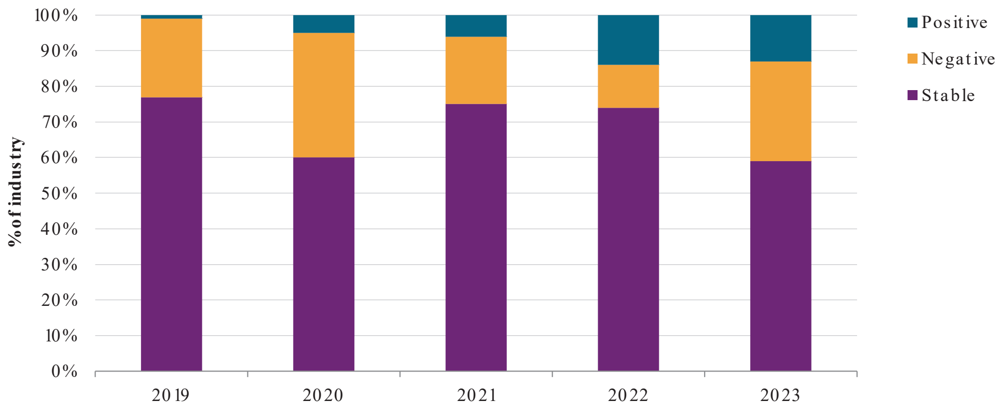


High Percentage Of Negative Outlooks

Currently, about 28% of the industry has a negative outlook or is listed on CreditWatch with negative implications. This is now the third time in the past five years that the year-end percentage of negative outlooks and CreditWatch listings has exceeded 20%. Given the current high percentage of negative outlooks it is increasingly likely that credit quality will again weaken in 2024.

Chart 2

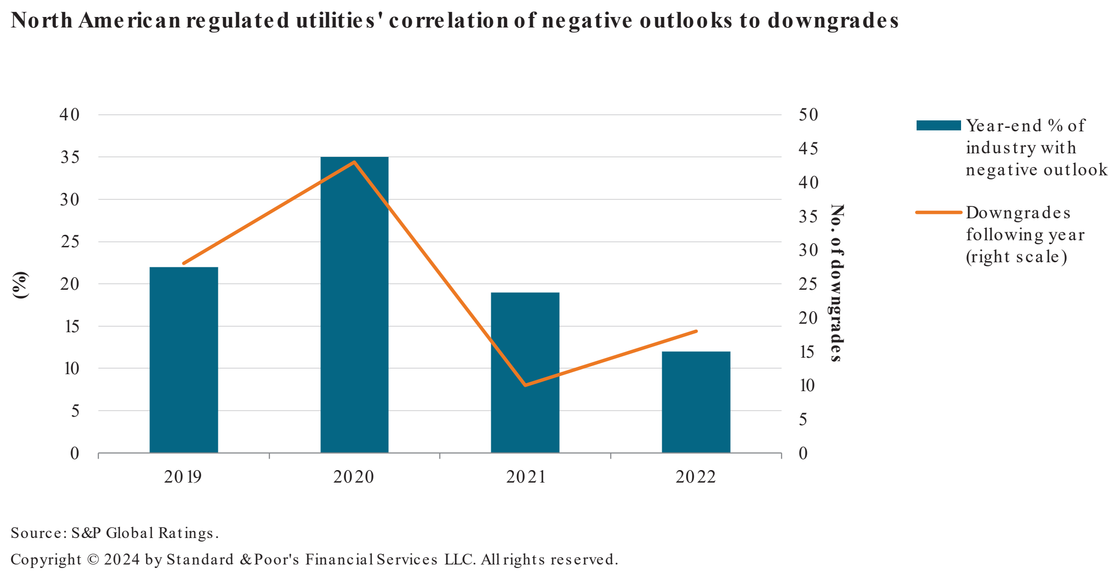
Outlooks for the North American regulated utilities industry
At year end.



Source: S&P Global Ratings.

Future rating actions are typically correlated with our outlooks. The industry's share of negative outlooks reached a record high of 35% at year-end 2020, and the following year saw a record 43 downgrades. The industry's current percentage of negative outlooks is significantly larger than it was at year-ends 2021 and 2022, when downgrades still materially outpaced upgrades the following year. As such, given the current high percentage of negative outlooks, we anticipate that 2024 will be another challenging year for the industry's credit quality.

Chart 3

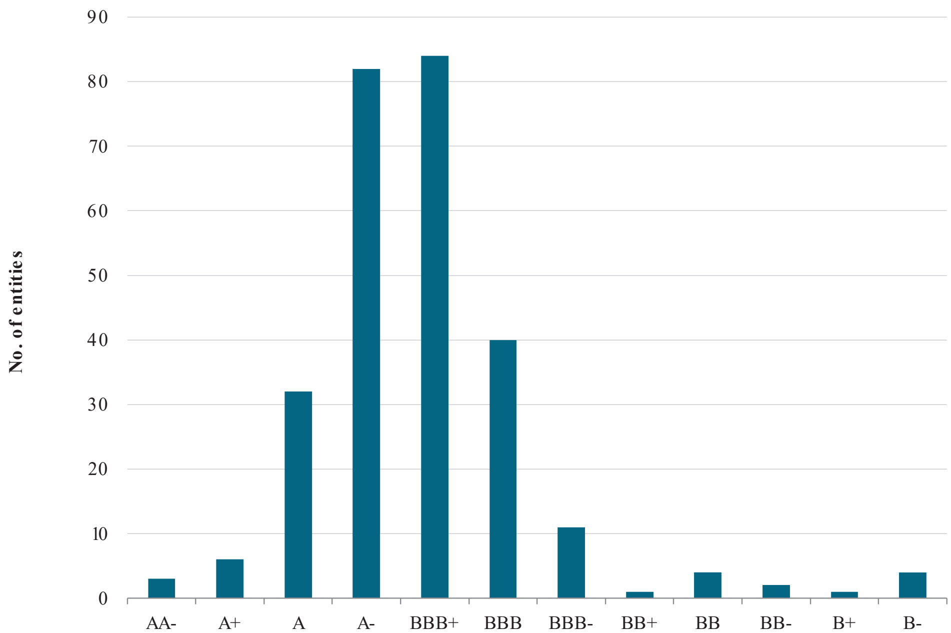


Median Credit Rating To Remain Investment Grade

The median rating among North American investor-owned regulated utilities is 'BBB+'. Despite our expectations for downgrades to again outpace upgrades in 2024, we expect that the median rating will remain 'BBB+'. To weaken the median rating to 'BBB', the industry would need about 70 downgrades to 'BBB' from the 'BBB+' level or above. This degree of credit weakening is well above our base-case expectations for 2024. However, this magnitude of weakening could occur over the next three years if this negative pace persists.

Chart 4

North American regulated utilities ratings distribution
As of Feb. 1, 2024.



Source: S&P Global Ratings.

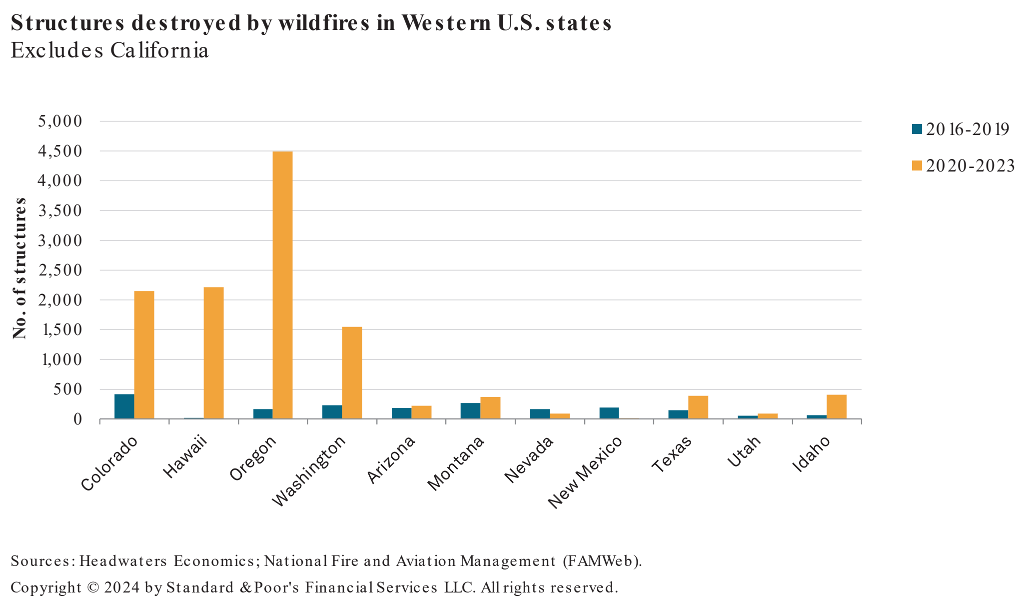
Headwinds To Credit Quality

The industrywide negative outlook reflects rising physical risks as well as financial measures, which are weakening due to rising capital spending and cash flow deficits that are not funded in a sufficiently credit supportive manner. Furthermore, much of the industry operates with minimal financial cushion from their downgrade threshold. This increases the susceptibility to a downgrade if negative events occur beyond our base case.

Increase in physical risk

Climate change and an increase in wildfire risks are threatening credit quality. Wildfire risk was generally limited to California utilities just five years ago but has spread over the past several years.

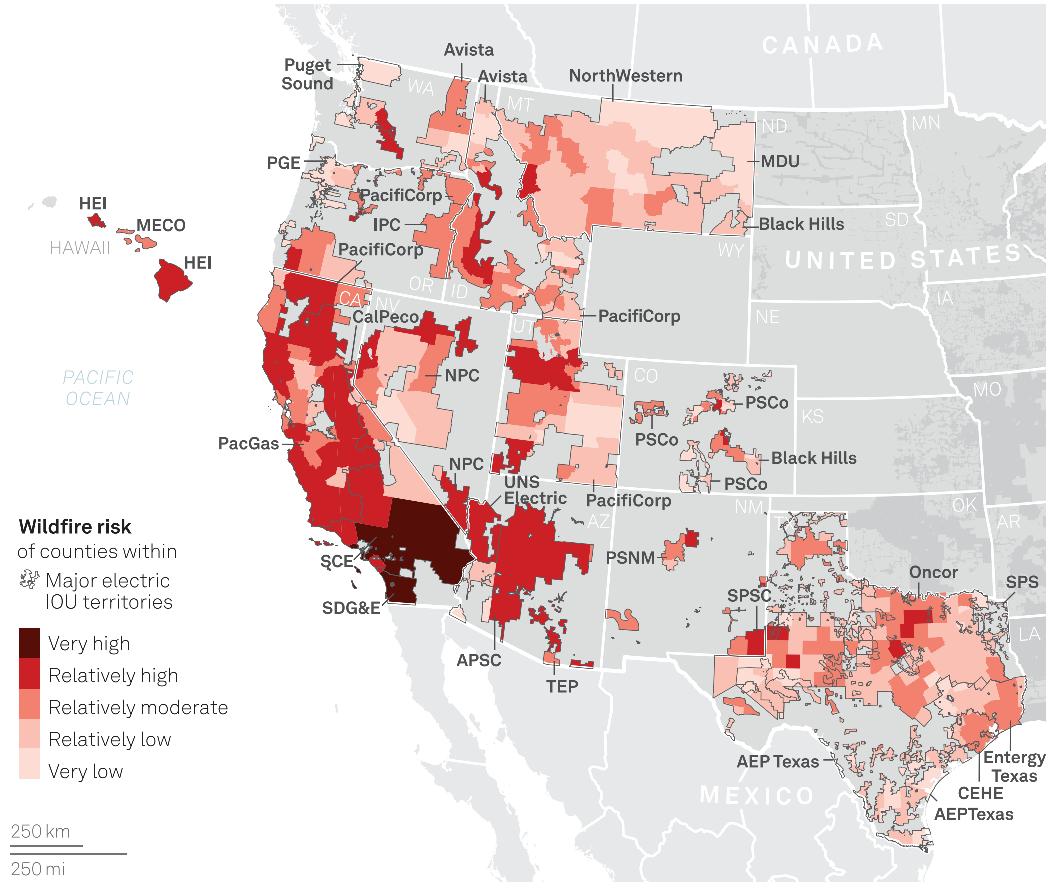
Chart 5



Since 2020, the number of structures destroyed by wildfires in Colorado, Hawaii, Idaho, Oregon, Washington, and Texas have all increased by more than 100% compared to 2016-2019. Meanwhile, Arizona, Montana, and Utah have each experienced increases of at least 20% over the same timeframe. Additionally, areas designated as high fire risk continue to increase across the Western U.S. due to climate change. To reduce these risks, many utilities are actively implementing mitigation plans designed to reduce wildfire exposure and litigation risks.

Filed: 2024-08-22, EB-2024-0063, Exhibit N-M2-0-SEC-32, Attachment 7, Page 8 of 17

Wildfire risk across West Coast electricity territories

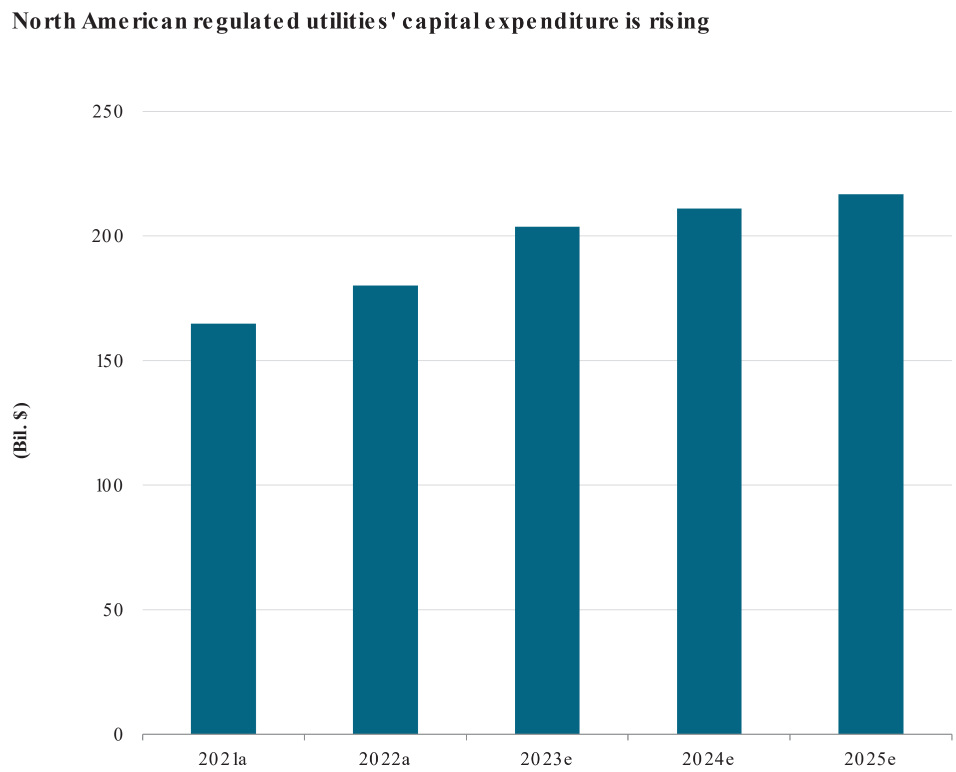


Source: FEMA, S&P Global Market Intelligence.

Increase in capital expenditure and cash flow deficits

The industry's capital spending remains at record levels, supporting initiatives for safety, reliability, energy transition, and growth. We consider these trends long term and expect that capital spending will only continue to increase over this decade.

Chart 6

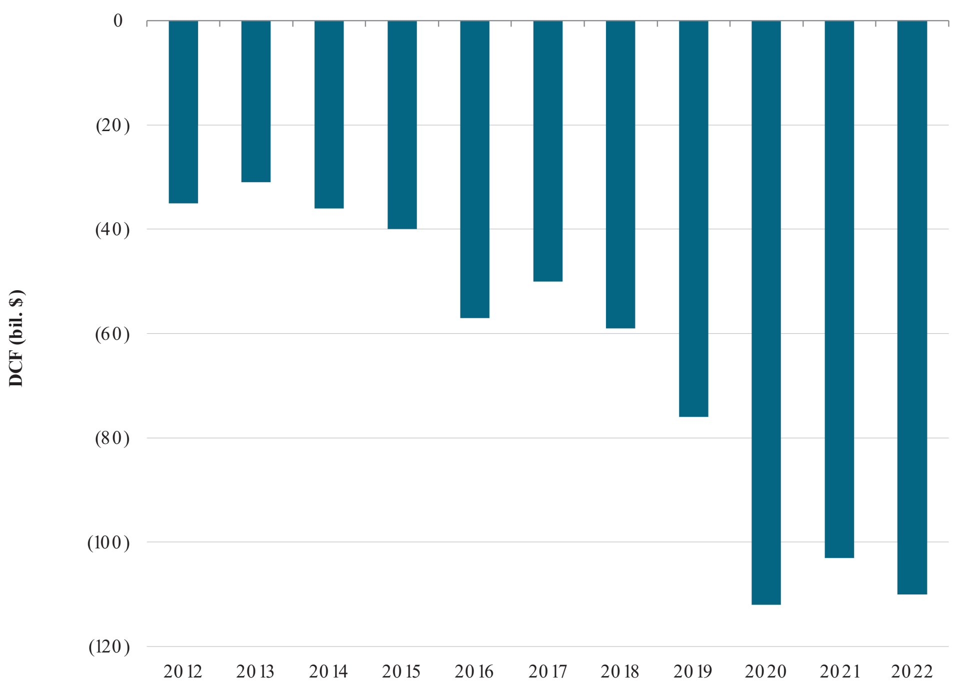


a--Actual. e--Estimate. Source: S&P Global Ratings.

Accordingly, cash flow deficits have increased, pressuring the industry's credit quality. For 2024, our base case assumes that the industry will fund its approximate $85 billion of cash flow deficits with about $40 billion in asset sales and equity issuance.

Chart 7

Discretionary cash flow (DCF) of rated investor-owned utilities

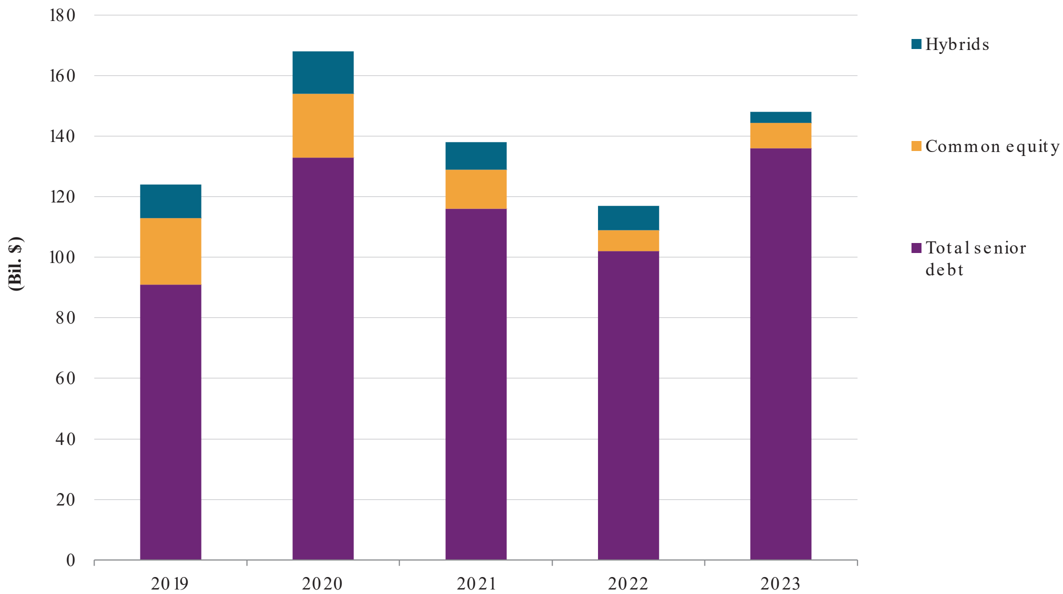


Source: S&P Global Ratings.

For 2023, the industry's actual equity issuance was considerably below our expectations, resulting in a weakening of financial performance and credit quality. If this trend persists, credit quality will again likely experience pressure in 2024.

Chart 8

Capital market issuance for North American regulated utilities

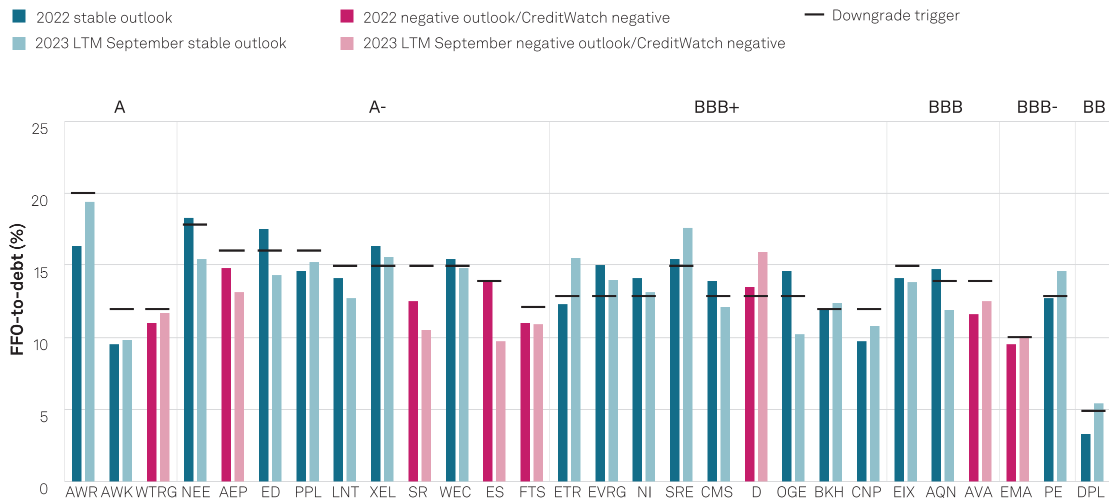


Senior debt includes first-mortgage bonds and senior unsecured. Hybrids includes junior subordinated debt, preferreds, subordinated debt, and equity units. Source: S&P Global Ratings, S&P Market Intelligence.

Strained financial cushion

About 35% of the industry is sustaining performance with minimal financial cushion, reflecting funds from operations (FFO) to debt that is less than 100 basis points (bps) above their downgrade threshold. The limited financial cushion affects a company's ability to absorb unexpected events beyond the base case for our ratings, increasing its susceptibility to a downgrade. Such unexpected events include higher interest rates, changes to inflation, delays to offshore wind projects, and rising taxes.

North American regulated utilities with minimal financial cushion



Data as of Feb. 6, 2024. FFO--Funds from operations. LTM--Last 12 months. AWR--American States Water Co. AWK--American Water Works Co. Inc. WTRG--Essential Utilities Inc. NEE--NextEra Energy Inc. AEP--American Electric Power Co. Inc. ED--Consolidated Edison Inc. PPL--PPL Corp. LNT--Alliant Energy Corp. XEL--Xcel Energy Inc. SR--Spire Inc. WEC--WEC Energy Group Inc. ES--Eversource Energy. FTS--Fortis Inc. ETR--Entergy Corp. EVRG--Evergy Inc. NI--NiSource Inc. SRE--Sempra. CMS--CMS Energy Corp. D--Dominion Energy Inc. OGE--OGE Energy Corp. BKH--Black Hills Corp. CNP--CenterPoint Energy Inc. EIX--Edison International. AQN--Algonquin Power & Utilities Corp. AVA--Avista Corp. EMA--Emera Inc. PE--Puget Energy Inc. DPL--DPL Inc.
Source: S&P Global Ratings.

Upcoming debt maturities amid higher interest rates

The industry has considerable near-term debt maturities that must be refinanced, as well as rising discretionary cash flow deficits that are mostly funded with debt. Because of the regulatory lag, which is the timing difference between when a utility incurs costs and when it's recovered from ratepayers, rising interest rates weaken financial performance. S&P Global economists expect the federal funds rate will stabilize in 2024 and then begin to modestly decrease. Accordingly, as interest rates stabilize, it will ease pressure on the industry's financial performance.

Additionally, the spread between the 10-year treasury and the average authorized return on equity (ROE) has narrowed. Over the past three years, the 10-year treasury has increased by about 250 bps to about 4.0% from about 1.5% at year-end 2020. At the same time, average authorized ROE has essentially remained flat at about 9.5%. The narrowing of this spread directly hinders the industry's financial performance.

Elevated inflation rates

Although the rate of inflation has slowed from 2022 levels, it remains elevated relative to historical levels. We anticipate this will result in higher operations and maintenance (O&M) costs that could weaken financial performance. While some utilities have interim mechanisms that reduce the regulatory lag, most will have to file rate cases on a more frequent basis if inflation remains higher over the longer term.

Delayed renewable energy projects

Recently, several large offshore wind projects were delayed or canceled because of rising costs for these more challenging projects. For example, we recently placed Eversource Energy's ratings on CreditWatch with negative implications directly related to its share of higher costs associated with its offshore wind projects.

Alternative minimum tax (AMT)

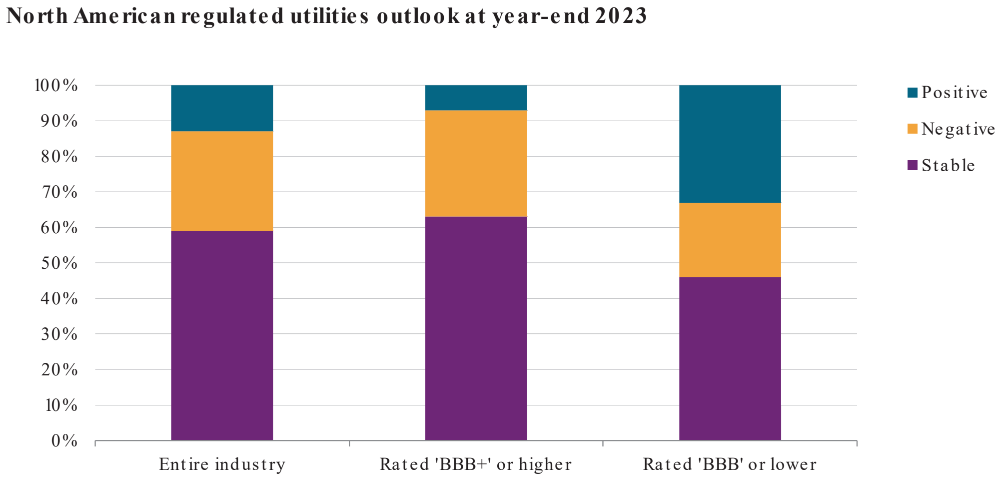
The Inflation Reduction Act of 2022 includes a 15% corporate AMT that we expect will weaken the financial measures of only about 10% of the industry. This is because the ATM is applicable to corporations with at least $1 billion of income that also do not have sufficient offsetting tax credits. Accordingly, we expect that most fully integrated large utilities with a growing or significant renewable generation portfolio will use their renewable tax credits to minimize or eliminate the AMT. However, the AMT could weaken financial measures of large electric transmission and distribution utilities, large natural gas local distribution companies, and large water utilities.

Lower-Rated Companies Will Likely Protect Credit Quality

We expect a majority of the industry's future downgrades will come from companies that are currently rated 'BBB+' or higher, as about 30% of companies in this category have a negative outlook. Overall, these higher-rated companies account for about 75% of the industry's portfolio. Conversely, we expect companies rated 'BBB' or lower will likely take measures to support or improve credit quality. This reflects the more than 30% of companies in this category that have a positive outlook.

Consequently, there is a broad industry trend that is bifurcating higher-rated and lower-rated companies that will likely result in weakening credit quality for the higher-rated companies and stable to improving credit quality for the smaller percentage of lower-rated companies. We believe this trend is consistent with the industry's current economic conditions of robust growth, cash flow deficits, and higher interest rates. Some higher-rated companies are determining that, under current conditions, they have excess credit capacity while lower-rated companies believe it is most optimal for them to operate at a higher rating.

Chart 9



Source: S&P Global Ratings.

This report does not constitute a rating action.

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S&P Global
Market Intelligence

Feb. 11, 2021
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RRA Regulatory Focus
2021 Energy Utility Regulatory Outlook

2020 may have been a year like no other, but 2021 is going to be anything but "normal," as energy utilities and regulators grapple with a change in administration shrouded in controversy, the coronavirus pandemic continues to place a strain on the utility sector and the economy in general, and the demands to speed the energy transition along continue at a fever pitch that will be accentuated by burgeoning federal policy.

Themes for 2021

- COVID-19 remains a ***distraction***
- New administration ***acclerates*** energy transition
- States ***renew focus*** on clean energy initiatives
- Changing industry structure leads to ***stranded costs***
- Capital spending ***remains robust***
- Rate case agenda ***moderates***
- Pressure to ***reduce*** authorized ROEs intensifies
- Merger activity ***picks up***

In addition to addressing these complex issues, regulators and utilities will remain focused on more traditional utility concerns, such as safety and reliability, resiliency and sustainability, infrastructure hardening and cyber security, environmental, social and governance policy, and social/environmental justice.

The related costs and capital spending will continue to drive rate case activity, while achieving rate recognition of the incremental investment and expenses will erode headroom in utility rates and put downward pressure on authorized ROEs that have been challenged for some time by historically low interest rates.

Merger activity that was curtailed during the early days of the pandemic picked up toward the end of 2020 and is expected to revive further in 2021.

COVID-19

Issues related to the COVID-19 pandemic created significant overhang for utilities and regulators in 2020; with the episodic spikes in cases across the U.S. and the challenges in distributing the vaccine, in addition to the lasting economic impacts of the outbreak, 2021 will be no different.

Moratoriums on utility service terminations were implemented in March and April 2020 by utilities in each of the 53 state-level jurisdictions followed by Regulatory Research Associates, a group within S&P Global Market Intelligence. In some instances, the moratoriums were mandatory, in others voluntary and in others they have swung back and forth between the two.

As of Jan. 31, 2021, the moratoriums had expired for 29 of the covered jurisdictions; however, consumer groups in several states are calling for the governor or regulators to reinstate them, and several U.S. Senators have publicly called for a nationwide prohibition on utility shut-offs.

By and large, the utilities continue to offer enhanced flexible payment options, guidance for customers about taking advantage of federal and state aid programs, and, in some instances, utility-funded bill payment assistance programs. In some instances where there were mandatory moratoriums in place that have expired, the utilities have voluntarily extended the moratorium for an additional period of time.

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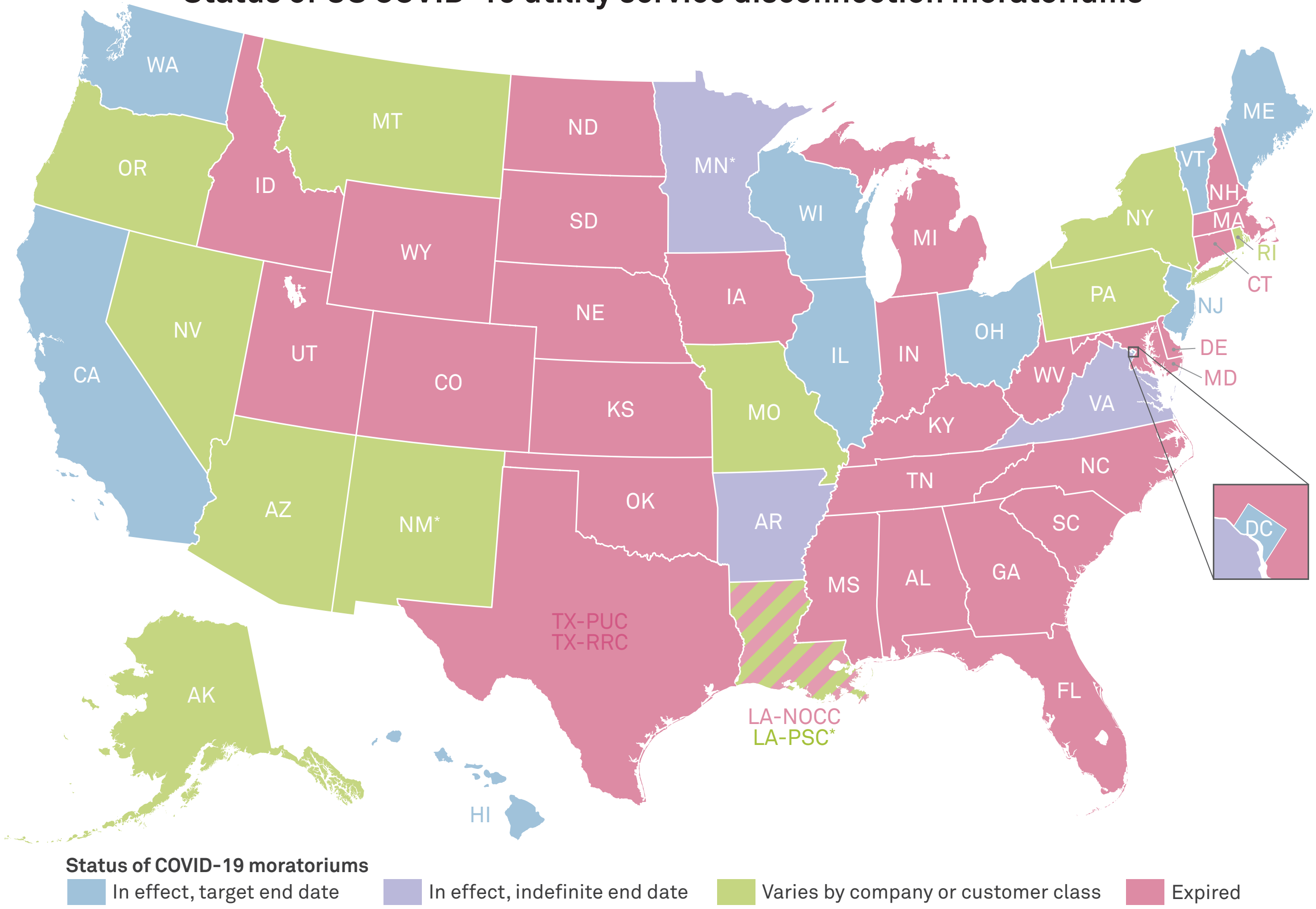
In 11 jurisdictions, the policy with respect to shutoffs varies by company, customer class and/or service type. In some of these jurisdictions, the moratoriums were voluntary, and certain companies have maintained them while others have not. In other states, a mandatory moratorium remains in place for certain customer classes or service types, but not for others. In still other jurisdictions a mandatory moratorium has largely expired for all customer classes, but certain "protected" customers still cannot be shut off.

Status of US COVID-19 utility service disconnection moratoriums



Data compiled Jan. 31, 2021.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission
* Disconnections may resume in February 2021 if moratorium is not extended.
Map credit: Ciaralou Agpalo Palicpic
Sources: Regulatory Research Associates, a group within S&P Global Market Intelligence; National Association of Utility Regulatory Commissioners; company websites

S&P Global
Market Intelligence

In 10 jurisdictions, moratoriums remain in place for all customers but with a specific target end date. These dates extend to as late as April 30, 2021. In some of these states, the COVID-19 moratorium extends to the beginning of an annual winter shut-off moratorium, and the winter moratorium picks up where the COVID-19 moratorium leaves off.

In three jurisdictions, Arkansas, Minnesota and Virginia, the moratoriums remain in place with no specific end date.

When it comes to recovery of the related costs, some states have adopted a generic policy, while others have taken a company-specific approach. The definition of what constitutes recoverable COVID-19 costs also varies from state to state. Direct costs such as those related to personal protection equipment and labor costs generally have been included. Lost revenue associated with forgone late payment fees, reconnection fees and continuation of service during the moratorium have also been considered recoverable costs for the most part. However, lost revenue associated with the related decline in sales or overall economic activity related to the pandemic have been challenged in some jurisdictions.

Thus far, 33 of the 53 jurisdictions have authorized at least one utility to defer COVID-19-related costs, which may or may not include lost revenue associated with the decline in economic activity. One state, Montana, has rejected requests by its utilities to defer costs associated with COVID-19.

It is important to note that deferral is not a guarantee of recovery. Recovery will likely be addressed in the context of a future base rate proceeding, and the commissions may ultimately disallow a portion of the costs as imprudent.

COVID-19 cost recovery provisions for utilities

Deferral		Other treatment	Customer-specific plans	Pending		No mechanism specified
Alaska	Minnesota	Georgia[3]	Colorado	Arizona	New Hampshire[4]	Alabama
Arkansas	Mississippi	New Hampshire[3]	New Hampshire[4]	Florida[5]	New York	Montana[6]
California	Nevada	South Dakota[3]	North Carolina[4]	Kentucky	North Carolina[4]	West Virginia
Connecticut	New Jersey	Texas PUC[2]	Ohio	Louisiana PSC	North Dakota	
Delaware	New Mexico		Rhode Island	Maine	South Carolina	
Dist. of Columbia	Oklahoma			Massachusetts	Tennessee	
Florida[1]	Oregon			Minnesota[5]	Utah[5]	
Georgia[1]	Pennsylvania			Missouri	Vermont	
Hawaii	South Dakota[1]			Nebraska	Wyoming[5]	
Idaho	Texas-PUC[2]					
Illinois	Texas-RRC					
Indiana	Utah[1]					
Iowa	Virginia					
Kansas	Washington[1]					
Louisiana NOCC	Wisconsin					
Maryland	Wyoming[1]					
Michigan						

Data compiled as of Jan. 31, 2021.
NOCC= New Orleans City Council; PSC=Public Service Commission; PUC= Public Utilitie(s) Comission; RRC=Railroad Commission
Deferral=Direct costs and/or lost revenues may be deferred for future recovery.
Customer specific plan= Commission,Governor or Legislature has issued a directive specifically stating that customers remain responsible for any arrearages, which are to be recovered on a customer-specific basis.
Other=Instances where the commission has identified a mechanism other than deferral for cost recovery. Existing regulatory mechanisms are not included unless the commission has specifically stated the mechanism would apply to COVID-19 costs.
Pending=Proceeding under way/legislation pending to determine cost recovery; may be on a generic or company-specific basis.
No action taken=No indication has been provided by the regulators or policymakers with respect to COVID-19 costs; no utility proposals have been filed.
[1]Deferral approved for at least one company on a company specific basis.
[2]Deferral of COVID-19 costs was approved for vertically integrated utilities and delivery-only utilities; the PUC established a COVID-19 specific funding mechanism to address bad debt for competitive retail electric providers.
[3]COVID-19 costs are to be addressed through a decoupling or other adjustment mechanism for at least one utility.
[4]Governor/commission directive initially called for customer repayment. An investigation has since been opened that could lead to other cost recovery options.
[5]Recovery method addressed for one or more companies or on a generic basis, pending for certain companies within the jurisdiction.
[6]One company-specific rrequest for deferral was rejected and another was withdrawn.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Even so, the longer the moratoriums remain in place, the more these deferred balances will rise, and the more problematic achieving cost recovery will become.

So far, RRA is aware of one instance where recovery of COVID-19 costs has been directly addressed in a rate case. In a late-December 2020 decision for Exelon Corp. subsidiary Baltimore Gas & Electric Co.'s electric and gas operations, the Maryland Public Service Commission authorized the company to establish a regulatory asset for the recovery of COVID-19 costs, net of savings, over a five-year period, with the unamortized balance included in rate base. Costs included in the regulatory asset include costs associated with additional personal protection equipment for field employees, cleaning services, sequestration preparation costs, employee benefit-related costs, incremental facilities and vehicle cleaning, incremental security costs, overtime labor costs, public relations and customer education costs, and other miscellaneous costs. These were offset by savings in the area of travel and entertainment expenses, as well as certain utilities expenses.

The company was also authorized to recover lost revenues for late payment fees and service application/reconnection fees over five years, but the amortized balance will be excluded from rate base.

California has taken a proactive approach in that legislation has been enacted that will provide the utilities the ability to securitize certain COVID-19 related deferrals.

Securitization is viewed as an attractive option because it minimizes customer rate impacts related to a particular utility asset by reducing the effective carrying charges on the assets to those of a highly rated corporate bond compared with the utility's weighted-average costs of capital or a lower-rated debt instrument.

It also reduces rate shock by facilitating a longer recovery period than might otherwise be the case and lowers the investment risk for the utility by providing the utility up-front recovery of the asset.

While it has not been used much in the gas industry, securitization has been used extensively in the electric industry.

In four states, regulators have adopted a different approach to addressing COVID-19 cost recovery for one or more companies, and five have made definitive statements that a customer-specific approach will be taken rather than socializing the costs through deferral or some other broad-based recovery mechanism. However, in two of those states, New Hampshire and North Carolina, proceedings are open that could lead to other cost recovery methods.

Consideration of a COVID-19 cost recovery framework for at least one utility is ongoing in 18 jurisdictions. These include jurisdictions where methodologies may have been approved for one or more companies, but proceedings are underway for others.

What is Securitization?

Refers to the issuance of bonds backed by a specific existing revenue stream that has been "guaranteed" by regulators and/or state legislators.

Generally requires a utility to assign the designated revenue stream to a "bankruptcy remote" special purpose entity, which in turn issues bonds that will be serviced by the transferred revenue stream.

The funds raised by the bond issuance flow to the utility.

In three states, Alabama, Montana and West Virginia, no explicit COVID-19 cost recovery framework is in place.

In Alabama, the major utilities in the state — Southern Co. subsidiary Alabama Power Co. and Spire Inc. subsidiaries Spire Alabama Inc. and Spire Gulf Inc. — operate under formula rate plans that allow annual adjustments to reflect incremental rate base, expenses and revenue. While these plans generally include earnings caps and limitations on the magnitude of the rate adjustments that may be implemented at one time, they should address at least a portion of COVID-19 costs. No such mechanisms are in place in West Virginia.

In Montana, the commission rejected one regulators' request for deferral in November 2020, and another utility withdrew the request in January 2021.

This type of innovative approach to the need to reflect new investment in rates while limiting the associated rate increases is something RRA expects to see more of in 2021.

New administration

Against the backdrop of, or perhaps exacerbated by COVID-19, the U.S. is recovering from a particularly contentious presidential election.

While there have been calls for a nationwide ban on utility service terminations during the pandemic, it is unlikely that a federal suspension moratorium will be forthcoming. Given the different degrees to which the pandemic has affected different states and the different frameworks in place to address the related issues, it is unlikely the states would welcome a one-size-fits-all approach. They would instead likely prefer to see federal action in the form of specific funds targeted for assisting customers with bill payments.

Perhaps recognizing this reality, the new administration's efforts so far have focused on direct relief to those economically impacted by COVID-19.

Aside from COVID-19-related issues, making good on his promise to accelerate the energy transition and curtail exploration and production activity, as well as to further his goal of achieving a net zero carbon electric grid by 2035, U.S. President Joe Biden has issued a series of executive orders in his first weeks in office that:

- Re-entered the U.S. into the Paris Climate Accord;
- Suspended new oil and natural gas leases in federal areas;
- Directed federal agencies to draft new methane regulations;
- Called for tighter emissions standards and promote development of electric vehicles and clean energy technologies;
- Directed the U.S. Department of Energy to propose revisions to four rulemakings on energy conservation and energy efficiency standards;
- Directed the Council on Environmental Quality to rescind its 2019 draft guidance on how greenhouse gas impacts would be considered under the National Environmental Policy Act;
- Established an agency to calibrate the social cost of carbon; and,
- Suspended certain bulk power cybersecurity issues.

The Biden administration has demonstrated the seriousness of its focus on clean energy by naming two "climate czars" — Gina McCarthy on domestic issues and John Kerry on international issues. Even so, it remains to be seen whether a federal renewable portfolio standard will be established, as key legislators have expressed concern about this approach. Given the regulatory framework within the U.S., such an initiative, and indeed any new environmental regulations that impact the utilities, will have to be enforced by state regulators, and costs resulting from the transition will largely be addressed at the state-level.

With regard to the gas industry, the Biden administration has pledged to curtail exploration and production activity but also states that it wants to preserve a role for natural gas.

The change in administration also brings with it the potential for a reversal, at least to some degree, of the Trump-era corporate tax reductions. Such a change would likely lead to a wave of federal and state regulatory activity to address the revenue requirement impacts of the changes, similar to the level of activity observed in 2018 upon implementation of the Trump tax reductions. However, the situation would perhaps be even more complicated due to the fact that the industry has not really finished grappling with the impacts of the 2018 changes.

Changes at FERC

With confirmation of the Trump administration's nominees to the Federal Energy Regulatory Commission, the commission begins 2021 with a full complement of commissioners for the first time in over two years.

Current FERC commissioners

Commissioners	Party	Began serving	Term ends	Background
James Danly	R	March 2020	June 2023	Attorney; FERC General Counsel; Skadden, Arps, Slate, Meagher and Flom law firm; Law Clerk, U.S. Court of Appeals for the Sixth Circuit; U.S. Army officer
Richard Glick, (Chairman)	D	November 2017	June 2022	Attorney; counsel for Senate Energy Committee; director of government affairs, Iberdrola Renewables; policy adviser to DOE secretary Bill Richardson
Neil Chatterjee	R	August 2017	June 2021	Attorney; aide to Senate Majority Leader Mitch McConnell, R-Ky.; National Rural Electric Cooperative Association; aide to Rep. Deborah Pryce, R-Ohio
Allison Clements	D	December 2020	June 2024	Attorney; founder and president of Goodgrid, LLC; senior attorney, Natural Resources Defense Council; director, Sustainable FERC Project
Mark Christie	R	January 2021	June 2025	Attorney; Chairman and member, Virginia State Corporation Commission; President, Organization of PJM States; U.S. Marine Corps officer

As of Jan. 31, 2021.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

As expected, Biden has named Democrat Richard Glick as FERC chair, and it is expected that with the expiration of Republican Neil Chatterjee's term in June, the makeup of the commission will shift from a 3-to-2 Republican majority to a 3-to-2 Democratic majority.

The presence on the FERC of Mark Christie, who prior to his appointment had served on the Virginia State Corporation Commission for more than 15 years, should lead to improvement in a sometimes strained relationship between FERC and state regulators. Moreover, recent statements by newly ensconced Commissioner Allison Clements add further weight to the idea that there will be enhanced cooperation with state regulators.

In the coming months, FERC will take up a series of issues and policies that have produced sharp partisan divisions among the incumbent commissioners. Among the first items to be addressed by the newly constituted FERC are the commissions much-maligned policies on transmission incentives, rules concerning cybersecurity, transmission formula rates and the methodology for setting base ROEs within this framework, and a major pipeline cancellation.

Also facing the new FERC are proceedings to address the tension between state public policy goals and FERC's role in regulating wholesale electricity markets and the commission's environmental analysis of new gas pipeline and LNG projects.

Energy transition

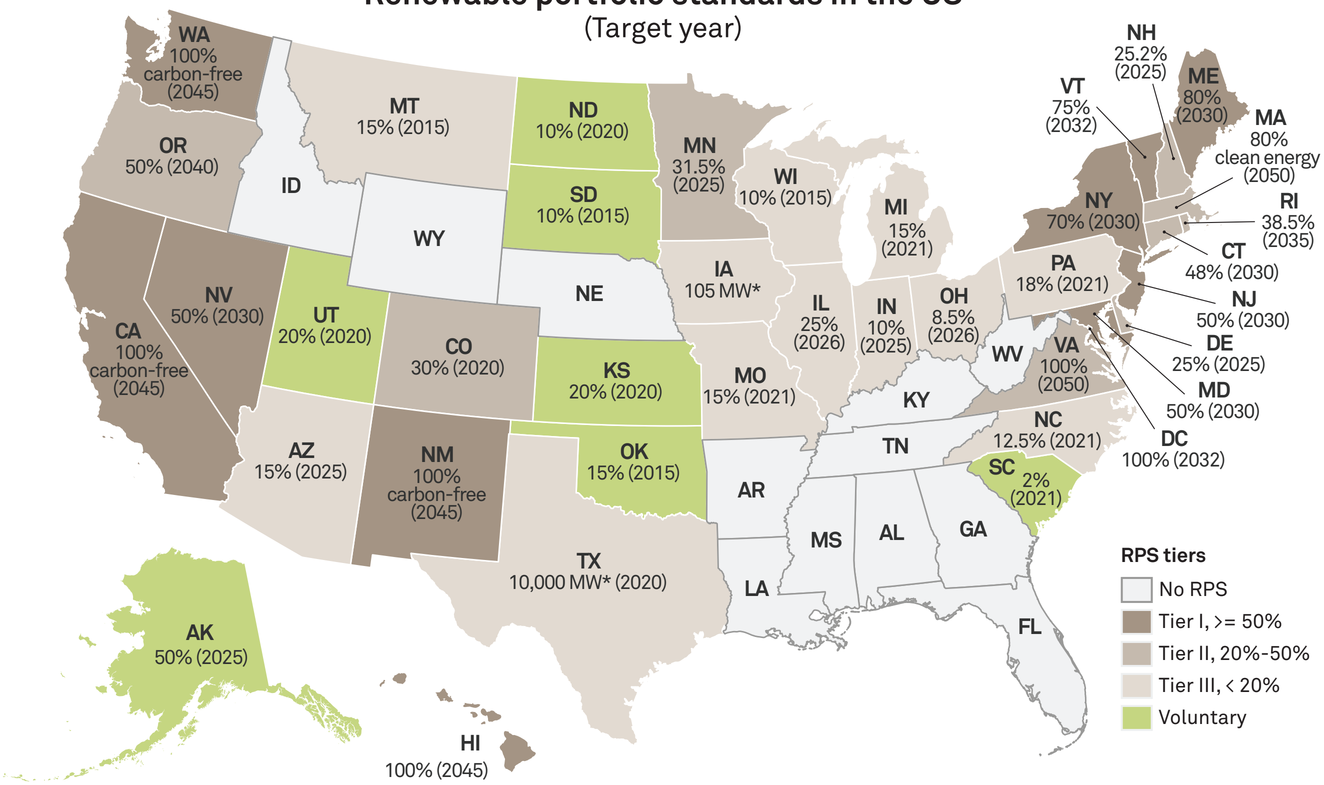
While the "energy transition" includes broader initiatives, such as reducing carbon emissions, deploying advanced technologies that are changing the way energy users interact with the grid and the role of the local utilities, the cornerstone of the transition is the proliferation of renewable resources.

With the absence in recent years of a federal policy with respect to renewables, the drive to expand renewables development has been led by the states, as demonstrated by the ongoing debates in several states regarding natural gas bans and the ever-expanding wave of renewable portfolio standards across the U.S.

A large part of the impetus for these movements is coming from customers, with large technology and industrial companies pledging to reduce their carbon footprints and a new generation of residential customers that want to know and control where their electricity and heat come from.

The investment community has played a role as well, with the recent focus on green investments, sustainability and environmental, social and governance issues.

Renewable portfolio standards in the US
(Target year)



As of Jan. 31, 2021.
* Already reached.
Map credit: Elizabeth Thomas
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Even though the COVID-19 pandemic slowed state legislative momentum in 2020, several states adopted enhanced renewable portfolio or carbon-free standards; and between 2018 and 2020, several states implemented aggressive renewable portfolio standards. California, New York, Virginia, New Mexico, Maine, Maryland, Nevada, Washington and others have increased their renewable generation mandates, with several calling for 100% renewable or carbon-free generation by 2050 or before.

Even so, there are currently a dozen states that have not implemented any kind of RPS or clean energy standard; a renewed federal policy push may force these states to develop standards of their own.

In 2021, S&P Global Market Intelligence expects the energy transition to again be a focus for state legislatures, as well as ESG issues and environmental justice.

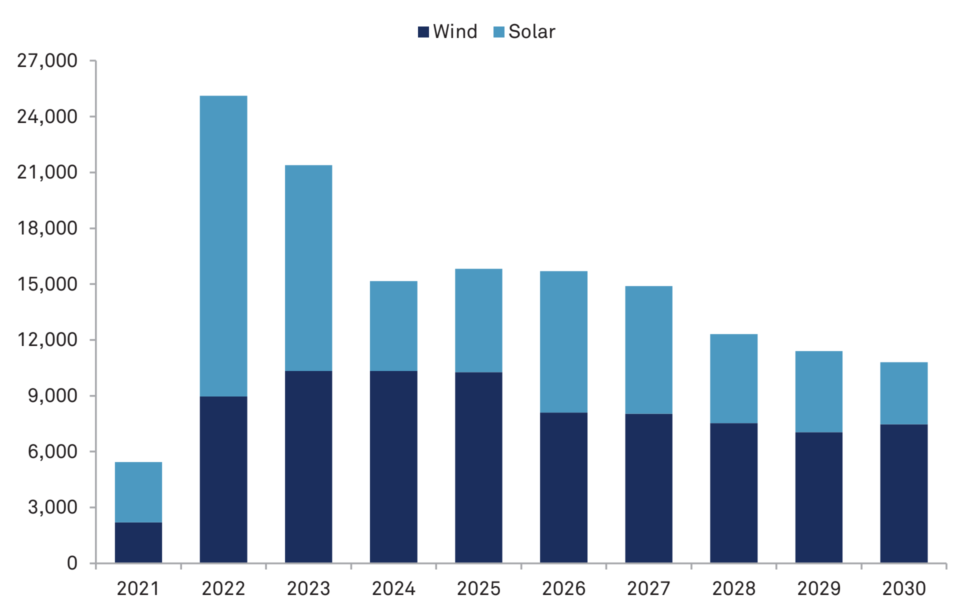
In response the wildfires that have plagued the state over the last few years, California may seek to accelerate attainment of its 100% RPS target. Georgia, which currently does not have an RPS standard, may move in this direction in 2021 — the state has already required the utilities to add solar generation through the integrated resource planning process.

There also may be additional activity in Maryland; although the state enacted a 50% RPS target in 2019, the governor had supported a 100% goal. Legislation to achieve this end was introduced in 2020 but was not passed by both houses before the state government shut down in response to COVID-19.

Similarly, RPS legislation had been introduced in Pennsylvania in 2020 but lost traction in the wake of COVID-19. Legislation has been introduced in several northeastern and pacific-northwestern states in recent years but up until now had failed to gain sufficient traction. This could change in 20201.

Based on the current standards, Market Intelligence estimates that 148,000 MW of new wind and solar capacity will be needed across the U.S. by 2030.

Total RPS-driven wind and solar capacity additions (MW), 2021-2030



As of Oct. 15, 2020.
Source: S&P Global Market Intelligence

For additional information see S&P Global Market Intelligence's report "*The 2021 Global Renewable Energy Outlook*."

Stranded costs

Changes in industry dynamics has led to the reemergence of the need to address "stranded costs" as utilities retire coal and other carbon-intensive generation sources ahead of schedule in favor of renewables and other non-emitting resources.

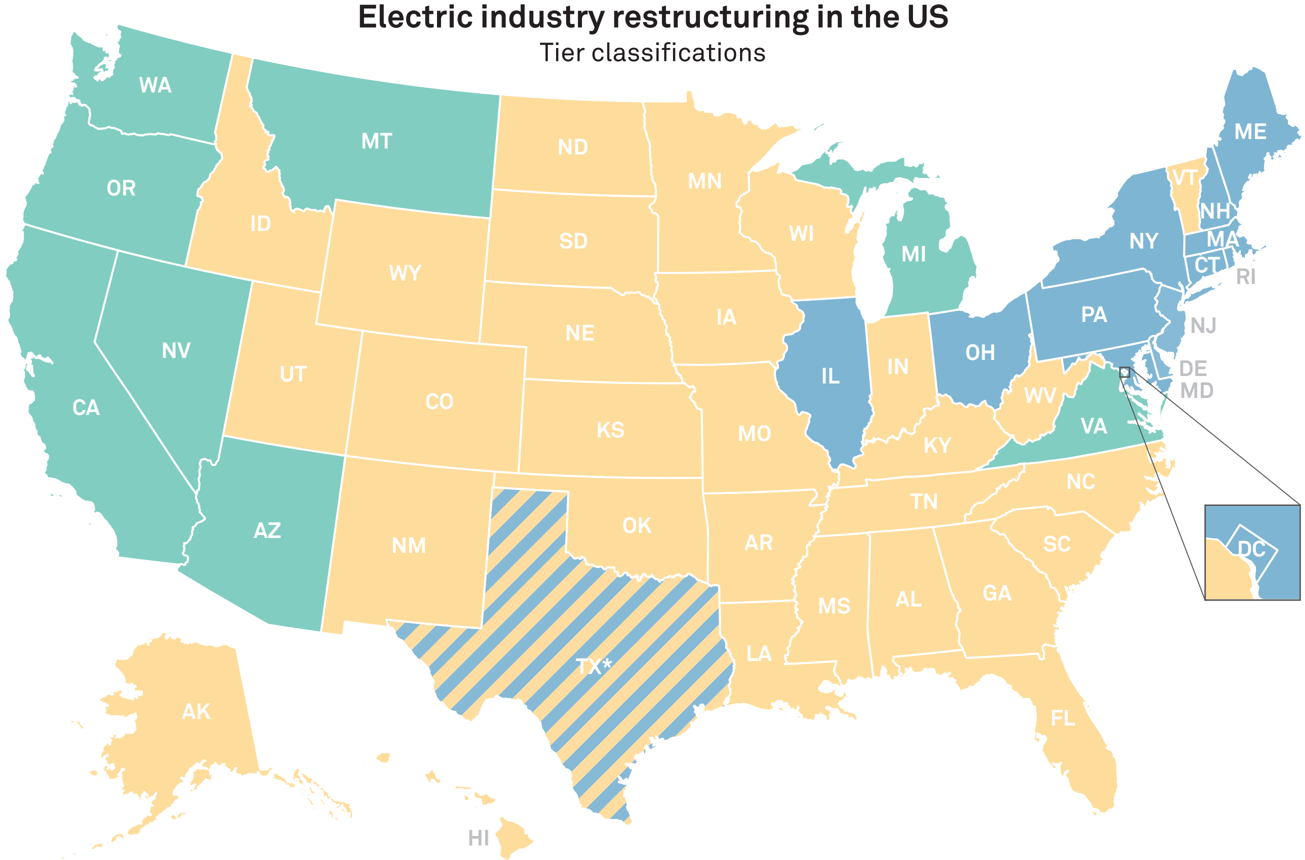
This is not really a new challenge for the electric industry. In the mid-to-late 1980s, stagnant load growth, cost increases to comply with more stringent regulatory standards, cost overruns on certain projects and poor financial health on the part of some utilities caused a series of generation projects to be abandoned prior to completion.

The term "stranded costs" became popular in the mid-1990s, as regulators and legislators grappled with whether or not to permit retail customers to select their generation providers.

In the end, 13 jurisdictions moved to full retail competition for generation, while nine implemented retail choice for only a portion of the customers in each territory.

Electric industry restructuring in the US

Tier classifications



Tier 1 Power prices are competitively determined for all retail customers within the jurisdiction; both standard-offer-service and retail-access customers. Retail access is permitted for all customers. For the most part, the utilities in these jurisdictions do not own generation.

Tier 2 Retail access is permitted to at least some customers/customer classes. Competitively priced power is limited to retail access customers. Power prices for standard-offer-service customers remain regulated. For the most part, utilities remain vertically integrated.

Tier 3 Power prices are fully regulated for all retail customers. All retail customers must purchase their power from the franchised utility. Utiities are vertically integrated.

Data gathered as of Jan. 31, 2021.
* In Texas, retail competition was implemented only within the ERCOT footprint, but within that footprint, power is competitively priced for all customers. Outside of ERCOT, power prices are regulated and the utilities are vertically integrated.
ERCOT = Electric Reliability Council of Texas Inc.
Map credit: Jose Miguel Fidel C. Javier
Source: Regulatory Research Associates, a group within S&P Global Market Intellgence

S&P Global
Market Intelligence

In the states that implemented full retail competition, the vertically integrated electric utilities were required to unbundle their rates into separate charges for transmission, distribution and generation. The utilities were also required to divest their generation assets or spin them off to separate unregulated affiliates.

The assumption was that the market price of power would drop below the unbundled generation cost that had been part of vertically integrated rates, and as a result the market value of the plants would be below the remaining book value of most of these assets

Policymakers generally agreed that under the "regulatory compact," the utilities should be compensated for stranded costs that arose from a change in the regulatory framework.

Where a company divested its assets, the difference between the sale price and book value was used to determine stranded costs; where the assets were spun off, the commission's made an administrative determination of stranded costs. These costs were then, generally, recovered over a period of years through a separate surcharge on customer bills. In some instances, these revenue streams were securitized.

The energy transition is already creating similar issues for carbon-emitting generation sources. Shifts in the location of the resource mix are changing transmission needs, and decentralized configurations, such as distributed generation and microgrids, present potential threats to the utilities' ability to recover fixed distribution system assets, which may lead to stranded costs in this segment of the industry as well.

What is the regulatory compact?

Derives from the "Takings Clause" of the Fifth Amendment to the U.S. Constitution

The utility is given a monopoly to provide service in a specific geographic area in exchange for being regulated by a government agency.

Utility agrees to provide safe and reliabe service at just and reasonable rates. ⟷ **Regulator agrees to provide the utility an opportunity to earn a fair return for its investors.**

States have already begun addressing the issue in various ways, primarily as it pertains to generation assets.

In some cases, the utility has been allowed to accelerate the depreciation of the asset while it is still in service in order to complete amortization of the remaining book value by the time the asset is shut down.

In others, the remaining book value of the asset is designated as a regulatory asset that is then recovered over a period of years, with or without a return on the unamortized balance. In some instances, securitization is being used to reduce the ratepayer impact of recovery of the remaining plant balances.

The potential for stranded costs in the distribution business is being and will likely continue to be addressed through the rate case process. Regulators are moving, albeit gradually, to reduce subsidies by allocating a greater portion of approved rate increases to customer classes that are underearning relative to other customer classes and increasing fixed monthly customer charges to more closely align with the fixed costs of providing service.

This has been a very gradual process, as by and large it is the residential customer class that then bears a greater portion of approved rate increases. This will be increasingly problematic as the pandemic and the resultant unemployment levels persist.

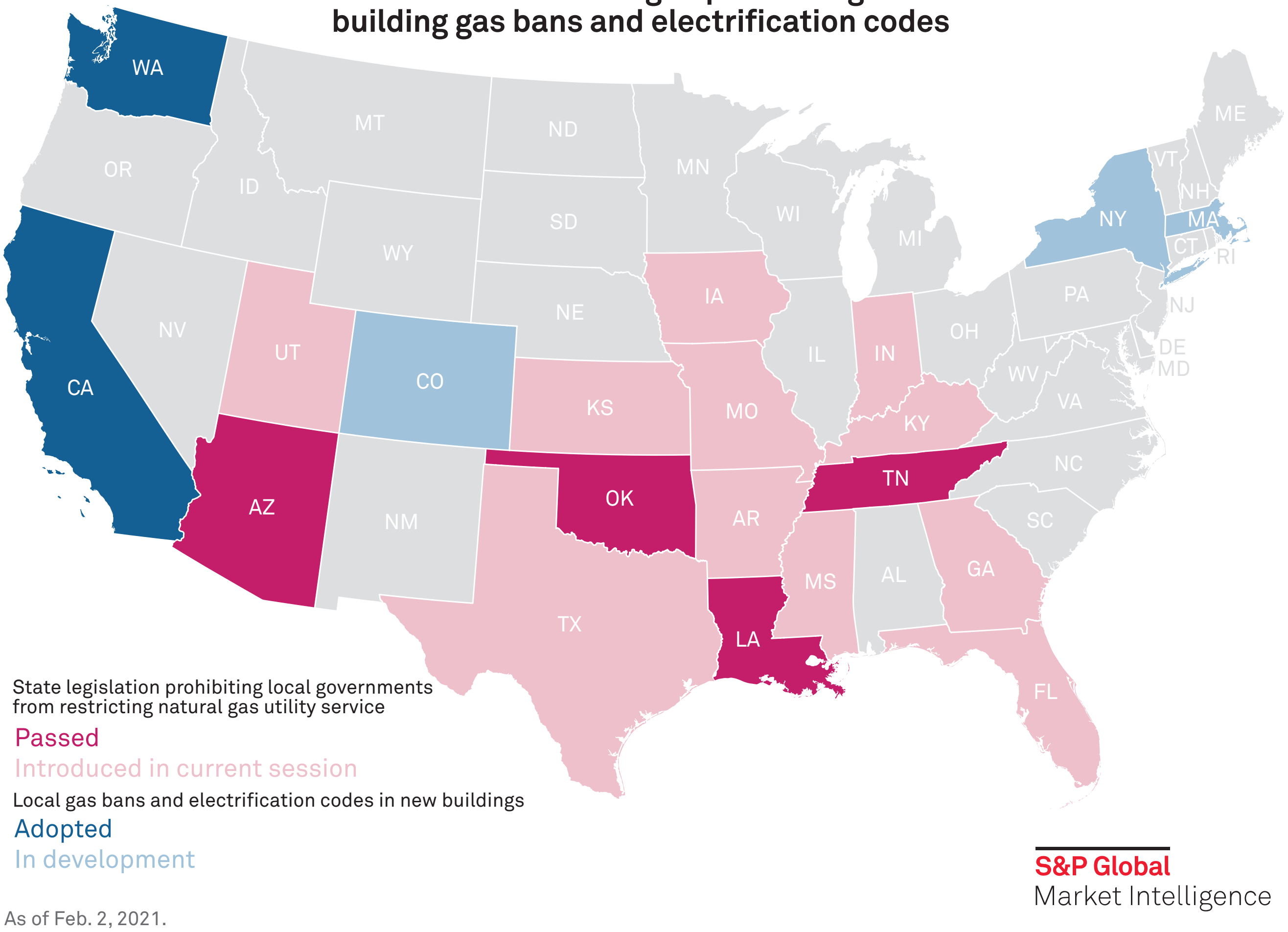
Stranded costs have not up until now been an issue for gas local distribution companies. While there is competition for the commodity portion of the business, it was part of the structure early on, and there was sea change to bring this about as there was in the electric industry. The commodity portion of the gas business is competitive for large commercial and industrial customers in every state and for small volume or residential customers in several.

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 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.

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. For the most part these initiatives to require all-electric new buildings are localized, occurring at municipal levels.

On the other side of the coin, in 2020 nine states introduced legislation prohibiting local governments from adopting so-called building gas bans and four enacted laws. There are currently at least 11 states considering bills prohibiting the so-called gas bans.

States advancing or prohibiting building gas bans and electrification codes



As of Feb. 2, 2021.
States where lawmakers introduced legislation prohibiting local restrictions on natural gas utility service in past sessions are not included.
Map credit: Ciaralou Agpalo Palicpic
Source: S&P Global Market Intelligence

Challenges with respect to addressing stranded costs arising from the latest energy transition are likely to continue and intensify in 2021 and beyond.

Rate case activity

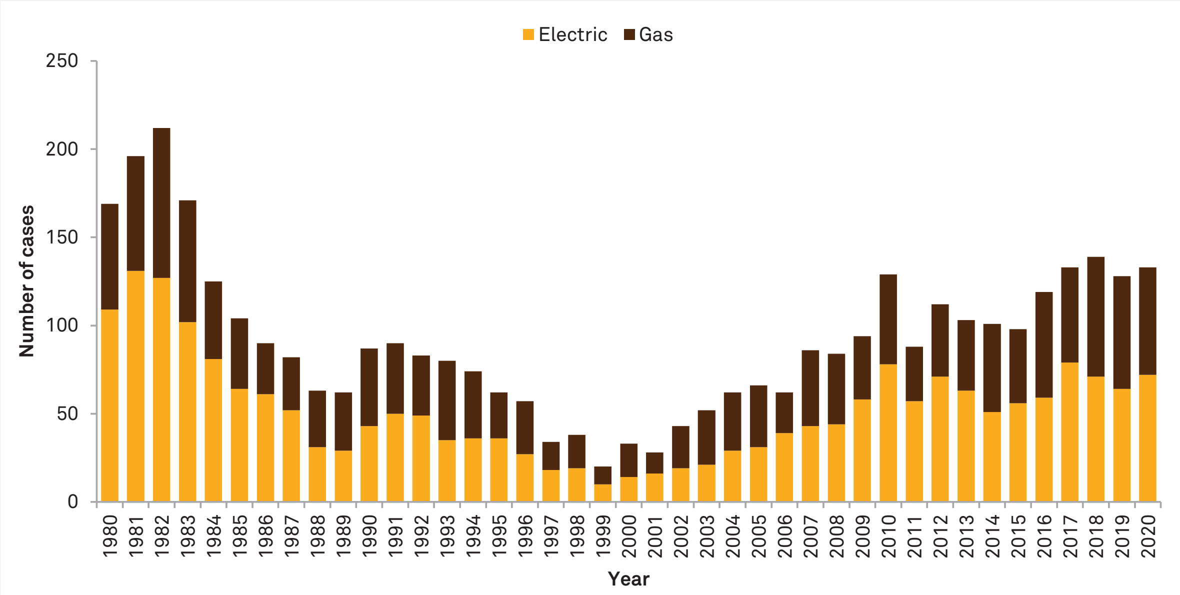
As previously alluded to, during 2020, COVID-19 took a lot of attention away from the traditional meat and potatoes issues that utilities generally focus on.

The pandemic caused several companies to forgo or postpone filing rate cases during 2020 and others to withdraw cases that had already been filed. In some instances, pending cases were suspended for a time and the procedural schedules were extended such that decisions would not be issued until 2021.

Even so, there were 133 electric and gas rate cases concluded in 2020, compared to 129 in 2019 and 139 in 2018.

It is worth noting that while the level of 2020 rate case activity was consistent with prior years, there were several instances where approved rate changes were deferred or accounting mechanisms, such as the return to ratepayers of regulatory liabilities on an accelerated basis, were employed to reduce or eliminate the immediate bill impact.

Major rate case decisions, 1980-2020



Data compiled as of Jan. 31, 2021.
Source: Regulatory Research Associates

For example, in the aforementioned case for Baltimore Gas & Electric Co., the Maryland PSC adopted a multiyear electric and gas rate plan under which the company is to accelerate the amortization of tax-reform-related regulatory liabilities in order to offset the rate increase that would have been approved for 2021. Notably, the PSC rejected the company's proposal to extend the amortization of certain regulatory assets and suspend amortization of others, concluding that doing so would create too much overhang for the years following the three-year plan.

Cases for Green Mountain Power, Hawaii Electric, Hawaii Electric Light, Madison Gas and Electric Co. and Wisconsin Power & Light were decided, with no rate changes authorized.

In cases for Pacific Gas & Electric and Jersey Central Power & Light the effective dates of new approved rates were postponed.

Thus far in 2021, 13 electric and gas rate case decisions have been issued and there are currently about 80 rate cases underway. In several of the pending cases, the companies are proposing mitigation measures like those observed in 2020, and this is a trend that is likely to continue for the duration of the pandemic.

Pent-up activity from 2020, the need to address COVID-19-related costs and burgeoning stranded costs, combined with activity generated by "normal" business activities, would argue for 2021 to be a year of frenetic rate case activity. With the economy still reeling from the pandemic, however, RRA expects the pace of rate case activity to be somewhat measured in 2021.

Capital spending

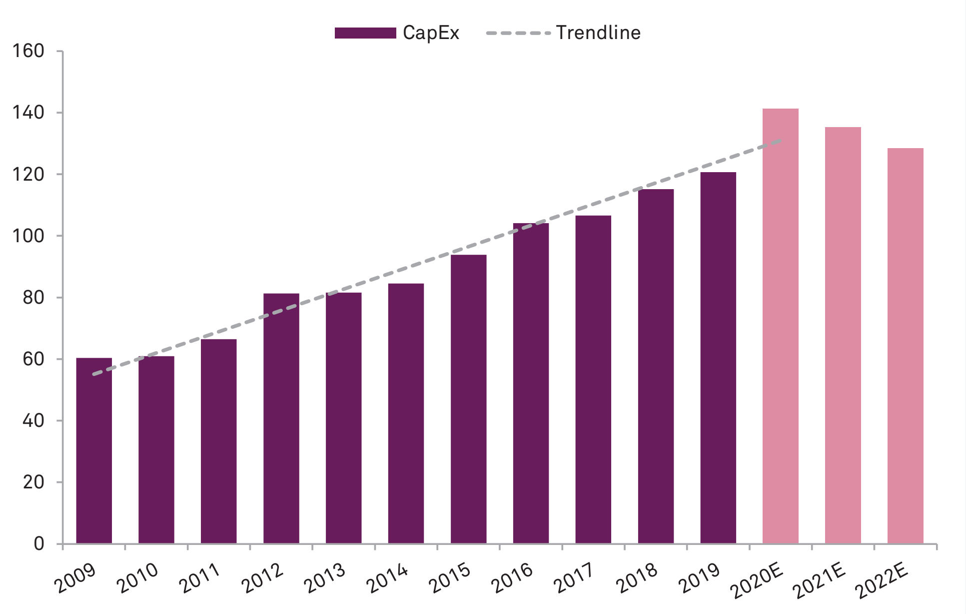
Aside from COVID-19 impacts and potential tax changes, robust capital spending will drive much of this expected rate case activity.

Even though many states have embraced alternative regulatory mechanisms and limited-issue riders to address various types of new investment, the investment continues to outpace ratemaking.

So far, the energy utilities have not reduced their capital spending plans in the wake of COVID-19.

In fact, based on a study conducted by the RRA Financial Focus team in October 2020, projected capital spending in 2020 for RRA's 47 covered energy companies stands at its highest level in recent decades, with more than $141 billion of planned spending. The 2020 spending level represents a 17% increase over actual 2019 spending of a little under $121 billion.

Energy utility actual and estimated capital expenditures ($B)



Compiled Oct. 27, 2020.
Source: S&P Global Market Intelligence

Utility capital spending has been trending upward for the last decade. While the spending forecasts of $135 billion and $128 billion for 2021 and 2022, respectively, indicate a decline relative to 2020, RRA anticipates both will rise as companies' plans for future projects solidify and new opportunities arise.

The nation's electric and gas utilities are investing in infrastructure to upgrade aging transmission and distribution systems, build new natural gas, solar and wind generation, and implement new technologies, including smart meter deployment, smart grid systems, cybersecurity measures and battery storage.

As noted earlier, the broader trend toward utility sector decarbonization, state RPS mandates and ESG considerations will continue to drive renewables expansion, along with falling technology costs.

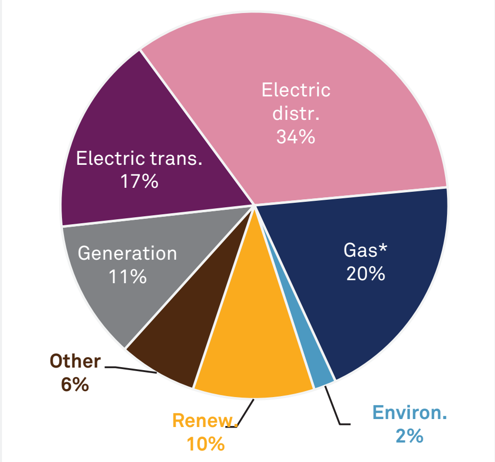
The increase in renewable generation, which are often great distances from load centers, will continue to drive new transmission line projects. Additionally, despite challenges to the rate of return levels authorized by the FERC, the average ROE allowed on transmission investments remains above the average equity return authorized by state commissions in traditional rate proceedings, providing additional impetus for transmission expansion.

From a natural gas perspective, while the momentum toward expansion in the midstream sector is waning, the replacement of mature gas distribution infrastructure has gained widespread momentum and is likely to continue at material levels for many years, considering state and federal mandates to address safety.

More than 60% of planned spending is arguably driven by the energy transition, with 51% earmarked for transmission and distribution infrastructure, 10% dedicated to renewables and 2% allocated to environmental spending.

While electric spending dominates, at 61% of the more than $400 million total for the 2020-22 period, gas spending at around 20% or roughly $81 billion is substantial, and this percentage of the total has been relatively consistent over the last several years.

CapEx by business category, 2020E-2022E



Compiled Oct. 27, 2020.
* Gas includes pipeline, storage, distribution and other gas infrastructure.
Source: S&P Global Market Intelligence

Authorized ROEs

In 2020, with the U.S. economy challenged by fallout from the COVID-19 pandemic, the averages of the equity returns authorized for electric and gas utilities nationwide fell to their lowest levels on record.

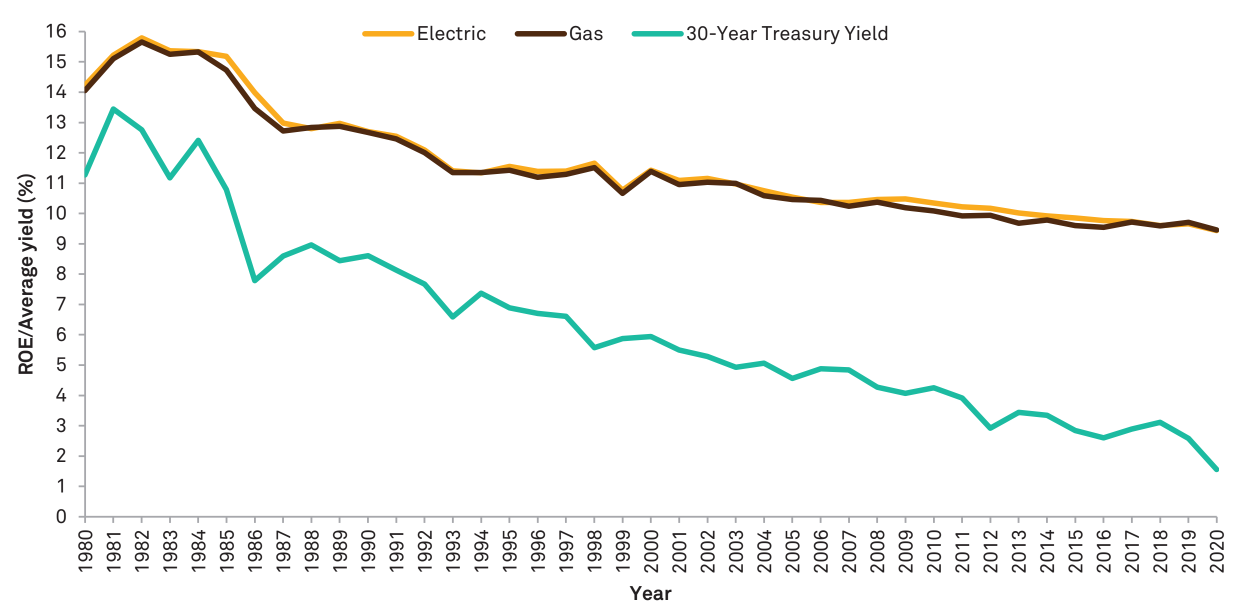
With recent interest rate cuts by the U.S. Federal Reserve and the current pandemic-induced recession, even lower authorized returns may be on the horizon.

The average return on equity authorized electric utilities was 9.44% in all rate cases decided in 2020, below the 9.66% average for all such cases in 2019. There were 55 electric ROE determinations in 2020 versus 47 in 2019.

The electric average includes several limited-issue rider cases that include premiums above a base ROE for investments in certain types of generation. Excluding these cases, the average authorized ROE was 9.39% in electric rate cases decided in 2020, versus 9.65% observed in 2019.

Average authorized ROE in the U.S. /30-year treasury bond yields

Calendar years 1980-2020



Data compiled as of Jan. 31, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

The average ROE authorized gas utilities in cases decided in 2020 was 9.46% versus the 9.71% average observed in 2019. There were 34 gas cases that included an ROE determination in 2020 versus 32 in 2019.

Prior to the pandemic, RRA observed a modest recovery in authorized ROEs as the U.S. Federal Reserve unwound its quantitative easing policy and implemented a series of gradual interest rate increases from 2015 through 2018.

As has typically been the case, authorized ROEs lagged interest rate trends somewhat and so continued to rise modestly during 2019 even though the Fed lowered interest rates to combat a slowing economy.

With more dramatic cuts implemented in the wake of the coronavirus and indications that policymakers plan to keep the rates near zero through 2023, our expectation is that the authorized ROEs will decline further.

While regulators continue to rely heavily on the discounted cash flow model, methodologies that are tied more closely to interest rates such as the capital asset pricing model and the risk premium model will argue for lower ROEs, as Treasury Yields, generally the proxy for the risk-free rate, have declined precipitously.

The reductions in treasury yields has outpaced reductions in authorized ROEs. As a result, an authorized ROE of 9.5%, which approximates prevailing averages, equates to about an 800-basis-point premium over treasuries. This is the largest spread RRA has ever observed, and stakeholders are going to be arguing for reductions in that premium.

While 9% has until recently been an invisible barrier that regulators were reluctant to breach, that has already begun to change, with 10 authorized returns — seven electric and three gas — below 9% approved in 2020. Notably, one of these included an explicit penalty for poor performance, and three others came as part of formulaic ROE determinations that are calculated based on a set premium over U.S. Treasuries.

With the level of planned capital spending, other costs associated with the energy transition, flat-to-modest sales growth absent the pandemic, political distaste for approving rate increases when the country is in the midst of a crisis, and shrinking headroom in utility rates, something will have to give. Should tax increases enter the equation, the pressure will be that much greater.

Since authorized returns are the area with the most room for subjective judgement, it stands to reason that ROEs will be what gives.

Merger and acquisition activity

Consolidation and sector convergence have historically been avenues utilities have pursued to lower costs and achieve growth. There was scant activity in the late-1980s and early 1990s due to statutory restrictions on utility mergers and the utilities' ability to grow their businesses through generation expansion.

Merger activity has been fairly robust since the mid-1990s, when one could argue that the energy transition actually began with the introduction of electric retail competition.

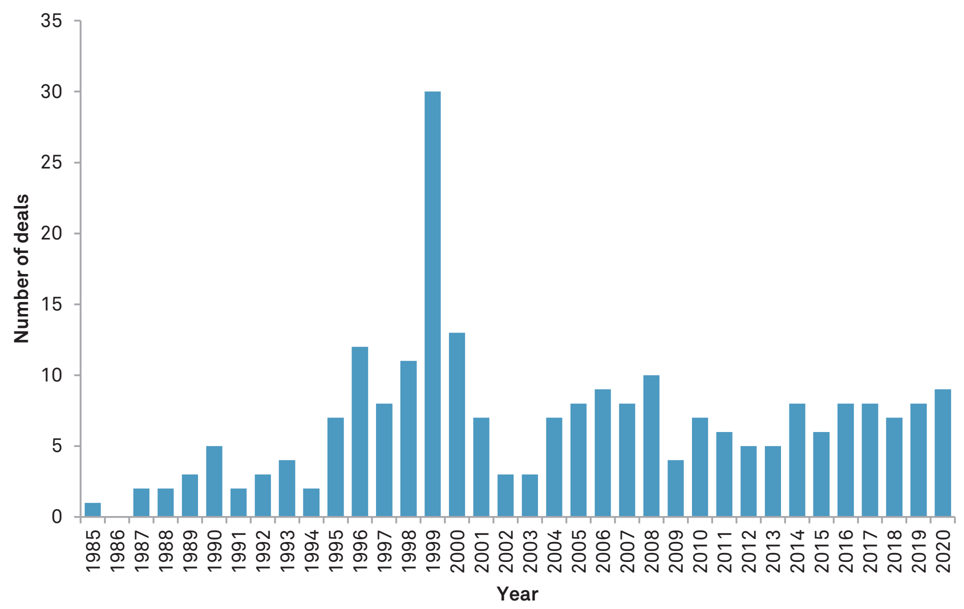
Over the last several years, activity has been somewhat more modest, with a smattering of large deals here and there, accompanied by smaller transactions targeting individual assets or asset classes being more the norm.

Even before COVID-19 entered the picture, prospects for M&A activity in the energy utility sector were lackluster due to pre-pandemic economic concerns, political uncertainty and enhanced scrutiny of deals in recent years by state regulators.

As public policy shifts raised concerns about the future of the gas industry, there has been a decline in the number transactions where the strategy was service type diversification or gaining a foothold in the midstream sector.

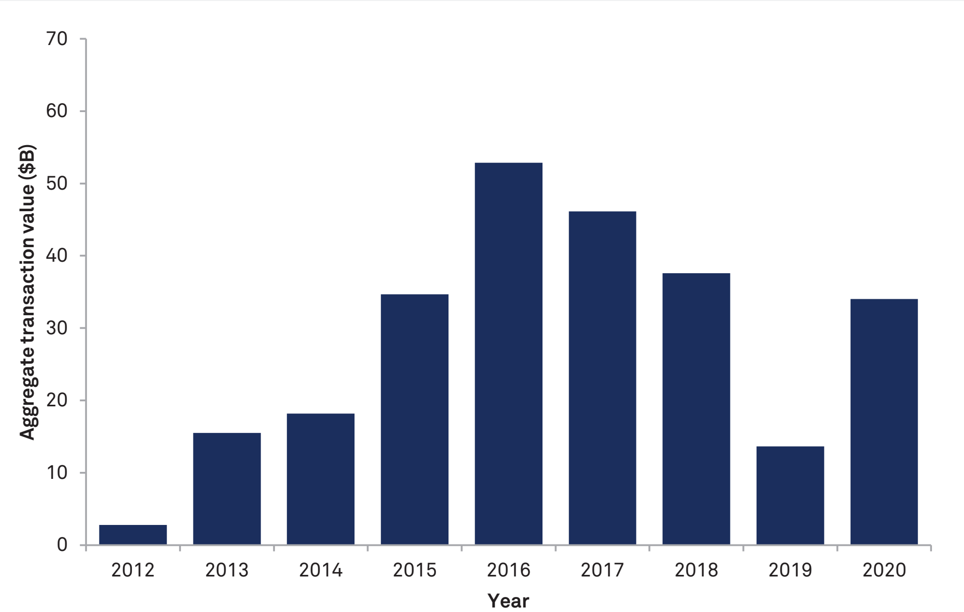
A handful of smaller deals were announced during the early part of 2020, along with NextEra Energy Inc.'s successful bid to acquire the South Carolina Public Service Authority, also known as Santee Cooper, for $9.6 billion.

Utility mergers and acquisitions announced, 1985-2020



As of Dec.31, 2020.
Source: Regulatory Research Associates, a group with in S&P Global Market Intelligence

Transaction value of utility mergers announced, 2012-2020



Data gathered as of Dec. 31, 2020.
Source: S&P Global Market Intelligence

M&A activity slowed during the second quarter of 2020, as potential participants adjusted to conducting negotiations in a different way and as the uncertainty associated with the pandemic altered the focus of many utilities. In the wake of the pandemic, utilities and regulators focused on the economic hardship facing customers, maintaining service while protecting their employees and continuing infrastructure maintenance and improvement plans in these challenging conditions.

Activity picked up again in July 2020 with Berkshire Hathaway Energy Inc.'s $11.5 billion acquisition Dominion Energy Inc.'s midstream businesses and NRG Energy's acquisition of DirectEnergy Inc. from Centrica PLC.

The fourth quarter brought two deal announcements, Avangrid Inc.'s $7.7 billion acquisition of PNM Resources Inc. and UGI Corp.'s $540 million purchase of Mountaineer Gas Co.

Notably during 2020, NextEra Energy also made unsuccessful overtures to Evergy Inc. and Duke Energy Corp.

This uptick in activity in late-2020 could well represent the beginning of another resurgence in transactions in the form of deals aimed at better positioning the participants to respond to the Energy Transition. The prospects for increased activity in 2021 are bolstered by announcements in recent months that PPL Corp. plans to divest its electric distribution businesses in the United Kingdom, Exelon Corp. is going to sell its generation business and DTE Energy Inc. may sell its midstream businesses. There have also been rumors of Berkshire Hathaway pursuing CenterPoint Energy Inc. or CenterPoint selling off its gas LDC business.

Even so, regulatory scrutiny of transactions is likely to continue to intensify and prove challenging for bringing planned deals to fruition, as evidenced by discussions at the November 2020 National Association of Regulatory Commissioners Annual Meeting, where speakers argued that that commissions need to:

- Become more involved in the review process, performing independent analyses of costs and benefits rather than relying on the assertions of the companies;
- Apply a more robust positive net benefit standard for approval of transactions rather than the no harm or public interest standards, and
- Conduct more intensive, after the fact reviews to be sure that benefits are realized.

Recap

2021 is shaping to be another challenging year for the utility industry and its regulators, as they continue to grapple with a mix of core traditional utility issues and the challenges presented by the energy transition under the overhang of the COVID-19 pandemic and its ramifications for the economy.

Rate case activity will likely continue at or near the levels seen in recent years, constrained by COVID-19 considerations. Authorized ROEs, and by extension industry profitability, will be pressured by historically low interest rates and the need to moderate rate changes in the current environment.

Energy issues will garner a significant amount of attention from state and federal lawmakers, and merger activity could pick up, with the strategy behind the deals driven by energy transition considerations.

S&P Global Ratings

RatingsDirect®

Why We See Ontario's Electricity And Gas Regulatory Framework As Strong

January 13, 2021

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S&P Global Ratings considers the province of Ontario to have predictable and stable regulatory frameworks for electricity and gas transmission system operators (TSOs) and distribution system operators (DSOs). This results in our assessment of Ontario regulation--which is administered largely by the Ontario Energy Board (OEB), the key source of our information--as strong (the most credit supportive assessment). We evaluate jurisdictions by the qualitative and quantitative factors that affect the regulatory advantage for the utilities we rate. We view the regulatory framework as the single most important factor in assessing a regulated utility's competitive position (see "Key Credit Factors For The Regulated Utilities Industry," published Nov. 19, 2013, on RatingsDirect).

Key Takeaways

- Regulatory frameworks for electricity and gas transmission and distribution networks in Ontario exhibit characteristics that are consistent with our most credit supportive (strong) regulatory advantage assessment.
- The regulation allows TSOs and DSOs to recover their capital and operational costs in a comprehensive and stable manner, and timely reviews ensure the adequacy of the regulation.
- TSOs and DSOs benefit from the regulator's solid track record of stability and political independence.

Table 1

Key Factors Of The Ontarian Regulatory Framework (Electricity And Gas)

Regulatory Stability
Regulation has been in place since 1997, using the performance-based ratemaking (PBR) since 2001 for electric utilities and 2009 gas utilities.
Predictable and transparent framework, currently on the fourth generation of PBR, with well-defined parameters.
Tariff-Setting Procedures And Design
The tariff structure is stable and aims for fair returns for operators.

Table 1

Key Factors Of The Ontarian Regulatory Framework (Electricity And Gas) (cont.)

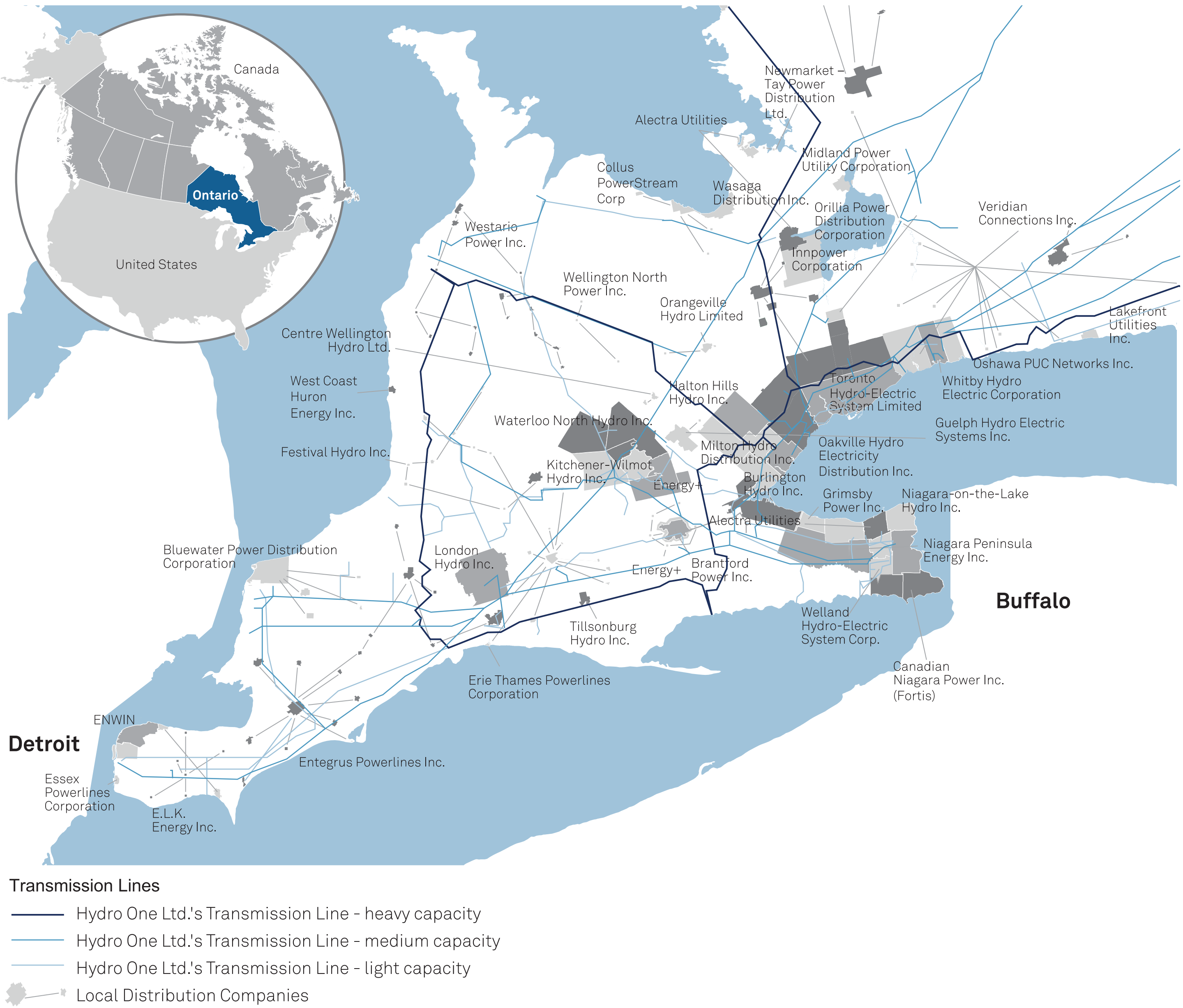
Remuneration for transmission and distribution operators allows for investment recovery, financial remuneration, and ongoing operational expense recovery.
Financial Stability
Sector can recover most of its costs.
Regulatory Independence And Insulation
The Ontario Energy Board is a regulatory body independent from the government with no indications of material political interference.
Rising generation costs towards a political ceiling of 10% annual increase may put pressure on the autonomy of the regulation.

Key Stakeholder

Ontario Province

Chart 1

Ontario Province Electricity Distribution



Not mentioned areas are serviced by Hydro One Networks Ltd. or local municipals. Sources: IESO, S&P Global Ratings.

Chart 2

Organization Of The Ontario Regulatory Environment For Utilities

Source: S&P Global Ratings.

The regulator

OEB is the provincial regulatory body responsible for the regulation of the natural gas and electricity sectors and executing the main energy policies established by the government. It protects the interests of consumers with respect to prices and adequacy, reliability, and quality of electricity service. It also ensures the financial and economic equilibrium of the regulated companies, guarantees that the activities of the regulated sectors are exercised in the public interest, and promotes use of electricity from renewable energy sources.

Other supervisory bodies

Government of Ontario-owned Independent Electricity System Operator (IESO) is responsible for directing the flow of electricity across the transmission lines, as well as planning the Ontario power system and coordinating conservation efforts across the province. OEB licenses IESO and sets the maximum fees IESO can charge.

Ontario Power Generation (OPG)

Province of Ontario-owned Ontario Power Generation is the largest electricity generator in the province, providing roughly half of the power to Ontarians through nuclear, hydroelectric, wind, gas, and biomass facilities.

Transmission system operators

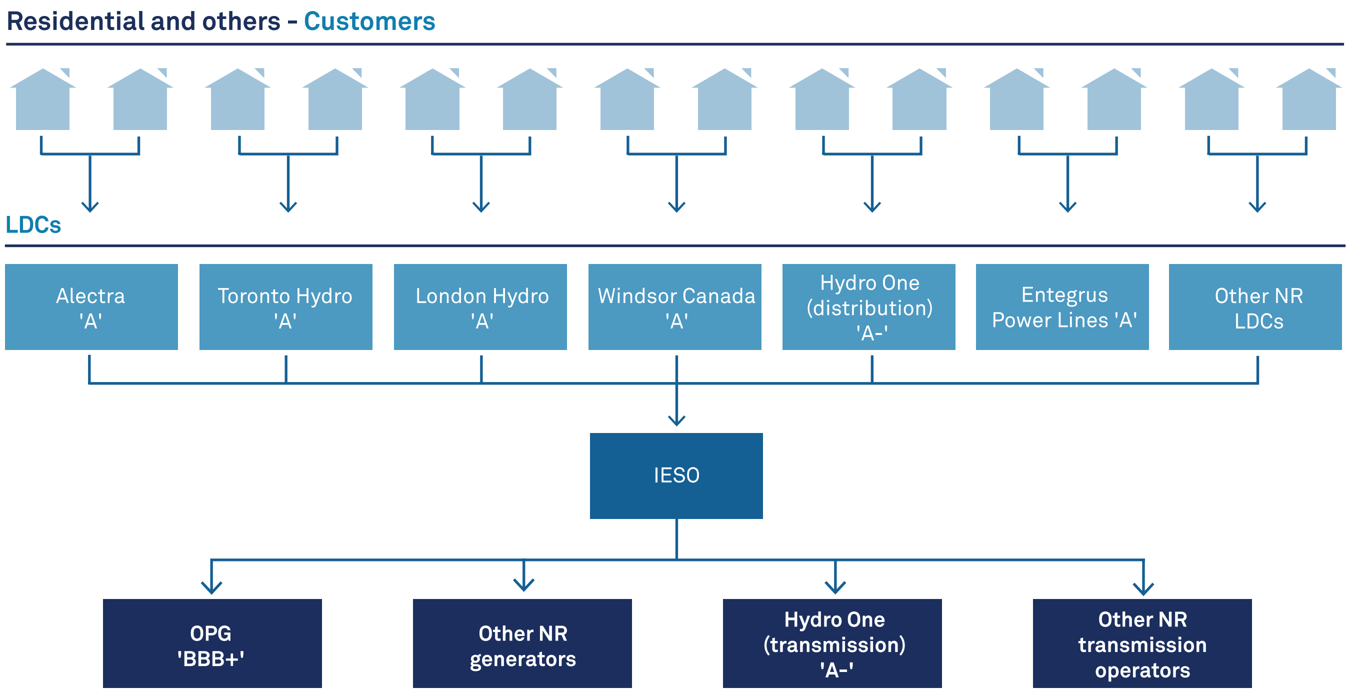
Hydro One Limited, through its subsidiaries, is the largest electricity TSO in Ontario. It owns the electricity transmission network of the province, delivering electricity to over 1.4 million customers. Hydro One also owns various DSOs in the province. Hydro One is about 47.3% owned by the government of Ontario and 52.7% publicly traded on the Toronto Stock Exchange.

Distribution system operators

Over 80 gas and electric utilities operate in the province. In April 2015, revenue decoupling was implemented for distribution operators with a fixed rate distribution tariff structure. Local distribution companies (LDCs) had four years to transition, and upon completion would have no exposure to volume risk. For electric distributors, it reduces cash flow volatility, while for gas distributors there is no need for weather normalization. In Ontario, most LDCs are owned by local governments.

Chart 3

Flow Of Funds For Electricity



*NR -- not rated. Source: S&P Global Ratings.

For gas LDCs, no intermediate party like IESO exists. The gas LDCs purchase gas from upstream pipeline companies, and the commodity cost related to purchased natural gas is passed directly to the customers with no markup. In addition, the federal carbon levy flows through to customers.

Regulatory Frameworks

In Ontario, regulatory frameworks provide incentive regulation and encourage utilities to become more efficient in ways that benefit customers and minimize rate increases. The first performance-based regulation (PBR) framework for electricity distribution was implemented in 2001 and gas distribution adopted the framework in 2009. OEB is currently on its fourth generation of the PBR framework. OEB typically resets transmission rates every two years based on cost of service (COS). Distribution rates are typically based on the PBR framework for 4-5 years between COS reset filings. In 2012, the Renewed Regulatory Framework for Electricity (RRFE) created three incentive rate-setting (IR) methodologies. The provincial utilities can choose from Price Cap IR, Custom IR, and Annual IR Index. All regulatory frameworks are based around a standardized return on equity (ROE) and capital structure. The PBR framework has a re-opener clause that allows utilities to re-base if they are under or over the authorized ROE threshold by 300 basis points (bps), eliminating large swings.

Table 2

Key Features of Utility Methodologies

Methodology	Utility	Key Features
Price Cap Incentive Rate-Setting	Electric DSOs, Gas DSOs, Electric TSOs	COS process first year, then price cap index formula. Productivity factor calculated by inflation minus stretch factor.
Custom Incentive Rate-Setting	Electric DSOs, Gas DSOs, Electric TSOs	Five-year forecast of utility's cost and sales volumes.
Annual Incentive Rate-Setting Index	Electric TSOs	Maximum stretch factor used. Price Cap IR formula used.

Price Cap IR The Price Cap incentive rate (IR)-setting methodology is the most frequently used and allows for base rates to be set through a COS process for the first year. The following four years are indexed by the fourth-generation price cap index formula. A productivity factor, calculated by inflation minus a stretch (or efficiency) factor, is included in the Price Cap IR annual adjustment mechanism. The lower the stretch factor (a scale set from 0% to 0.6%), the more efficient the utility. The assessment of the stretch factor is formula-driven but takes into consideration the size and scope of a utility too. It ensures a utility's rate will increase modestly below the inflation rate. Unique to the Price Cap IR method is the Incremental Capital Module (ICM). While a utility is operating under its PBR it can seek incremental rate recovery of additional capital spending above the originally approved capital spending in the base rate setting. Because of this flexibility of recovering incremental capital spending, OPG uses this methodology for their hydroelectric operations due to ongoing capital spending. Starting in early 2019, Enbridge Gas Inc. (EGI) operates under the Price Cap IR methodology. EGI's rates will increase based on inflation minus productivity, and the company will rely on harvesting synergies from the amalgamation of Enbridge Gas Distribution Inc. and Union Gas Ltd.

Custom IR Custom incentive rate-setting methodology sets base rates for five years using a five-year forecast based on a specific utility's costs and sales volumes. This methodology allows the utility to start earning on its rate base within the PBR period without having to wait for the next COS application. Custom IR is most suitable for entities with significantly large multi-year capital spending commitments with relatively certain timing and predictability of costs. Because of this, Hydro One uses this methodology for the transmission assets and OPG uses it for its nuclear business.

Annual IR Index Annual incentive-rating methodology uses the same annual adjustment formula as Price Cap IR, but the stretch factor is set at the highest level of 0.6%. This methodology does not require a periodic rate base reset using the COS process. The framework is most appropriate for distributors with limited incremental capital requirements and relatively steady investment needs.

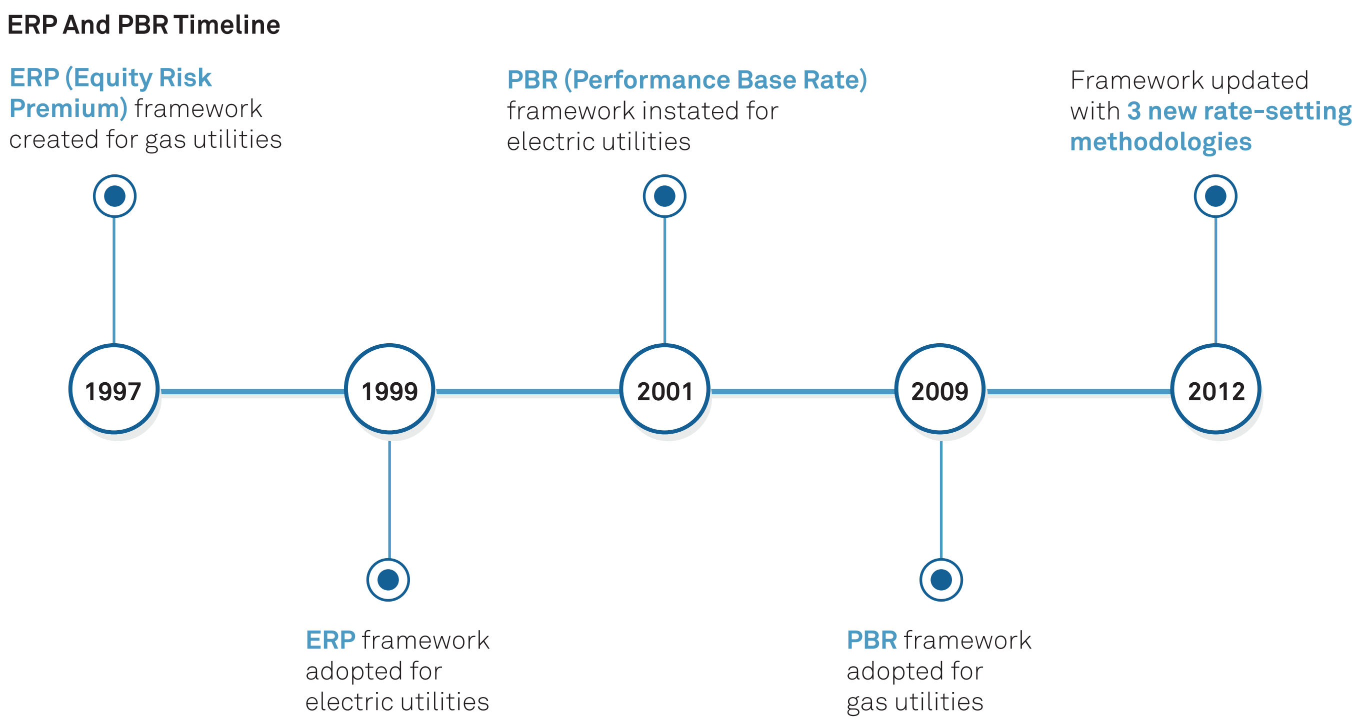
The availability of the above methodologies allows utilities to recover costs. The ability to recover all operating and capital costs in a timely manner is very supportive of credit quality.

Regulatory Stability

When assessing regulatory stability, we review the transparency of the key components of rate setting, the predictability of the framework, and the consistency of the framework over time. OEB publishes details of all hearings and rationales online and works with consultants and shareholders if there are any potential regulatory changes. This high level of transparency aligns with our most credit supportive (strong) assessment of the regulatory environment.

Given its track record of consistency and stability, we view the OEB's regulation as supportive and it underpins our expectation of consistent regulation across the regulatory cycle. This stability supports a utility's cost recovery and return on capital combined with lower-than-average volatility of earnings and cash flows. Regulatory lag is minimal since the OEB typically renders rate decisions within six to eight months.

Chart 4



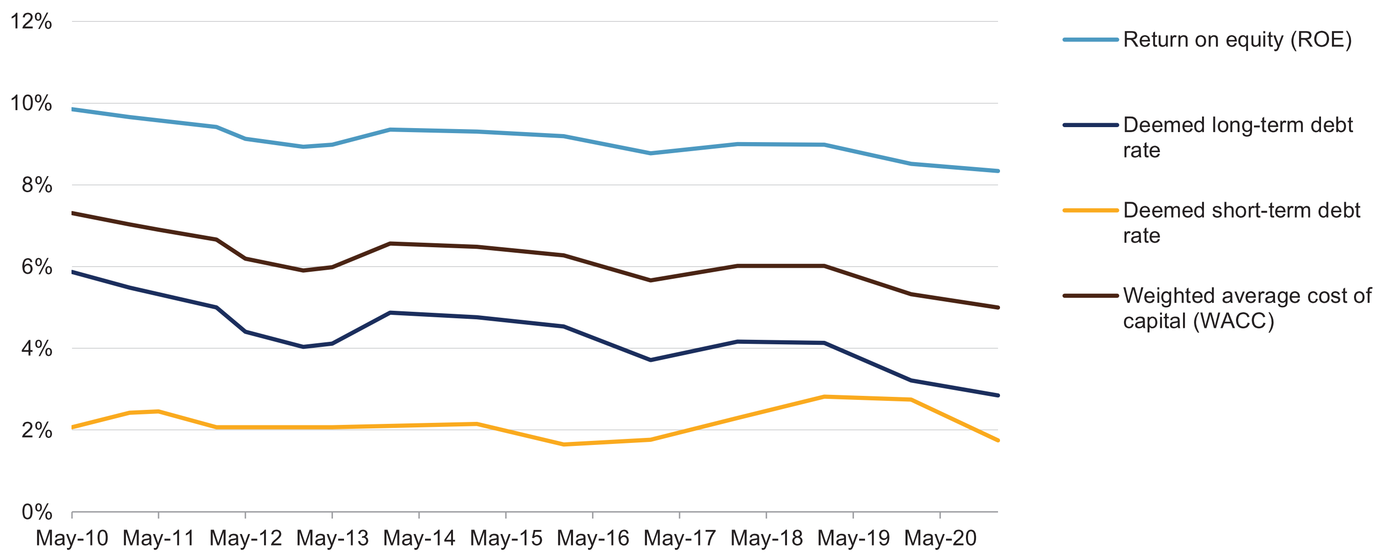
Source: S&P Global Ratings.

The deemed capital structure for ratemaking is consistent across the electric TSOs and DSOs with 40% equity, 56% long-term debt, and 4% short-term debt. For OPG's nuclear and hydro generation assets, the deemed capital structure is set at 45% equity and 55% debt. We view the overall regulatory framework for generation, which is typically considered riskier, as generally credit supportive with a modestly higher authorized return on total investment. For gas LDCs, the risk is considered less than electricity-related businesses, given the deemed capital structure is set at 36% equity and 64% debt. Additionally, gas LDCs must share over-earnings with ratepayers under an earnings sharing mechanism.

Cost of capital parameters, including the deemed (or authorized) long-term debt rate, deemed short-term debt rate, ROE, and weighted average cost of capital (WACC), have also seen relative levels of stability. OEB formulaically updates these rates every year, as shown in the chart below. The parameters have been modestly declining over the decade with 2021 parameters being the lowest on record. The current reference ROE is 8.52% and 40% equity based on the 2020 cost-of-capital update.

Chart 5

Cost of Capital Parameters



Tariff-Setting Procedures And Design

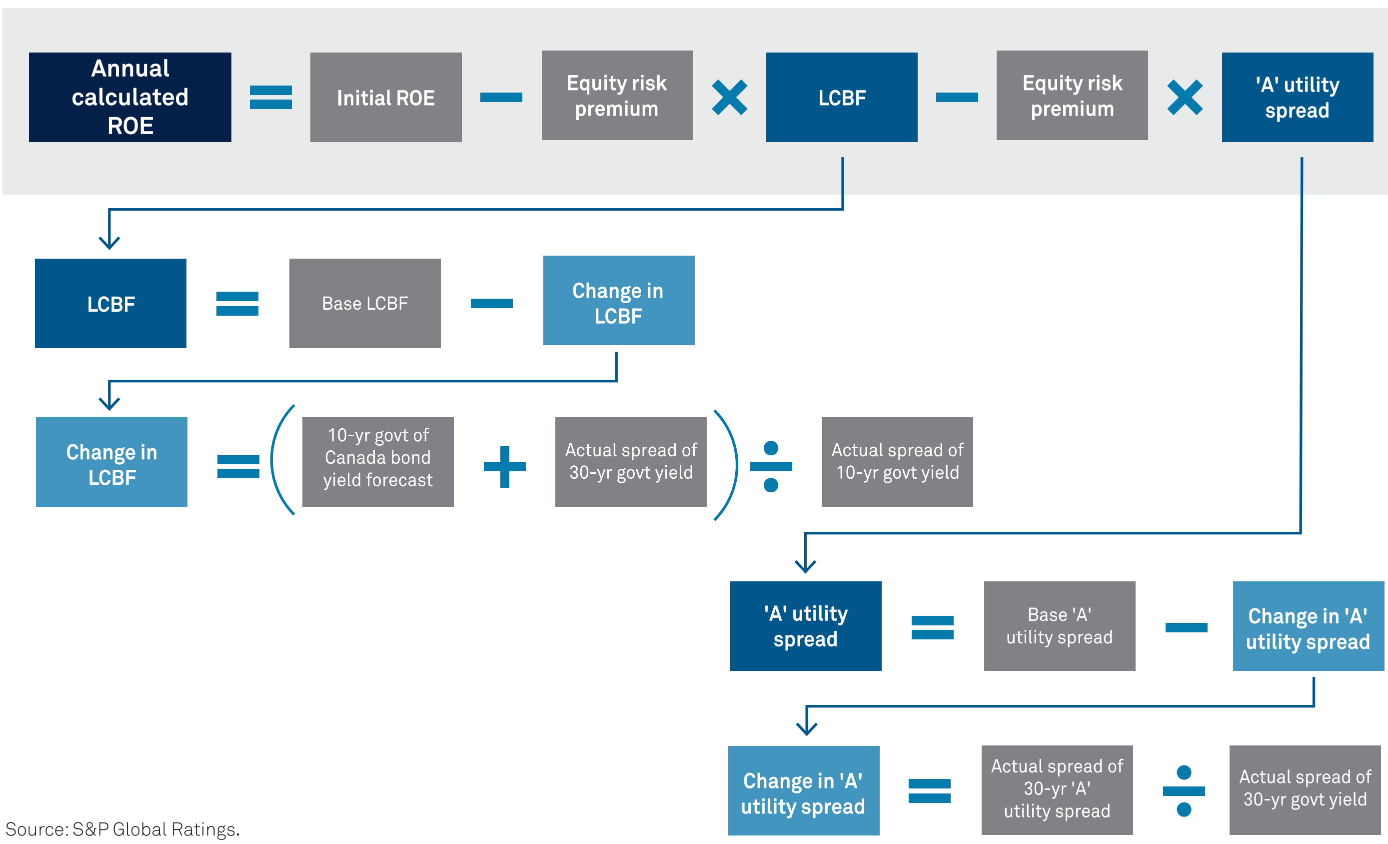
When assessing the tariff-setting, procedures, and design of a regulatory framework, we analyze whether all operating and capital costs are fully recoverable; the balance of interests and concerns of all stakeholders affected; and whether incentives are achievable and contained.

In Ontario, the rate-setting frameworks are based on regulatory periods with a fixed base ROE. The ROE is set annually according to a formulaic approach based on the Long Canada Bond Forecast (LCBF), 'A'-rated utility spread, and the initial ROE. In 2010, OEB addressed the relatively low return-on-equity levels and high sensitivity to changes in Canadian government long bond yields with a cost-of-capital reset decision. An adjustment of 50% was applied to the LCBF and 'A'-rated utility spread. This decision to reset cost-of-capital produced a 135 bps improvement in ROE levels.

Once a year, typically in September, OEB contacts the prime Canadian banks for estimates of the spreads. The LCBF is calculated by subtracting the base LCBF from the change in LCBF. The change in LCBF is estimated by adding the 10-year government of Canada bond yield forecast and the actual spread of 30-year over 10-year government of Canada bond yield. The 'A' utility spread is calculated by the difference of the change in 'A' utility bond yield spread and base 'A'-rated utility bond yield spread. The change in 'A' utility bond yield spread is calculated by the 30-year 'A' rated utility yield spread over the 30-year government of Canada yield spread. The LCBF and 'A' utility bond yield spread are then multiplied by a 0.5 equity risk premium, which was determined during the reset of cost-of-capital parameters in 2010. Then they are subtracted from the initial ROE, to get to the annual calculated ROE.

Chart 6

Annual Calculated ROE

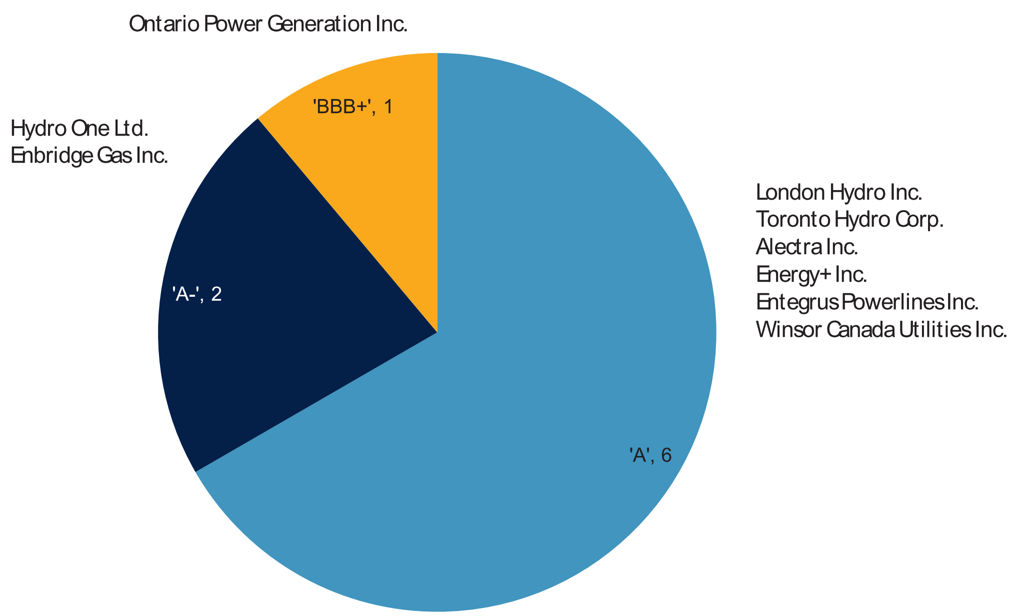


Source: S&P Global Ratings.

This formula-based approach enables predictable, transparent and consistent return on investments (ROI), or cost of capital, across the sector. It allows for rate-setting to be dynamic, especially with recent interest rate fluctuations. This approach only takes into consideration the spreads for 'A' rated utilities. Ontario has three utilities rated below 'A', indicated in the chart below. These utilities typically will generate a lower ROI, as their cost of debt may be relatively higher as compared to 'A' rated utilities. In addition, the formulaic approach for calculating the approved ROE may result in lower approved ROEs in the currently prevailing low-interest-rate environment and pressure the financial metrics.

Chart 7

Ontario Gas & Electric Utilities We Rate



Source: S&P Global Ratings

Financial Stability

When assessing the financial stability of a regulatory framework, we look at the timeliness of cost recovery and cash flow volatility; how much flexibility there is in the framework to allow the recovery of unexpected costs; the attractiveness of the framework to long-term capital; and capital support during construction to alleviate funding and cash flow pressure during periods of heavy investments.

We believe the OEB's regulatory environment facilitates supportive financial stability in the sector. Limited commodity risk exists since electricity costs and natural gas prices are ultimately passed through to the ratepayers. Companies can recover most of their costs, including operating expenditures, depreciation, and capital returns. Additionally, a significant level of protection exists against volume risk and non-controllable costs. Transmission operators have a limited history of stranded costs.

OEB allows utilities to recover all prudently incurred operating and capital costs in a timely manner. Variance accounts track any shortfalls and are trued up annually. OEB preapproves capital programs and has no history of significant disallowances, and utilities typically do not spend on unapproved capital programs. Preapproval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs. Major capital costs are added to rate base after completion of the project.

In addition, OEB has established deferral and variance accounts (DVAs) for specific duration and purposes. There is a perpetual DVA in place for electricity LDCs for pass-through of commodity and transmission costs. The DVAs for the pass-through of electricity commodity and transmission costs ensure the utilities experience little risk on the commodity charge except for possible bad debts.

The settlement process in Ontario exposes the electricity LDCs to the potential bad debts risks that include commodity costs. In light on the current pandemic, the OEB directed the electricity LDCs to extend the winter disconnection ban due to non-payment of electricity bills by three months. Although the OEB established three separate DVAs for tracking incremental costs, the electricity LDCs may face liquidity drawdowns due to incremental deferred payments or bad debts. OEB acknowledged that the utilities may incur incremental costs as a result of the ongoing COVID-19 emergency and has launched consultation to study the impact of it. In order to mitigate the impact, the initial steps included the approval of a situational DVA to track the incremental costs for future recovery. Although, the recovery of these tracked costs will depend on causality, materiality and prudency tests, it does provide financial stability to the utilities facing cost overruns to maintain the essential services under challenging circumstances. Furthermore, the electricity LDCs with more exposure to commercial and industrial customers may face higher headwinds compared with LDCs with operations in more metropolitan areas with larger composition of residential customers. OEB's vigilant monitoring, transparent policies, and timely measures during the COVID-19 emergency to address the potential cash flow and liquidity risks to the utilities supports our assessment of highly supportive financial stability.

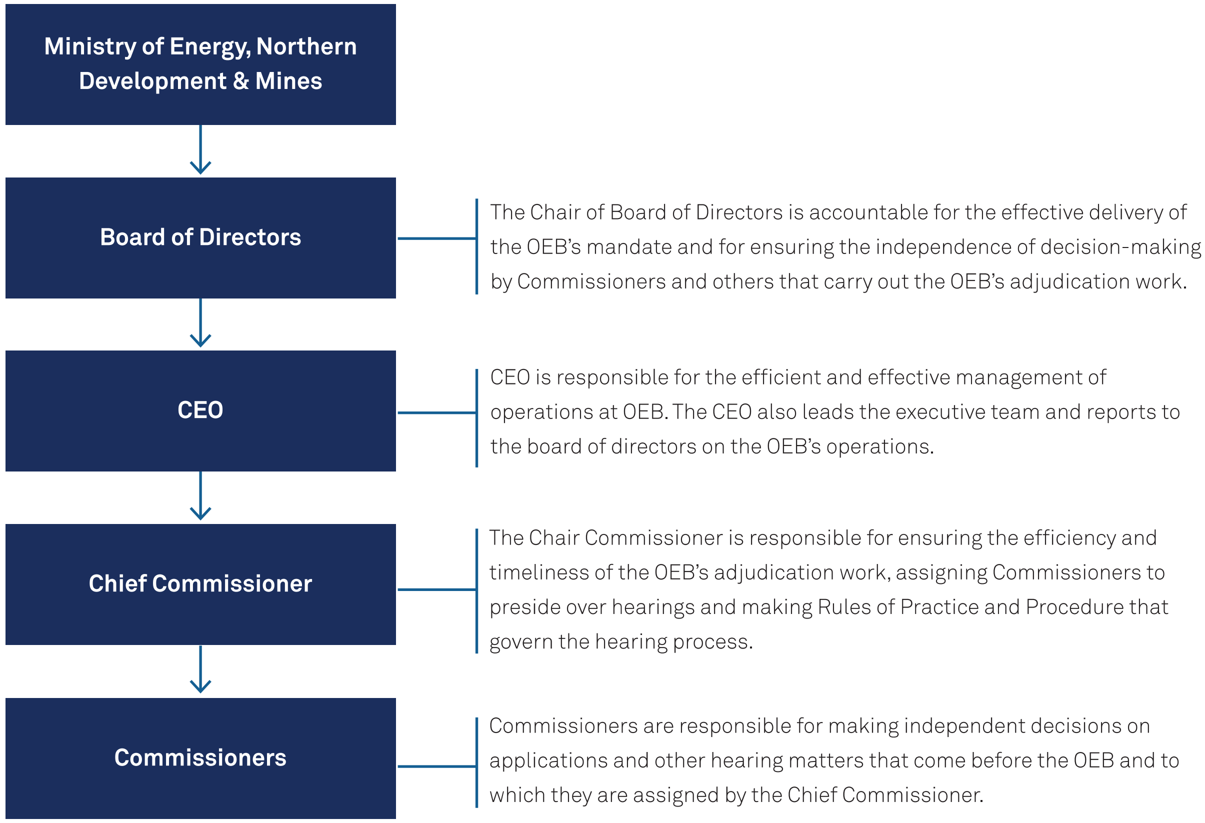
Regulatory Independence And Insulation

When assessing regulatory independence and insulation, we look at the market framework and how the law preserves and separates the regulator's powers, as well as any risks of political intervention. The Ontarian market framework was established in 1999, in which legislation outline OEB's framework regarding electricity and natural gas regulation and competitive electricity marketplace. OEB is very transparent about its framework, and its processes are generally governed by the Statutory Powers Procedure Act.

The Board of directors (BoD), Chief Executive Officer (CEO), and Commissioners are appointed by the Lieutenant Governor in Council, providing relatively more regulatory independence. The BoD oversees the management of the OEB's business and affairs and is responsible for the governance of the OEB.

Chart 8

OEB's Organizational Structure



Sources: oeb.ca, S&P Global Ratings.

OEB has had considerable political independence since its inception in the late 1990s. Within the past decade, no overarching government interference has occurred, and the Ontarian government in recent years has strengthened this barrier.

In 2017 Hydro One announced an acquisition of U.S.-based utility Avista Corp. However, the deal was halted after Hydro One's then-CEO retired and the company's entire board of directors resigned. These actions occurred after the premier of Ontario opposed the acquisition of Avista due to an expectation of increased rates for Hydro One ratepayers to recover the acquisition premium to buy the U.S. utility. The government of Ontario, subsequently in 2018 through the Hydro One Accountability Act, established a new executive compensation framework for the board, CEO, and other executives. With the newly appointed individuals, the Ontario government exercised its legislative ability to lower electricity rates, which was consistent with the governor's election campaign promises. Ultimately, the acquisition was terminated in late 2018 after the Washington Utilities and Transportation Commission denied the merger.

Following the termination of the Hydro One's acquisition of Avista, in 2019 the Ontario government enacted Bill 87: Fixing the Hydro Mess Act. This legislation modernized OEB, addressed governance and efficiency issues, and amended the OEB Act, Electricity Act and Fair Hydro Act. A board of directors and new chair were established, creating an interface for the Ontarian government, and the position of CEO of the OEB was created to provide executive leadership for operational and policy aspects. Commissioners are now expected to take an independent adjudicative role in hearing and determining matters within the jurisdiction. Broadly, the Board of directors are allowed to exercise the powers of the Board with respect to administrative functions while panels of commissioners assigned by the chief commissioner for the purpose exercise the powers of the Board with respect to its adjudicative and regulatory functions.

Regulatory Impact On Utilities' Credit Quality

The four pillars--regulatory stability, tariff-setting procedures, financial stability, and regulatory independence--are the key elements in the Ontario's natural gas and electricity regulatory environment. We believe the Ontarian regulatory framework is the most credit supportive kind, benefiting all key stakeholders. Regulatory stability comes from the choice of the three IR methodologies, in which utilities can maximize efficiency and recover prudent costs in a timely manner. OEB establishes a high level of stability, setting a uniform ROE level for all utilities. With its high level of transparency, OEB lays the groundwork for a better regulatory environment as key stakeholders become more confident in OEB's decisions. Since 1998, utilities operating in Ontario have a well-established track record of recovering their operating and capital costs.

We are following ongoing rate applications, specifically for Enbridge Gas Inc., Hydro Ottawa Limited, and Hydro One Networks. Enbridge Gas has numerous rate applications, including several projects, one to raise natural gas rates, and a dispute regarding 2019 utility earnings and deferral variance disposition. Hydro Ottawa Ltd. is currently going through its 2021 rate application, and Hydro One Networks is waiting for OEB's decision on eliminating the Hydro One seasonal rate class.

During the COVID-19 pandemic, OEB established an account for utilities to track any incremental costs and lost revenues as a result of the economic repercussions. Within the account, OEB will assess any claimed costs and/or lost revenues within established materiality thresholds. Submissions needed to be filed by late May 2020 to be considered. This is a recent example of OEB's prompt response to deal with credit pressures in a balanced manner for all key stakeholders.

We could reassess our regulatory assessment if:

- The formulaic approach for calculating the authorized ROE on the approved capital structure becomes ineffective under the current low-interest-rate environment and the OEB fails to adjust its approach.
- There was a loss of regulatory independence or instances of political interference in the framework.
- Any material changes in regulation likely to decrease transparency, consistency and timely recovery of costs.
- A material increase in provincial or sovereign risk factors that could negatively affect the operator's financial compensation.

Related Criteria

- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013

Related Research

- Updates And Insights On Regulatory Jurisdictions Shaping Policies For North American Utilities--November 2020, Nov. 9, 2020

This report does not constitute a rating action.

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

View Analyst Contact Information

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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

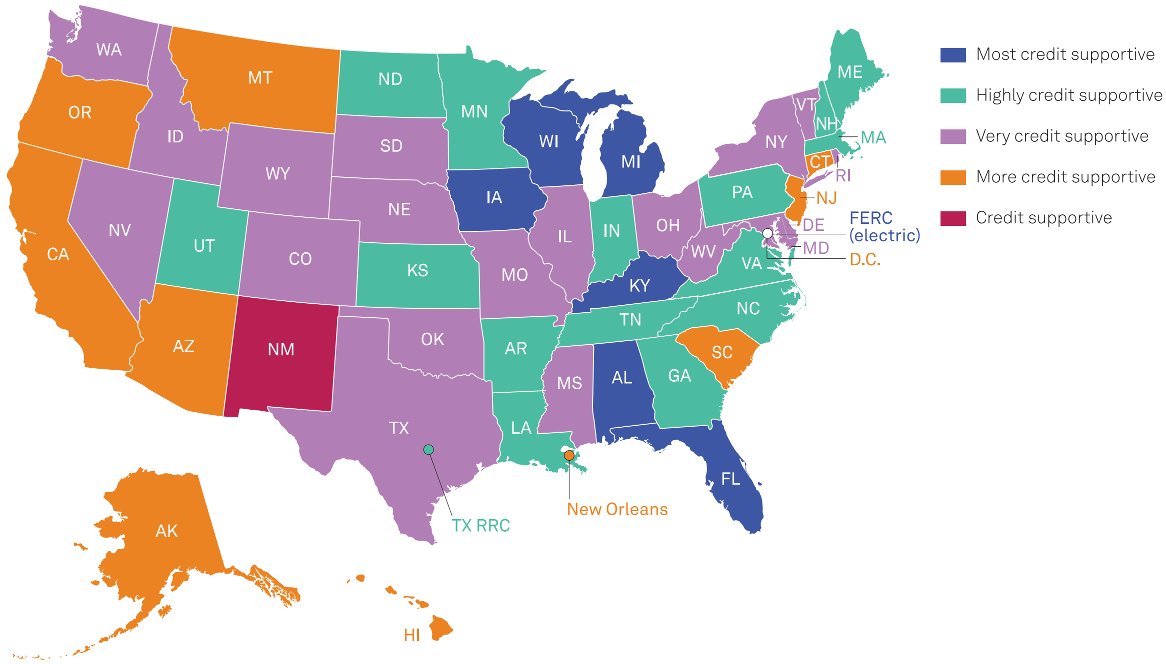
Credit supportive (adequate)	More credit supportive (strong/adequate)	Very credit supportive (strong/adequate)	Highly credit supportive (strong/adequate)	Most credit suppor (strong
New Mexico	Alaska	Colorado	Alberta	Alabama
Nova Scotia	Arizona	Delaware	Arkansas	British Columbi

Prince Edward Island	California	Idaho	Georgia	Federal Energy Regulatc Commis (electric
	Connecticut	Illinois	Indiana	Florida
	District of Columbia	Maryland	Kansas	Iowa
	Hawaii	Missouri	Louisiana	Kentuck
	Montana	Mississippi	Maine	Michigaı
	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.

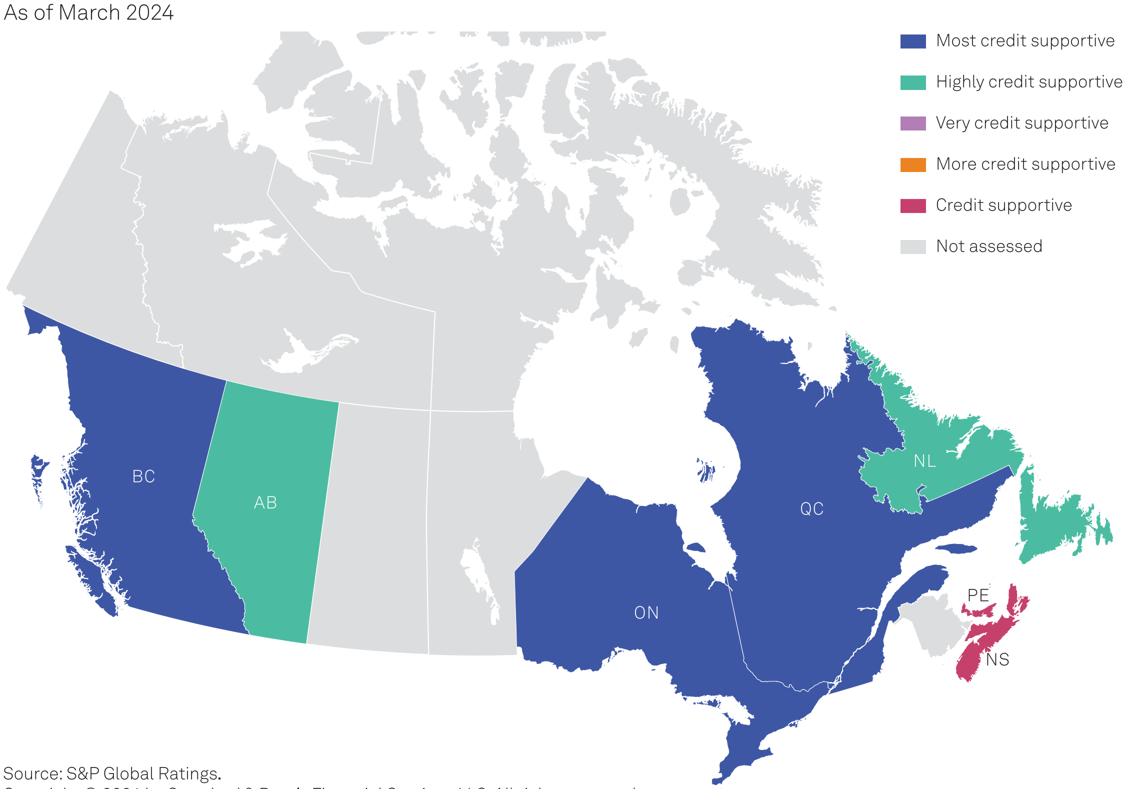
For jurisdictions assessed in Graphics 1 and 2, colors delineate our assessment of credit supportiveness. We do not have assessments for Canadian provinces where we do not have utility ratings. The charts depict scale and offer some detail regarding our assessment of the rules and implementation of regulation. 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



Source: S&P Global Ratings.

Regulatory assessment by Canadian province/territory
As of March 2024



Source: S&P Global Ratings.

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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UBS

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US Utilities

2024 Outlook: A Year for Resolutions and Resolve

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Resolutions in 2024

Resolution: The action or an act of resolving or determining; something which has been resolved upon; a fixed or positive intention (Source: OED). We believe 2024 will be a year of resolution of several factors that will determine utility performance. We see resolution in the coming year around:

- Balance Sheets. Equity will be necessary to fund the clean energy transition.
- The economy. Recession or soft landing, which will determine the path for interest rates and sector valuation.
- Valuation. Stocks trading at valuation discounts could revert to the mean as the macro picture and equity needs become clearer. We believe the group returns to fundamentals as more of a significant driver of performance.
- Regulation. Should get back to a focus on the clean energy transition as affordability pressures ease and reliability issues are addressed.
- Politics. The 2024 election should provide clarity around rhetoric vs. reality of modification or repeal of the Inflation Reduction Act.
- Execution. Track records should become clearer as new CEOs attain another year in their roles and can prove their ability to achieve eps guidance.

Resolve in 2024

Resolve: transitive. To reconcile opposing elements or tendencies within (a conflict, contradiction, etc.); Firmness or steadfastness of purpose; determination; an instance of this. (Source: OED). We also believe that both utility management teams and investors will need the resolve to take action and see these resolutions through. Resolve to:

- Wait for equity. Where there is potential balance sheet pressure despite any valuation overhangs it will be better to back the management teams that have the resolve to issue the equity and remove the valuation overhangs.
- Not focus on the macro. Recession tail winds will lift all boats, and a soft landing will be a stock picking environment without a sector tail wind. Better fundamentals will perform relatively better in either scenario.
- Look for discount valuation gaps to resolve. Focus on names with catalysts to avoid value traps.
- Ignore the political rhetoric come the Fall. Potential IRA repeal post the 2024 election as the reality is likely to be much more benign than the election rhetoric. This could push normal 3Q relative outperformance in 4Q.
- Look to the CEOs. Those who can continue to, or begin to build an execution track record across the year will enjoy relative better share price performance.
- Expand regulatory risk exposure. Look to more constructive regulation where the regulators have the resolve to drive the clean energy transition, particularly in the 2H, as easing of affordability pressures, may make this resolve easier for regulators in 2024 that it has been in 2022 and 2023.
- Favorite names for 2024 are Buy rated ETR, NI, PCG, SRE. In Power we prefer CEG and in water we prefer WTRG. We also remain Buy rated on CMS, EIX, EXC, NEE and SO and in power on VST.

Figure 1: Regulated Utility Coverage Universe

Rating	Ticker	12/11/23	Price Target	Total Return inc. Div. Yld	UBS 2021A EPS	UBS 2022A EPS	UBS 2023E EPS	UBS 2024E EPS	UBS 2025E EPS	2025 P/E Ratio	2025 Prem/ Disc	Current Dividend Yield	5 Yr EPS Growth	5 Yr DPS Growth	Regulatory Quartile
Buy	NEE	$59.71	$74	27%	$2.55	$2.90	$3.19	$3.39	$3.66	16.3x	9%	2.8%	7.1%	10.0%	1st
Buy	SRE	$73.94	$89	23%	$4.21	$4.61	$4.49	$4.79	$5.08	14.6x	(3%)	3.1%	7.2%	7.0%	3rd
Buy	EXC	$39.52	$47	22%	$1.83	$2.27	$2.36	$2.54	$2.77	14.3x	(5%)	3.4%	7.1%	7.2%	3rd
Buy	NI	$26.34	$31	21%	$1.37	$1.46	$1.57	$1.68	$1.80	14.7x	(2%)	3.6%	6.8%	4.6%	2nd
Buy	ETR	$102.11	$119	21%	$6.02	$6.42	$6.75	$7.18	$7.67	13.3x	(11%)	4.0%	6.9%	2.3%	3rd
Buy	PCG	$17.63	$21	19%	$1.08	$1.10	$1.23	$1.35	$1.46	12.1x	(19%)	0.2%	8.8%	10.0%	2nd
Buy	EIX	$68.03	$78	19%	$4.59	$4.63	$4.69	$5.10	$5.72	11.9x	(21%)	4.2%	6.7%	4.0%	2nd
Neutral	EMA	$48.85	$54	15%	$2.81	$3.03	$3.22	$3.39	$3.53	13.8x	(8%)	5.5%	4.6%	4.7%	2nd
Neutral	AEP	$80.49	$89	15%	$4.74	$5.09	$5.25	$5.64	$5.91	13.6x	(9%)	3.9%	5.7%	7.0%	3rd
Neutral	FE	$37.26	$41	14%	$2.60	$2.41	$2.56	$2.56	$2.88	12.9x	(14%)	4.2%	6.7%	2.6%	3rd
Buy	SO	$71.36	$78	13%	$3.41	$3.60	$3.65	$4.05	$4.35	16.4x	9%	3.8%	6.6%	2.8%	1st
Neutral	AEE	$78.18	$86	13%	$3.82	$4.14	$4.36	$4.71	$5.05	15.5x	3%	3.0%	7.1%	6.0%	2nd
Neutral	WEC	$84.21	$92	13%	$4.11	$4.46	$4.62	$4.94	$5.28	15.9x	6%	3.5%	6.3%	6.6%	1st
Neutral	PEG	$62.98	$68	11%	$3.67	$3.47	$3.46	$3.66	$3.99	15.8x	5%	3.4%	5.1%	7.0%	2nd
Neutral	ED	$91.87	$99	11%	$4.37	$4.57	$5.03	$5.34	$5.66	16.2x	8%	3.4%	6.7%	4.5%	4th
Neutral	PPL	$26.33	$28	10%	$1.05	$1.41	$1.60	$1.70	$1.79	14.7x	(2%)	3.3%	7.0%	7.6%	3rd
Neutral	DTE	$110.09	$117	10%	$5.99	$5.96	$5.76	$6.70	$7.15	15.4x	3%	3.3%	6.6%	6.8%	1st
Neutral	ES	$60.79	$64	9%	$3.54	$4.05	$4.32	$4.57	$4.60	13.2x	(12%)	4.2%	5.0%	5.5%	4th
Neutral	EVRG	$51.78	$54	9%	$3.58	$3.71	$3.66	$3.87	$4.09	12.6x	(16%)	4.5%	4.3%	7.0%	4th
Neutral	D	$47.65	$49	8%	$3.86	$4.10	$2.81	$3.17	$3.45	13.8x	(8%)	5.6%	-0.3%	1.5%	3rd
Buy	CMS	$58.08	$61	8%	$2.65	$2.89	$3.10	$3.32	$3.55	16.3x	9%	3.2%	7.7%	7.0%	1st
Neutral	LNT	$51.51	$54	8%	$2.65	$2.80	$2.90	$3.08	$3.27	15.7x	5%	3.3%	5.5%	6.0%	1st
Neutral	DUK	$95.36	$98	7%	$5.24	$5.27	$5.63	$5.97	$6.35	15.0x	0%	4.2%	6.3%	4.0%	1st
Neutral	IDA	$99.37	$102	6%	$4.85	$5.11	$5.12	$5.44	$5.86	16.9x	13%	3.1%	7.1%	5.4%	2nd
Neutral	XEL	$61.55	$63	6%	$2.96	$3.17	$3.35	$3.59	$3.89	15.8x	6%	3.2%	7.0%	5.9%	3rd
Neutral	POR	$43.11	$43	4%	$2.72	$2.74	$2.62	$2.96	$3.25	13.3x	(12%)	4.1%	6.0%	6.0%	3rd
Neutral	OGE	$35.40	$35	4%	$2.36	$3.32	$2.05	$2.11	$2.26	15.6x	4%	4.7%	6.5%	3.0%	3rd
Neutral	AES	$18.05	$18	3%	$1.52	$1.67	$1.73	$1.78	$2.07	8.7x	(42%)	3.5%	4.7%	5.0%	2nd
Sell	PNW	$75.65	$74	2%	$5.47	$4.26	$4.20	$4.96	$5.23	14.5x	(4%)	4.5%	6.5%	4.6%	4th
Neutral	CNP	$29.05	$29	2%	$1.64	$1.38	$5.00	$1.66	$1.75	16.6x	11%	2.4%	8.3%	8.0%	4th
Sell	FTS	$55.33	$50	(6%)	$2.59	$2.78	$3.06	$3.17	$3.27	16.9x	13%	3.9%	5.5%	4.2%	3rd
Electric Utility Average										**15.0x**		**3.8%**	**6.2%**	**5.5%**	

Source: Factset, UBS Estimates

A YEAR FOR RESOLUTIONS & RESOLVE

Executive Summary

Utilities remain overvalued to interest rates by ~11%, our valuation regression model by ~7%, and in relation to earnings yields versus return spreads versus the risk free rate. A bid for value within the group has emerged since November 12 with a trend to sell winners and buy laggards. This is likely to keep the group trading tight versus historical valuation spreads, and to the extent this also occurs in the broader market, it would likely exacerbate the overvaluation of the sector into 2024. For investors in utilities, valuation discipline will be more important than ever, and related to this factor we favor Buy rated EIX, ETR, and PCG.

The overvaluation should resolve as headwinds for sector performance come to the fore in the first half of next year. Some balance sheets look stretched, and we believe that ratings agencies will become more strict around achievement of required metrics to maintain ratings next year. We see equity needs increasing as capital requirements to execute the clean energy transition increase when capital forecasts are updated for about half the group on year-end calls, and the remaining half on third quarter calls in the fall. Here we prefer names where we don't forecast an equity need in 2024, which are Buy rated SO and SRE.

Achievement of original earnings guidance continues to be an execution hallmark for the sector. We see the management teams across utilities at an interesting inflection point with almost 80% of the CEOs and CFOs in our coverage universe having tenure in those roles of under five years. The market may need more time to include a premium or discount related to earnings consistency in valuation. Here we prefer Buy rated CMS, and see the potential for building a foundation for a track record of delivery over time at Buy rated EXC and NI. The discount related to lack of execution could occur sooner as those companies that miss original earnings guidance in 2023 or appear to be doing so across 2024 will potentially have to rebase expectations.

The election in 2024 will matter insofar as rhetoric around potential repeal of the Inflation Reduction Act enters the campaign. While we believe the reality of potential repeal is minimal given current polling and the necessary Republican Congressional majorities that would be necessary, rhetoric and uncertainty is likely to be a headwind. Generalist money is likely to seek defensive positioning in other sectors if IRA repeal rhetoric remains front and center in the news, potentially limiting upside related to defensive utility fund flows should the recession case for the economy play out, or some other crisis that impacts financial markets occur. Heated rhetoric could be a headwind to the most IRA levered names (AES, CEG, NEE, and XEL).

We would view any election rhetoric dislocations in the fall as buying opportunities for Buy rated NEE and CEG if polling continues to indicate at that time that the election outcome remains close for both the Presidency and control of Congress. The backdrop of any election related headwinds could exacerbate the typical group seasonal underperformance in the first and second quarters, and delay the typical relative outperformance in the third quarter, potentially setting the group up for a fourth quarter rally, dependent upon the election outcome.

Resolution of the economic path between recession and soft landing in 2024 and the end of the Fed rate hike cycle likely mean that the macro backdrop is no longer the main factor for performance as we move through 2024 and stock performance will shift over time to be more driven by stock specific fundamentals. This will overall be a positive for dedicated utility investors. However, the positive backdrop will likely be weighted to the second half and even into the fourth quarter of the year.

Investors in 2024 will need the resolve to wait out the sector overvaluation, equity needs, and election rhetoric headwinds. We believe a more rational valuation entry point emerges as the sector moves toward a more constructive regulatory backdrop and is driven by more stock specific fundamental factors.

The Pivotal Questions for 2024

Will the Bid for Value Continue?

Yes, the bid for value is likely to continue into year end, and we think the group will continue to trade at a tight valuation spread versus history. If this also occurs in the market overall, it could exacerbate the overvaluation of the utility sector vs. interest rates into 2024.

The utility sector has seen a bid for value, with a trend to sell those stocks that have outperformed the index through November 12, and rotate into performance laggards. (See Figure 2 below).

- Of the stocks that were the top eleven performers through November 12 this year, five (50%) are in the top ten underperformers since then: FTS, EXC, EMA, PEG, and ED.
- Of the stocks that were the bottom ten performers through November 12 this year, seven (~60%) are the top twelve performers since.
- If a sell relative winners buy laggards theme also plays out in the overall market into year end, this will be a positive for utility performance given the significant underperformance by over 32% relative YTD as of November 12 as shown in Figure 2 below. This could be problematic for 2024 as it could exacerbate the overvaluation of the utility sector versus interest rates entering 2024, although the UTY has so far only outperformed the S&P 500 by 70bp since November 12.

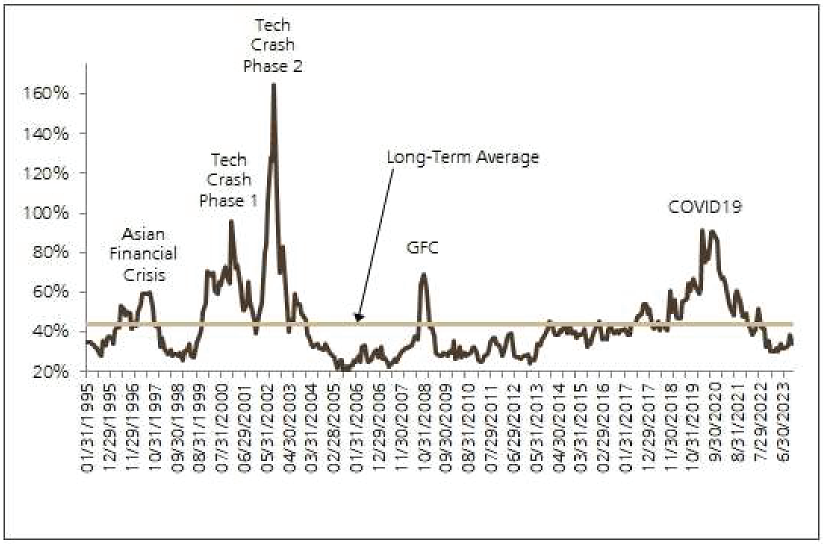
Figure 2: Performance YTD Thru 11/12 and Since

YTD performance thru November 12th				Performance Since November 12th			
Ticker	1/3/2023	11/12/2023	%	Ticker	11/12/2023	12/11/2023	%
SP50	$3,824.14	$4,415.24	15.5%	AES	$15.70	$18.05	15.0%
PCG	$15.68	$16.78	7.0%	ES	$53.80	$60.79	13.0%
FTS-TSE	$55.34	$55.70	0.7%	DTE	$98.57	$110.09	11.7%
PEG	$62.05	$61.61	-0.7%	NEE	$55.14	$59.71	8.3%
EIX	$64.28	$63.72	-0.9%	DUK	$88.27	$95.36	8.0%
SO	$71.90	$68.10	-5.3%	PNW	$70.46	$75.65	7.4%
PNW	$74.63	$70.46	-5.6%	CNP	$27.12	$29.05	7.1%
ED	$95.76	$89.35	-6.7%	EIX	$63.72	$68.03	6.8%
CNP	$29.56	$27.12	-8.3%	LNT	$48.57	$51.51	6.1%
SRE	$76.86	$70.34	-8.5%	D	$44.96	$47.65	6.0%
EMA-TSE	$52.62	$48.08	-8.6%	ETR	$96.61	$102.11	5.7%
EXC	$43.16	$39.43	-8.6%	FE	$35.30	$37.26	5.6%
NI	$27.44	$25.00	-8.9%	IDA	$94.22	$99.37	5.5%
ETR	$109.13	$96.61	-11.5%	UTY	$767.03	$808.28	5.4%
LNT	$55.37	$48.57	-12.3%	NI	$25.00	$26.34	5.4%
CMS	$63.73	$55.60	-12.8%	SRE	$70.34	$73.94	5.1%
IDA	$108.23	$94.22	-12.9%	PCG	$16.78	$17.63	5.1%
PPL	$29.20	$25.34	-13.2%	WEC	$80.31	$84.21	4.9%
AEE	$88.49	$76.27	-13.8%	EVRG	$49.41	$51.78	4.8%
OGE	$39.51	$33.97	-14.0%	SO	$68.10	$71.36	4.8%
WEC	$94.16	$80.31	-14.7%	SP50	$4,415.24	$4,622.44	4.7%
DUK	$103.70	$88.27	-14.9%	CMS	$55.60	$58.08	4.5%
XEL	$70.07	$59.20	-15.5%	OGE	$33.97	$35.40	4.2%
FE	$42.03	$35.30	-16.0%	XEL	$59.20	$61.55	4.0%
DTE	$117.86	$98.57	-16.4%	PPL	$25.34	$26.33	3.9%
UTY	$919.97	$767.03	-16.6%	AEP	$77.70	$80.49	3.6%
AEP	$94.87	$77.70	-18.1%	ED	$89.35	$91.87	2.8%
EVRG	$62.93	$49.41	-21.5%	AEE	$76.27	$78.18	2.5%
D	$62.97	$44.96	-28.6%	PEG	$61.61	$62.98	2.2%
NEE	$83.83	$55.14	-34.2%	EMA-TSE	$48.08	$48.85	1.6%
ES	$84.22	$53.80	-36.1%	EXC	$39.43	$39.52	0.2%
AES	$28.11	$15.70	-44.1%	FTS-TSE	$55.70	$55.33	-0.7%

Source: Factset, UBS Estimates

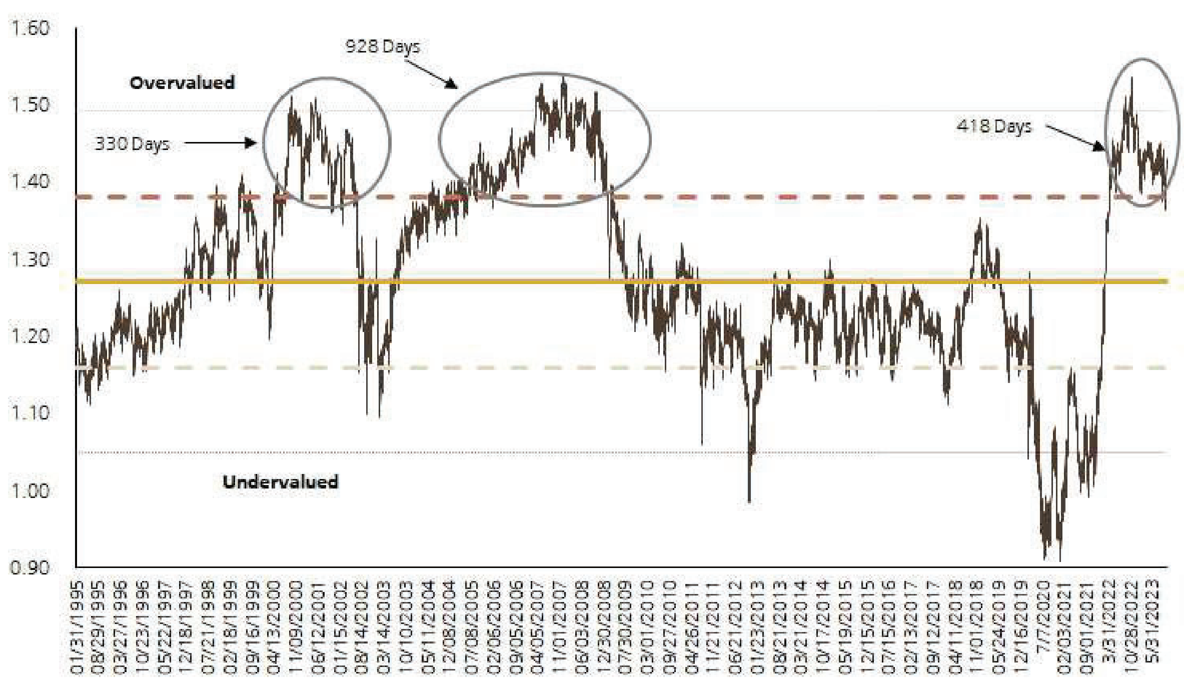
We think this trend has the potential to continue until year end and will likely tighten the group valuation spread which is already trading tight versus the historical mean, as shown in Figure 3 below. We don't think a quality premium spread can occur unless a deep recession case for the economy plays out. The group has historically traded tight to the average valuation spread for anywhere from two to four years after recrossing below the mean post peaking, which occurred in January 2022. Overall despite the decline in interest rates, the utility sector remains ~11% overvalued to interest rates, and overvalued to our regression model by ~ 7% (see our interactive model here, and note: New Analytical Valuation Approach for Regulated Utilities , June 12 2023).

Figure 3: Utility Valuations: Top Quartile/Bottom Quartile FY2 P/E Ratios



Source: Factset, UBS Estimates

Figure 4: Regulated Utility Dividend Yields vs. Baa Corporate Bond Yields



Source: Factset, Federal Reserve, UBS Estimates

To resolve the overvaluation vs. interest rates without stock volatility would require interest rates to fall by ~110bps all else equal. Our regression model would screen to fair value if Baa corporate bond yields fell to ~5.1% (vs. ~5.8% currently), or if the

DJ Utilities index declined to ~815 with flat Baa corporate bond yields, without any degradation or improvement in FY2 earnings per share.

Looking at historical relative valuation cycles, to achieve upside from here, or to get back to a peak over two standard deviations above the mean requires a significant recession/crisis (the 2001 recession), or some significantly positive sector fundamental driver (natural gas price peak in 2007, when several utilities owned generation assets, or the passage of the IRA in late summer/early fall 2022), as detailed in Figure 5.

Figure 5: Prior Cycles in Relative Utility Valuations vs. Interest Rates

First Cycle Above 1 Std. Deviation

Cycle Timeline	Date	DJU	Absolute %	S&P 500	Relative %	Baa Yield	10 Year	Spread	Fed Funds	Rel. Value Mark	Comments
Previous Trough	5/16/1994	178.55	n/a	444.49	n/a	8.47%	7.24%	1.23%	4.25%	1.06	
1st Above 1 Std Dev	5/4/2000	320.78	80%	1409.57	-137%	8.87%	6.46%	2.41%	6.00%	1.38	GDP Growth Averages 4%+ 1994-2001
Peak in Relative Value	5/24/2001	397.68	24%	1293.17	32%	8.17%	5.52%	2.65%	4.00%	1.51	**Recession March 2001 - November 2001**
Break in 1 Std Dev	2/22/2002	276.32	-31%	1089.84	-15%	7.84%	4.84%	3.00%	1.75%	1.35	Enron Bankruptcy in December 2001
Break Back Peak	4/3/2002	304.03	10%	1125.40	7%	8.12%	5.30%	2.82%	1.75%	1.47	**Post Enron Bounce; Market Bounce Defense Leads**
Break Below 1 Std	6/25/2002	271.11	-11%	976.14	2%	7.87%	4.88%	2.99%	1.75%	1.37	Market Decline; Defense outperforms
Trough in Rel. Value	10/9/2002	167.57	-38%	776.76	-18%	7.58%	3.61%	3.97%	1.75%	1.10	Market Bottoms in late 2002; Defense Lags

Second Cycle Above 1 Std. Deviation

Cycle Timeline	Date	DJU	Absolute %	S&P 500	Relative %	Baa Yield	10 Year	Spread	Fed Funds	Rel. Value Mark	Comments
Previous Trough	10/9/2002	167.57	n/a	776.76	n/a	7.58%	3.61%	3.97%	1.75%	1.10	
1st Above 1 Std Dev	6/1/2004	274.72	64%	1121.20	20%	6.80%	4.71%	2.09%	1.00%	1.38	**Natural gas price rally drives unregulated values higher**
Peak in Relative Value	12/13/2007	547.05	99%	1488.41	66%	6.79%	4.18%	2.61%	4.25%	1.54	**Rates rise; natural gas prices remain high**
Break in 1 Std Dev	2/17/2009	347.77	-36%	789.17	11%	7.95%	2.64%	5.31%	0.25%	1.37	2008 Financial Crisis; Defense Better Relative as rates cut
Trough in Rel. Value	11/15/2012	438.05	26%	1353.33	-46%	4.48%	1.58%	2.90%	0.25%	0.99	Rates Stay low, Market Rebounds, Defenses Lag Rebound

Third Cycle Above 1 Std. Deviation

Cycle Timeline	Date	DJU	Absolute %	S&P 500	Relative %	Baa Yield	10 Year	Spreads	Fed Funds	Rel. Value Mark	Comments
Previous Trough	12/23/2020	840.18	n/a	3690.01	n/a	3.17%	0.96%	2.21%	0.25%	0.91	Defense underperforms in Tech/Stay at Home Rally; Abnormally low rates
1st Above 1 Std Dev	4/8/2022	1070.84	27%	4488.28	6%	4.38%	2.72%	1.66%	0.50%	1.38	**Fed Hikes rates on inflation; defensives lead rally to market top**
Peak in Relative Value	9/12/2022	1061.77	-1%	4110.41	8%	5.54%	3.37%	2.17%	2.50%	1.51	IRA Legislation Peak; Fed hasn't raises by >300bp yet
Break in 1 Std Dev.	12/8/2023	874.02	-18%	4604.37	-30%	6.38%	4.59%	1.79%	5.50%	1.37	Defense lags rates +300bp in 12 months, inflation shifts lower, soft landing thesis

Source: Factset, US BEA, Federal Reserve, UBS Estimates

Will Equity Needs Continue and Expand?

Yes. Some balance sheets look stretched, and we believe based on our meeting with S&P at the EEI Financial Conference in November (see our note: here), that rating agencies will become more strict around credit metrics, increasing equity needs as capital requirements to execution the clean energy transition increase.

Balance sheets have become a focus for investors into year-end and we believe that 2024 will be a year where we see a resolution of equity needs for companies with credit metrics near or below there downgrade thresholds. We see the equity needs for the group as outlined below in Figure 6.

Figure 6: Current Modeled Equity Needs

Ticker	Company (Dollars in Millions)	2022A	2023E	2024E	2025E	2026E	2027E	Total '23-'27	Conversion/ DRIP/ Programs	Block Equity	Block Equity Remaining
AES	AES Corp	$0	$0	$0	$0	$500	$500	$1,000	$0	$1,000	$1,000
LNT	Alliant Energy	$25	$250	$25	$150	$275	$200	$900	$900	$0	$0
AEE	Ameren Corp	$333	$908	$600	$600	$600	$600	$3,308	$3,308	$0	$0
AEP	American Electric Power	$827	$950	$400	$800	$800	$600	$3,550	$3,550	$0	$0
CNP	Centerpoint Energy	$0	$444	$250	$250	$250	$250	$1,444	$1,444	$0	$0
CMS	CMS Energy	$69	$440	$0	$250	$250	$250	$1,190	$1,190	$0	$0
ED	Consolidated Edison	$57	-$1,000	$0	$950	$900	$900	$1,750	-$1,000	$2,750	$2,750
D	Dominion Energy	$1,866	$0	$0	$0	$125	$125	$250	-$2,350	$2,600	$0
DTE	DTE Energy	$1,300	$200	$100	$150	$150	$150	$750	$750	$0	$0
DUK	Duke Energy	$9	$0	$0	$0	$0	$425	$425	$425	$0	$0
EIX	Edison International	$13	$350	$260	$100	$100	$100	$910	$910	$0	$0
EMA	Emera Inc. (C$)	$277	$520	$520	$520	$520	$520	$2,600	$2,600	$0	$0
ETR	Entergy Corp	$885	$65	$65	$800	$825	$825	$2,580	$2,580	$0	$0
EVRG	Evergy	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ES	Eversource Energy	$0	$51	$300	$1,200	$0	$0	$1,551	$551	$1,000	$1,000
EXC	Exelon	$563	$250	$100	$75	$250	$250	$925	$925	$0	$0
FE	FirstEnergy Corp	$0	$100	$100	$100	$100	$100	$500	$500	$0	$0
FTS	Fortis Inc. (C$)	$53	$450	$450	$450	$450	$235	$2,035	$2,035	$0	$0
IDA	IDACORP	$0	$300	$0	$300	$50	$50	$700	$100	$600	$300
NEE	NextEra Energy	$0	$2,500	$2,500	$2,500	$2,500	$2,500	$12,500	$12,500	$0	$0
NI	NiSource Inc.	$154	$0	$600	$250	$250	$250	$1,350	$1,350	$0	$0
OGE	OGE Energy Corp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PCG	PG&E Corp	$0	$0	$0	$300	$300	$300	$900	$900	$0	$0
PNW	Pinnacle West Capital Corp	$0	$0	$500	$0	$0	$0	$500	$0	$500	$500
POR	Portland General Electric	$0	$492	$200	$200	$205	$205	$1,302	$1,302	$0	$0
PPL	PPL Corporation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEG	Public Service Ent Group	-$500	$0	$0	$0	$0	$0	$0	$0	$0	$0
SRE	Sempra Energy	-$474	$1,239	$0	$0	$0	$0	$1,239	$1,239	$0	$0
SO	Southern Company	$1,510	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEC	WEC Energy Group	$0	$0	$500	$400	$400	$400	$1,700	$1,700	$0	$0
XEL	Xcel Energy	$322	$147	$500	$1,000	$1,000	$1,000	$3,647	$3,647	$0	$0
AWR	American States Water	$4	$0	$60	$60	$60	$0	$180	$180	$0	$0
AWK	American Water Works	$0	$1,688	$0	$0	$500	$500	$2,688	$0	$2,688	$1,000
CWT	California Water Service Group	$107	$113	$20	$25	$25	$25	$208	$208	$0	$0
WTRG	Essential Utilities	$79	$323	$150	$125	$150	$125	$873	$873	$0	$0
SJW	SJW Group	$39	$75	$20	$20	$20	$20	$155	$155	$0	$0
	Total	**$7,517**	**$10,855**	**$8,220**	**$11,575**	**$11,555**	**$11,405**	**$53,610**	**$42,472**	**$11,138**	**$6,550**
									79%	21%	% Total

Source: Factset, Company SEC Filings, Company Earnings Releases & Presentations, UBS Estimates

There are risks related to increases in estimated equity needs as capital programs increase to enable the clean energy transition. We see the most significant potential needs where forecast FFO/Debt is near or below the Standard & Poors downgrade threshold range. Our 2025 forecast FFO/Debt is below or within ~100bps of the S&P downgrade threshold for AEP, CNP, DTE, EMA, EVRG, FTS, PPL, and WEC, although we would note that for AEP we do not include incremental asset sale proceeds.

Figure 7: Historical and Projected FFO/Debt vs. S&P and Upgrade/Downgrade Triggers

	2022 FFO/ Debt	2023 FFO/ Debt	2024 FFO/ Debt	2025 FFO/ Debt	S&P 2022	S&P 2023E	Upgrade Trigger	Downgrade Trigger
Alliant Energy	15.8%	16.1%	15.6%	15.5%	14.1%	15%-17%	20%	15%
Ameren Corp	15.1%	15.7%	15.4%	15.8%	17.2%	17%-18%	18%	13%
American Electric Power	14.8%	14.5%	14.4%	13.8%	14.8%	13%-15%	N/A	16%
American States Water Company	17.2%	20.9%	20.6%	21.7%	16.3%	19%-20%	25%	20%
American Water Works Company	12.0%	13.0%	12.8%	13.0%	9.5%	13%-14%	16%	12%
California Water Service Group	20.3%	19.8%	21.9%	21.5%	N/A	N/A	N/A	N/A
Centerpoint Energy	12.9%	12.8%	12.5%	12.3%	9.7%	12%-13%	15%	12%
CMS Energy	14.0%	14.8%	15.0%	15.6%	13.9%	14%-16%	16%	13%
Consolidated Edison	19.5%	19.9%	20.3%	19.6%	17.6%	17%-19%	21%	16%
Dominion Energy	15.0%	12.4%	15.7%	16.2%	13.5%	12%-14%	N/A	13%
DTE Energy	14.1%	13.9%	14.4%	13.9%	14.3%	13%-14%	18%	13%
Duke Energy	12.9%	13.7%	13.8%	13.8%	13.6%	12%-14%	16%	12%
Edison International	14.1%	18.2%	17.4%	17.2%	14.1%	14%-18%	25%	15%
Emera Inc (C$)	9.4%	9.7%	10.0%	10.5%	10.5%	10%-11%	N/A	10%
Entergy, Inc	11.6%	13.9%	14.0%	14.1%	12.3%	14%-17%	18%	13%
Essential Utilities	11.5%	12.2%	12.8%	13.2%	11.0%	11%-12%	N/A	12%
Evergy	16.2%	15.7%	14.8%	14.8%	15.0%	14%-16%	N/A	16%
Eversource Energy	13.5%	12.0%	12.2%	14.8%	14.0%	11%-13%	N/A	13%
Exelon	14.3%	13.7%	13.9%	14.1%	13.1%	11%-13%	N/A	13%
FirstEnergy Corp	12.8%	10.6%	13.0%	13.6%	9.8%	11%-13%	N/A	12%
Fortis Inc (C$)	10.4%	11.2%	11.5%	11.8%	10.6%	11%-12%	N/A	12%
IDACORP Inc.	16.9%	15.5%	19.0%	16.0%	16.8%	16%-18%	20%	14%
NextEra Energy	20.1%	22.0%	19.4%	19.0%	18.3%	18%-20%	25%	18%
NiSource	13.9%	15.2%	14.8%	14.2%	13.9%	14%-16%	16%	13%
OGE Energy Corp	32.6%	22.7%	20.9%	19.4%	14.6%	17%-19%	18%	13%
PG&E Corp	12.1%	12.0%	13.9%	14.3%	11.8%	12%-14%	15%	13%
Pinnacle West Capital Corp	14.2%	13.5%	14.9%	15.0%	16.6%	14%-16%	N/A	13%
Portland General Electric	17.4%	15.9%	18.0%	17.0%	18.2%	14%-18%	18%	15%
PPL Corporation	16.0%	16.8%	16.3%	16.3%	14.6%	17%-19%	21%	16%
Public Service Ent Group	15.3%	15.6%	15.4%	15.9%	13.6%	16%-18%	20%	13%
Sempra Energy	17.3%	16.9%	18.1%	19.1%	15.4%	14%-15%	25%	15%
SJW Group	14.8%	14.8%	11.0%	11.3%	9.6%	10%-11%	N/A	10%
Southern Company	14.8%	14.8%	15.5%	16.1%	16.0%	17%-18%	17%	N/A
WEC Energy Group	14.7%	14.3%	14.3%	14.4%	15.4%	14%-16%	N/A	15%
Xcel Energy	17.3%	17.4%	17.9%	16.7%	16.4%	15%-17%	20%	15%

Source: Standard & Poors, UBS Estimates

Can Newer CEOs Begin or Continue to Build Execution Track Records?

Potentially, but investors should be tracking this closely. With almost 80% of the CEOs in our coverage universe having tenures under five years, the market may need more time to include a premium or discount related to earnings consistency in valuation.

Given the defensive nature of the utility sector, investors in utilities are often seeking stability and yield. Our valuation framework for utilities includes a +/- 4% premium/ discount for those companies that have performed in the top and bottom quartile of achieving or exceeding initial earnings per share guidance ranges. The sector is at an interesting inflection point in this regard, given that ~77% of the CEO's have tenures in that role of under five years, and ~71% of CFO's also have tenures in their roles of under five years, as shown in Figure 8.

Figure 8: CEO and CFO Tenure by Company

Ticker	Chief Executive Officer	Tenure	Chief Financial Officer	Tenure
AES	Andrés Ricardo Gluski Weilert	12.30	Stephen Coughlin	2.20
DUK	Lynn J. Good	10.10	Brian D. Savoy	1.30
OGE	Robert Sean Trauschke	9.30	W. Bryan Buckler	2.93
EIX	Pedro J. Pizarro	7.52	Maria C. Rigatti	7.19
POR	Maria MacGregor Pope	6.20	Joseph R. Trpik, Jr.	0.50
EMA	Scott Carlyle Balfour	5.80	Gregory W. Blunden	7.80
SRE	Jeffrey Walker Martin	5.60	Trevor Ian Mihalik	5.60
LNT	John O. Larsen	4.42	Robert J. Durian	7.00
PPL	Vincent Sorgi	4.40	Joseph P. Bergstein, Jr.	4.40
DTE	Jerry Norcia	4.40	David Ruud	3.60
PNW	Jeffrey B. Guldner	4.10	Andrew Cooper	1.60
IDA	Lisa A. Grow	3.81	Brian R. Buckham	1.80
XEL	Robert C. Frenzel	3.75	Brian J. van Abel	3.75
CNP	David J. Lesar	3.59	Christopher A. Foster	0.59
D	Robert M. Blue	3.20	Steven D. Ridge	1.10
ED	Timothy P. Cawley	3.00	Robert N. Hoglund	18.30
CMS	Garrick J. Rochow	3.00	Rejji P. Hayes	6.60
EVRG	David A. Campbell	2.92	Kirk Andrews	2.80
PCG	Patricia K. Poppe	2.92	Carolyn Jeanne Burke	0.73
FTS	David G. Hutchens	2.90	Jocelyn H. Perry	5.52
ES	Joseph R. Nolan, Jr.	2.60	John M. Moreira	5.30
AEE	Martin J. Lyons, Jr.	1.93	Michael L. Moehn	4.02
WEC	Scott J. Lauber	1.83	Xia Liu	3.52
NI	Lloyd M. Yates	1.80	Shawn Anderson	0.75
NEE	John W. Ketchum	1.77	Terrell Kirk Crews, II	1.77
PEG	Ralph A. LaRossa	1.30	Daniel J. Cregg	8.16
AEP	Julia A. Sloat	1.30	Charles E. Zebula	0.25
EXC	Calvin G. Butler, Jr.	1.20	Jeanne M. Jones	1.20
ETR	Andrew S. Marsh	1.10	Kimberly A. Fontan	1.10
SO	Christopher C. Womack	0.69	Daniel S. Tucker	2.27
FE	Brian X. Tierney	0.52	K. Jon Taylor	3.60

Source: Factset, UBS

NOTES: Karen L. Sedgwick will take over as SRE CFO on 1/1/2024; Lisa Barton will take over as LNT CEO, also on 1/1/2024. Gale Klappa will shift to Chairman of the Board of WEC vs. Executive Chair in spring 2024.

Given that top quartile execution premiums are awarded for companies that have achieved or exceeded initial earnings guidance 90% of the time or more in the last decade, the market may not express a management quality premium until CEO and CFO tenure aligns more closely with delivered execution over more than five years. As a result this premium and discount is likely to be in flux, particularly in 2024, as more newly minted CEOs and CFOs attempt to prove out an execution track record to the market. The current execution track record that also gives credit for execution under prior management teams is provided in Figure 9.

Figure 9: Time Beat (based off last 10 years) & Time Beat/Meet (based on total years giving guidance)

	% Time Beat	% Time Beat/Meet	% Beat Ests	vs. S&P 500	vs. XLU	Beat	Miss	Meet
Average	68%	78%	4.6%	-7.8%	-1.7%	7	2	1
	% Time Beat	% Time Beat/Meet	% Beat Ests	vs. S&P 500	vs. XLU	Beat	Miss	Meet
ETR	100%	100%	13.2%	-12.0%	-5.6%	10	0	0
IDA	100%	100%	6.2%	-1.7%	0.5%	10	0	0
WEC	100%	100%	2.1%	-3.9%	2.4%	10	0	0
SRE	90%	90%	7.0%	-6.3%	-0.4%	9	1	0
DTE	90%	90%	5.6%	-3.9%	2.2%	9	1	0
AEP	90%	90%	3.2%	-5.7%	0.4%	9	1	0
PEG	90%	100%	3.0%	-6.9%	-0.9%	9	0	1
XEL	90%	100%	1.4%	-5.3%	1.0%	9	0	1
CNP	80%	100%	8.6%	-13.8%	-7.8%	8	0	2
PPL	80%	89%	5.1%	-16.0%	-9.9%	8	1	0
AEE	80%	100%	3.7%	-3.9%	2.6%	8	0	2
NI	80%	89%	2.7%	-1.7%	4.6%	8	1	0
ED	80%	80%	2.3%	-14.0%	-7.7%	8	2	0
NEE	80%	90%	1.9%	6.4%	12.8%	8	1	1
CMS	80%	90%	0.7%	-2.4%	3.6%	8	1	1
LNT	70%	70%	2.9%	-3.6%	2.5%	7	3	0
AWK	70%	90%	2.4%	5.0%	11.6%	7	1	2
PNW	70%	70%	2.3%	-8.5%	-1.9%	7	3	0
DUK	70%	70%	1.1%	-11.0%	-4.9%	7	3	0
EIX	60%	86%	12.5%	-13.9%	-7.4%	6	1	0
FE	60%	60%	5.4%	-23.1%	-16.5%	6	4	0
EXC	60%	78%	3.5%	-15.5%	-7.9%	6	2	1
EVRG	50%	71%	7.3%	-5.1%	0.9%	5	2	0
SO	50%	83%	2.8%	-12.8%	-6.4%	5	1	0
OGE	40%	40%	5.7%	-14.6%	-8.5%	4	6	0
POR	40%	40%	4.5%	-6.1%	-3.7%	4	6	0
AES	40%	50%	2.1%	-12.1%	-6.0%	4	5	1
PCG	30%	50%	21.1%	-9.8%	-3.7%	3	4	1
WTRG	30%	67%	1.0%	-12.3%	0.4%	3	2	1
ES	30%	40%	0.9%	-6.6%	0.3%	3	6	1
D	30%	40%	0.4%	-1.6%	-0.4%	3	6	1

Note: % Time Beat is of last 10 years and % Time Beat/Meet is based on total years giving guidance.

Source: FactSet, S&P Capital IQ Pro, UBS Estimates

Shorter tenured executives have a chance to begin to build the foundations for an execution track record with 2023 year end reporting and through achievement of guidance in 2024. Of the CEO's with tenures below two years, we see the potential for achievement of early execution bona fides for AEP, EXC, ETR, and FE. SO and PEG trade at higher valuations and we see a continuation of the execution track record as important for maintaining those premium valuations. We see this as particularly important for SO post the last new nuclear plant unit going into service in the spring. Continued execution is also important for PEG with their simplified business model and re-basing of their earnings forecast in the fall of 2022, and a rate case in New Jersey in 2024.

We currently don't give ETR credit for their meet and beat track record shown in Figure 9 given the historical wider guidance ranges the company has provided, although these have narrowed to $0.30 from $0.50 as the business model was simplified over time. ETR did provide a narrower $0.20 guidance range for 2023 at $6.65-$6.85 achievement of which could begin a process for the market to account for the execution track record in the valuation of the stock. Companies with longer tenured CEOs like OGE and DUK have simpler business models going forward than in the past, and potentially provide an execution reset around utility and parent only guidance for earnings per share. In California, EIX and PCG have the opportunity to continue to create a foundation for an execution track record after the wildfires in that state.

Can Regulation Get More Constructive?

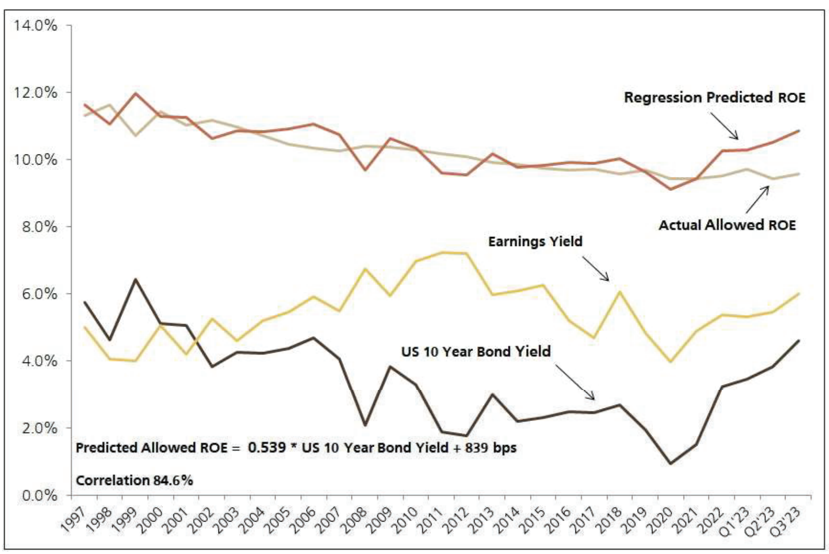
Yes, we believe so as affordability pressures ease and reliability concerns are addressed. Although for investors, we would advocate that expansion of regulatory risk in the portfolio is something to be considered in the 2H'24.

There are several affordability advantages that are likely to make regulation capable of becoming broadly more constructive in 2024 than we have seen in 2023. Broadly speaking, electricity continues to remain affordable in relation to disposable income (see Figure 13). If interest rates remain relatively stable, most of the necessary rate increases related to the pass through cost of higher debt financing are likely to become more manageable within the rate case process. Other costs have eased, including fuel expenses both as natural gas prices have come down, and as renewables have and will continue to get added to the generation mix. Cost pressures will be further mitigated as tax credits are generated across more types of capital investment, as a result of the Inflation Reduction Act.

Earnings yields, which now look overvalued to return spreads (see Figure 10), can also ease into a more appropriate valuation level without potential severe dislocations if interest rates level off or decline. However, we would note that in addition to dividend yields vs. corporate bond yields and our regression model, earnings yields also screen overvalued. As shown in Figure 10, earnings yields have risen in the last few years despite return spreads tightening as interest rates have moved higher without a corresponding move higher by regulators in allowed ROEs. If rates decline, a counterpoint to an improving regulatory backdrop, will likely be that regulators will feel justified in having used an incremental approach to ROE adjustments versus more volatile moves in interest rates in 2023 as return spreads re-expand.

While regulatory pressures will likely ease in 2024, we'd be more inclined to stick to more constructive regulatory jurisdictions earlier in the year, and potentially expand regulatory exposure later in the year as easing pressures begin to work their way into regulatory processes. Ongoing and expected rate cases into and throughout 2024 are shown in Figure 11 below.

Figure 10: Earnings Yield Not Consistent with Regulated Return Spreads



Source: Factset, S&P Capital IQ Pro, UBS Estimates

Figure 11: Current and Expected Rate Cases

Ticker	Filed By	State	Type	Date Filed	Commission Decision Expected	Current ROE (%)	Requested ROE (%)	% of Rate Base	Status
AEE	Ameren Illinois	Illinois	Electric	1/20/2023	12/14/2023	Formula	10.50	18%	
AEE	Union Electric	Missouri	Electric					52.0%	Filing Expected 2Q'24
AEP	Indiana Michigan Power Co.	Indiana	Electric	8/9/2023	5/31/2024	9.70	10.50	9.0%	
AEP	Kentucky Power Co.	Kentucky	Electric	6/29/2023	1/14/2024	9.30	9.90	3.0%	Settlement Reached at 9.75% ROE
AEP	Appalachian Power Co.	West Virginia	Electric	4/28/2023	9/1/2023		NA		Fuel Recovery Case
AEP	Public Service Co. of OK	Oklahoma	Electric			9.30		7.0%	Filing Expected January '24
AEP	AEP Texas	Texas	Electric			9.40		16.0%	Filing Expected Mid-'24
AES	AES Indiana	Indiana	Electric	6/28/2023	6/30/2024	9.99	10.60	30.0%	Settled
CMS	Consumers Energy Co.	Michigan	Electric	4/26/2023	3/1/2024	9.90	10.25	62.0%	Propesed Decision by 12/21
CMS	Consumers Energy Co.	Michigan	Gas			9.90		38.0%	Filing Expected Q4'23
CNP	Sthrn IN Gas & Electric Co.	Indiana	Electric			10.40		8.0%	Expected Filing December '23
CNP	CenterPoint Energy Resources	Minnesota	Natural Gas	11/1/2023	9/1/2024	9.39	10.30	9.0%	Open
CNP	Centerpoint Energy Resources	Texas	Gas (RRC)	10/30/2023	6/25/2024	9.64	10.50	10.0%	Filing Expected
CNP	Centerpoint Energy Houston	Texas	Electric			9.40		53.0%	Filing Expected 2Q'24
CWT	California Water Service Group	California	Water	4Q/2021	6/7/2024	10.27		90.0%	Settled
CWT	California Water Service Group	California	Water			10.27		90.0%	Filing Expected 2Q'24
D	The East Ohio Gas Co.	Ohio	Natural Gas	10/31/2023	12/31/2024	N/A	10.40	7.0%	
D	Virginia Electric & Power Co.	Virginia	Electric	7/3/2023	2/28/2024	9.30	9.70	70.0%	
D	Dominion Energy Inc.	Wyoming	Natural Gas	3/1/2023	12/1/2023	9.35	10.30	1.0%	Settlement @ 9.65%
D	Virginia Electric and Power	Virginia	Electric			9.70		70.0%	Filing Expected 2Q'25
DTE	DTE Electric	Michigan	Electric			9.90		80.0%	Filing Expected by 6/24
DTE	DTE Gas	Michigan	Gas			9.90		20.0%	Filing Expected 1Q'24
DUK	Piedmont Natural Gas Co.	Tennessee	Natural Gas	5/19/2023	10/31/2023	9.80	9.80	1.0%	Settlement; No ROE
DUK	Duke Energy Florida	Florida	Electric - MYP			10.10		19.0%	Filing Expected Mid-'24
DUK	Duke Energy Indiana	Indiana	Electric			9.70		10.0%	Filing Expected Mid-'24
EIX	Southern California Edison Co.	California	Electric	5/12/2023	11/12/2024	10.05	NA	81.0%	Intervenor Testimony 2/29/24
EIX	Southern California Edison Co.	California	Electric	10/13/2023	1/1/2024	10.05	10.75	81.0%	Cost of Capital
EMA	New Mexico Gas Co.	New Mexico	Natural Gas	9/14/2023	10/1/2024	9.38	10.50	4.0%	Open
ETR	Entergy Arkansas LLC	Arkansas	Electric	7/7/2023	12/13/2023	9.65	9.65	28.0%	Settlement
ETR	Entergy Louisiana	Louisiana	Electric	8/30/2023	8/31/2024	9.50	10.50	46.0%	Open
EXC	Potomac Electric Power Co.	District of Colu	Electric	4/13/2023	6/1/2024	9.28	10.50	6.0%	Settlement Pending
EXC	Delmarva Power & Light Co.	Delaware	Electric	12/15/2022	12/31/2023	9.60	10.50	2.0%	Open
EXC	Commonwealth Edison Co.	Illinois	Electric	1/17/2023	12/14/2023	Formula	10.65	36.0%	Open
EXC	Baltimore Gas and Electric Co.	Maryland	Electric	2/17/2023	12/14/2023	9.50	10.40	11.0%	Open
EXC	Baltimore Gas and Electric Co.	Maryland	Natural Gas	2/17/2023	12/14/2023	9.65	10.40	8.0%	Open
EXC	Potomac Electric Power Co.	Maryland	Electric	5/16/2023	6/30/2024	9.55	10.50	6.0%	Open
EXC	PECO Energy Company	Pennslyvania	Electric			N/A		20.0%	Filing Expected Late Q1'24
FE	Jersey Cntrl Power & Light Co.	New Jersey	Electric	3/16/2023	3/31/2024	9.60	10.40	11.0%	Suspended for Settlement Talks
FE	Monongahela Power Co.	West Virginia	Electric	5/31/2023	3/31/2024	N/A	10.85	5.0%	Hearing 1/24/24
FE	Ohio Subs CE/OE/TE	Ohio	Electric			10.50		15.0%	Filing Expected May 2024
FE	Penn. Utilites ME/PE/PP/WPP	Pennsylvania	Electric			N/A		25.0%	Filing Expected Q1'24
FTS	UNS Electric Inc.	Arizona	Electric	11/18/2022	2/1/2024	9.50	10.25	20.0%	Open
FTS	Central Hudson Gas & Electric	New York	Electric	7/31/2023	6/30/2024	9.00	9.80	7.4%	Open
FTS	Central Hudson Gas & Electric	New York	Natural Gas	7/31/2023	6/30/2024	9.00	9.80	7.4%	Open
IDA	Idaho Power Co.	Idaho	Electric	6/1/2023	1/1/2024	10.00	10.40		Settlement Reached at 9.6% ROE
LNT	Interstate Power & Light Co.	Iowa	Electric	10/12/2023	8/12/2024	10.02	10.12	51.0%	Open
LNT	Interstate Power & Light Co.	Iowa	Natural Gas	10/12/2023	8/12/2024	9.60	10.00	4.0%	Open
NI	Northern IN Public Svc Co. LLC	Indiana	Natural Gas	10/25/2023	8/31/2024	9.85	10.70	21.0%	Opne
NI	Columbia Gas of Maryland Inc	Maryland	Natural Gas	6/23/2023	12/20/2023	NA	NA	1.0%	Open
OGE	Oklahoma Gas and Electric Co.	Arkansas	Electric	10/2/2023	3/11/2024	9.50	NA	10.0%	Open
OGE	Oklahoma Gas & Electric	Oklahoma	Electric			9.50		80.0%	Filing Expected Q4'23
PCG	Pacific Gas and Electric Co.	California	Electric	10/13/2023	1/1/2024	10.00	10.70	68.0%	Cost of Capital
PEG	Public Service Electric & Gas	New Jersey	Electric/Gas			9.60		52.0%	Filing Expected 4Q'23
PNW	Arizona Public Service Co.	Arizona	Electric	10/28/2022	1/15/2024	8.90	10.25	83.0%	Open
POR	Portland General Electric Co.	Oregon	Electric	2/15/2023	12/18/2023	9.50	9.80	100.0%	Completed 4Q'23
SJW	Connecticut Water	Connecticut	Water	10/4/2023		9.00	10.50	33.0%	Open
SJW	San Jose Water	California	Water			9.81	NA	54.0%	Filing Expected 2Q'24
SRE	San Diego Gas & Electric Co.	California	Electric	5/16/2022	11/16/2023		10.65	16.0%	Cost of Capital
SRE	San Diego Gas & Electric Co.	California	Natural Gas	5/16/2022	11/16/2023		NA	6.0%	Cost of Capital
SRE	Southern California Gas Co.	California	Natural Gas	5/16/2022	11/16/2023		10.50	33.0%	Cost of Capital
WTRG	Aqua Pennsylvania	Pennsylvania	Water			10.15		46.0%	Filing Expected 1Q'24
WTRG	Peoples Gas	Pennsylvania	Gas				NA	30.0%	Filing Expected 4Q'23
XEL	Southwestern Public Svc Co.	Texas	Electric	2/8/2023	2/12/2024	N/A	10.65	8.0%	Settlement Pending
XEL	Public Svc Co of Colorado	Colorado	Gas			9.30		26.0%	Filing Expected Q1'24

Source: S&P Global Market Intelligence, Factset, UBS Estimates

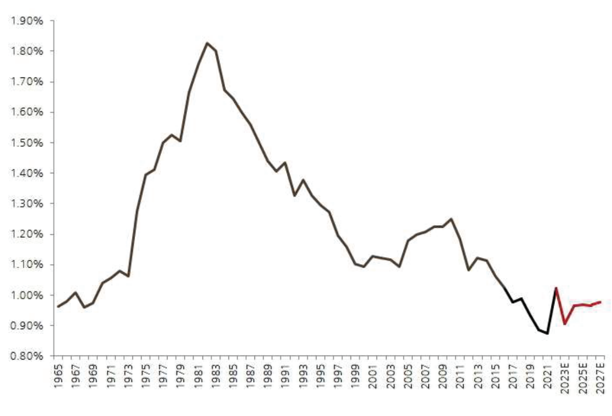
Figure 12: Jurisdictional Regulatory Rankings

TIER 1	TIER 2	TIER 3	TIER 4	TIER 5
		Massachusetts		
		North Dakota		
		Oklahoma		
		Oregon		
		South Carolina		
		Kentucky		
	Iowa	Newfoundland & Labrador	West Virginia	
Florida	Michigan	Prince Edward Island	Kansas	
British Columbia	New Jersey	Virginia	Maryland	District of Columbia
North Carolina	FERC	Wyoming	Rhode Island	Nevada
Utah	California	Tennessee	Alaska	New Mexico
Wisconsin	Idaho	Ontario	Minnesota	South Dakota
Pennsylvania	Missouri	Hawaii	Mississippi	Alberta
Alabama	Washington	Louisiana	New Hampshire	Vermont
Georgia	Colorado	Nova Scotia	Arizona	Connecticut
Arkansas	Delaware	Ohio	Nebraska	Montana
Indiana	Illinois	Texas	New York	Maine
JD Power Average Customer Service Scores				
739	734	722	720	718

Source: Canadian Provincial Regulatory Websites, S&P Global Market Intelligence, Factset, JD Power, UBS Estimates

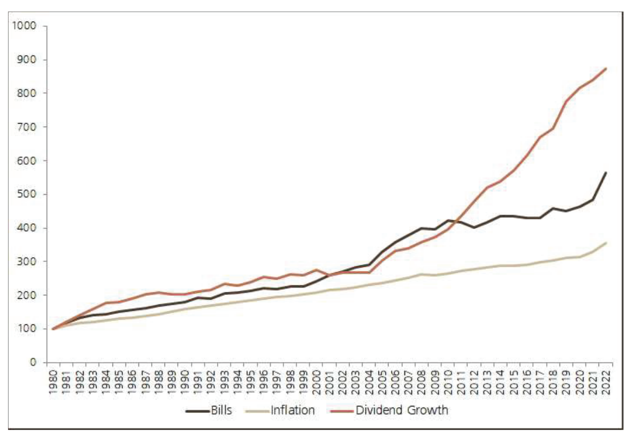
NOTE: Green/Red moved Up/Down 1 Tier in Fall 2023 Update vs. Spring 2023 Analysis

Figure 13: Electricity Cost as a % of Disposable Income 1965-2022 Actual, 2023-2027 Forecast



Source: US BEA, EIA, Factset, EEI,UBS Estimates

Figure 14: Increases in Electric Bills, Inflation, and Annual Regulated Utility Dividends Since 1980



Source: US BEA, EIA, Factset, EEI, UBS Estimates

Figure 15: Pricing Power: Affordability Inflation vs. EPS Growth

Source: Company Filings, Factset, S&P Global Market Intelligence, UBS Estimates

NOTE: Dot color indicates company's regulatory ranking quartile premised upon weighted average earnings power across jurisdictions; Green = 1st, Blue = 2nd, Yellow = 3rd, and Red = 4th.

Will Interest Rates and the Fed Still be the Main Factor for Utility Performance?

No. Resolution of the economic path between recession and soft landing and the end of the Fed rate hike cycle likely mean that the macro is no longer the main factor for performance as we move through 2024 and stock performance will shift over time to be more driven by stock specific fundamentals.

While the macro and interest rates will always matter for utility performance, they are unlikely to be the main driver in 2024 once the backdrop resolves into a recession or soft landing. The UBS House View from our Economics team is for a recession in 2Q and 3Q 2024 (FOMC and CPI Wrapping Up 2023, December 8 2023). UBS Strategist Jonathan Golub's 2024 outlook (S&P to 4850 by YE 2024, Risks to the Upside, December 11 2023) takes an underweight view on the utility sector. The outlook notes that on average, stocks fall six to seven months prior to a recession. However, declines have ranged from zero to fifteen months prior. With P/Es two to three multiple points below their 2022 highs, and the backdrop strong, we see further upside over the near-term. That said, we expect a double-digit drawdown some time in 2024.

As noted in the strategists outlook for the new year, the market prices in recessions on average six to seven months in advance. The outlook also notes that there is a wide dispersion around that average, and given the uncertainty we believe exists around the path for the economy, we don't believe investors can get paid by being early with defensive utility positioning around any call for a recession. As is also noted in the outlook notes that the large spread between current strength and expected weakness presents a dilemma for investors. The strategic outlook recommends remaining constructively positioned until the data deteriorates, with a focus on (1) labor market conditions, (2) credit performance, and (3) profit projections. Utility valuations, as noted above, also seem to largely price in the mild recession thesis at current levels as utilities are at fair value to an interest rate move lower by ~110bps.

The Fed cycle of rate hikes being over also matters, as the relative underperformance that always results during the cycle when the Fed raises rates by more than approximately 300bps ends (see circles cycles in Figure 16 below). While on average utilities are relative outperformers by 200-500bps in the twelve months after the completion of a Fed hike cycle, there is a significant divergence in this performance dependent upon whether a recession occurs. In the three non-commodity driven cycles that resulted in recessions, the next twelve months saw the DJU outperform the S&P 500 by 19%, 6%, and 32% respectively (see the bolded cycles in Figure 16 below). In the cycles where a recession did not occur, excluding the current cycle, the DJU performed relative to the S&P 500 1%, 2%, -14%, and -8% respectively. If the current hike cycle ended in July 2023, then the DJU has underperformed the S&P 500 on a relative basis by ~8% since. A recession would likely significantly reverse this relative underperformance while a soft landing could deepen it.

Figure 16: Fed Rate Cycle Performance Assuming Hike Cycle Ended in July '23

Duration	Fed Rate Hike Cycles		Starting	Ending	Entire Hike Cycle			Last Hike to 12Mo After		
Months	Start Date	End Date	Rates	Rates	DJU	S&P500	Relative	DJU	S&P500	Relative
17	Mar-22	Jul-23	0.25	5.50	-6%	3%	-9%	-7%	0%	-8%
37	Dec-15	Dec-18	0.50	2.50	30%	23%	7%	20%	28%	-8%
24	Jun-04	Jun-06	1.25	5.25	48%	10%	38%	21%	21%	1%
9	Aug-99	May-00	5.25	6.50	4%	7%	-3%	**18%**	**-14%**	**32%**
12	Feb-94	Jan-95	3.25	6.00	-14%	-2%	-12%	19%	33%	-14%
22	Apr-87	Feb-89	6.75	9.75	-9%	2%	-11%	**18%**	**12%**	**6%**
14	May-83	Jul-84	9.56	11.63	-3%	-9%	6%	32%	30%	2%
10	Aug-80	May-81	10.00	20.00	-2%	8%	-10%	**6%**	**-13%**	**19%**
47	Apr-76	Feb-80	4.88	20.00	26%	11%	15%	-3%	10%	-13%
27	Mar-72	May-74	5.63	13.00	-34%	-17%	-17%	4%	2%	1%
		Average			4%	3%	1%	13%	11%	2%
		Avg. w/o Commodity Cycles			-4%	2%	-6%	14%	10%	5%

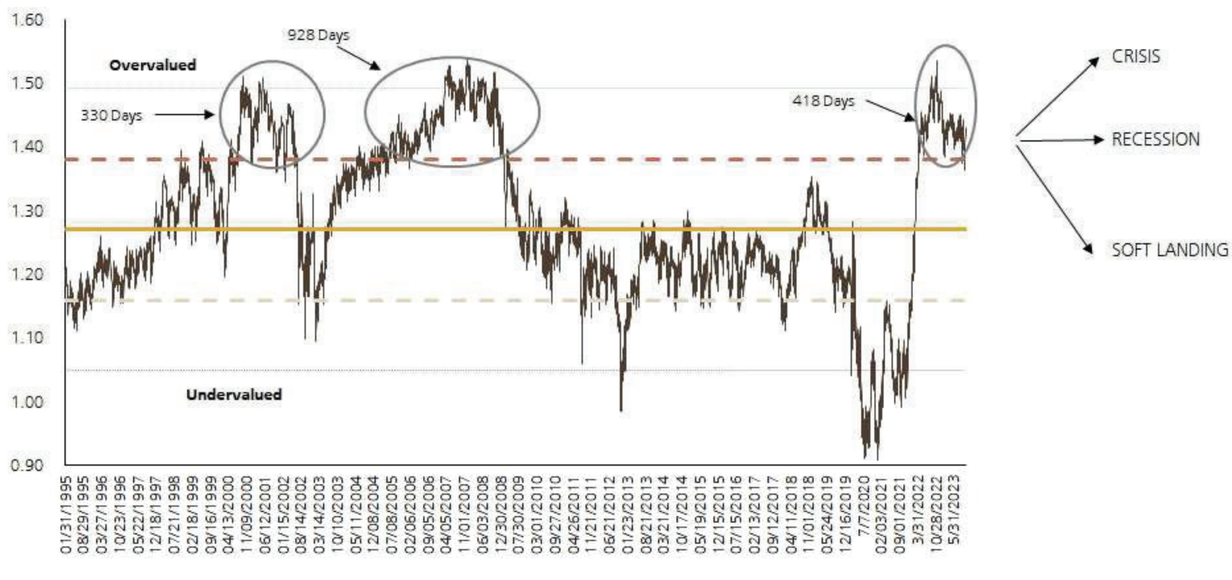
Commodity Driven Cycles '76-'80 |'04-'06

Source: Federal Reserve, Factset, US BEA, UBS Estimates

NOTE: Circles indicate cycles where Fed increased rates >300bps; **BOLD** indicates recession post hike cycle

We would also say that given the current valuation of the group versus interest rates that a large proportion of the recession thesis is likely to be already priced in, and that scenario would likely have limited valuation and multiple expansion from here on an absolute basis even if it would lead to better relative performance versus the market. The other important thing to remember about the path for resolution of the overvaluation in Figure 17 is that there are several ways for this to resolve toward fair value: interest rates can move lower, stocks can move lower (dividend yields increase), or resolution comes as both decline.

Figure 17: Path for Valuation vs. Rates Depends on Backdrop; Mild Recession Likely Priced In



Source: Factset, Federal Reserve, UBS Estimates

Will the Rhetoric Around the IRA in the 2024 Election Matter?

Yes. The rhetoric around IRA repeal in the Presidential election campaign in 2024 is likely to provide a headwind to performance until the fall. Once in fall, we believe there could be a buying opportunity if the rhetoric causes downside valuation dislocations and polls continue to indicate that the reality of repeal post election remains unlikely.

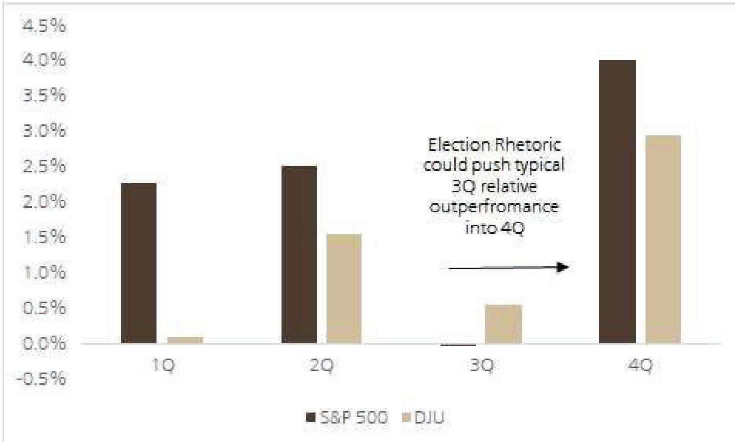
Any potential tail winds for group performance around a recession case for the economy or the end of the Fed rate hike cycle could run into headwinds related to the 2024 election. Rhetoric has already begun from the Trump campaign around the gutting of the Inflation Reduction Act, which is seen as one of the main achievements of the Biden Administration (source: Financial Times). Regardless of the likelihood of a Trump or Republican Congressional victory of significant size for the act of Congress necessary for IRA repeal, the rhetoric likely proves a headwind to sector performance.

The Executive Branch could make administrative agency changes like eliminating fuel efficiency standards for vehicles and elimination of the Loans Program Office at the US Department of Energy. However, actual repeal of the IRA would take Republican majorities in both chambers of Congress large enough to out vote any moderate Republicans that may not advocate for repeal. As the FT article states the majority of investments spurred by the IRA are in Republican congressional districts. Further, wind, solar, and nuclear related tax credits may ultimately prove durable as wind and solar credits have been renewed historically on a bipartisan basis, and Trump has made statements that have been supportive of nuclear.

We view any election rhetoric dislocations in the Fall as buying opportunities if polling continues to indicate at that time that the election outcome remains close for both the Presidency and control of Congress. This is a longer dated thought around a buying opportunity/bull thesis into 2025 as the rhetoric will likely remain headwind to performance throughout 2024 until the elections the first Tuesday in November. This could resolve earlier in the year if the polls tilt toward one party, or other issues begin to dominate the campaign.

The backdrop of any election related headwinds could exacerbate the typical group seasonal underperformance in the first and second quarters, and delay the typical relative outperformance in the third quarter, potentially setting the group up for a fourth quarter rally, dependent upon the election outcome.

Figure 18: DJU vs. S&P 500, Quarterly Performance Average Since 1972



Source: Factset, UBS Estimates

Valuation Method and Risk Statement

North America Utilities: Our valuation methodology for the group is price to earnings based. The adjustments applied fall into 7 categories. These are as follows: 1) Group Valuation Bias: Flowing from our valuation work comparing Baa corporate yields to group dividend yields and RU price to earnings ratios to those for the S&P 500, we incorporate a positive or negative adjustment to our group multiple representing the gap we calculate to the nearest 5%; 2) Growth Adjustment: We adjust our valuations based on the growth quartile each utility occupies. First quartile receives a 4% premium, second quartile a 2% premium, third quartile a 2% discount and fourth quartile a 4% discount; 3) Regulatory Adjustment: Our valuation adjustments for regulation are based on our proprietary Regulatory Rankings. First quartile jurisdictions receive 9%, second quartile 3%, third quartile -3% and fourth quartile -9%; 4) Clean Energy Transition: A potential 5% premium for a risk adjusted clean energy transition growth opportunity; 5) Earnings Consistency Adjustment: For companies that fall in the top quartile of % Time Beat/Meet, we include +4% for top quartile and -4% for bottom quartile; 6) Multi Utility Diversified Valuation: For multi utilities (those with more than 15% of unregulated earnings), we perform a sum-of- the-parts analysis applying business/region appropriate valuations to those diversified businesses; 7) One-off Adjustments: In special situations, we value risk on an issue-specific basis. Common areas where we apply such an adjustment include: large project construction risk, legal risk, and announced M&A completion risk. We identify the following risk factors: rising interest rates; regulatory and policy risks; operational risks; construction risks; cybersecurity risk to the transmission grid and/or customer data, and extreme weather events.

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12-Month Rating	Definition	Coverage[1]	IB Services[2]
Buy	FSR is > 6% above the MRA.	54%	40%
Neutral	FSR is between -6% and 6% of the MRA.	38%	42%
Sell	FSR is > 6% below the MRA.	9%	40%
Short-Term Rating	**Definition**	**Coverage[3]**	**IB Services[4]**
Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%
Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%

Source: UBS. Rating allocations are as of 30 September 2023.
1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category.
4:Percentage of companies within the Short-Term rating category for which investment banking (IB) services were provided within the past 12 months.

KEY DEFINITIONS: Forecast Stock Return (FSR) is defined as expected percentage price appreciation plus gross dividend yield over the next 12 months. In some cases, this yield may be based on accrued dividends. **Market Return Assumption (MRA)** is defined as the one-year local market interest rate plus 5% (a proxy for, and not a forecast of, the equity risk premium). **Under Review (UR)** Stocks may be flagged as UR by the analyst, indicating that the stock's price target and/or rating are subject to possible change in the near term, usually in response to an event that may affect the investment case or valuation. **Short-Term Ratings** reflect the expected near-term (up to three months) performance of the stock and do not reflect any change in the fundamental view or investment case. **Equity Price Targets** have an investment horizon of 12 months.

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UBS Securities LLC: Gregg Orrill, Jeffrey Keitel, Ross Fowler, CFA, William Appicelli, CFA.

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Company Name	Reuters	12-month rating	Price	Price date
AES Corp[4,5,16,7]	AES.N	Neutral	US$18.05	11 Dec 2023
Alliant Energy Corp[16]	LNT.O	Neutral	US$51.51	11 Dec 2023
Ameren Corp[16]	AEE.N	Neutral	US$78.18	11 Dec 2023
American Electric Power Inc[2,4,16,7,6b]	AEP.O	Neutral	US$80.49	11 Dec 2023
American States Water Co[16]	AWR.N	Neutral	US$81.53	11 Dec 2023
American Water Works Co[16]	AWK.N	Neutral	US$130.71	11 Dec 2023
CMS Energy Corp[16]	CMS.N	Buy	US$58.08	11 Dec 2023
California Water Service Group[16]	CWT.N	Sell	US$52.50	11 Dec 2023
CenterPoint Energy Inc[2,4,5,16,7]	CNP.N	Neutral	US$29.05	11 Dec 2023
Consolidated Edison Inc[16]	ED.N	Neutral	US$91.87	11 Dec 2023
Constellation Energy Corp[4,5,16]	CEG.O	Buy	US$116.15	11 Dec 2023
DTE Energy Co[16]	DTE.N	Neutral	US$110.09	11 Dec 2023
Dominion Energy Inc[2,4,5,16,7,6b]	D.N	Neutral	US$47.65	11 Dec 2023
Duke Energy Corp[2,13,4,5,16,7,6b]	DUK.N	Neutral	US$95.36	11 Dec 2023
Edison International[2,16,7]	EIX.N	Buy	US$68.03	11 Dec 2023
Emera Inc[5]	EMA.TO	Neutral	C$48.85	11 Dec 2023
Entergy Corp[16,7,6b]	ETR.N	Buy	US$102.11	11 Dec 2023
Essential Utilities Inc[13,16]	WTRG.N	Buy	US$35.74	11 Dec 2023
Evergy, Inc[16]	EVRG.O	Neutral	US$51.78	11 Dec 2023
Eversource Energy[16,7,6b,6c]	ES.N	Neutral	US$60.79	11 Dec 2023
Exelon Corp[2,4,5,16,7,6b,6c]	EXC.O	Buy	US$39.52	11 Dec 2023
FirstEnergy Corp[16]	FE.N	Neutral	US$37.26	11 Dec 2023
Fortis Inc[2,4,16]	FTS.TO	Sell	C$55.33	11 Dec 2023
IDACORP Inc[16]	IDA.N	Neutral	US$99.37	11 Dec 2023
NextEra Energy Inc[2,4,5,16,7,6a]	NEE.N	Buy	US$59.71	11 Dec 2023
NiSource Inc.[13,4,5,16,7]	NI.N	Buy	US$26.34	11 Dec 2023
OGE Energy Corp[16]	OGE.N	Neutral	US$35.40	11 Dec 2023

Company Name	Reuters	12-month rating	Price	Price date
PG&E Corp[2,16,7,6b,6c]	PCG.N	Buy	US$17.63	11 Dec 2023
PPL Corp[2,4,5,16]	PPL.N	Neutral	US$26.33	11 Dec 2023
Pinnacle West Capital Corp[16,7,6b]	PNW.N	Sell	US$75.65	11 Dec 2023
Portland General Electric Company[16]	POR.N	Neutral	US$43.11	11 Dec 2023
Public Service Enterprise Group[16,7,6b]	PEG.N	Neutral	US$62.98	11 Dec 2023
SJW Group[16]	SJW.N	Neutral	US$66.44	11 Dec 2023
Sempra[5,16]	SRE.N	Buy	US$73.94	11 Dec 2023
Southern Co[13,16]	SO.N	Buy	US$71.36	11 Dec 2023
Vistra Corp.[2,4,5,16,6a]	VST.N	Buy	US$36.88	11 Dec 2023
WEC Energy Group Inc[16]	WEC.N	Neutral	US$84.21	11 Dec 2023
Xcel Energy Inc[2,4,5,16]	XEL.O	Neutral	US$61.55	11 Dec 2023

Source: UBS Global Research; LSEG Eikon. All prices as of local market close. Ratings in this table are the most current published ratings prior to this report. They may be more recent than the stock pricing date.

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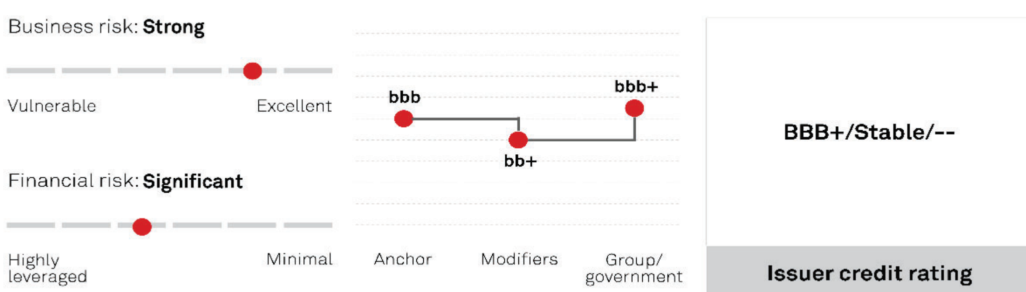

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Credit Highlights

Overview

Key strengths	Key risks
Lower-risk, rate-regulated utility operations.	Limited geographic and regulatory diversity.
Diverse portfolio of power-generating assets.	Refurbishment of legacy nuclear generation plant exposes it to execution risk.
High likelihood of extraordinary government support.	Robust capital spending leads to negative discretionary cash flow, indicating a need for external funding.

Ontario Power Generation Inc. (OPG) is exposed to execution risks from the refurbishment of the Darlington Nuclear Plant. It expects to refurbish all four units by the end of 2026. The refurbishment project, which began in 2016, is still in progress and remains on track for a timely completion. The company recently announced that it successfully refurbished Darlington Nuclear Generating Station Unit 3 169 days ahead of schedule. This is a major milestone in OPG's nuclear refurbishment project, which it expects will extend the power plant's lifecycle 30 years. Refurbishing the four Darlington units remains on plan for completion by the end of 2026. We expect OPG to assess and seek ways to manage the effects of the COVID-19 pandemic on the project’s total cost, which is otherwise still in line with the $12.8 billion budget. Any material cost overruns would pressure OPG's credit measures. However, the early return of Unit 3 will modestly improve OPG's cash flow.

The ultimate parent of OPG, the Province of Ontario, has directed OPG to conduct a technical feasibility assessment to determine if Pickering Units 5-8 should be refurbished. The province also announced its support for the continued operation of Pickering generating station Units 5-8 up to September 2026 to manage electricity demand growth. We continue to monitor the outcome of the assessment; the current base-case capital forecast does not include any potential investments related to Pickering refurbishment.

The Ontario government and OPG announced the commencement of planning and licensing for three additional small modular reactors (SMRs) at the Darlington nuclear site. The company partnered with GE Hitachi Nuclear Energy, SNC-Lavalin, and Aecon to construct a 300 megawatt (MW) SMR project at the Darlington facility. The Canadian Infrastructure Bank provided a $970 million commitment to fund the project. The company expects to complete the construction of the first unit by the end of 2028. As OPG scales up its investment in SMR projects, it will be highly important that it funds them in a credit-supportive manner and that its recovery is based on rate-regulated mechanisms to preserve its credit quality.

As reported in Canadian popular media, New Brunswick Power Corporation (NB Power) and OPG are exploring a potential partnership that could involve a partial ownership stake in the Point Lepreau nuclear generating station. Since its completed refurbishment in 2012, NB Power's Point Lepreau generating station has been affected by operational challenges, with its most recent December shutdown further adding to the company's debt burden and hurting its profit for fiscal 2022-23. NB Power seeks to leverage OPG's expertise to support the power plant. The effect on OPG's credit quality will largely depend on the details of the potential partnership including, operational involvement, and financial liability related to this nuclear plant. We continue to monitor for further developments.

We expect OPG will continue to manage its regulatory risk and maintain financial measures in the lower half of our significant financial risk profile category. Specifically, we expect funds from operations (FFO) to debt of around 17% in 2023 and 13.0%-14.0% in 2024 and 2025.

Outlook

The stable outlook on OPG incorporates the following expectations: more stable cash flows, a pause in acquisition spending, effective management of its regulatory risk, and that OPG will complete its future nuclear refurbishments on time and on budget. We also forecast FFO to debt of 13.0%-14%.

Downside scenario

We could take a negative rating action on OPG over the next 12-18 months if its financial measures weaken, including FFO to debt consistently below 13%. This could occur if the company experiences delays and cost overruns in its Darlington refurbishment program, faces adverse regulatory decisions, or undertakes significant debt-funded acquisitions. Alternatively, we could lower our rating if we downgrade the Province of Ontario or the relationship between OPG and the province unexpectedly deteriorates.

Upside scenario

Although highly unlikely, we could take a positive rating action on OPG over the next 24 months if there is no change to its relationship with the Province of Ontario, it doesn't expand its nonutility businesses through acquisitions, and it materially improves its financial measures, including FFO to debt consistently more than 20%.

Our Base-Case Scenario

Assumptions

- OPG continues to manage its regulatory risk;
- Capital spending averages C$3.75 billion per year through 2025;
- Distribution to noncontrolling interest holders average about C$20 million per year;
- There are no material acquisitions; and
- All debt maturities are refinanced or repaid.

Key metrics

Ontario Power Generation Inc.--Forecast summary

Period ending	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026
(Mil. CAD)	2019a	2020a	2021a	2022a	2023e	2024f	2025f	2026f
EBITDA	2,460	3,412	2,944	3,161	2,996	2,539	3,086	3,863
Less: Cash interest paid	(300)	(392)	(371)	(359)	(374)	(405)	(464)	(516)
Less: Cash taxes paid	(300)	(241)	(173)	(207)	(260)	(149)	(210)	(327)
Funds from operations (FFO)	1,860	2,779	2,400	2,595	2,362	1,985	2,411	3,020
Capital expenditure (capex)	1,837	1,653	1,943	2,432	3,687	3,721	3,856	4,255
Dividends	17	19	19	17	19	19	19	15
Debt	13,175	15,814	13,582	10,000	13,774	15,438	16,893	18,124
Adjusted ratios								
Debt/EBITDA (x)	5.4	4.6	4.6	3.2	4.6	6.1	5.5	4.7
FFO/debt (%)	14.1	17.6	17.7	25.9	17.1	12.9	14.3	16.7
FFO cash interest coverage (x)	7.2	8.1	7.5	8.2	7.3	5.9	6.2	6.9

All figures are adjusted by S&P Global Ratings, unless stated as reported. a--Actual. e--Estimate. f--Forecast. C$--Canadian dollar.

Company Description

OPG is an Ontario-based electricity generation company. The company's generation fleet comprises about 18,225 MW of capacity. OPG is wholly owned by the Province of Ontario.

Peer Comparison

Ontario Power Generation Inc.--Peer Comparisons

	Ontario Power Generation Inc.	Hydro One Inc.	Enmax Corp.
Foreign currency issuer credit rating	BBB+/Stable/--	A-/Stable/A-2	BBB-/Stable/--
Local currency issuer credit rating	BBB+/Stable/--	A-/Stable/A-2	BBB-/Stable/--
Period	Annual	Annual	Annual
Period ending	2022-12-31	2022-12-31	2022-12-31
Mil.	C$	C$	C$
Revenue	7,349	7,740	3,663
EBITDA	3,161	2,801	719
Funds from operations (FFO)	2,595	2,177	561
Interest	381	525	158
Cash interest paid	359	591	158
Operating cash flow (OCF)	2,872	2,121	716
Capital expenditure	2,432	1,999	581
Free operating cash flow (FOCF)	440	122	135
Discretionary cash flow (DCF)	423	(540)	73
Cash and short-term investments	1,753	458	48
Gross available cash	1,753	458	48
Debt	10,000	15,244	4,120
Equity	18,989	11,682	3,073
EBITDA margin (%)	43.0	36.2	19.6
Return on capital (%)	7.1	6.4	5.2
EBITDA interest coverage (x)	8.3	5.3	4.6
FFO cash interest coverage (x)	8.2	4.7	4.6
Debt/EBITDA (x)	3.2	5.4	5.7
FFO/debt (%)	25.9	14.3	13.6
OCF/debt (%)	28.7	13.9	17.4
FOCF/debt (%)	4.4	0.8	3.3
DCF/debt (%)	4.2	(3.5)	1.8

Business Risk

Our assessment on OPG's business risk incorporates its mostly low-risk, regulated operations under the generally supportive regulatory oversight of the Ontario Energy Board (OEB), its effective management of regulatory risk, its limited regulatory and geographic diversity, and its exposure to execution risk related to the refurbishment of its legacy nuclear generation plant. The company generates about 70% of its consolidated EBITDA from its business regulated by the OEB, which we view as a generally constructive regulatory environment. We expect that OPG will continue to manage its regulatory risk and benefit from credit-supportive regulatory mechanisms, including an incentive ratemaking methodology for hydroelectric and a custom incentive regulation framework for nuclear.

Our assessment of OPG's business risk profile also incorporates its contracted nonregulated generation, which accounts for about 30% of its consolidated EBITDA. The contracted, nonregulated power business increases the company's volumetric, operational, and commodity risks. However, these risks are partially offset by the business' long-term contracts with creditworthy counterparties. Given OPG's nonregulated power exposure, we assess it at the lower end of the range for its business risk profile category compared with its peers. In addition, the company is exposed to execution risks related to its Darlington Nuclear Plant refurbishment project.

Financial Risk

We use our medial-volatility table financial benchmarks to assess OPG's financial risk, which reflects its lower-risk, regulated electric generation operations and effective management of regulatory risk. These benchmarks are more relaxed than the benchmarks we use for typical corporate issuers. Under our base-case scenario, we assume capital spending averaging C$3.75 billion per year through 2025 and dividends of about C$20 million per year. We also expect OPG's discretionary cash flow will remain negative due to its elevated capital spending, indicating a need for external funding. In addition, we forecast FFO to debt around 17% in 2023 and 13.0%-14.0% in 2024 and 2025. Over the same period, we anticipate its S&P Global Ratings-adjusted FFO cash interest coverage will be about 6.0xx, which further bolsters our financial risk profile assessment.

Debt maturities

- 2023: C$43 million;
- 2024: C$606 million;
- 2025: C$589 million;
- 2026: C$674 million;
- 2027: C$530 million; and
- Thereafter: C$7.7 billion.

Ontario Power Generation Inc.--Financial Summary

Period ending	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022
Reporting period	2017a	2018a	2019a	2020a	2021a	2022a
Display currency (mil.)	C$	C$	C$	C$	C$	C$
Revenues	5,144	5,474	6,022	7,240	6,877	7,349
EBITDA	1,609	2,019	2,460	3,412	2,944	3,161
Funds from operations (FFO)	1,159	1,530	1,860	2,779	2,400	2,595
Interest expense	293	278	347	418	383	381
Cash interest paid	255	287	300	392	371	359
Operating cash flow (OCF)	797	1,510	2,399	2,722	2,358	2,872
Capital expenditure	1,691	1,635	1,837	1,653	1,943	2,432
Free operating cash flow (FOCF)	(894)	(125)	562	1,069	415	440

Ontario Power Generation Inc.--Financial Summary

Discretionary cash flow (DCF)	(909)	(426)	545	1,050	396	423
Cash and short-term investments	418	349	648	889	868	1,753
Gross available cash	418	349	648	889	868	1,753
Debt	10,583	11,437	13,175	15,814	13,582	10,000
Common equity	11,911	13,127	14,275	15,532	16,967	18,989
Adjusted ratios						
EBITDA margin (%)	31.3	36.9	40.9	47.1	42.8	43.0
Return on capital (%)	4.4	5.2	5.4	7.2	6.0	7.1
EBITDA interest coverage (x)	5.5	7.3	7.1	8.2	7.7	8.3
FFO cash interest coverage (x)	5.5	6.3	7.2	8.1	7.5	8.2
Debt/EBITDA (x)	6.6	5.7	5.4	4.6	4.6	3.2
FFO/debt (%)	11.0	13.4	14.1	17.6	17.7	25.9
OCF/debt (%)	7.5	13.2	18.2	17.2	17.4	28.7
FOCF/debt (%)	(8.4)	(1.1)	4.3	6.8	3.1	4.4
DCF/debt (%)	(8.6)	(3.7)	4.1	6.6	2.9	4.2

Reconciliation Of Ontario Power Generation Inc. Reported Amounts With S&P Global Adjusted Amounts (Mil. C$)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2022									
Company reported amounts	10,217	18,813	7,349	3,161	2,037	256	3,161	2,997	17	2,557
Cash taxes paid	-	-	-	-	-	-	(207)	-	-	-
Cash interest paid	-	-	-	-	-	-	(234)	-	-	-
Lease liabilities	62	-	-	-	-	-	-	-	-	-
Postretirement benefit obligations/ deferred compensation	1,474	-	-	-	-	-	-	-	-	-
Accessible cash and liquid investments	(1,753)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	125	(125)	(125)	-	(125)
Nonoperating income (expense)	-	-	-	-	64	-	-	-	-	-

Reconciliation Of Ontario Power Generation Inc. Reported Amounts With S&P Global Adjusted Amounts (Mil. C$)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Noncontrolling/ minority interest	-	176	-	-	-	-	-	-	-	-
Total adjustments	(217)	176	-	-	64	125	(566)	(125)	-	(125)
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	10,000	18,989	7,349	3,161	2,101	381	2,595	2,872	17	2,432

Liquidity

We assess OPG's liquidity as adequate because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and its net sources will remain positive even if its consolidated EBITDA declines 10%. We believe the company's predictable regulatory framework provides it with cash flow stability even in times of economic stress, which supports our use of slightly lower thresholds to assess its liquidity.

In addition, we believe OPG can absorb high-impact, low-probability events. This reflects its $3.2 billion various credit facilities and our expectation that it can reduce its high capital spending during stressful periods. Furthermore, our assessment reflects the company's generally prudent risk management, solid relationships with its banking group, and satisfactory standing in the credit markets.

Overall, we anticipate OPG can withstand adverse market circumstances over the next 12 months while maintaining sufficient liquidity to meet its obligations. The company's next major long debt maturity is in 2024, when about $600 million comes due, which we expect it will proactively address well in advance of the due date.

Principal liquidity sources

- Cash and liquid investments of about C$1.59 billion;
- Average credit facility availability of C$3.2 billion; and
- Estimated cash FFO of about C$2.3 billion.

Principal liquidity uses

- Debt maturities of about C$533 million;
- Capital spending of C$3.7 billion; and
- Distributions to noncontrolling interest holders of about C$20 million.

Environmental, Social, And Governance

Environmental factors are a moderately negative consideration in our credit rating analysis of OPG because it has a consolidated exposure to nuclear and hydroelectric generation. The company's nuclear generation exposes it to waste and storage challenges while its hydroelectric generation exposes it to water resource use.

Social factors are a moderately negative consideration in our credit rating analysis based on the health and safety risks related to its nuclear generation. However, OPG undertakes several initiatives, including nuclear byproduct and waste management, that comply with the Canadian Nuclear Safety Commission's (CNSC) rigorous regulatory requirements and employs a comprehensive nuclear safety and emergency preparedness program designed to protect employees and the public, the environment, property, and assets, all while ensuring operational continuity. In addition, to manage the water resources, OPG uses hydrological models, weather forecasts, satellite imagery, weather station data, and other tools to manage water levels, flows, and water storage. These initiatives somewhat offset the environmental and social risks.

Group Influence

Our ratings on OPG incorporate a high likelihood that its provincial owner, the Government of Ontario, will provide extraordinary support to the utility during periods of financial distress. OPG plays an important role for Ontario because it supplies about half of the province's electricity. In addition, the utility plays a vital role in Ontario's energy and environmental policies. Furthermore, the province has a record of providing support, both directly and indirectly, to the utility. For these reasons, we view the likelihood of extraordinary government support as high.

Issue Ratings--Subordination Risk Analysis

Capital structure

OPG's capital structure comprises roughly C$10.1 billion of debt.

Analytical conclusions

We rate the company's senior unsecured debt at the same level as our issuer credit rating because its priority debt is less than 50% of its total consolidated debt. We also rate OPG's commercial paper at 'A-1(Low)' on the Canadian National Scale.

Rating Component Scores

Foreign currency issuer credit rating	BBB+/Stable/--
Local currency issuer credit rating	BBB+/Stable/--
Business risk	Strong
Country risk	Very Low
Industry risk	Low
Competitive position	Strong
Financial risk	Significant
Cash flow/leverage	Significant
Anchor	bbb
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Negative (-1 notch)
Liquidity	Adequate (no impact)
Management and governance	Satisfactory (no impact)
Comparable rating analysis	Negative (-1 notch)
Stand-alone credit profile	bb+

Related Criteria

- 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: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- 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
- Criteria | Corporates | Industrials: Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- ARCHIVE | General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Ratings Detail (as of August 08, 2023)*

Ontario Power Generation Inc.	
Issuer Credit Rating	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	BBB+
Issuer Credit Ratings History	
17-Jul-2020	BBB+/Stable/--
30-Jul-2019	BBB+/Negative/--
07-Jul-2015	BBB+/Stable/--
Related Entities	
Hydro One Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2

Ratings Detail (as of August 08, 2023)*

Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	A-
Hydro One Ltd.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured	BBB+
Ontario (Province of)	
Issuer Credit Rating	A+/Positive/A-1
Commercial Paper	
Foreign Currency	A-1
Senior Unsecured	A+
UMH Energy Partnership	
Senior Secured	BBB+/Stable

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

PRESS RELEASE

MAY 01, 2024

Morningstar DBRS Confirms East-West Tie's Ratings at A (low) with Stable Trends

UTILITIES & INDEPENDENT POWER

DBRS Limited (Morningstar DBRS) confirmed East-West Tie Limited Partnership's (East-West Tie or the Company) Issuer Rating and Senior Secured Debt rating at A (low) with Stable trends.

KEY CREDIT RATING CONSIDERATIONS

East-West Tie's ratings are based on the Company's regulated electricity transmission operations in the Province of Ontario (rated AA (low) with a Positive trend by Morningstar DBRS), which contribute 100% of its earnings, offset by a weaker financial risk assessment. The Stable trends reflect the expected steady stream of earnings and cash flows.

Morningstar DBRS considers the regulatory framework under the Ontario Energy Board (OEB) to be supportive of the current ratings. East-West Tie is regulated under a Custom Incentive Rate-setting (IR) regime where it can recover all prudent costs and earn a reasonable return on equity (8.34% for 2022 to 2027). In November 2023, the Company filed an application with the OEB for 2024 rates, including the recovery of $160 million of additional costs that arose during construction because of the coronavirus pandemic, wildfires, and changes in construction techniques and routing. Morningstar DBRS had previously noted that any disallowances that lead to a write-off of these costs would have no impact on the key credit metrics as they have been fully funded through equity. Additionally, Morningstar DBRS expects East-West Tie to fund any additions to the rate base in line with the regulated capital structure of 60% debt, leading to minimal impact to the key credit metrics.

CREDIT RATING DRIVERS

A positive rating action may occur if the Company improves its cash flow-to-debt ratio to the "A" rating category for a sustained period (above 12.5%). Morningstar DBRS considers a negative rating action to be unlikely given the business risk assessment but could occur if East-West Tie's cash flow-to-debt ratio weakens below the 8% to 9% assumed for the current ratings.

EARNINGS OUTLOOK

East-West Tie's earnings increased in 2023 following the first full year of service for the transmission line. Overall, East-West Tie's revenue requirements during the Custom IR term will escalate annually by a revenue cap index based on an inflation factor less a stretch factor. As such, Morningstar DBRS expects the Company's earnings to be very predictable and stable over the medium term.

FINANCIAL OUTLOOK

Morningstar DBRS expects East-West Tie's cash flows to be stable as well, tracking the net income. Additionally, capital expenditures for the Company should be minimal over the near term as the transmission line is newly constructed. East-West Tie's key credit metrics for 2023 were stronger than expected as the $428 million of Senior Secured Amortizing Notes (the Notes) were only issued in May. Overall, Morningstar DBRS expects the Company's key credit metrics to be supportive of the A (low) ratings. East-West Tie is expected to maintain its debt-to-capital ratio at 60%, in line with the regulatory capital structure, through principal repayments on the Notes, which amortizes according to a 30-year mortgage-style schedule with a balloon payment (65% of the original issuance amount) at maturity, and by managing its distribution payouts. Over the medium term, Morningstar DBRS expects East-West Tie's debt-to-capital and EBIT-interest coverage ratios to be in line with the "A" rating category, offset by a weaker cash flow-to-debt ratio of 8% to 9% because of lower annual depreciation leading to weaker operating cash flows.

CREDIT RATING RATIONALE

East-West Tie's credit ratings are supported by its low business risk and the supportive regulatory environment. This is partly offset by its refinancing risk, weaker cash flow-to-debt metric, limited access to equity markets, and reliance on a single transmission line for its revenues and cash flows.

ENVIRONMENTAL, SOCIAL, AND GOVERNANCE CONSIDERATIONS

Environmental (E) Factors

There were no Environmental factor(s) that had a relevant or significant effect on the credit analysis.

Social (S) Factors

There were no Social factor(s) that had a relevant or significant effect on the credit analysis.

Governance (G) Factors

There were no Governance factor(s) that had a relevant or significant effect on the credit analysis.

A description of how Morningstar DBRS considers ESG factors within the Morningstar DBRS analytical framework can be found in the Morningstar DBRS Criteria: Approach to Environmental, Social, and Governance Risk Factors in Credit Ratings (January 23, 2024; https://dbrs.morningstar.com/research/427030/).

BUSINESS RISK ASSESSMENT (BRA) AND FINANCIAL RISK ASSESSMENT (FRA)

A) Weighting of BRA Factors

In the analysis of East-West Tie, the BRA factors are considered in the order of importance contemplated in the methodology.

B) Weighting of FRA Factors

In the analysis of East-West Tie, the FRA factors are considered in the order of importance contemplated in the methodology.

C) Weighting of the BRA and the FRA

In the analysis of East-West Tie, the BRA carries greater weight than the FRA.

Notes:

All figures are in Canadian dollars unless otherwise noted.

Morningstar DBRS applied the following principal methodology:

Global Methodology for Rating Companies in the Regulated Utility and Independent Power Producer Industries (April 15, 2024; https://dbrs.morningstar.com/research/431184/).

Morningstar DBRS credit ratings may use one or more sections of the Morningstar DBRS Global Corporate Criteria (April 15, 2024; https://dbrs.morningstar.com/research/431186/), which covers, for example, topics such as holding companies and parent/subsidiary relationships, guarantees, recovery, and common adjustments to financial ratios.

The credit rating methodologies used in the analysis of this transaction can be found at: https://dbrs.morningstar.com/about/methodologies.

A description of how Morningstar DBRS analyzes corporate finance transactions and how the methodologies are collectively applied can be found at: https://dbrs.morningstar.com/research/431153.

The related regulatory disclosures pursuant to the National Instrument 25-101 Designated Rating Organizations are hereby incorporated by reference and can be found by clicking on the link under Related Documents or by contacting us at info-DBRS@morningstar.com.

The credit rating was initiated at the request of the rated entity.

The rated entity or its related entities did participate in the credit rating process for this credit rating action.

Morningstar DBRS had access to the accounts, management and other relevant internal documents of the rated entity or its related entities in connection with this credit rating action.

This is a solicited credit rating.

The conditions that lead to the assignment of a Negative or Positive trend are generally resolved within a 12-month period. Morningstar DBRS trends and credit ratings are under regular surveillance.

Information regarding Morningstar DBRS credit ratings, including definitions, policies, and methodologies, is available on dbrs.morningstar.com or contact us at info-DBRS@morningstar.com.

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Ratings

East-West Tie Limited Partnership

Date Issued	Debt Rated	Action	Rating	Trend	Attributes
01-May-24	Issuer Rating	Confirmed	A (low)	Stb	CA
01-May-24	Senior Secured Debt	Confirmed	A (low)	Stb	CA

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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

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[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:

[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)	Monthly Billing The OEB amended the DSC related to billing frequency. Reduced Billing Lag 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.	Monthly Billing 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). Reduced Billing Lag 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).

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2]

Question(s):

For electricity distributors, please provide Concentric's view on the relative business and financial risk between Custom IR and IRM rate frameworks.

Response:

Incentive rate-setting mechanism ("IRM") frameworks involve the establishment of a cost of service (or rebasing) followed by four years of IRM adjustments. The Custom IR framework involves a five-year forecast of a distributor's revenue requirement and sales volumes.[1] Both frameworks establish a revenue envelope within which the utility operates. Concentric does not view these frameworks as significantly affecting utility risk relative to one another, although, as the OEB acknowledged in the "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach," the circumstances that lead a utility to apply for IRM versus Custom IR could reflect differences in risk profiles. For instance, the "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach," found that Custom IR may be appropriate for utilities with "large or highly variable capital requirements," which could indicate an elevated level of risk.[2]

1 Ontario Energy Board, "Filing Requirements For Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications," May 24, 2022, Section 3.1.

2 Ontario Energy Board, "Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach," October 18, 2012, at 14.

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:

[M2, p.33]

Question(s):

With respect to short-term debt:

a) For each of the CLD+ utilities[1], please provide its actual sources of short-term debt, the current interest rate, and how the interest rate is calculated.

b) In Concentric's experience, how does the sources of actual short-term debt for CLD+ utilities compare to utilities outside of Ontario.

Response:

a)

Utility	Sources of STD	Current Interest Rate (approximate)	Interest Rate Calculation
Elexicon Energy Inc.	**Operating Loan (TD Bank)**	6.95%	Prime minus 25bps
UCT 2 (see also the note below)	**Credit Facility**	6.145%	CDOR
Toronto Hydro	**Commercial Paper**	4.70%	Based on prevailing short-term rate (Bank of Canada / CORRA),

[1] For the purpose of these interrogatories, reference to CLD+ utilities include: Alectra Utilities Corporation (Alectra), Elexicon Energy Inc. (Elexicon), Enbridge Gas Inc. (Enbridge), Hydro One Networks Inc. (Hydro One); Hydro Ottawa Limited, Ontario Power Generation Inc, (OPG), Toronto Hydro-Electric System Limited; and Upper Canada Transmission 2, Inc (UCT 2).

Utility	Sources of STD	Current Interest Rate (approximate)	Interest Rate Calculation
			spreads, bank commissions and CP rating agency fees
Hydro Ottawa	**Banker's Acceptance Loan**	6.0285%	Canadian Bankers' Acceptance (BA) Rates – 1 Month rate plus a bankers' acceptance fee of 0.80%; 5.2285% + 0.80% = 6.0285%
Hydro Ottawa	**Bank Indebtedness**	6.70%	Bank of Canada Prime Rate - 0.50%; 7.20% - 0.50% = 6.70%
Hydro One	**Commercial Papers**	4.4% to 4.9%, as of August 15, 2024	Market-determined interest rate
Hydro One	**Floating Rate Note**	5.03% as of August 15, 2024	CORRA plus 0.50% per annum, reset quarterly
Alectra	**Commercial Paper**	4.65%-4.70%	Based on prevailing short-term rate (Bank of Canada / CORRA), spreads, bank commissions and CP rating agency fees
Enbridge Gas, Inc.	**See note below**		
OPG	**See note below**		

UCT 2

UCT 2's short-term debt is a $30,546,500 Credit Facility (with a $50,000,000 limit) with interest based on a variable Canadian Dollar Offered Rate (CDOR). The short-term debt rate used in EB-2023-0298 is 6.145%, which is derived from the variable rate effective May 2023, the period closest to debt issuance.

Enbridge Gas Inc.

Enbridge Gas Inc. (EGI) short-term debt is sourced through the Canadian Commercial Paper (CP) market. EGI CP is priced by auction. EGI provides its funding requirements (amount and maturity) to a network of CP dealers and then issues CP through the CP dealer(s) offering the lowest interest rate. The average cost of one-month CP, the most common tenor issued by EGI, during the first half of 2024 was ~5.20%.

The EGI Commercial Paper program is backstopped by $2.5B in committed credit facilities from several commercial banks. These committed credit facilities are priced at CORRA plus a spread when drawn. The annual standby fees associated with the Credit Facilities are included in Fixed Financing Costs within the revenue requirement.

OPG

OPG’s actual sources of short-term debt and interest rates are from the commercial paper market in Canada and/or United States. OPG maintains a $1B CAD and a $750M USD commercial paper program. OPG’s short-term debt interest rate calculated as a weighted average, as of June 30, 2024 is 4.88%. OPG’s borrowing rate under OPG’s commercial paper programs is market-based, comprised of a corporate spread over a benchmark rate, and a dealer fee.

b) In Concentric’s experience, the sources of actual short-term debt for CLD+ utilities (i.e., bank loans, commercial paper programs, credit facilities, etc.) are generally consistent with sources of actual short-term debt for utilities outside of Ontario.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.36]

Question(s):

With respect to Figure 2:

a) What is the source for 'Actual CAN A-Rate Utility Long-Term Debt Rate'?

b) Is the Actual CAN A-Rate Utility Long-Term Debt Rate representing embedded cost of debt or new issuances only?

Response:

a) The source of the "Actual CAN A-Rated Utility Long-Term Debt Rate" is Bloomberg's BVCAUA30 BVLI Index, which represents 30-year A-rated Canadian utility bond yields.

b) The series represents bond yields on new A-rated utility issuances only.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.39]

Question(s):

Concentric references Hydro One's January 2023 sustainable bond issuance transaction fees. Please provide a breakdown of those costs and provide details regarding which categories and amounts are as a result of it being the first sustainable bond issuance.

Response:

On January 27, 2023, Hydro One Inc. issued an aggregate principal amount of $1,050 million of medium term notes pursuant to Hydro One Limited's Sustainable Financial Framework. The aggregate notes were comprised of three tranches of debt with varying maturity dates and coupon rates. The net proceeds (net of $4.3 million in issuance fees) from the issuance of the Sustainable Bonds were approximately $1,045.5 million.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.39]

Question(s):

In SEC's experience, debt issuance/transaction costs on debt may or may not be material cost (e.g. bond issuance for large utility vs. bank loan for a small distributor, even proportionately can have very different costs). Furthermore, utilities who include a transaction cost as part of the interest rate often apply a 5-basis point adder regardless of the actual costs.

a) Please provide Concentric's views on when it is and is not appropriate to include transaction cost as part of the long-term debt rate.

b) For each CLD+ utility, please confirm that it recovers its debt issuance/transaction costs entirely through the amortizing costs over the life of a debt instrument. If not confirmed, how are those costs recovered.

c) For each CLD+ utility, for each of its last 5 debt issuances, please provide the, i) actual transaction issuance/costs (that would otherwise not be funded out of base rates), ii) based on the debt amount and term, the effective interest rate of the actual transaction costs when amortized over the life of the debt instrument, the iii) actual incremental amount that was added to the issuance debt rate for transaction/issuance.

Response:

a) Please see Concentric's report, Exhibit M2, at 39-40, where Concentric proposes to maintain the status quo with regard to the treatment of debt issuance/transaction costs and provides support for that recommendation.

b) Toronto Hydro – Confirmed.
Alectra – Confirmed.
Enbridge Gas Inc. – Confirmed.

OPG – Confirmed.

Hydro Ottawa - Any issuance costs are amortized over a five-year period which is consistent with the write-off for tax purposes.

UCT 2 - Actual debt issuance costs were not requested to be included in the revenue requirement in the company's current IR term. The unamortized debt issuance costs will be included in the calculation for the next IR term and amortized over the remaining life of the debt instrument.

Hydro One: Confirmed. As discussed in paragraph 3.6 of Exhibit F, Tab 1, Schedule 3 of EB-2021-0110 (page 11), debt issuance costs specific to each debt issue are included in the Premium Discount and Expenses column of the debt schedules and reflected in the Effective Cost Rate.

c) Concentric understands part (ii) as asking for the effective interest rate inclusive of the actual transaction costs.

Toronto Hydro:

Debenture Series	Date of Issuance	Terms (yrs)	Maturity Date	Prinicipal	Interest Rate	Issuance Costs	Effective Interest Rate	Incremental Rate
Series 17	18-Oct-2021	10	20-Oct-2031	$ 150,000,000	2.52%	$ 887,422	2.60%	0.08%
Series 18	18-Oct-2021	30	18-Oct-2051	$ 200,000,000	3.32%	$ 1,383,230	3.38%	0.06%
Series 19	13-Oct-2022	30	13-Oct-2052	$ 300,000,000	5.00%	$ 2,127,135	5.11%	0.11%
Series 20	14-Jun-2023	10	14-Jun-2033	$ 250,000,000	4.66%	$ 1,591,529	4.79%	0.13%
Series 21	12-Oct-2023	5	12-Oct-2028	$ 200,000,000	5.18%	$ 1,171,731	5.38%	0.20%

UCT 2:

Debt Issuance Cost	$5,462,938
Effective Interest Rate	NA
Incremental Rate	NA

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%

Hydro Ottawa:

Type of Debt Instrument	Date of Issuance	Term (Years)	Maturity Date	Principal ($)	Issuance Cost	Coupon Rate (%)	Effective interest rate*	Incremental amount
Promissory Note	9/Feb/15	30	2/Feb/45	$121,333,000	$786,032.67	3.639%	3.661%	0.022% Note 1
Promissory Note	25/Jun/15	10	25/Jun/25	$15,999,000	$88,067.61	2.614%	2.669%	0.055% Note 2
Promissory Note	25/Jun/15	30	25/Jun/45	$14,001,000	$91,082.12	3.639%	3.661%	0.022% Note 3
Promissory Note	16/Oct/19	10	16/Oct/29	$87,500,000	$0	2.660%	2.660%	0%
Promissory Note	16/Oct/19	30	16/Oct/49	$162,500,000	$0	3.210%	3.210%	0%

* Effective Interest rate of the actual transaction costs when amortized over the life of the debt instrument
** Actual incremental amount that was added to the issuance debt rate for transaction/issuance

1. The rate of interest payable on the principal amount or the amount remaining unpaid from time to time on this Promissory Note shall be 3.769% per annum from February 9, 2015 to February 8, 2020 (the first five years). Subsequently, the rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 3.639% per annum from February 9, 2020 to February 8, 2045.
2. The rate of interest payable on the principal amount or the amount remaining unpaid from time to time on this Promissory Note shall be 2.724% per annum from June 25, 2015 to June 25, 2020 (the first five years). Subsequently, the rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 2.614% per annum from June 26, 2020 to June 25, 2025.
3. The rate of interest payable on the principal amount or the amount remaining unpaid from time to time on this Promissory Note shall be 3.769% per annum from June 25, 2015 to June 25, 2020 (the first five years). Subsequently, the rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 3.639% per annum from June 26, 2020 to June 25, 2045.

Hydro One:

Last 5 Debt Issuances as at August 20, 2024
Hydro One Inc.

Offering Date	Term (Years)	Maturity Date	Principal Amount ($Millions)	Coupon Rate	Yield	Premium / (Discount)	Debt Issuance Costs[1]	Effective Interest Rate	Incremental Amount
12-Dec-23	31.0	30-Nov-54	100.0	4.85%	4.56%	4.9	(0.50)	4.58%	0.029%
12-Jan-24	5.9	30-Nov-29	250.0	3.93%	4.09%	(2.1)	(0.88)	4.16%	0.068%
12-Jan-24	10.1	1-Mar-34	550.0	4.39%	4.40%	(0.3)	(2.20)	4.45%	0.049%
20-Aug-24	10.4	4-Jan-35	700.0	4.25%	4.25%	(0.3)	(2.80)	4.30%	0.048%
20-Aug-24	30.3	30-Nov-54	500.0	4.85%	4.64%	16.6	(2.50)	4.67%	0.030%

A portion of each debt issue listed above has been allocated to Hydro One Networks Inc. Distribution and Hydro One Networks Inc. Transmission

OPG:

List of last 5 debt issuances Impacting OPG's Regulated Operations as of June 30, 2024 ($M)*

Line No.	Issue	Issue Date	Term (years)	Maturity Date	Principal ($M)	Issuance Costs ($M)	Effective Interest Rate (%)	Interest (Coupon) Rate (%)	Incremental (%)
	List of last 5 debt issuances								
1	Green Bond	6/28/2024	10.0	6/28/2034	496.7	3.3	5.08%	4.83%	0.25%
2	Green Bond	6/28/2024	30.0	6/28/2054	496.2	3.8	5.17%	4.99%	0.18%
3	Green Bond	7/18/2022	10.0	7/19/2032	297.9	2.1	4.98%	4.92%	0.05%
4	Green Bond	6/22/2018	30.0	6/22/2048	417.1	3.0	3.92%	3.84%	0.08%
5	Green Bond	1/18/2019	30.0	1/18/2049	0.4	0.0	4.34%	4.25%	0.09%

*For OPG, shown are the last five public debt issuances as OPG's other debt issuances do not incur a transaction cost.

Enbridge Gas Inc:

Line No.	Issuance Date	Issuance Maturity	Term (years)	Interest Rate	Notional ($ million)	Issuance Costs ($ million)	Impact on Effective Rate	Effective Rate
1	8/17/2022	8/17/2032	10.0	4.15%	$325	$1.3	0.04%	4.19%
2	8/17/2022	8/17/2052	30.0	4.55%	$325	$1.6	0.02%	4.57%
3	10/6/2023	10/6/2028	5.0	5.46%	$250	$1.0	0.08%	5.54%
4	10/6/2023	10/6/2033	10.0	5.70%	$400	$1.7	0.04%	5.74%
5	10/6/2023	10/6/2053	30.0	5.67%	$350	$1.9	0.02%	5.69%