NOTICE OF CONFIDENTIAL MATERIAL
A PORTION OF THIS TESTIMONY OR TESTIMONY AND ATTACHMENTS HAS/HAVE BEEN FILED UNDER SEAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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IN THE MATTER OF ADVICE NO. 1029-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE FEBRUARY 29, 2022	**PROCEEDING NO. 24AL-______G**

DIRECT TESTIMONY AND ATTACHMENTS OF PAUL A. JOHNSON

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

NOTICE OF CONFIDENTIAL MATERIAL
A PORTION OF THIS TESTIMONY OR TESTIMONY AND ATTACHMENTS HAS/HAVE BEEN FILED UNDER SEAL

Confidential: Attachment PAJ-12_C redactions on pages 1, 2 and 3
Attachment PAJ-13_C redactions on pages 1, 2 and 3
Attachment PAJ-14_C redactions on pages 1, 2 and 3
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January 29, 2024

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * * *

IN THE MATTER OF ADVICE NO. 1029-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE FEBRUARY 29, 2022	**) PROCEEDING NO. 24AL-______G**

DIRECT TESTIMONY AND ATTACHMENTS OF PAUL A. JOHNSON

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul A. Johnson. My business address is 401 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc. ("XES") as Vice President, Treasurer, and Investor Relations. XES, which is a wholly owned subsidiary of Xcel Energy, Inc. ("Xcel Energy") provides an array of support services to Public Service Company of Colorado ("Public Service" or the "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am filing testimony on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As Vice President of Investor Relations and Treasurer, I am responsible for recommending and implementing the financing required to achieve target capital structure objectives at each of the regulated utility operating companies and at Xcel Energy. I am also responsible for corporate cash forecasting and management, pension plan management, hazard risk insurance, treasury services, and financial policies. In addition, I am responsible for developing and maintaining relationships with investors, investor analysts, and internal and external stakeholders to ensure they are well informed to make financial or investment decisions. I also am responsible for working with the various credit rating agencies and providing timely updates as required. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Direct Testimony, is to:

- Discuss the importance of financial integrity to Public Service, its customers, and its other stakeholders, and the need for Public Service to maintain stable financial health in order to access capital markets and raise capital in varied economic conditions and at reasonable costs;
- Discuss the criteria that the credit rating agencies use to measure financial integrity;
- Provide a current assessment of Public Service's financial integrity and describe the impact that regulatory decisions, changes in cash flow, and

the timely recovery of prudent utility costs have on Public Service's financial integrity;

- Present and support Public Service's forecasted Weighted Average Cost of Capital ("WACC") for the recommended test year ended December 31, 2023 ("2023 Test Year" or "Test Year"), including the data points for cost of debt and capital structure necessary for the Company to calculate a revenue requirement and otherwise manage its authorized WACC; and

- Present and support the use of a 13-month average capital structure, a 13-month average cost of long-term debt, and 13-month average cost of short-term debt for the Gas Department for the informational historical period ended September 30, 2023.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring the following attachments:

- Attachment PAJ-1, which is a Moody's Investor Service publication titled *Rating Methodology: Regulated Electric & Gas Utilities* December 23, 2013.

- Attachment PAJ-2, which is a Standard & Poor's Rating Services publication titled *Key Credit Factors for the Regulated Utilities Industry* November 19, 2013.

- Attachment PAJ-3, which is a Standard & Poor's Rating Services publication titled *Corporate Methodology: Ratios and Adjustments* November 19, 2013.

- Attachment PAJ-4, which is a S&P Global Ratings publication titled *Public Service Co. of Colorado* July 5, 2023.

- Attachment PAJ-5, which is a S&P Global Ratings publication titled *Xcel Energy, Inc. Outlook Remains Stable: PSCo Outlook Not Negative Amid Increasing Wildfire Risks; Ratings Affirmed* July 28, 2023.

- Attachment PAJ-6, which is a S&P Global Ratings publication titled *Public Service Co. of Colorado's Authorized Rate Increase is in line with Base Case* September 12, 2023.

- Attachment PAJ-7, which is a Moody's Investor Service publication titled *Public Service Company of Colorado* January 31, 2023.
- Attachment PAJ-8, which is Moody's Investor Service publication titled *Moody's affirms NSP-Minnesota's A2 ratings; stable outlook* December 12, 2023.
- Attachment PAJ-9, which is a Moody's Investor Service publication titled *Moody's downgrades Pinnacle West to Baa1 and Arizona Public Service to A3; outlook negative* November 17, 2021.
- Attachment PAJ-10, which is a Company-generated spreadsheet that models how a utility's credit quality can be managed via different levers.
- Attachment PAJ-11, which is a RRA Regulatory Focus publication titled *Major energy rate case decisions in the US – January – September* dated November 1, 2023.
- CONFIDENTIAL Attachment PAJ-12, which is a Company-generated spreadsheet, that models the credit metrics if Public Service did not file a rate case.
- CONFIDENTIAL Attachment PAJ-13, which is a Company-generated spreadsheet, that models the credit metrics if the proposed return on equity and equity ratio were authorized.
- CONFIDENTIAL Attachment PAJ-14, which is a Company-generated spreadsheet, that models the credit metrics if the proposed return on equity was authorized with a 50% equity ratio.
- CONFIDENTIAL Attachment PAJ-15, which is a Company-generated spreadsheet, that models the credit metrics if the proposed return on equity was authorized with a 40% equity ratio.
- Attachment PAJ-16, which is a Scotiabank publication titled *Indicative New Issue Spreads* dated December 27, 2023.

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS IN YOUR TESTIMONY.

A. I recommend the Commission approve Public Service's Test Year WACC of 7.50 percent. Table PAJ-D-1 below shows components of the WACC to arrive at this overall number, as necessary for Company witness Mr. Arthur P. Freitas to develop the cost of service and for Public Service to manage its capital structure.

Table PAJ-D-1:
Requested WACC

		As of December 31, 2023[1]	
	Ratio	**Rate**	**WACC**
Long-Term Debt	43.18%	4.05%	1.75%
Short-Term Debt	1.82%	5.81%	0.11%
Equity	55.00%	10.25%	5.64%
		Total Cost	**7.50%**

This data compares closely to the actual historical data as of September 30, 2023, except that the Company is requesting a lower equity ratio and an increase in the rate of return on equity in this proceeding, as discussed by Company witness Ms. Ann E. Bulkley. Table PAJ-D-2 below demonstrates the Company's overall WACC in the Informational Historic Test Year ("IHTY").

Table PAJ-D-2:
IHTY WACC

		As of September 30, 2023[2]	
	Ratio	**Rate**	**WACC**
Long-Term Debt	43.38%	3.95%	1.71%
Short-Term Debt	1.09%	5.38%	0.06%
Equity	55.53%	9.20%[3]	5.11%
		Total Cost	**6.88%**

Q. PLEASE SUMMARIZE WHY THE COMPANY'S CAPITAL STRUCTURE AND COST OF DEBT PROPOSALS IN THIS PROCEEDING ARE REASONABLE.

[1] Forecasted equity, long-term debt, and short-term debt balances. Preliminary actuals as of December 31, 2023 indicate that the equity ratio is 55.04 percent.
[2] Historical 13-month average equity, long-term debt, and short-term debt balances September 2022 through September 2023.
[3] Cost of equity is the level the Company has used as a result of the last authorized cost of equity range approved by the Commission in Proceeding No. 22AL-0530E; Decision No. C23-0592 (mailed Sept. 6, 2023).

A. The 55.0 percent equity ratio included in the requested WACC for the 2023 Test Year reflects a reduction in the Company's historical actual equity ratio, consistent with the Commission's commentary in the last natural gas rate case. In addition, it is within the range of equity ratios suggested by the Commission in that proceeding. Finally, the recommended equity ratio supports the current credit ratings, allows strong access to the credit markets, and reflects the increased risk that Public Service faces due to wildfire risk and recently updated legislation impacting the natural gas business, as Ms. Bulkley discusses in her Direct Testimony. The Company is requesting a capital structure that positions it to continue to attract capital at reasonable rates, by supporting and maintaining the Company's credit metrics and overall financial integrity.

II. FINANCIAL INTEGRITY, RATING AGENCY METHODOLOGIES, AND APPLICATION TO PUBLIC SERVICE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will:

- Discuss financial integrity and the importance of maintaining it over time so the utility can serve and respond to customer needs;
- Provide a current assessment of Public Service's financial integrity and the related impact to Public Service's customers; and
- Identify both how Public Service is working to maintain its financial integrity and how its financial integrity could be strengthened through a supportive regulatory decision in this case.

Financial Integrity

Q. WHAT IS FINANCIAL INTEGRITY?

A. "Financial integrity" refers to a company's financial strength and its ability to attract capital to support operations and investment over the course of an economic cycle. The ability to attract capital in all market conditions, and at a reasonable cost, is essential for a utility to fulfill its obligation to provide safe and reliable utility service to customers. Achieving and maintaining strong financial integrity ensures that the utility will have the flexibility and liquidity to access the capital markets during unanticipated macroeconomic events outside of its control, such as the COVID-19 pandemic, Winter Storm Uri, and wildfires.

The financial integrity of a regulated utility is largely a function of its capital structure, return on equity ("ROE"), and cash flow, but other factors can also affect a utility's financial integrity. To maintain a strong financial profile, a utility needs to have the opportunity to recover all prudently incurred costs in a timely manner, which includes not only the costs of capital investments and operations and maintenance expense, but also the costs of servicing debt and providing a fair return for equity investors.

Q. HOW DO A UTILITY'S CREDIT RATINGS AFFECT ITS ABILITY TO ACCESS CAPITAL ON REASONABLE TERMS?

A. A credit rating measures credit risk, which is the ability and willingness of an issuer to fulfill its financial obligations in full and on time. Credit ratings are an independent assessment of a utility's financial integrity. These ratings project a long-term view of a company's financial health by addressing the relative probability that an issuer or an issue will experience default, *i.e.,* the failure to pay either the required periodic interest payment or the principal. Credit ratings also help debt investors differentiate between companies who are competing for the same investment dollars. The credit ratings assigned by rating agencies indicate their opinions of a company's ability to meet its financial obligations and the overall level of risk. Rating agency opinions are considered valuable by potential investors because they represent independent, third-party opinions that are based upon a consistent approach to the evaluation of company risk over time. Ratings therefore affect the number of potential investors and the cost of a company's debt and offer important insight into a company's investment risk in the past and future.

This point becomes even more true in a volatile market environment or when economic conditions worsen. As credit availability tightens, investors become increasingly selective with respect to the companies which qualify for their investment. Utilities with higher credit ratings are associated with reduced risk, which attracts investors at a lower cost of debt (e.g., lower average credit spreads) and favorably positions a utility relative to lower-rated comparable companies. The stronger the company's credit ratings, the larger the pool of investors willing to consider investing in the company's debt and the lower the coupon rate[4] the Company will need to pay in order to issue debt. Investment-grade credit ratings are crucial because the cost of debt increases very rapidly, and the number of potential buyers decreases substantially for those companies rated near the bottom of or below investment grade.

Equity investors also look at credit ratings as an indicator of risk, which they rely on to differentiate between utilities. Because the income available to common equity holders is subordinate to debt obligations, the weakening of a company's creditworthiness also increases the cost of equity, which will ultimately increase the cost of capital for all customers. "As a company increases the relative amount of debt capital in its capital structure, total fixed charges increase, and the probability of failing to meet the growing fixed charge burden increases also. The residual earnings available to common stockholders become increasing volatile and risky as the firm increases its financial leverage. Because of the increase in financial risk, investors will require a higher return on equity."[5] For these reasons, it is critical to protect Public Service's credit ratings in order to attract all forms of

[4] The coupon rate is the rate of interest paid by bond issuers on the bond's face value. A bond is priced at the underlying Treasury rate plus a credit spread.
[5] Dr. Roger A. Morin, *Modern Regulatory Finance* at 513.

capital at favorable rates in competitive environments. Ultimately, customers of the higher-rated utility benefit from lower capital costs as the lower financing costs are reflected in the rates paid by customers.

Q. HOW DOES MAINTAINING FINANCIAL INTEGRITY BENEFIT PUBLIC SERVICE'S CUSTOMERS?

A. A utility's financial integrity directly affects both the Company's ability to access capital to ensure liquidity for day-to-day operations and fund necessary investments on behalf of customers, and the cost of that capital ultimately included in the utility's overall rates. Attracting reasonably priced capital in all market conditions, including following unexpected macroeconomic events, is critical to being able to invest in the infrastructure necessary for Public Service to provide safe and reliable utility service. In turn, these investments support important activities like compliance with federal and state system integrity requirements, wildfire responses, leak mitigation, responsiveness to customer requests for service, local government infrastructure requirements, and working toward cleaner heating options for customers.

In contrast, weaker financial integrity increases the issued cost of debt and the implied cost of equity, which increases the overall WACC and the ultimate financing costs that are paid by customers. Weaker financial integrity can also limit liquidity and access to capital markets to fund operations to accomplish utility and state goals. Stronger financial integrity produces the opposite effects, which in turn benefits customers through a lower cost of service.

Q. IN THE CONTEXT OF A GAS RATE CASE, WHY ARE THESE PRINCIPLES IMPORTANT TO THE COMMISSION'S DETERMINATION OF THE APPROPRIATE WACC?

A. It is important for Public Service to continue making investments to ensure the natural gas system is safe, reliable, and resilient, while at the same time aggressively pursuing Colorado's policy goals to reduce associated greenhouse gas emissions. Investment is also needed on the electric side of the business to, among other things, support the clean energy transition.

It is essential to establish a reasonable capital structure, cost of debt, and rate of return on equity to support all of these activities because Public Service raises capital as a single company with regulated gas, electric, and steam departments, and finances the business with a mix of long-term debt, short-term debt, and equity. It is therefore important for Public Service's capital structure and overall financial integrity to illustrate to credit rating agencies and investors that Public Service represents a quality investment, particularly as the natural gas utility business is being perceived as a higher-risk financial investment than in the past. To these ends, the Commission's approval of Public Service's requested 7.50 percent WACC and requested equity ratio would support Public Service's current investment grade credit ratings and demonstrate ratemaking consistency and predictability.

Rating Agency Methodologies

Q. PLEASE EXPLAIN THE RATING AGENCY SCALES.

A. Credit rating agencies provide ratings for both the business entity and for the various debt issuances of the entity. The investment-grade rating categories include the High Grade (Triple-A and Double-A) and the Medium Grade category (Single-A and Triple-B ratings). The ratings are generally further delineated by S&P and Fitch through the use of pluses or minuses to show a company's relative standing within the categories.[6] The highest investment-grade rating is AAA; the lowest investment-grade rating is BBB-. Debt rated BB+ or below is considered speculative grade.

Q. DOES PUBLIC SERVICE HAVE ITS OWN CREDIT RATINGS?

A. Yes, because Public Service issues its own debt. Rating agencies perform an operating company-specific, bottoms up review on Public Service to determine credit quality. Moody's and Fitch both perform Public Service-specific analysis and generally do not consider the parent company in this analysis. While S&P does assign a "family style" rating, it also assigns a Public Service-specific rating through the Stand-Alone Credit Profile.

In addition, Public Service issues its own financial statements, has its own credit ratings, and has its own unique operating environment and regulatory construct. All of these company-specific factors are taken into consideration by both fixed income and equity investors when they determine their required cost of capital to invest in Public Service.

Q. WHAT ARE PUBLIC SERVICE'S CURRENT CREDIT RATINGS?

[6] Moody's uses numbers to show a company's standing within a category.

A. Public Service currently has a corporate credit rating of A3 from Moody's and A- from both S&P and Fitch, as reflected in Table PAJ-D-3 below.

Table PAJ-D-3

	S&P	**Moody's**	**Fitch**
Corporate Rating	A-	A3	A-
Senior Secured	A	A1	A+
Commercial Paper	A-2	P-2	F2
Outlook	Negative	Stable	Stable

Q. HOW IS A CREDIT RATING ESTABLISHED?

A. Credit ratings are established through both qualitative and quantitative analysis. The qualitative side is the assessment of business risk, which is built up from the broad macro-environment risks at the country and industry level. The issuer's specific risk within its business and economic environment is then determined. For a utility, regulatory risk is the most significant overall business risk. According to S&P, "[t]he regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance,"[7] which leads to the quantitative side of the analysis. This assessment examines financial ratios to analyze the financial risk of the issuer.

Business risk and financial risk can be viewed as the total risk of an entity, so that more of one risk must be offset by less of the other risk to arrive at a specific

[7] Attachment PAJ-2 at 6.

rating. Because utilities are subject to regulation, regulatory risk is a key consideration in ratings outcomes.[8]

Q. HOW IS REGULATORY RISK ANALYZED?

A. For Moody's, regulatory risk constitutes up to 60 percent of the credit profile, and for S&P it is up to 80 percent.[9] Both focus on the basic regulatory framework, including: (1) the legal foundation for utility regulation, (2) the ratemaking policies and procedures that determine how well the utility is afforded the opportunity to earn a reasonable return with a reasonable cash component, and (3) the history of regulatory behavior by the governing bodies applying those laws, policies, and procedures. Rating agencies then examine the mechanics of regulation, particularly the rate-setting process.

Q. HAVE CREDIT RATING AGENCIES COMMENTED ON THE IMPORTANCE OF THE REGULATORY FRAMEWORK IN EVALUATING A UTILITY'S FINANCIAL INTEGRITY?

A. Yes. S&P has noted that the regulatory framework "is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[10] S&P further states that "we base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability,

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[8] Attachment PAJ-1 at 4; Attachment PAJ-2 at 6.
[9] Attachment PAJ-1 at 4 (Regulatory Framework (25 percent) plus Ability to Cover Costs and Earn Returns (25%) plus Diversification (10 percent)); Attachment PAJ-2 at 6, 9 (Competitive Advantage (60 percent) plus Scale, Scope, and Diversity (20 percent)).
[10] Attachment PAJ-2 at 6.

efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return."[11]

Q. ARE THE FRAMEWORK AND THE MECHANICS OF REGULATION THE ONLY CONSIDERATIONS IN DETERMINING REGULATORY RISK?

A. No. Rating agencies also place high value on transparency, predictability, and consistency in regulation.[12] Rating agencies rate many types and tenors of fixed income securities, but they regard debtholders who extend credit over long periods as their primary audience and strive to rate long-term debt as accurately as possible. Utilities fund capital expenditures primarily with long-term debt and equity to match the long lives of the assets they are supporting and utility investors value ratings that are stable. Regulatory frameworks and practices that allow rating agencies to confidently project future cash flows and debt leverage will result in a better business risk profile. This predictability offers creditors the ability to accurately assess risk over most of the debt's term and improves the ability of the company to manage its business activities and capital program for the long-term benefit of ratepayers.

Q. ARE THERE EXAMPLES THAT DEMONSTRATE THE CLOSE ATTENTION INVESTORS AND CREDIT RATING AGENCIES PAY TO REGULATORY OUTCOMES?

[11] Attachment PAJ-2 at 6.
[12] Attachment PAJ-1 at 10; Attachment PAJ-2 at 6-8.

A. Yes. For example, in November 2021, both APS and its parent Pinnacle West Capital Corporation ("Pinnacle West") were downgraded by rating agencies, and Pinnacle West saw its stock prices materially drop. After an adverse regulatory decision from the Arizona Corporation Commission in an Arizona Public Service ("APS") rate case, Moody's stated in its downgrade report that "APS is now operating in a regulatory environment that is prioritizing customer bill impact and affordability concerns to the detriment of credit supportive cost recovery for the utility, unlike most other regulatory frameworks where utilities and their regulators have been more balanced and achieved both goals."[13]

Similarly, Xcel Energy, Inc., parent company of NSPM, saw its stock price drop following the Minnesota Public Utilities Commission's June 1, 2023 oral decision in NSPM's most recent electric rate case, with Xcel Energy stock price declining 3.3 percent, underperforming its peer group by 380 points, and losing approximately $1.4 billion of relative market capitalization just on June 1 and June 2, 2023. The outcome of the case prompted a ratings review by Moody's. In its December 12, 2023 report, Moody's stated that a NSPM ratings downgrade would be possible if "there is further deterioration in the credit supportiveness of its regulatory environment in Minnesota or unexpected deterioration in its credit metrics."[14] Both of these cases demonstrate the close attention paid by investors

[13] Attachment PAJ-9 at 2.
[14] Attachment PAJ-8 at 2.

and rating agencies to regulatory risk and regulatory outcomes. Company witness Ms. Bulkley provides additional examples in her Direct Testimony.

Q. WHAT FINANCIAL CONSIDERATIONS CONSTITUTE THE QUANTITATIVE SIDE OF CREDIT ANALYSIS?

A. Credit analysis is distinguished by its emphasis on cash flow. Credit analysts focus on the cash-flow dynamics of a company's financial results more than the earnings because servicing debt requires cash flow not just earnings.[15] The other major element of financial risk to a credit analyst is the total amount of debt or debt-like obligations, also referred to as off-balance sheet debt, that will be imputed on the issuer's balance sheet. Items that the rating agencies regard as debt-like include lease liabilities, long-term purchase power obligations, pension obligations, and asset-retirement obligations.

Q. WHAT ARE THE PRIMARY FINANCIAL METRICS THAT CREDIT RATING AGENCIES ANALYZE?

A. The primary financial metrics evaluated by the major credit rating agencies include some version of the following coverage ratios: (1) the ratio of FFO or CFO to total debt ("FFO/Debt" or "CFO/Debt"); (2) the ratio of FFO or CFO to interest ("FFO/Interest" or "CFO/Interest"); and (3) the ratio of debt to earnings before interest, taxes, depreciation, and amortization ("Debt/EBITDA"). These financial metrics are a measure of the utility's ability to manage its debt burden over time

[15] For Moody's, the measurement is called "CFO pre-Working Capital-to-Debt." S&P has a similar measure, called "Funds-From-Operations" ("FFO"), which they also compare to the overall debt burden.

and to meet its financial obligations. The greater the business risk of a particular company, the stronger these financial metrics must be to provide evidence to the credit rating agencies and investors that the company can withstand the financial effect of both macroeconomic and company-specific risks.

Q. WHAT TYPES OF DEBT OBLIGATIONS DO RATING AGENCIES INCLUDE IN THEIR CREDIT METRICS CALCULATIONS?

A. The total debt calculated by rating agencies includes debt and debt-like obligations, including on-balance sheet obligations such as finance and operating leases as well as off-balance sheet obligations. Off-balance sheet obligations are payment obligations, these include items such as long-term purchase power agreements, pension obligations, operating leases, guarantees, and asset retirement obligations, that do not appear on the balance sheet as debt; however, rating agencies may treat them as debt because the utility has little or no discretion whether to pay for these obligations.[16] After those off-balance sheet obligations are taken into account, the ratings agencies look to Public Service's actual *economic* equity ratio, which is lower than the authorized regulated equity ratio. The lower economic equity ratio generally has an adverse impact on Public Service's credit metrics. For example, during 2022, S&P identified $771.0 million of incremental debt obligations for off-balance sheet items for Public Service. As a result of such off-balance sheet items, a regulated equity ratio of 55.53 percent

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[16] *See* Attachments PAJ-1, PAJ-2, and PAJ-3 for a discussion of adjustments for off-balance sheet obligations.

translates to an economic equity ratio of 53.20 percent under S&P methodology.[17] The regulated equity ratio thus understates Public Service's true leverage because it excludes off-balance sheet items. Therefore, the economic equity ratio will *always* be lower than the authorized regulated equity ratio as long as Public Service has these additional liabilities. The Commission should, therefore, set an authorized equity ratio that will be sufficient to maintain credit ratings after reflecting the rating agency adjustments.

Q. WHAT IS THE SIGNIFICANCE TO THIS RATE CASE OF THE RATIOS THE CREDIT RATING AGENCIES EVALUATE?

A. This rate case outcome will affect the financial ratios and credit metrics. The ratios help rating agencies and investors determine whether a company will be able to service its existing debt obligations at the required level and will have the flexibility to take on incremental debt. Including existing off-balance sheet obligations in calculating a company's total debt affects many of the financial metrics. In general, the higher the proportion of debt in a capital structure, the more downward pressure on cash flow metrics and credit ratings, and upward pressure on cost of capital to the utility and its customers.

Regulatory lag (including the use of historical test years and the reduction in the use of riders that the Public Service natural gas business has experienced in recent years) also reduces cash flow and increases debt levels—both of which

[17] 2022 S&P Off-Balance Sheet Debt with 13-month average ended September 30, 2023.

have a negative impact on credit metrics. In order to provide safe, reliable, and clean service, utilities require significant and consistent capital investment. When a utility is unable to recover its costs through rates on a timely basis, the utility's cash flow is reduced compared to the cash it must utilize to service its obligations. To cover the shortfall, the utility is under increased pressure to issue more debt. If debt levels increase too much relative to cash flows from operations, the credit ratings will deteriorate and the utility's access to capital markets can become strained.

Public Service's Risk Profile and Credit Metrics

Q. HAS PUBLIC SERVICE'S RISK PROFILE CHANGED SINCE THE LAST RATE CASE?[18]

A. Yes. As discussed in Ms. Bulkley's testimony, Colorado has enacted legislation to reduce Green House Gas ("GHG") emissions that have increased the Company's business risk. In addition, Colorado legislation Senate Bill ("SB") 23-291 became law in August 2023. This new law has multiple sections and directs several different actions and studies. However, it has three components that taken together affect the Company's risk profile. First, SB 23-291 requires utilities to file a natural gas price risk management plan to levelize or mitigate fuel price volatility. Second, the bill requires the Commission to develop rules regarding mechanisms to align the financial incentives of the utility with customers (essentially a fuel cost

[18] Proceeding No. 22AL-0046G; Decision No. C22-0642 (mailed Oct. 25, 2022).

risk-sharing mechanism). Third, SB 23-291 provides an itemized listing of costs of doing business that Public Service will not be allowed to recover. Accordingly, these SB 23-291 provisions require Public Service to absorb fuel price volatility under certain circumstances, bear some portion of fuel price volatility risk, and exclude certain items from cost recovery.

As a result, the legislation will likely have an impact on future cash flows and risk profile. For example, the natural gas performance incentive mechanism may result in the disallowance of certain fuel costs, with potential for some upside benefit to utilities when fuel costs are low.[19] If such potential disallowances are material, the mechanism will increase volatility in recovery of fuel costs and cash flows, which will increase the risk profile of Public Service. In addition, any deferral of fuel costs under the Commission-approved gas price risk management plan will reduce cash flows and likely increase the issuance of debt. None of our projected credit metrics reflect the recently passed legislation, which will potentially have an adverse impact on cash flows, credit metrics, and risk profile for Public Service in the future.

Q. HAVE ANY CREDIT RATING AGENCIES SPECIFICALLY NOTED AN IMPACT OF THE NEW LEGISLATION ON PUBLIC SERVICE?

A. Yes. On July 5, 2023, S&P issued a report on Public Service and indicated that the legislation was negative from a credit standpoint:

> We believe the legislative developments are mostly negative for credit quality, increasing the risk of commodity cost disallowance and

[19] Proceeding No. 23M-0493EG.

> reducing the flexibility that the regulatory framework provides in recovering unexpected costs when they arise. While the ability for IOUs to propose hedging strategies to potentially dampen commodity cost volatility is positive for credit quality, hedging contracts come with a significant cost.[20]

Q. ARE THERE OTHER FACTORS THAT ARE CHANGING THE RISK PROFILE OF PUBLIC SERVICE?

A. Yes. Public Service's risk profile has been adversely impacted by wildfire risk. On July 28, 2023, S&P placed Public Service's ratings on a negative outlook, reflecting concerns about wildfire risk and litigation, along with concerns about the regulatory environment.

> **Managing regulatory risk in Colorado could become more challenging.** We expect PSCo could implement more aggressive wildfire mitigation tactics, such as public safety power shut-offs, to proactively reduce the risk of causing a catastrophic wildfire. Should the frequency of these shut-offs increase, frustrated customers and adverse public opinion could negatively affect PSCo's ability to consistently manage regulatory risk. We believe the legislative response to PSCo's recovery of $508 million in extraordinary gas costs related to the February 2021 winter storm supports our view. SB 291, which was enacted in May 2023, limits commodity cost volatility that is borne by ratepayers by transferring commodity price risk to the state's investor-owned utilities (IOUs), including PSCo.
>
> The negative outlook on PSCo reflects the probability that managing regulatory risk could become more challenging for the company over the next 24 months as it navigates the legal proceedings related to the Marshall Fire. Our base case incorporates PSCo's stand-alone adjusted FFO to debt of 20% through 2025.[21]

While it may be tempting to argue that wildfire risk relates primarily to the electric operations and is not relevant to the natural gas rate case, Public Service

[20] Attachment PAJ-4 at 2.
[21] Attachment PAJ-5 at 2, 4.

is one legal entity that issues debt and its credit rating and overall profile reflect the circumstances of both natural gas and electric operations. Therefore, the credit profile of both natural gas and electric operations are impacted adversely by wildfire risk.

Q. HAS THE INCREASE IN PUBLIC SERVICE'S RISK PROSPECT IMPACTED CREDIT SPREADS?

A. Yes. Public Service's 30-year credit spreads previously were quoted by various banks as five basis points wider than NSPM. However, over the last six months, Public Service's 30-year credit spread to NSPM is now quoted at 25 basis points wider to reflect the changing risk profile.[22]

Q. PLEASE DESCRIBE PUBLIC SERVICE'S CURRENT CREDIT METRICS.

A. Consistent with prior rate cases, Public Service has provided several credit metric scenarios, consistent with past Commission requests. The scenarios are summarized, and the resulting credit metrics are shown in Table PAJ-D-4 below.

- Scenario 1 – **No Rate Case Filing:** No gas rate filing is made; Company manages to an equity ratio 55.00 percent and 9.20 percent ROE; expected result: current credit metrics at bottom of S&P expected range but ratings likely maintained in the near term.[23]

- Scenario 2 – **Company Rate Case Proposal Approved:** PSCo rate request is approved as filed without modification, 55.00 percent equity ratio, 10.25 percent ROE; expected result: current credit rating maintained.[24]

- Scenario 3 – **Equity Ratio 50%:** 50 percent equity ratio, 10.25 percent ROE; expected result: potential credit rating downgrade.[25]

[22] Attachment PAJ-16.
[23] CONFIDENTIAL Attachment PAJ-12.
[24] CONFIDENTIAL Attachment PAJ-13.
[25] CONFIDENTIAL Attachment PAJ-14.

- Scenario 4 – **Equity Ratio 40%**: 40 percent equity ratio, 10.25 percent ROE; expected result: multiple notch credit rating downgrade probable.[26]

Q. WHAT METRICS DO CREDIT RATING AGENCIES EXPECT FOR PUBLIC SERVICE?

A. S&P explicitly expects Public Service's stand-alone funds FFO to debt be 20-22 percent through 2025,[27] with a downgrade if stand-alone FFO to debt weakens consistently below 17 percent over the next 24 months.[28] S&P also notes that Public Service has significant capital spending which could erode the financial cushion if the timeliness of cost recovery weakens.[29] Moody's credit metric downgrade threshold for Public Service is 19 percent and their current credit quality is dependent on continued credit-supportive regulatory outcomes that allow it to report a ratio of CFO-pre W/C to debt in the range of 19-21 precent.[30]

Q. WHAT ARE THE QUANTITATIVE RESULTS OF THE SCENARIO ANALYSIS?

A. Table PAJ-D-4 below provides a summary of key credit metric ratios under each scenario for 2024-2025. The primary S&P metric shown is the ratio of FFO/Debt, and the primary Moody's metric shown is the CFO pre-WC/Debt.

[26] CONFIDENTIAL Attachment PAJ-15.
[27] Attachment PAJ-4 at 2.
[28] Attachment PAJ-5 at 4.
[29] Attachment PAJ-6 at 1.
[30] Attachment PAJ-7 at 1.

Table PAJ-D-4
Summary of Credit Metrics[31]

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
	No Rate Case Filing[32]	**Company Rate Case Proposal Approved**[33]	**Equity Ratio 50%**[34]	**Equity Ratio 40%**[35]
Equity Ratio	55%	55%	50%	40%
FFO/Debt 2024	19.7%	19.9%	17.6%	14.4%
FFO/Debt 2025	20.0%	20.9%	18.0%	13.5%
CFO pre-WC/Debt 2024	20.0%	20.2%	17.8%	14.4%
CFO pre-WC/Debt 2025	20.3%	21.3%	18.2%	13.5%

Q. WHAT DO YOU SEE AS THE KEY TAKEAWAYS FROM THIS ANALYSIS?

A. This analysis shows that Public Service would be at risk of a downgrade under two of the scenarios. Public Service would likely maintain its current credit ratings in the scenarios where the Company's current rate case proposal is approved without modification (Scenario 2) or at current levels (Scenario 1) in the near term. However, Public Service strives to manage its credit metrics to the mid-to-high end of the stated guidance ranges, provided by the rating agencies, in order to be able to withstand economic volatility or unexpected market events. Targeting credit metrics on the threshold of a downgrade would allow very little flexibility for Public

[31] The credit metrics shown in Table PAJ-D-4 are based on the consolidated credit metrics of Public Service as it is one legal entity, and the credit ratings are based on the consolidated financial results for the entire company.
[32] CONFIDENTIAL Attachment PAJ-12.
[33] CONFIDENTIAL Attachment PAJ-13.
[34] CONFIDENTIAL Attachment PAJ-14.
[35] CONFIDENTIAL Attachment PAJ-15.

Service to respond to or weather unexpected economic events, such as Winter Storm Uri.

For example, Public Service had to issue $750 million of debt in March 2021 to fund the higher natural gas prices to consistently provide its customers reliable energy during the extremely cold weather. This debt issuance was upsized by $350 million to cover these unexpected expenses and delays in the recovery of these costs. Ultimately, in Proceeding No. 21A-0192EG, and for Public Service Gas, the Commission approved recovery of $293,607,161 beginning on August 15, 2022 over a period of 30 months, with no carrying charge.[36] Similarly, for Public Service Electric, the Commission approved recovery of $217,813,346 beginning on August 15, 2022, over a period of 24 months, with no carrying charge.[37] In other words, Public Service was able to defer the cost on customers' behalf for approximately 18 months prior to starting collection, with collection itself still ongoing at this time. Public Service would not have been able to provide this benefit if it did not have a cushion in its credit metrics.

Public Service would likely be at risk of a credit downgrade under Scenarios three and four. These potential downgrades are due to the degradation of credit metrics resulting from lowering the equity ratio without any corresponding offset to

[36] COLO. PUC No. 6 Gas Tariff, Sheet No. 51 ("Through Decision No. C22-0413 issued in Proceeding No. 21A-0192EG the Commission approved the recovery of incremental fuel cost from August 15, 2022, through February 14, 2025").
[37] COLO. PUC No. 8 Electric Tariff, Sheet No. 147A ("Through Decision No. C22-0413 issued in Proceeding No. 21A-0192EG the Commission approved the recovery of incremental fuel costs from August 15, 2022+++ through August 14, 2024").

mitigate the impact of lower cash flows and higher debt levels, also signaling increased business risk.

Q. WHY SHOULD THE COMMISSION AUTHORIZE AN INCREASE IN ROE, SO LONG AS PUBLIC SERVICE CREDIT METRICS ARE PRESERVED WITHOUT A RATE CASE IN THE NEAR TERM?

A. Credit metrics are indeed crucial for maintaining the operations of a financially sound utility. The manner of establishing rates, and the level and timing of cost recovery has a direct impact on a utility's ability to earn its authorized ROE and produce enough earnings and cash flow to support its credit metrics and ratings. In this case, the primary driver is capital investment in the natural gas system since the end of the test year ended December 31, 2021, approved in our last case, and associated depreciation expenses and property tax. S&P and Moody's weight regulatory risk as a main factor when determining the credit quality for a utility, and the timeliness of cost recovery impacts the rating agencies' perceptions and influence investor decisions. As Mr. Steven P. Berman discusses, without a rate case the Company's earned returns will continue to decline to a point where the credit metrics will fall below rating agency expectations necessary to support credit ratings. In turn, these credit ratings – combined with the return on equity investments authorized by a commission's decisions – affect investors' willingness to provide capital to the utility ultimately used to support its business and provide service to customers.

Overall, rating agencies' stated perceptions of commissions' decisions and support for cost recovery further influence investors' willingness to invest in a utility. The rating agencies have emphasized that balanced, constructive outcomes in a utility rate proceeding are indicative of a supportive, stable regulatory environment and underpin a utility's financial integrity. Regulatory Research Associates, a group within S&P Global Commodity Insights, conducted research identifying that the average 2022 return on equity awarded in fully litigated gas cases was 9.67 percent.[38] In Public Service's last gas rate case,[39] the ROE authorized was a range between 9.20 percent to 9.50 percent, but the Company could not select an ROE at the high end of this range without significantly reducing its capital structure (a less cost efficient way of maintaining credit metrics). With the robust capital expenditures planned, it is important that Public Service receive regulatory support and is able to compete with comparable utilities for investment capital.

Q. IS THE COMPANY ALSO PROVIDING THE GAS HIGH LEVEL LEVERS MODEL THAT EXAMINES THE IMPACT OF CAPITAL STRUCTURE, ROE, REGULATORY LAG AND DEPRECIATION EXPENSES ON THE PRIMARY CASH FLOW CREDIT METRICS?

A. Yes. The "Levers Model" refers to a Microsoft Excel spreadsheet that illustrates how credit metrics can be managed, at least directionally, through discrete

[38] Attachment PAJ-11 at 3.
[39] Proceeding No. 22AL-0046G; Decision No. C22-0642.

methods or a combination of methods to maintain or achieve desired results. The spreadsheet also compares the relative cost of each method. The Levers Model is included as Attachment PAJ-10. This spreadsheet was developed within the Company to distill a complex financial topic down to a simple and digestible presentation where key inputs and calculations can be examined. Modeled assumptions and figures are intentionally generic and meant to be representative of Public Service consolidated but vary from detailed specifics to provide simplification. This model is not sophisticated in comparison to the analyses described above but is provided based on interest from the Commission in past rate case proceedings.

III. PUBLIC SERVICE'S PROPOSED CAPITAL STRUCTURE

Q. PLEASE SUMMARIZE THE FACTORS THAT ARE CONSIDERED IN PLANNING AND MANAGING THE CAPITAL STRUCTURE FOR PUBLIC SERVICE.

A. Public Service considers a number of factors, including:

- Credit rating evaluations that reflect rating agency assessments of Public Service's business and financial risk;
- Public Service's long-term capital investment plans;
- Capital structures of other vertically-integrated, regulated utilities;
- The long-term stability of the capital structure being appropriately matched with the lives of Public Service asset investments;
- The current macroeconomic outlook and associated risk factors affecting the utility sector and capital markets generally;
- The need to manage the maturities of long-term debt to avoid excessive refinancing risk in any given year; and
- The Commission's authorized capital structure.

Q. HOW DID YOU DETERMINE PUBLIC SERVICE'S COMMON EQUITY BALANCE FOR THE TEST YEAR?

A. The Company proposes a move from approximately a 55-56 percent regulated equity ratio as in past rate cases, to a targeted 55.0 percent regulated equity ratio, consistent with the Commission's directive to implement a reduction in the Company's equity ratio. The recommended equity ratio addresses Commission concerns, supports the current credit ratings, allows strong access to the credit markets, and reflects the increased risk that Public Service faces due to recent legislation and wildfire risks. Put differently, this proposal, combined with a reasonable increase in the Company's ROE, will help maintain Public Service's financial integrity during the period when rates from this case will be in effect and despite some of the increased risks Public Service is currently experiencing.

Q. IS PUBLIC SERVICE PROPOSING A RANGE OF EQUITY RATIOS AS OPPOSED TO A POINT ESTIMATE?

A. No. The Company is requesting a lower, round number equity ratio in recognition of the Commission's concern for false precision with respect to establishing a single point equity ratio. However, it is also important for Public Service to have a target equity ratio that is clear to investors and rating agencies. While there is a range of reasonableness when it comes to the components of WACC, Public Service has recommended an equity ratio of 55 percent, which is within the previous range of 52-55 percent suggest by the Commission and lower than the currently authorized levels. In addition, the equity ratio supports Public Service's current credit ratings and projected cost of long-term and short-term debt, as well as providing access to capital markets in varying market conditions and at an attractive cost of capital. Having a targeted equity ratio at the Company's proposed level is intended to provide reasonable certainty and direction for management of debt issuance and equity infusions while recognizing the Commission's recent policy preferences. The Company is open to considering alternative capital structures, depending on level of ROE, level of depreciation, test year, interim rates, and use of riders, which all influence cash flows and credit metrics.

However, it is important to note that managing key credit metrics through the authorized equity ratio is an efficient lever from a revenue requirements standpoint, having lower than a one-for-one impact to revenue requirements. This is because changing the equity ratio has a favorable impact to both the cash flow and debt sides of the credit metric equation and it does so while displacing debt interest expense.

IV. COST OF LONG-TERM AND SHORT-TERM DEBT

Q. WHAT IS PUBLIC SERVICE'S EMBEDDED COST OF LONG-TERM DEBT AT THE END OF THE TEST YEAR?

A. Public Service's embedded cost of long-term debt as of December 31, 2023 is 4.05 percent. The cost of debt is based on a yield-to-maturity calculation where the debt expenses include interest as well as fees associated with issuing the bond, such as legal, underwriting, rating agency and other costs. These annualized costs are divided by the net proceeds of the bonds outstanding to derive an overall cost of debt for Public Service.

Q. WHAT IS PUBLIC SERVICE'S EMBEDDED COST OF SHORT-TERM DEBT AT THE END OF THE TEST YEAR?

A. Public Service's embedded cost of short-term debt is 5.81 percent, which is the Company's 13-month average cost of short-term debt as of December 31, 2023. The cost of short-term debt is based on actual short-term debt interest rates including interest on commercial paper as well as fees associated with maintaining the Company's credit facility.

Q. IS PUBLIC SERVICE PROPOSING TO INCLUDE THIS DATA IN THE COST OF SERVICE FOR THIS PROCEEDING?

A. Yes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATEMENT OF QUALIFICATIONS

I received my Bachelor of Science in Business from Winona State University and my MBA from the University of St. Thomas. I am a CFA charter holder and passed the CPA and CMA exams.

I currently serve as the Vice President of Investor Relations and Treasurer and have held this position since July 2021. Prior to this role, I served in the following roles during my tenure at Xcel Energy: Vice President, Investor Relations (2013-2021);Vice President, Investor Relations and Business Development (2012-2013); Vice President, Investor Relations and Financial Management (2011-2012); Managing Director of Investor Relations and Assistant Treasurer (2008-2011); Managing Director of Investor Relations (2007-2008); Director of Investor Relations (2001-2006); Director of External Reporting (1998-2001); Controller and Assistant Treasurer for Energy Masters (1995-1998); and Administrator in Internal Reporting (1992-1995).

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE NO. 1029-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE FEBRUARY 29, 2024	)	**PROCEEDING NO. 24AL-______G**

AFFIDAVIT OF PAUL A. JOHNSON
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Paul A. Johnson, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the Direct Testimony and attachments are true and correct to the best of my information, knowledge and belief; and that I would give the same testimony orally and would present the same attachments if asked under oath.

Dated at Minneapolis, Minnesota, this 23 day of January, 2024.

Paul A. Johnson
Vice President, Treasurer, and Investor Relations

Subscribed and sworn to before me this 23rd day of January, 2024.

Amy Deborah Reineke
Notary Public

Amy Deborah Reineke
NOTARY PUBLIC
MINNESOTA
My Commission Expires 1/31/2026

My Commission expires 01/31/26

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

Regulated Electric and Gas Utilities

This rating methodology replaces "Regulated Electric and Gas Utilities" last revised on December 23, 2013. We have updated some outdated links and removed certain issuer-specific information.

Table of Contents:

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Summary

This rating methodology explains our approach to assessing credit risk for regulated electric and gas utilities globally. This document does not include an exhaustive treatment of all factors that are reflected in our ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.[1]

This report includes a detailed rating grid which is a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas utility industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the grid in this document uses historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

THIS METHODOLOGY WAS UPDATED ON AUGUST 2, 2018. WE HAVE MADE MINOR FORMATTING ADJUSTMENTS THROUGHOUT THE METHODOLOGY.

THIS RATING METHODOLOGY WAS UPDATED ON FEBRUARY 15, 2018. WE HAVE CORRECTED THE FORMATTING OF THE FACTOR 4: FINANCIAL STRENGTH TABLE ON PAGE 34.

THIS RATING METHODOLOGY WAS UPDATED ON SEPTEMBER 27, 2017. WE REMOVED A DUPLICATE FOOTNOTE THAT WAS PLACED IN THE MIDDLE OF THE TEXT ON PAGE 7.

[1] This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains four key factors that are important in our assessment for ratings in the regulated electric and gas utility sector:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength

Some of these factors also encompass a number of sub-factors. There is also a notching factor for holding company structural subordination.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that might map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), our approach to ratings within a utility family (Appendix B), a description of the various types of companies rated under this methodology (Appendix C), key industry issues over the intermediate term (Appendix D), regional and other considerations (Appendix E), and treatment of power purchase agreements (Appendix F).

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. A link to documents that describe our approach to such cross-sector credit rating methodological considerations can be found in the Related Research section of this report.

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[2] electric and gas utilities that are not Networks[3]. Regulated Electric and Gas Utilities are companies whose predominant[4] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

This rating methodology covers regulated electric and gas utilities worldwide. These companies are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor owned companies, commercially oriented government owned companies or, in the case of independent system operators, not-for-profit or similar entities. As detailed in Appendix C, this methodology covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, local gas distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often more accessible for participation by interveners, including disaffected customers and the politicians who want their votes. Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, Regulated Water Companies and Natural Gas Pipelines.[5]

The Regulated Electric and Gas Utility sector is predominantly investment grade, reflecting the stability generally conferred by regulation that typically sets prices and also limits competition, such that defaults have been lower than in many other non-financial corporate sectors. However, the nature of regulation can

[2] Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators.

[3] Regulated Electric and Gas Networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

[4] We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply due to a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

[5] A link to credit rating methodologies covering these and other sectors can be found in the Related Research section of this report.

vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments.

About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in six sections, which are summarized as follows:

1. Identification and Discussion of the Rating Factors in the Grid

The grid in this rating methodology focuses on four rating factors. The four factors are comprised of sub-factors that provide further detail:

Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%	Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%
		Consistency and Predictability of Regulation	12.5%
Ability to Recover Costs and Earn Returns	25%	Timeliness of Recovery of Operating and Capital Costs	12.5%
		Sufficiency of Rates and Returns	12.5%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Key Financial Metrics	40%		
		CFO pre-WC + Interest / Interest	7.5%
		CFO pre-WC / Debt	15.0%
		CFO pre-WC – Dividends / Debt	10.0%
		Debt/Capitalization	7.5%
Total	100%		100%
Notching Adjustment			
Holding Company Structural Subordination			0 to -3

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by our analysts.[6] All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.[7]

[6] For definitions of our most common ratio terms, please see "Moody's Basic Definitions for Credit Statistics, User's Guide," a link to which may be found in the Related Research section of this report.

[7] Our standard adjustments are described in "Financial Statement Adjustments in the Analysis of Non-Financial Corporations". A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

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. We utilize historical data (in most cases, an average of the last three years of reported results) in the rating grid. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of several years or more, or for individual twelve month periods.

3. Mapping Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa).

4. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

5. Determining the Overall Grid-Indicated Rating[8]

To determine the overall grid-indicated rating, we convert each of the sub-factor ratings into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor 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

8 In general, the grid-indicated rating is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the grid-indicated rating is oriented to the baseline credit assessment. For an explanation of baseline credit assessment, please refer to our rating methodology on government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. The documents that provide broad guidance for these notching decisions are our rating methodologies on loss given default for speculative grade non-financial companies and for aligning corporate instrument ratings based on differences in security and priority of claim. The link to these and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
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
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 grid-indicated rating.

6. Appendices

The Appendices present a full grid and provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

Our analysis of electric and gas utilities focuses on four broad factors:

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

There is also a notching factor for holding company structural subordination.

Factor 1: Regulatory Framework (25%)

Why It Matters

For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.

Utility rates[9] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

How We Assess Legislative and Judicial Underpinnings of the Regulatory Framework for the Grid

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is – the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Since the focus of our scoring is on each issuer, we consider how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators will use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and rules will receive higher scores in the Legislative and Judicial Underpinnings sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score.

In general, we view national utility regulation as being less liable to political intervention than regulation by state, provincial or municipal entities, so the very highest scoring in this sub-factor is reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally "above-the-fray" in terms of impartial and technically-oriented rate setting, and very high scoring may be appropriate.

9 In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

The relevant judicial system can be a major factor in the regulatory framework. This is particularly true in litigious societies like the United States, where disagreements between the utility and its state or municipal regulator may eventually be adjudicated in federal district courts or even by the US Supreme Court. In addition, bankruptcy proceedings in the US take place in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as favorable for the credit- supportiveness of the regulatory framework.

Electric and gas utilities are generally presumed to have a strong monopoly that will continue into the foreseeable future, and this expectation has allowed these companies to have greater leverage than companies in other sectors with similar ratings. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could cause lower scoring, because the utility can only recover its costs and investments and service its debt if customers purchase its services. There have some instances of incursions into utilities' monopoly, including municipalization, self-generation, distributed generation with net metering, or unauthorized use (beyond the level for which the utility receives compensation in rates). Incursions that are growing significantly or having a meaningful impact on rates for customers that remain with the utility could have a negative impact on scoring of this sub-factor and on factor 2 - Ability to Recover Costs and Earn Returns.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. We have observed that some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our factor scoring will seek to reflect that evolution. For instance, a new framework will typically become tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders and trackers. These changes would likely impact scoring of sub-factor 2b - Timeliness of Recovery of Operating and Capital Costs, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings. On the negative side, a judiciary that had formerly been independent may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

How We Assess Consistency and Predictability of Regulation for the Grid

For the Consistency and Predictability sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure - power plants, electric transmission and distribution systems, and/or natural gas distribution systems. When the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and when the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility will receive higher scores in this sub-factor. When the process includes substantial political intervention, which could take the form of legislators or other government officials publically second- guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or when regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility will receive lower scores in this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. We have observed that some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit supportive outcomes, so they will score higher in this sub-factor. Conversely, if a utility has multiple rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus score lower in this sub-factor.

In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision- making.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

This rating factor examines the ability of a utility to recover its costs and earn a return over a period of time, including during differing market and economic conditions. While the Regulatory Framework looks at the transparency and predictability of the rules that govern the decision-making process with respect to utilities, the Ability to Recover Costs and Earn Returns evaluates the regulatory elements that directly impact the ability of the utility to generate cash flow and service its debt over time. The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility (as was the case when "used and useful" requirements threatened some utilities that experienced years of delay in completing nuclear power plants in the 1980s). While our scoring for the Ability to Recover Costs and Earn Returns may primarily be influenced by our assessment of the regulatory relationship, it can also be highly impacted by the management and business decisions of the utility.

How We Assess Ability to Recover Costs and Earn Returns

The timeliness and sufficiency of rates are scored as separate sub-factors; however, they are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assurance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. During the past five years, utilities have benefitted from low interest rates and generally decreasing fuel costs and purchased power costs, but these market conditions could easily reverse. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

While Factors 1 and 2 are closely inter-related, scoring of these factors will not necessarily be the same. We have observed jurisdictions where the Regulatory Framework caused considerable credit concerns – perhaps it was untested or going through a transition to de-regulation, but where the track record of rate case outcomes was quite positive, leading to a higher score in the Ability to Recover Costs and Earn Returns. Conversely, there have been instances of strong Legislative and Judicial Underpinnings of the Regulatory Framework where the commission has ignored the framework (which would affect Consistency and Predictability of Regulation as well as Ability to Recover Costs and Earn Returns) or has used extraordinary measures to prevent or defer an increase that might have been justifiable from a cost perspective but would have caused rate shock.

One might surmise that Factors 2 and 4 should be strongly correlated, since a good Ability to Recover Costs and Earn Returns would normally lead to good financial metrics. However, the scoring for the Ability to Recover Costs and Earn Returns sub-factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be impacted by one-time events, market conditions or construction cycles - trends that we believe could normalize or even reverse.

How We Assess Timeliness of Recovery of Operating and Capital Costs for the Grid

The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to estimate the lag between the time that a utility incurs a major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

How We Assess Sufficiency of Rates and Returns for the Grid

The criteria we consider include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning returns. We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, comparison will be made to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons given by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa	
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.	

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa	
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.	

Factor 3: Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that economic cycles, material changes in a single regulatory regime or commodity price movements will have a severe impact on cash flow and credit quality of a utility. While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness.

Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.

For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.

How We Assess Market Position for the Grid

Market position is comprised primarily of the economic diversity of the utility's service territory and the diversity of its regulatory regimes. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area.

Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources. For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com. We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub- factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

How We Assess Generation and Fuel Diversity for the Grid

Criteria include the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer economically to shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to Challenged Source and Threatened Sources (see the explanations for how we generally characterize these generation sources in the table below). A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, since utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score more highly in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will incur lower scores.

In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources. In evaluating threatened sources, we consider the utility's progress in its plan to replace those sources, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. Especially if there are no peers in the same jurisdiction, we also examine the extent to which the utility's generation resources plan is aligned with the relevant government's fuel/energy policy.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5.00% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5.00% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definiitons
Market Position	5.00% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.

Generation and Fuel Diversity	5.00% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength (40%)

Why It Matters

Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers.

How We Assess It for the Grid

In comparison to companies in other non-financial corporate sectors, the financial statements of regulated electric and gas utilities have certain unique aspects that impact financial analysis, which is further complicated by disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) versus International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non- utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from ratepayers over a set period of time. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction-work-in-progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. For this reason, we focus more on a utility's cash flow than on its reported net income.

Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities.

However, under IFRS the two measures are essentially the same. In general, we view changes in working capital as less important in utility financial analysis because they are often either seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We will nonetheless examine the impact of working capital changes in analyzing a utility's liquidity (see Other Rating Considerations – Liquidity).

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

For this scoring grid, we have identified four key ratios that we consider the most consistently useful in the analysis of regulated electric and gas utilities. However, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. Our ratings consider the overall financial strength of a company, and in individual cases other financial indicators may also play an important role.

CFO Pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is an indicator for a utility's ability to cover the cost of its borrowed capital. The numerator in the ratio calculation is the sum of CFO Pre-WC and interest expense, and the denominator is interest expense.

CFO Pre-Working Capital / Debt

This important metric is an indicator for the cash generating ability of a utility compared to its total debt. The numerator in the ratio calculation is CFO Pre-WC, and the denominator is total debt.

CFO Pre-Working Capital Minus Dividends / Debt

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi- permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. The numerator of this ratio is CFO Pre-WC minus dividends, and the denominator is total debt.

Debt/Capitalization

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with our standard adjustments[10], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[11]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology (as described in Appendix E) have different levels of business risk.

Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

Other types of utilities may have lower business risk, such that we believe that they are most appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural

[10] In certain circumstances, analysts may also apply specific adjustments.

[11] We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level.

disasters. For instance, we tend to view many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we will apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened degree of exposure to catastrophic storm damage, or increased regulatory scrutiny due to poor reliability, or other considerations. The Standard Grid will also apply to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

The four key ratios, their weighting in the grid, and the Standard and LBR scoring thresholds are detailed in the following table.

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.50%		≥ 8.0x	6.0x - 8.0x	4.5x - 6.0x	3.0x - 4.5x	2.0x - 3.0x	1.0x - 2.0x	< 1.0x
CFO pre-WC / Debt	15.00%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10.00%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.50%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Notching for Structural Subordination of Holding Companies

Why It Matters

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are upstreamed by the OpCos[12]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non- financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[13] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

The grids for factors 1-4 are primarily oriented to OpCos (and to some degree for HoldCos with minimal current structural subordination; for example, there is no current structural subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring grid outcomes (on average) closer to the actual ratings of HoldCos.

How We Assess It

Grid-indicated ratings of holding companies may be notched down based on structural subordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer are essential.

Some of the potentially pertinent factors that could increase the degree and/or impact of structural subordination include the following:

» Regulatory or other barriers to cash movement from OpCos to HoldCo

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[14]

» Significant dividend limitations or potential limitations at an important OpCo

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

Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating factors that could decrease the degree and/or impact of structural subordination include the following:

12 The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo.

13 Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc.

14 While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists

- Substantial diversity in cash flows from a variety of utility OpCos
- Meaningful dividends to HoldCo from unlevered utility OpCos
- Dependable, meaningful dividends to HoldCo from non-utility OpCos
- The group's investment program is primarily in strong utility businesses
- Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the grid may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the grid convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the degree to which operating companies have credit insulation due to regulation or other protective factors. Appendix B has additional insights on ratings within a utility family.

Rating Methodology Assumptions, Limitations, and Other Rating Considerations

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the grid to map more closely to actual ratings. Accordingly, the four rating factors and the notching factor in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that lack of access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, 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, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible precisely to express these in the rating methodology grid without making the grid excessively complex and significantly less transparent.

Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

We consider other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas utilities, 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. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high price tags. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be debt financed. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capex are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities were swift to cut or defer discretionary spending during the 2007-2009 recession. Dividends represent a quasi-permanent outlay, since utilities typically only rarely will cut their dividend. Liquidity is also important to meet maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the grid would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets, even under difficult conditions. As a result, liquidity generally has not been an issue for most utilities and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important 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 cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality and Financial Policy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

We also assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management is willing stretch its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect we have observed is that utility subsidiaries often pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

Size – Natural Disasters, Customer Concentration and Construction Risks

The size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Particularly in the US, we have not observed material differences in the success of utilities' regulatory outreach based on their size. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the grid attempts to incorporate the first two of these into Factor 3, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. While construction projects always carry the risk of cost over-runs and delays, these risks are materially heightened for projects that are very large relative to the size of the utility.

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple ratings grid.[15]

Diversified Operations at the Utility

A small number of regulated utilities have diversified operations that are segments within the utility company, as opposed to the more common practice of housing such operations in one or more separate affiliates. In general, we will seek to evaluate the other businesses that are material in accordance with the appropriate methodology and the rating will reflect considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses when segment financial results are not fully broken out and these may be addressed through estimation based on available information. Since regulated utilities are a relatively low risk business compared to other corporate sectors, in most cases diversified non-utility operations increase the business risk profile of a utility. Reflecting this tendency, we note that assigned ratings are typically lower than grid- indicated ratings for such companies.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Investment and Acquisition Strategy

In our credit assessment we take into consideration management's investment strategy. Investment strategy is benchmarked with that of the other companies in the rated universe to further verify its consistency. Acquisitions can strengthen a company's business. Our assessment of a company's tolerance for acquisitions at a given rating level takes into consideration (1) management's risk appetite, including the likelihood of further acquisitions over the medium term; (2) share buy-back activity; (3) the company's commitment to specific leverage targets; and (4) the volatility of the underlying businesses, as well as that of the business acquired. Ratings can often hold after acquisitions even if leverage temporarily climbs above normally acceptable ranges. However, this depends on (1) the strategic fit; (2) pro-forma

15 See also the cross-sector methodology "How Sovereign Credit Quality May Affect Other Ratings." A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

capitalization/leverage following an acquisition; and (3) our confidence that credit metrics will be restored in a relatively short timeframe.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations, the proper tone at the top and consistency in accounting policies and procedures.

Weaknesses in the overall financial reporting processes, financial statement restatements or delays in regulatory filings can be indications of a potential breakdown in internal controls.

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based onlegislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward- looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor- unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward- looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non- refundable interim rates) can be collected, and permit inclusion of important forward -looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate- payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de- activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
CFO pre-WC / Debt	15%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.5%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. Financing of these entities varies by region, in part due to the regulatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries or minority interests in other companies. However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jurisdictions. A HoldCo may have both levered and unlevered OpCos.

General Approach to a Utility Family

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[16] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

In considering how closely aligned or how differentiated ratings should be among members of a utility family, we assess a variety of factors, including:

» Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

» Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity facility may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may better be able to withstand a temporary hiatus of external liquidity or access to capital markets

» Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family

» The extent to which higher leverage at one entity increases default risk for other members of the family

» An entity's exposure to or insulation from an affiliate with high business risk

» Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc.

» The relative size and financial significance of any particular OpCo to the HoldCo and the family

[16] See paragraph at the end of this section for approaches to Hybrid HoldCos.

See also those factors noted in Notching for Structural Subordination of Holding Companies.

Our approach to a Hybrid HoldCo (see definition in Appendix C) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses. If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity under more than one methodology. When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating.

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

Where higher barriers to cash movement exist on an OpCo or OpCos due the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. For instance, for utility families with OpCos in the US, where regulatory barriers to free cash movement are relatively high, greater importance is generally placed on the stand-alone credit profile of the OpCo.

Our observation of major defaults and bankruptcies in the US sector generally corroborates a view that regulation creates a degree of separateness of default probability. For instance, Portland General Electric (Baa1 RUR-up) did not default on its securities, even though its then-parent Enron Corp. entered bankruptcy proceedings. When Entergy New Orleans (Ba2 stable) entered into bankruptcy, the ratings of its affiliates and parent Entergy Corporation (Baa3 stable) were unaffected. PG&E Corporation (Baa1 stable) did not enter bankruptcy proceedings despite bankruptcies of two major subsidiaries - Pacific Gas & Electric Company (A3 stable) in 2001 and National Energy Group in 2003.

The degree of separateness may be greater or smaller and is assessed on a case by case basis, because situational considerations are important. One area we consider is financing arrangements. For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness. For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposures to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo under its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source. However, the ability of an OpCo to finance itself by accessing capital markets must also be considered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are.

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness.

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt.

While most of the regulatory barriers to cash movement are very real, they are not absolute. Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible.

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Typically, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

Our approach to rating issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos (e.g., many parts of Asia and Europe) places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities.

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. In these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group.

Appendix C: Brief Descriptions of the Types of Companies Rated Under This Methodology

The following describes the principal categories of companies rated under this methodology:

Vertically Integrated Utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business. They build power plants, procure fuel, generate power, build and maintain the electric grid that delivers power from a group of power plants to end-users (including high and low voltage lines, transformers and substations), and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission & Distribution Utility: Transmission & Distribution utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region.

T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from Networks, whose customers are retail electric suppliers and/or other electricity companies. In a smaller number of cases, T&Ds rated under this methodology may not have an obligation to provide POLR services, but are regulated in sub- sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority.

Local Gas Distribution Company: Distribution is the final step in delivering natural gas to customers. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure). LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distinguish LDCs from gas networks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Integrated Gas Utility: Integrated gas regulated utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities; and performing other supply-related activities, such as customer billing and metering. The rates or tariffs for the totality of these activities are set by the relevant regulatory authority. Many integrated gas utilities are national in scope.

Combination Utility: Combination utilities are those that combine an LDC or Integrated Gas Utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Regulated Generation Utility: Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. In the US, this means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator (primarily FERC). Companies that have been included in this group include certain generation companies (including in Korea and China) that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology (for example, Unregulated Utilities and Power Companies).

Independent System Operator: An Independent System Operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources. ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity. The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers. ISOs may not be rate-regulated in the traditional sense, but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

In the US, most ISOs were formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), but the ISO that operates solely in Texas falls under state jurisdiction. Some US ISOs also perform certain additional functions such that they are designated as Regional Transmission Organizations (or RTOs).

Transmission-Only Utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs. Transmission-only utilities in most parts of the world other than the US have been rated under the Regulated Networks methodology.

Utility Holding Company (Utility HoldCo): As detailed in Appendix B, regulated electric and gas utilities are often part of corporate families under a parent holding company. The operating subsidiaries of Utility HoldCos are overwhelmingly regulated electric and gas utilities.

Hybrid Holding Company (Hybrid HoldCo): Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a Hybrid HoldCo.

Appendix D: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

As highly regulated monopolistic entities, regulated utilities continually face political and regulatory risk, and managing these risks through effective outreach to key customers as well as key political and regulatory decision-makers is, or at least should be, a core competency of companies in this sector. However, larger waves of change in the political, regulatory or economic environment have the potential to cause substantial changes in the level of risk experienced by utilities and their investors in somewhat unpredictable ways.

One of the more universal risks faced by utilities currently is the compression of allowed returns. A long period of globally low interest rates, held down by monetary stimulus policies, has generally benefitted utilities, since reductions in allowed returns have been slower than reductions in incurred capital costs. Essentially all regulated utilities face a ratcheting down of allowed and/or earned returns. More difficult to predict is how regulators will respond when monetary stimulus reverses, and how well utilities will fare when fixed income investors require higher interest rates and equity investors require higher total returns and growth prospects.

The following global snapshot highlights that regulatory frameworks evolve over time. On an overall basis in the US over the past several years, we have noted some incremental positive regulatory trends, including greater use of formula rates, trackers and riders, and (primarily for natural gas utilities) de-coupling of returns from volumetric sales. In Canada, the framework has historically been viewed as predictable and stable, which has helped offset somewhat lower levels of equity in the capital structure, but the compression of returns has been relatively steep in recent years. In Japan, the regulatory authorities are working through the challenges presented by the decision to shut down virtually all of the country's nuclear generation capacity, leading to uncertainty regarding the extent to which increased costs will be reflected in rate increases sufficient to permit returns on capital to return to prior levels. China's regulatory framework has continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favored generation sources balanced by an overall state policy of assuring sustainability of the sector, adequate supply of electricity and affordability to the general public. Singapore and Hong Kong have fairly well developed and supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea and Thailand have been moving towards a more transparent regulatory framework. The Philippines is in the process of deregulating its power market, while Indian power utilities continue to grapple with structural challenges. In Latin America, there is a wide dispersion among frameworks, ranging from the more stable, long established and predictable framework in Chile to the decidedly unpredictable framework in Argentina. Generally, as Latin American economies have evolved to more stable economic policies, regulatory frameworks for utilities have also shown greater stability and predictability.

All of the other issues discussed in this section have a regulatory/political component, either as the driver of change or in reaction to changes in economic environments and market factors.

Economic and Financial Market Conditions

As regulated monopolies, electric and gas utilities have generally been quite resistant to unsettled economic and financial market conditions for several reasons. Unlike many companies that face direct market-based competition, their rates do not decrease when demand decreases. The elasticity of demand for electricity and gas is much lower than for most products in the consumer economy.

When financial markets are volatile, utilities often have greater capital market access than industrial companies in competitive sectors, as was the case in the 2007-2009 recession. However, regulated electric and gas utilities are by no means immune to a protracted or severe recession.

Severe economic malaise can negatively affect utility credit profiles in several ways. Falling demand for electricity or natural gas may negatively impact margins and debt service protection measures, especially when rates are designed such that a substantial portion of fixed costs is in theory recovered through volumetric charges. The decrease in demand in the 2007-2009 recession was notable in comparison to prior recessions, especially in the residential sector. Poor economic conditions can make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, recessions can coincide with a lack of confidence in the utility sector that impacts access to capital markets for a period of time. For instance, in the Great Depression and (to a lesser extent) in the 2001 recession, access for some issuers was curtailed due to the sector's generally higher leverage than other corporate sectors, combined with a concerns over a lack of transparency in financial reporting.

Fuel Price Volatility and the Global Impact of Shale Gas

The ability of most utilities to pass through their fuel costs to end users may insulate a utility from exposure to price volatility of these fuels, but it does not insulate consumers. Consumers and regulators complained vociferously about utility rates during the run-up in hydro-carbon prices in 2005-2008 (oil, natural gas and, to a lesser extent, coal). The steep decline in US natural gas prices since 2009, caused in large part by the development of shale gas and shale oil resources, has been a material benefit to US utilities, because many have been able to pass through substantial base rate increases during a period when all-in rates were declining. Shale hydro-carbons have also had a positive impact, albeit one that is less immediate and direct, on non-US utilities. In much of the eastern hemisphere, natural gas prices under long-term contracts have generally been tied to oil prices, but utilities and other industrial users have started to have some success in negotiating to de-link natural gas from oil. In addition, increasing US production of oil has had a noticeable impact on world oil prices, generally benefitting oil and gas users.

Not all utilities will benefit equally. Utilities that have locked in natural gas under high-priced long- term contracts that they cannot re-negotiate are negatively impacted if they cannot pass through their full contracted cost of gas, or if the high costs cause customer dissatisfaction and regulatory backlash. Utilities with large coal fleets or utilities constructing nuclear power plants may also face negative impacts on their regulatory environment, since their customers will benefit less from lower natural gas prices.

Distributed Generation Versus the Central Station Paradigm

The regulation and the financing of electric utilities are based on the premise that the current model under which electricity is generated and distributed to customers will continue essentially unchanged for many decades to come. This model, called the central station paradigm (because electricity is generated in large, centrally located plants and distributed to a large number of customers, who may in fact be hundreds of miles away), has been in place since the early part of the 20th century. The model has worked because the economies of scale inherent to very large power plants has more than offset the cost and inefficiency (through power losses) inherent to maintaining a grid for transmitting and distributing electricity to end users.

Despite rate structures that only allow recovery of invested capital over many decades (up to 60 years), utilities can attract capital because investors assume that rates will continue to be collected for at least that long a period. Regulators and politicians assume that taxes and regulatory charges levied on electricity usage will be paid by a broad swath of residences and businesses and will not materially discourage usage of electricity in a way that would decrease the amount of taxes collected. A corollary assumption is that the number of customers taking electricity from the system during that period will continue to be high enough such that rates will be reasonable and generally more attractive than other alternatives. In the event that consumers were to switch en masse to alternate sources of generating or receiving power (for instance distributed generation), rates for remaining customers would either not cover the utility's costs, or rates would need to be increased so much that more customers may be incentivized to leave the system. This scenario has been experienced in the regulated US copper wire telephone business, where rates have increased quite dramatically for users who have not switched to digital or wireless telephone service. While this scenario continues to be unlikely for the electricity sector, distributed generation, especially from solar panels, has made inroads in certain regions.

Distributed generation is any retail-scale generation, differentiated from self-generation, which generally describes a large industrial plant that builds its own reasonably large conventional power plant to meet its own needs. While some residential property owners that install distributed generation may choose to sever their connection to the local utility, most choose to remain connected, generating power into the grid when it is both feasible and economic to do so, and taking power from the grid at other times. Distributed generation is currently concentrated in roof-top photovoltaic solar panels, which have benefitted from varying levels of tax incentives in different jurisdictions.

Regulatory treatment has also varied, but some rate structures that seek to incentivize distributed renewable energy are decidedly credit negative for utilities, in particular net metering.

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. California is an example of a state employing net solar metering in its rate structure, whereas in New Jersey, which has the second largest residential solar program in the US, utilities buy power at a price closer to their blended cost of generation, which is much lower than the retail rate.

To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

In our current view, the possibility that there will be a widespread movement of electric utility customers to sever themselves from the grid is remote. However, we acknowledge that new technologies, such as the development of commercially viable fuel cells and/or distributed electric storage, could disrupt materially the central station paradigm and the credit quality of the utility sector.

Nuclear Issues

Utilities with nuclear generation face unique safety, regulatory, and operational issues. The nuclear disaster at Fukushima Daiichi had a severely negative credit impact on its owner, Tokyo Electric Power Company, Incorporated, as well as all the nuclear utilities in the country. Japan previously generated about 30% of its power from 50 reactors, but all are currently either idled or shut down, and utilities in the country face materially higher costs of replacement power, a credit negative.

Fukushima Daiichi also had global consequences. Germany's response was to require that all nuclear power plants in the country be shut by 2022. Switzerland opted for a phase-out by 2031. (Most European nuclear plants are owned by companies rated under other the Unregulated Utilities and Power Companies methodology.) Even in countries where the regulatory response was more moderate, increased regulatory scrutiny has raised operating costs, a credit negative, especially in the US, where low natural gas prices have rendered certain primarily smaller nuclear plants uneconomic. Nonetheless, we view robust and independent nuclear safety regulation as a credit-positive for the industry.

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. decided to shut permanently Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was closed permanently in 2013 after its owners, including Southern California Edison Company (A3, RUR-up) and San Diego Gas & Electric Company (A2, RUR-up), decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

Korea Hydro and Nuclear Power Company Limited and its parent, Korea Electric Power Corporation, faced a scandal related to alleged corruption and acceptance of falsified safety documents provided by its parts suppliers for nuclear plants. Korean prosecutors' widening probe into KHNP's use of substandard parts at many of its 23 nuclear power plants caused three plants to be shut down temporarily.

Appendix E: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance in the publication "Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers," including a one notch differential between senior secured and senior unsecured debt.[17] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

Wider notching differentials between debt classes may also be appropriate in speculative grade. Additional insights for speculative grade issuers are provided in the publication "Loss Given Default for Speculative-Grade Companies."[18]

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

In some cases, there is only a one notch differential between US first mortgage bonds and the senior unsecured rating. For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

Securitization

The use of securitization, a financing technique utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been quite pervasive in the past two decades. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses. States that have implemented securitization frameworks include Arkansas, California, Connecticut, Illinois, Louisiana, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, Ohio, Pennsylvania, Texas and West Virginia. In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The utility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the securitized debt is

[17] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

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lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, we make our own assessment of the appropriate credit representation but in most cases follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even though it is technically non- recourse.

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership have dominated the credit profiles of utilities in Asia Pacific (excluding Japan), generally leading to ratings that are a number of notches above the Baseline Credit Assessment. Regulated electric and gas utilities with significant government ownership are rated using this methodology in conjunction with the Joint Default Analysis approach in our methodology for Government-Related Issuers.[19]

Support system for large corporate entities in Japan can provide ratings uplift, with limits

Our ratings for large corporate entities in Japan reflect the unique nature of the country's support system, and they are higher than they would otherwise be if such support were disregarded. This is reflected in the tendency for ratings of Japanese utilities to be higher than their grid implied ratings. However, even for large prominent companies, our ratings consider that support will not be endless and is less likely to be provided when a company has questionable viability rather than being in need of temporary liquidity assistance.

[19] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Appendix F: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards. While we regard PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover the IPP's debt service and are made irrespective of whether the utility calls on the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also typically be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus we analyze them as PPAs.

PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks. In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received). When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet.

However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes.

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default. Costs of a PPA that cannot be recovered in retail rates creates material risk, especially if they also cannot be recovered through market sales of power.

Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and each particular circumstance may be treated differently by Moody's. Factors which determine where on the continuum we treat a particular PPA include the following:

» Risk management: An overarching principle is that PPAs have normally been used by utilities as a risk management tool and we recognize that this is the fundamental reason for their existence. Thus, we will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

» Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly we regard these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, our treatment of PPA obligations will alter accordingly.

» Price considerations: The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity. A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. We will focus particularly on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow.

» Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or take a proportional approach to all of the utility's PPAs.

» Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. We will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.

» Purchase requirements: Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term. If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.

» Default provisions: In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility. In addition, PPAs are not typically considered debt for cross- default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

Each of these factors will be considered by our analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, we may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility.

» Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, we may view the PPA as being most akin to an operating cost. Provided that the accounting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

» Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified otherwise due to limited information.

» Net Present Value: Where the analyst has sufficient information, we may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be our estimate of the cost of capital of the utility.

» Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.

» Mark-to-Market: In situations in which we believe that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may use a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations.

» Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will in some circumstances use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results. If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related sector and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information. Definitions of Moody's most common ratio terms can be found in "Moody's Basic Definitions for Credit Statistics, User's Guide", accessible via this link.

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Key Credit Factors For The Regulated Utilities Industry

*(**Editor's Note:** This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," published Nov. 26, 2008, "Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.)*

1. Standard & Poor's Ratings Services is refining and adapting its methodology and assumptions for its Key Credit Factors: Criteria For Regulated Utilities. We are publishing these criteria in conjunction with our corporate criteria (see "Corporate Methodology, published Nov. 19, 2013). This article relates to our criteria article, "Principles Of Credit Ratings," Feb. 16, 2011.

2. This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," Nov. 26, 2008, "Criteria: Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.

SCOPE OF THE CRITERIA

3. These criteria apply to entities where regulated utilities represent a material part of their business, other than U.S. public power, water, sewer, gas, and electric cooperative utilities that are owned by federal, state, or local governmental bodies or by ratepayers. A regulated utility is defined as a corporation that offers an essential or near-essential infrastructure product, commodity, or service with little or no practical substitute (mainly electricity, water, and gas), a business model that is shielded from competition (naturally, by law, shadow regulation, or by government policies and oversight), and is subject to comprehensive regulation by a regulatory body or implicit oversight of its rates (sometimes referred to as tariffs), service quality, and terms of service. The regulators base the rates that they set on some form of cost recovery, including an economic return on assets, rather than relying on a market price. The regulated operations can range from individual parts of the utility value chain (water, gas, and electricity networks or "grids," electricity generation, retail operations, etc.) to the entire integrated chain, from procurement to sales to the end customer. In some jurisdictions, our view of government support can also affect the final rating outcome, as per our government-related entity criteria (see "General Criteria: Rating Government-Related Entities: Methodology and Assumptions," Dec. 9, 2010).

SUMMARY OF THE CRITERIA

4. Standard & Poor's is updating its criteria for analyzing regulated utilities, applying its corporate criteria. The criteria for evaluating the competitive position of regulated utilities amend and partially supersede the "Competitive Position" section of the corporate criteria when evaluating these entities. The criteria for determining the cash flow leverage

assessment partially supersede the "Cash Flow/Leverage" section of the corporate criteria for the purpose of evaluating regulated utilities. The section on liquidity for regulated utilities partially amends existing criteria. All other sections of the corporate criteria apply to the analysis of regulated utilities.

IMPACT ON OUTSTANDING RATINGS

5. These criteria could affect the issuer credit ratings of about 5% of regulated utilities globally due primarily to the introduction of new financial benchmarks in the corporate criteria. Almost all ratings changes are expected to be no more than one notch, and most are expected to be in an upward direction.

EFFECTIVE DATE AND TRANSITION

6. These criteria are effective immediately on the date of publication.

METHODOLOGY

Part I--Business Risk Analysis

Industry risk

7. Within the framework of Standard & Poor's general criteria for assessing industry risk, we view regulated utilities as a "very low risk" industry (category '1'). We derive this assessment from our view of the segment's low risk ('2') cyclicality and very low risk ('1') competitive risk and growth assessment.

8. In our view, demand for regulated utility services typically exhibits low cyclicality, being a function of such key drivers as employment growth, household formation, and general economic trends. Pricing is non-cyclical, since it is usually based in some form on the cost of providing service.

Cyclicality

9. We assess cyclicality for regulated utilities as low risk ('2'). Utilities typically offer products and services that are essential and not easily replaceable. Based on our analysis of global Compustat data, utilities had an average peak-to-trough (PTT) decline in revenues of about 6% during recessionary periods since 1952. Over the same period, utilities had an average PTT decline in EBITDA margin of about 5% during recessionary periods, with PTT EBITDA margin declines less severe in more recent periods. The PTT drop in profitability that occurred in the most recent recession (2007-2009) was less than the long-term average.

10. With an average drop in revenues of 6% and an average profitability decline of 5%, utilities' cyclicality assessment calibrates to low risk ('2'). We generally consider that the higher the level of profitability cyclicality in an industry, the higher the credit risk of entities operating in that industry. However, the overall effect of cyclicality on an industry's risk profile may be mitigated or exacerbated by an industry's competitive and growth environment.

Competitive risk and growth

11. We view regulated utilities as warranting a very low risk ('1') competitive risk and growth assessment. For competitive risk and growth, we assess four sub-factors as low, medium, or high risk. These sub-factors are:

- Effectiveness of industry barriers to entry;
- Level and trend of industry profit margins;
- Risk of secular change and substitution by products, services, and technologies; and
- Risk in growth trends.

Effectiveness of barriers to entry--low risk

12. Barriers to entry are high. Utilities are normally shielded from direct competition. Utility services are commonly naturally monopolistic (they are not efficiently delivered through competitive channels and often require access to public thoroughfares for distribution), and so regulated utilities are granted an exclusive franchise, license, or concession to serve a specified territory in exchange for accepting an obligation to serve all customers in that area and the regulation of its rates and operations.

Level and trend of industry profit margins--low risk

13. Demand is sometimes and in some places subject to a moderate degree of seasonality, and weather conditions can significantly affect sales levels at times over the short term. However, those factors even out over time, and there is little pressure on margins if a utility can pass higher costs along to customers via higher rates.

Risk of secular change and substitution of products, services, and technologies--low risk

14. Utility products and services are not overly subject to substitution. Where substitution is possible, as in the case of natural gas, consumer behavior is usually stable and there is not a lot of switching to other fuels. Where switching does occur, cost allocation and rate design practices in the regulatory process can often mitigate this risk so that utility profitability is relatively indifferent to the substitutions.

Risk in industry growth trends--low risk

15. As noted above, regulated utilities are not highly cyclical. However, the industry is often well established and, in our view, long-range demographic trends support steady demand for essential utility services over the long term. As a result, we would expect revenue growth to generally match GDP when economic growth is positive.

B. Country risk

16. In assessing "country risk" for a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

C. Competitive position

17. In the corporate criteria, competitive position is assessed as ('1') excellent, ('2') strong, ('3') satisfactory, ('4') fair, ('5') weak, or ('6') vulnerable.

18. The analysis of competitive position includes a review of:

- Competitive advantage,
- Scale, scope, and diversity,
- Operating efficiency, and
- Profitability.

19. In the corporate criteria we assess the strength of each of the first three components. Each component is assessed as either: (1) strong, (2) strong/adequate, (3) adequate, (4) adequate/weak, or (5) weak. After assessing these components, we determine the preliminary competitive position assessment by ascribing a specific weight to each component. The applicable weightings will depend on the company's Competitive Position Group Profile. The group profile for regulated utilities is "National Industries & Utilities," with a weighting of the three components as follows: competitive advantage (60%), scale, scope, and diversity (20%), and operating efficiency (20%). Profitability is assessed by combining two sub-components: level of profitability and the volatility of profitability.

20. "Competitive advantage" cannot be measured with the same sub-factors as competitive firms because utilities are not primarily subject to influence of market forces. Therefore, these criteria supersede the "competitive advantage" section of the corporate criteria. We analyze instead a utility's "regulatory advantage" (section 1 below).

Assessing regulatory advantage

21. The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance.

22. We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. Our view of these four pillars is the foundation of a utility's regulatory support. We then assess the utility's business strategy, in particular its regulatory strategy and its ability to manage the tariff-setting process, to arrive at a final regulatory advantage assessment.

23. When assessing regulatory advantage, we first consider four pillars and sub-factors that we believe are key for a utility to recover all its costs, on time and in full, and earn a return on its capital employed:

24. Regulatory stability:

- Transparency of the key components of the rate setting and how these are assessed
- Predictability that lowers uncertainty for the utility and its stakeholders
- Consistency in the regulatory framework over time

25. Tariff-setting procedures and design:

- Recoverability of all operating and capital costs in full
- Balance of the interests and concerns of all stakeholders affected
- Incentives that are achievable and contained

26. Financial stability:

- Timeliness of cost recovery to avoid cash flow volatility
- Flexibility to allow for recovery of unexpected costs if they arise
- Attractiveness of the framework to attract long-term capital
- Capital support during construction to alleviate funding and cash flow pressure during periods of heavy investments

27. Regulatory independence and insulation:

- Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers
- Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event

28. We have summarized the key characteristics of the assessments for regulatory advantage in table 1.

Table 1

Preliminary Regulatory Advantage Assessment

Qualifier	What it means	Guidance
Strong	The utility has a major regulatory advantage due to one or a combination of factors that support cost recovery and a return on capital combined with lower than average volatility of earnings and cash flows.	The utility operates in a regulatory climate that is transparent, predictable, and consistent from a credit perspective.
	There are strong prospects that the utility can sustain this advantage over the long term.	The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base).
	This should enable the utility to withstand economic downturns and political risks better than other utilities.	The tariff set may include a pass-through mechanism for major expenses such as commodity costs, or a higher return on new assets, effectively shielding the utility from volume and input cost risks.
		Any incentives in the regulatory scheme are contained and symmetrical.
		The tariff set includes mechanisms allowing for a tariff adjustment for the timely recovery of volatile or unexpected operating and capital costs.
		There is a track record of earning a stable, compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.
		There is support of cash flows during construction of large projects, and pre-approval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs.
		The utility operates under a regulatory system that is sufficiently insulated from political intervention to efficiently protect the utility’s credit risk profile even during stressful events.
Adequate	The utility has some regulatory advantages and protection, but not to the extent that it leads to a superior business model or durable benefit.	It operates in a regulatory environment that is less transparent, less predictable, and less consistent from a credit perspective.
	The utility has some but not all drivers of well-managed regulatory risk. Certain regulatory factors support the business’s long-term stability and viability but could result in periods of below-average levels of profitability and greater profit volatility. However, overall these regulatory drivers are partially offset by the utility’s disadvantages or lack of sustainability of other factors.	The utility is exposed to delays or is not, with sufficient certainty, able to recover all of its fixed and variable operating costs, investments. and capital costs (depreciation and a reasonable return on the asset base) within a reasonable time.
		Incentive ratemaking practices are asymmetrical and material, and could detract from credit quality.
		The utility is exposed to the risk that it doesn’t recover unexpected or volatile costs in a full or less than timely manner due to lack of flexible reopeners or annual revenue adjustments.
		There is an uneven track record of earning a compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.

Table 1

Preliminary Regulatory Advantage Assessment (cont.)		
		There is little or no support of cash flows during construction, and investment decisions on large projects (and therefore the risk of subsequent disallowances of capital costs) rest mostly with the utility.
		The utility operates under a regulatory system that is not sufficiently insulated from political intervention and is sometimes subject to overt political influence.
Weak	The utility suffers from a complete breakdown of regulatory protection that places the utility at a significant disadvantage.	The utility operates in an opaque regulatory climate that lacks transparency, predictability, and consistency.
	The utility's regulatory risk is such that the long-term cost recovery and investment return is highly uncertain and materially delayed, leading to volatile or weak cash flows. There is the potential for material stranded assets with no prospect of recovery.	The utility cannot fully and/or timely recover its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base).
		There is a track record of earning minimal or negative rates of return in cash through various economic and political cycles and a projected inability to improve that record sustainably.
		The utility must make significant capital commitments with no solid legal basis for the full recovery of capital costs.
		Ratemaking practices actively harm credit quality.
		The utility is regularly subject to overt political influence.

29. After determining the preliminary regulatory advantage assessment, we then assess the utility's business strategy. Most importantly, this factor addresses the effectiveness of a utility's management of the regulatory risk in the jurisdiction(s) where it operates. In certain jurisdictions, a utility's regulatory strategy and its ability to manage the tariff-setting process effectively so that revenues change with costs can be a compelling regulatory risk factor. A utility's approach and strategies surrounding regulatory matters can create a durable "competitive advantage" that differentiates it from peers, especially if the risk of political intervention is high. The assessment of a utility's business strategy is informed by historical performance and its forward-looking business objectives. We evaluate these objectives in the context of industry dynamics and the regulatory climate in which the utility operates, as evaluated through the factors cited in paragraphs 24-27.

30. We modify the preliminary regulatory advantage assessment to reflect this influence positively or negatively. Where business strategy has limited effect relative to peers, we view the implications as neutral and make no adjustment. A positive assessment improves the preliminary regulatory advantage assessment by one category and indicates that management's business strategy is expected to bolster its regulatory advantage through favorable commission rulings beyond what is typical for a utility in that jurisdiction. Conversely, where management's strategy or businesses decisions result in adverse regulatory outcomes relative to peers, such as failure to achieve typical cost recovery or allowed returns, we adjust the preliminary regulatory advantage assessment one category worse. In extreme cases of poor strategic execution, the preliminary regulatory advantage assessment is adjusted by two categories worse (when possible; see table 2) to reflect management decisions that are likely to result in a significantly adverse regulatory outcome relative to peers.

Table 2

Determining The Final Regulatory Advantage Assessment

	--Strategy modifier--			
Preliminary regulatory advantage score	**Positive**	**Neutral**	**Negative**	**Very negative**
Strong	Strong	Strong	Strong/Adequate	Adequate
Strong/Adequate	Strong	Strong/Adequate	Adequate	Adequate/Weak
Adequate	Strong/Adequate	Adequate	Adequate/Weak	Weak
Adequate/Weak	Adequate	Adequate/Weak	Weak	Weak
Weak	Adequate/Weak	Weak	Weak	Weak

Scale, scope, and diversity

31. We consider the key factors for this component of competitive position to be primarily operational scale and diversity of the geographic, economic, and regulatory foot prints. We focus on a utility's markets, service territories, and diversity and the extent that these attributes can contribute to cash flow stability while dampening the effect of economic and market threats.

32. A utility that warrants a Strong or Strong/Adequate assessment has scale, scope, and diversity that support the stability of its revenues and profits by limiting its vulnerability to most combinations of adverse factors, events, or trends. The utility's significant advantages enable it to withstand economic, regional, competitive, and technological threats better than its peers. It typically is characterized by a combination of the following factors:

- A large and diverse customer base with no meaningful customer concentration risk, where residential and small to medium commercial customers typically provide most operating income.
- The utility's range of service territories and regulatory jurisdictions is better than others in the sector.
- Exposure to multiple regulatory authorities where we assess preliminary regulatory advantage to be at least Adequate. In the case of exposure to a single regulatory regime, the regulatory advantage assessment is either Strong or Strong/Adequate.
- No meaningful exposure to a single or few assets or suppliers that could hurt operations or could not easily be replaced.

33. A utility that warrants a Weak or Weak/Adequate assessment lacks scale, scope, and diversity such that it compromises the stability and sustainability of its revenues and profits. The utility's vulnerability to, or reliance on, various elements of this sub-factor is such that it is less likely than its peers to withstand economic, competitive, or technological threats. It typically is characterized by a combination of the following factors:

- A small customer base, especially if burdened by customer and/or industry concentration combined with little economic diversity and average to below-average economic prospects;
- Exposure to a single service territory and a regulatory authority with a preliminary regulatory advantage assessment of Adequate or Adequate/Weak; or
- Dependence on a single supplier or asset that cannot easily be replaced and which hurts the utility's operations.

34. We generally believe a larger service territory with a diverse customer base and average to above-average economic growth prospects provides a utility with cushion and flexibility in the recovery of operating costs and ongoing investment (including replacement and growth capital spending), as well as lessening the effect of external shocks (i.e.,

extreme local weather) since the incremental effect on each customer declines as the scale increases.

35. We consider residential and small commercial customers as having more stable usage patterns and being less exposed to periodic economic weakness, even after accounting for some weather-driven usage variability. Significant industrial exposure along with a local economy that largely depends on one or few cyclical industries potentially contributes to the cyclicality of a utility's load and financial performance, magnifying the effect of an economic downturn.

36. A utility's cash flow generation and stability can benefit from operating in multiple geographic regions that exhibit average to better than average levels of wealth, employment, and growth that underpin the local economy and support long-term growth. Where operations are in a single geographic region, the risk can be ameliorated if the region is sufficiently large, demonstrates economic diversity, and has at least average demographic characteristics.

37. The detriment of operating in a single large geographic area is subject to the strength of regulatory assessment. Where a utility operates in a single large geographic area and has a strong regulatory assessment, the benefit of diversity can be incremental.

Operating efficiency

38. We consider the key factors for this component of competitive position to be:

- Compliance with the terms of its operating license, including safety, reliability, and environmental standards;
- Cost management; and
- Capital spending: scale, scope, and management.

39. Relative to peers, we analyze how successful a utility management achieves the above factors within the levels allowed by the regulator in a manner that promotes cash flow stability. We consider how management of these factors reduces the prospect of penalties for noncompliance, operating costs being greater than allowed, and capital projects running over budget and time, which could hurt full cost recovery.

40. The relative importance of the above three factors, particularly cost and capital spending management, is determined by the type of regulation under which the utility operates. Utilities operating under robust "cost plus" regimes tend to be more insulated given the high degree of confidence costs will invariably be passed through to customers. Utilities operating under incentive-based regimes are likely to be more sensitive to achieving regulatory standards. This is particularly so in the regulatory regimes that involve active consultation between regulator and utility and market testing as opposed to just handing down an outcome on a more arbitrary basis.

41. In some jurisdictions, the absolute performance standards are less relevant than how the utility performs against the regulator's performance benchmarks. It is this performance that will drive any penalties or incentive payments and can be a determinant of the utilities' credibility on operating and asset-management plans with its regulator.

42. Therefore, we consider that utilities that perform these functions well are more likely to consistently achieve determinations that maximize the likelihood of cost recovery and full inclusion of capital spending in their asset bases. Where regulatory resets are more at the discretion of the utility, effective cost management, including of labor, may allow for more control over the timing and magnitude of rate filings to maximize the chances of a constructive outcome such as full operational and capital cost recovery while protecting against reputational risks.

43. A regulated utility that warrants a Strong or Strong/Adequate assessment for operating efficiency relative to peers generates revenues and profits through minimizing costs, increasing efficiencies, and asset utilization. It typically is characterized by a combination of the following:

- High safety record;
- Service reliability is strong, with a track record of meeting operating performance requirements of stakeholders, including those of regulators. Moreover, the utility's asset profile (including age and technology) is such that we have confidence that it could sustain favorable performance against targets;
- Where applicable, the utility is well-placed to meet current and potential future environmental standards;
- Management maintains very good cost control. Utilities with the highest assessment for operating efficiency have shown an ability to manage both their fixed and variable costs in line with regulatory expectations (including labor and working capital management being in line with regulator's allowed collection cycles); or
- There is a history of a high level of project management execution in capital spending programs, including large one-time projects, almost invariably within regulatory allowances for timing and budget.

44. A regulated utility that warrants an Adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that support profit sustainability combined with average volatility. Its cost structure is similar to its peers. It typically is characterized by a combination of the following factors:

- High safety performance;
- Service reliability is satisfactory with a track record of mostly meeting operating performance requirements of stakeholders, including those of regulators. We have confidence that a favorable performance against targets can be mostly sustained;
- Where applicable, the utility may be challenged to comply with current and future environmental standards that could increase in the medium term;
- Management maintains adequate cost control. Utilities that we assess as having adequate operating efficiency mostly manage their fixed and variable costs in line with regulatory expectations (including labor and working capital management being mostly in line with regulator's allowed collection cycles); or
- There is a history of adequate project management skills in capital spending programs within regulatory allowances for timing and budget.

45. A regulated utility that warrants a weak or weak/adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that fail to support profit sustainability combined with below-average volatility. Its cost structure is worse than its peers. It typically is characterized by a combination of the following:

- Poor safety performance;
- Service reliability has been sporadic or non-existent with a track record of not meeting operating performance requirements of stakeholders, including those of regulators. We do not believe the utility can consistently meet performance targets without additional capital spending;
- Where applicable, the utility is challenged to comply with current environmental standards and is highly vulnerable to more onerous standards;
- Management typically exceeds operating costs authorized by regulators;
- Inconsistent project management skills as evidenced by cost overruns and delays including for maintenance capital spending; or
- The capital spending program is large and complex and falls into the weak or weak/adequate assessment, even if

operating efficiency is generally otherwise considered adequate.

Profitability

46. A utility with above-average profitability would, relative to its peers, generally earn a rate of return at or above what regulators authorize and have minimal exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations. Conversely, a utility with below-average profitability would generally earn rates of return well below the authorized return relative to its peers or have significant exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations.

47. The profitability assessment consists of "level of profitability" and "volatility of profitability."

Level of profitability

48. Key measures of general profitability for regulated utilities commonly include ratios, which we compare both with those of peers and those of companies in other industries to reflect different countries' regulatory frameworks and business environments:

- EBITDA margin,
- Return on capital (ROC), and
- Return on equity (ROE).

49. In many cases, EBITDA as a percentage of sales (i.e., EBITDA margin) is a key indicator of profitability. This is because the book value of capital does not always reflect true earning potential, for example when governments privatize or restructure incumbent state-owned utilities. Regulatory capital values can vary with those of reported capital because regulatory capital values are not inflation-indexed and could be subject to different assumptions concerning depreciation. In general, a country's inflation rate or required rate of return on equity investment is closely linked to a utility company's profitability. We do not adjust our analysis for these factors, because we can make our assessment through a peer comparison.

50. For regulated utilities subject to full cost-of-service regulation and return-on-investment requirements, we normally measure profitability using ROE, the ratio of net income available for common stockholders to average common equity. When setting rates, the regulator ultimately bases its decision on an authorized ROE. However, different factors such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of-service-based utilities centers on the utility's ability to consistently earn the authorized ROE.

51. We will use return on capital when pass-through costs distort profit margins--for instance congestion revenues or collection of third-party revenues. This is also the case when the utility uses accelerated depreciation of assets, which in our view might not be sustainable in the long run.

Volatility of profitability

52. We may observe a clear difference between the volatility of actual profitability and the volatility of underlying regulatory profitability. In these cases, we could use the regulatory accounts as a proxy to judge the stability of earnings.

53. We use actual returns to calculate the standard error of regression for regulated utility issuers (only if there are at least

seven years of historical annual data to ensure meaningful results). If we believe recurring mergers and acquisitions or currency fluctuations affect the results, we may make adjustments.

Part II--Financial Risk Analysis

D. Accounting

54. Our analysis of a company's financial statements begins with a review of the accounting to determine whether the statements accurately measure a company's performance and position relative to its peers and the larger universe of corporate entities. To allow for globally consistent and comparable financial analyses, our rating analysis may include quantitative adjustments to a company's reported results. These adjustments also align a company's reported figures with our view of underlying economic conditions and give us a more accurate portrayal of a company's ongoing business. We discuss adjustments that pertain broadly to all corporate sectors, including this sector, in "Corporate Methodology: Ratios And Adjustments." Accounting characteristics and analytical adjustments unique to this sector are discussed below.

Accounting characteristics

55. Some important accounting practices for utilities include:

- For integrated electric utilities that meet native load obligations in part with third-party power contracts, we use our purchased power methodology to adjust measures for the debt-like obligation such contracts represent (see below).
- Due to distortions in leverage measures from the substantial seasonal working-capital requirements of natural gas distribution utilities, we adjust inventory and debt balances by netting the value of inventory against outstanding short-term borrowings. This adjustment provides an accurate view of the company's balance sheet by reducing seasonal debt balances when we see a very high certainty of near-term cost recovery (see below).
- We deconsolidate securitized debt (and associated revenues and expenses) that has been accorded specialized recovery provisions (see below).
- For water utilities that report under U.K. GAAP, we adjust ratios for infrastructure renewals accounting, which permits water companies to capitalize the maintenance spending on their infrastructure assets (see below). The adjustments aim to make those water companies that report under U.K. GAAP more comparable to those that report under accounting regimes that do not permit infrastructure renewals accounting.

56. In the U.S. and selectively in other regions, utilities employ "regulatory accounting," which permits a rate-regulated company to defer some revenues and expenses to match the timing of the recognition of those items in rates as determined by regulators. A utility subject to regulatory accounting will therefore have assets and liabilities on its books that an unregulated corporation, or even regulated utilities in many other global regions, cannot record. We do not adjust GAAP earnings or balance-sheet figures to remove the effects of regulatory accounting. However, as more countries adopt International Financial Reporting Standards (IFRS), the use of regulatory accounting will become more scarce. IFRS does not currently provide for any recognition of the effects of rate regulation for financial reporting purposes, but it is considering the use of regulatory accounting. We do not anticipate altering our fundamental financial analysis of utilities because of the use or non-use of regulatory accounting. We will continue to analyze the effects of regulatory actions on a utility's financial health.

Purchased power adjustment

57. We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates. (See "Standard & Poor's Methodology For Imputing Debt for U.S. Utilities' Power Purchase Agreements," May 7, 2007, for more background and information on the adjustment.)

58. We calculate the present value (PV) of the future stream of capacity payments under the contracts as reported in the financial statement footnotes or as supplied directly by the company. The discount rate used is the same as the one used in the operating lease adjustment, i.e., 7%. For U.S. companies, notes to the financial statements enumerate capacity payments for the coming five years, and a thereafter period. Company forecasts show the detail underlying the thereafter amount, or we divide the amount reported as thereafter by the average of the capacity payments in the preceding five years to get an approximation of annual payments after year five.

59. We also consider new contracts that will start during the forecast period. The company provides us the information regarding these contracts. If these contracts represent extensions of existing PPAs, they are immediately included in the PV calculation. However, a contract sometimes is executed in anticipation of incremental future needs, so the energy will not flow until some later period and there are no interim payments. In these instances, we incorporate that contract in our projections, starting in the year that energy deliveries begin under the contract. The projected PPA debt is included in projected ratios as a current rating factor, even though it is not included in the current-year ratio calculations.

60. The PV is adjusted to reflect regulatory or legislative cost-recovery mechanisms when present. Where there is no explicit regulatory or legislative recovery of PPA costs, as in most European countries, the PV may be adjusted for other mitigating factors that reduce the risk of the PPAs to the utility, such as a limited economic importance of the PPAs to the utility's overall portfolio.The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor.

61. Risk factors based on regulatory or legislative cost recovery typically range between 0% and 50%, but can be as high as 100%. A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity. These utilities are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties that act as intermediaries between retail customers and electricity suppliers. We employ a 50% risk factor in cases where regulators use base rates for the recovery of the fixed PPA costs. If a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed. In certain jurisdictions, true-up mechanisms are more favorable and frequent than the review of base rates, but still do not amount to pure fuel adjustment clauses. Such mechanisms may be triggered by financial thresholds or passage of prescribed periods of time. In these instances, a risk factor between 25% and 50% is

employed. Specialized, legislatively created cost-recovery mechanisms may lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors. We also exclude short-term PPAs where they serve merely as gap fillers, pending either the construction of new capacity or the execution of long-term PPAs.

62. Where there is no explicit regulatory or legislative recovery of PPA costs, the risk factor is generally 100%. We may use a lower risk factor if mitigating factors reduce the risk of the PPAs on the utility. Mitigating factors include a long position in owned generation capacity relative to the utility's customer supply needs that limits the importance of the PPAs to the utility or the ability to resell power in a highly liquid market at minimal loss. A utility with surplus owned generation capacity would be assigned a risk factor of less than 100%, generally 50% or lower, because we would assess its reliance on PPAs as limited. For fixed capacity payments under PPAs related to renewable power, we use a risk factor of less than 100% if the utility benefits from government subsidies. The risk factor reflects the degree of regulatory recovery through the government subsidy.

63. Given the long-term mandate of electric utilities to meet their customers' demand for electricity, and also to enable comparison of companies with different contract lengths, we may use an evergreening methodology. Evergreen treatment extends the duration of short- and intermediate-term contracts to a common length of about 12 years. To quantify the cost of the extended capacity, we use empirical data regarding the cost of developing new peaking capacity, incorporating regional differences. The cost of new capacity is translated into a dollars-per-kilowatt-year figure using a proxy weighted-average cost of capital and a proxy capital recovery period.

64. Some PPAs are treated as operating leases for accounting purposes--based on the tenor of the PPA or the residual value of the asset on the PPA's expiration. We accord PPA treatment to those obligations, in lieu of lease treatment; rather, the PV of the stream of capacity payments associated with these PPAs is reduced to reflect the applicable risk factor.

65. Long-term transmission contracts can also substitute for new generation, and, accordingly, may fall under our PPA methodology. We sometimes view these types of transmission arrangements as extensions of the power plants to which they are connected or the markets that they serve. Accordingly, we impute debt for the fixed costs associated with such transmission contracts.

66. Adjustment procedures:

- Data requirements:
- Future capacity payments obtained from the financial statement footnotes or from management.
- Discount rate: 7%.
- Analytically determined risk factor.

- Calculations:
- Balance sheet debt is increased by the PV of the stream of capacity payments multiplied by the risk factor.
- Equity is not adjusted because the recharacterization of the PPA implies the creation of an asset, which offsets the debt.
- Property, plant, and equipment and total assets are increased for the implied creation of an asset equivalent to the

debt.

- An implied interest expense for the imputed debt is determined by multiplying the discount rate by the amount of imputed debt (or average PPA imputed debt, if there is fluctuation of the level), and is added to interest expense.
- We impute a depreciation component to PPAs. The depreciation component is determined by multiplying the relevant year's capacity payment by the risk factor and then subtracting the implied PPA-related interest for that year. Accordingly, the impact of PPAs on cash flow measures is tempered.
- The cost amount attributed to depreciation is reclassified as capital spending, thereby increasing operating cash flow and funds from operations (FFO).
- Some PPA contracts refer only to a single, all-in energy price. We identify an implied capacity price within such an all-in energy price, to determine an implied capacity payment associated with the PPA. This implied capacity payment is expressed in dollars per kilowatt-year, multiplied by the number of kilowatts under contract. (In cases that exhibit markedly different capacity factors, such as wind power, the relation of capacity payment to the all-in charge is adjusted accordingly.)
- Operating income before depreciation and amortization (D&A) and EBITDA are increased for the imputed interest expense and imputed depreciation component, the total of which equals the entire amount paid for PPA (subject to the risk factor).
- Operating income after D&A and EBIT are increased for interest expense.

Natural gas inventory adjustment

67. In jurisdictions where a pass-through mechanism is used to recover purchased natural gas costs of gas distribution utilities within one year, we adjust for seasonal changes in short-debt tied to building inventories of natural gas in non-peak periods for later use to meet peak loads in peak months. Such short-term debt is not considered to be part of the utility's permanent capital. Any history of non-trivial disallowances of purchased gas costs would preclude the use of this adjustment. The accounting of natural gas inventories and associated short-term debt used to finance the purchases must be segregated from other trading activities.

68. Adjustment procedures:

- Data requirements:
- Short-term debt amount associated with seasonal purchases of natural gas devoted to meeting peak-load needs of captive utility customers (obtained from the company).

- Calculations:
- Adjustment to debt--we subtract the identified short-term debt from total debt.

Securitized debt adjustment

69. For regulated utilities, we deconsolidate debt (and associated revenues and expenses) that the utility issues as part of a securitization of costs that have been segregated for specialized recovery by the government entity constitutionally authorized to mandate such recovery if the securitization structure contains a number of protective features:

- An irrevocable, non-bypassable charge and an absolute transfer and first-priority security interest in transition property;
- Periodic adjustments ("true-up") of the charge to remediate over- or under-collections compared with the debt service obligation. The true-up ensures collections match debt service over time and do not diverge significantly in the short run; and,
- Reserve accounts to cover any temporary short-term shortfall in collections.

70. Full cost recovery is in most instances mandated by statute. Examples of securitized costs include "stranded costs" (above-market utility costs that are deemed unrecoverable when a transition from regulation to competition occurs) and unusually large restoration costs following a major weather event such as a hurricane. If the defined features are present, the securitization effectively makes all consumers responsible for principal and interest payments, and the utility is simply a pass-through entity for servicing the debt. We therefore remove the debt and related revenues and expenses from our measures. (See "Securitizing Stranded Costs," Jan. 18, 2001, for background information.)

71. Adjustment procedures:

- Data requirements:
- Amount of securitized debt on the utility's balance sheet at period end;
- Interest expense related to securitized debt for the period; and
- Principal payments on securitized debt during the period.

- Calculations:
- Adjustment to debt: We subtract the securitized debt from total debt.
- Adjustment to revenues: We reduce revenue allocated to securitized debt principal and interest. The adjustment is the sum of interest and principal payments made during the year.
- Adjustment to operating income after depreciation and amortization (D&A) and EBIT: We reduce D&A related to the securitized debt, which is assumed to equal the principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.
- Adjustment to interest expense: We remove the interest expense of the securitized debt from total interest expense.

- Operating cash flows:
- We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

Infrastructure renewals expenditure

72. In England and Wales, water utilities can report under either IFRS or U.K. GAAP. Those that report under U.K. GAAP are allowed to adopt infrastructure renewals accounting, which enables the companies to capitalize the maintenance spending on their underground assets, called infrastructure renewals expenditure (IRE). Under IFRS, infrastructure renewals accounting is not permitted and maintenance expenditure is charged to earnings in the year incurred. This difference typically results in lower adjusted operating cash flows for those companies that report maintenance expenditure as an operating cash flow under IFRS, than for those that report it as capital expenditure under U.K. GAAP. We therefore make financial adjustments to amounts reported by water issuers that apply U.K. GAAP, with the aim of making ratios more comparable with those issuers that report under IFRS and U.S. GAAP. For example, we deduct IRE from EBITDA and FFO.

73. IRE does not always consist entirely of maintenance expenditure that would be expensed under IFRS. A portion of IRE can relate to costs that would be eligible for capitalization as they meet the recognition criteria for a new fixed asset set out in International Accounting Standard 16 that addresses property, plant, and equipment. In such cases, we may refine our adjustment to U.K. GAAP companies so that we only deduct from FFO the portion of IRE that would not be capitalized under IFRS. However, the information to make such a refinement would need to be of high quality, reliable, and ideally independently verified by a third party, such as the company's auditor. In the absence of this, we assume

that the entire amount of IRE would have been expensed under IFRS and we accordingly deduct the full expenditure from FFO.

74. Adjustment procedures:

- Data requirements:
- U.K. GAAP accounts typically provide little information on the portion of capital spending that relates to renewals accounting, or the related depreciation, which is referred to as the infrastructure renewals charge. The information we use for our adjustments is, however, found in the regulatory cost accounts submitted annually by the water companies to the Water Services Regulation Authority, which regulates all water companies in England and Wales.

- Calculations:
- EBITDA: Reduced by the value of IRE that was capitalized in the period.
- EBIT: Adjusted for the difference between the adjustment to EBITDA and the reduction in the depreciation expense, depending on the degree to which the actual cash spending in the current year matches the planned spending over the five-year regulatory review period.
- Cash flow from operations and FFO: Reduced by the value of IRE that was capitalized in the period.
- Capital spending: Reduced by the value of infrastructure renewals spending that we reclassify to cash flow from operations.
- Free operating cash flow: No impact, as the reduction in operating cash flows is exactly offset by the reduction in capital spending.

E. Cash flow/leverage analysis

75. In assessing the cash flow adequacy of a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology"). We assess cash flow/leverage on a six-point scale ranging from ('1') minimal to ('6') highly leveraged. These scores are determined by aggregating the assessments of a range of credit ratios, predominantly cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations.

76. The corporate methodology provides benchmark ranges for various cash flow ratios we associate with different cash flow leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

77. If an industry's volatility levels are low, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment are less stringent, although the width of the ratio range is narrower. Conversely, if an industry has standard levels of volatility, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment may be elevated, but with a wider range of values.

78. We apply the "low-volatility" table to regulated utilities that qualify under the corporate criteria and with all of the following characteristics:

- A vast majority of operating cash flows come from regulated operations that are predominantly at the low end of the utility risk spectrum (e.g., a "network," or distribution/transmission business unexposed to commodity risk and with very low operating risk);
- A "strong" regulatory advantage assessment;

- An established track record of normally stable credit measures that is expected to continue;
- A demonstrated long-term track record of low funding costs (credit spread) for long-term debt that is expected to continue; and
- Non-utility activities that are in a separate part of the group (as defined in our group rating methodology) that we consider to have "nonstrategic" group status and are not deemed high risk and/or volatile.

79. We apply the "medial volatility" table to companies that do not qualify under paragraph 78 with:

- A majority of operating cash flows from regulated activities with an "adequate" or better regulatory advantage assessment; or
- About one-third or more of consolidated operating cash flow comes from regulated utility activities with a "strong" regulatory advantage and where the average of its remaining activities have a competitive position assessment of '3' or better.

80. We apply the "standard-volatility" table to companies that do not qualify under paragraph 79 and with either:

- About one-third or less of its operating cash flow comes from regulated utility activities, regardless of its regulatory advantage assessment; or
- A regulatory advantage assessment of "adequate/weak" or "weak."

Part III--Rating Modifiers

F. Diversification/portfolio effect

81. In assessing the diversification/portfolio effect on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

G. Capital structure

82. In assessing the quality of the capital structure of a regulated utility, we use the same methodology as with other corporate issuers (see "Corporate Methodology").

H. Liquidity

83. In assessing a utility's liquidity/short-term factors, our analysis is consistent with the methodology that applies to corporate issuers (See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," Nov. 19, 2013) except for the standards for "adequate" liquidity set out in paragraph 84 below.

84. The relative certainty of financial performance by utilities operating under relatively predictable regulatory monopoly frameworks make these utilities attractive to investors even in times of economic stress and market turbulence compared to conventional industrials. For this reason, utilities with business risk profiles of at least "satisfactory" meet our definition of "adequate" liquidity based on a slightly lower ratio of sources to uses of funds of 1.1x compared with the standard 1.2x. Also, recognizing the cash flow stability of regulated utilities we allow more discretion when calculating covenant headroom. We consider that utilities have adequate liquidity if they generate positive sources over uses, even if forecast EBITDA declines by 10% (compared with the 15% benchmark for corporate issuers) before covenants are breached.

I. Financial policy

85. In assessing financial policy on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

J. Management and governance

86. In assessing management and governance on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

K. Comparable ratings analysis

87. In assessing the comparable ratings analysis on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

Appendix--Frequently Asked Questions

Does Standard & Poor's expect that the business strategy modifier to the preliminary regulatory advantage will be used extensively?

88. Globally, we expect management's influence will be neutral in most jurisdictions. Where the regulatory assessment is "strong," it is less likely that a negative business strategy modifier would be used due to the nature of the regulatory regime that led to the "strong" assessment in the first place. Utilities in "adequate/weak" and "weak" regulatory regimes are challenged to outperform due to the uncertainty of such regulatory regimes. For a positive use of the business strategy modifier, there would need to be a track record of the utility consistently outperforming the parameters laid down under a regulatory regime, and we would need to believe this could be sustained. The business strategy modifier is most likely to be used when the preliminary regulatory advantage assessment is "strong/adequate" because the starting point in the assessment is reasonably supportive, and a utility has shown it manages regulatory risk better or worse than its peers in that regulatory environment and we expect that advantage or disadvantage will persist. An example would be a utility that can consistently earn or exceed its authorized return in a jurisdiction where most other utilities struggle to do so. If a utility is treated differently by a regulator due to perceptions of poor customer service or reliability and the "operating efficiency" component of the competitive position assessment does not fully capture the effect on the business risk profile, a negative business strategy modifier could be used to accurately incorporate it into our analysis. We expect very few utilities will be assigned a "very negative" business strategy modifier.

Does a relatively strong or poor relationship between the utility and its regulator compared with its peers in the same jurisdiction necessarily result in a positive or negative adjustment to the preliminary regulatory advantage assessment?

89. No. The business strategy modifier is used to differentiate a company's regulatory advantage within a jurisdiction where we believe management's business strategy has and will positively or negatively affect regulatory outcomes beyond what is typical for other utilities in that jurisdiction. For instance, in a regulatory jurisdiction where allowed returns are negotiated rather than set by formula, a utility that is consistently authorized higher returns (and is able to earn that return) could warrant a positive adjustment. A management team that cannot negotiate an approved capital spending program to improve its operating performance could be assessed negatively if its performance lags behind peers in the same regulatory jurisdiction.

What is your definition of regulatory jurisdiction?

90. A regulatory jurisdiction is defined as the area over which the regulator has oversight and could include single or multiple subsectors (water, gas, and power). A geographic region may have several regulatory jurisdictions. For example, the Office of Gas and Electricity Markets and the Water Services Regulation Authority in the U.K. are considered separate regulatory jurisdictions. In Ontario, Canada, the Ontario Energy Board represents a single jurisdiction with regulatory oversight for power and gas. Also, in Australia, the Australian Energy Regulator would be considered a single jurisdiction given that it is responsible for both electricity and gas transmission and distribution networks in the entire country, with the exception of Western Australia.

Are there examples of different preliminary regulatory advantage assessments in the same country or jurisdiction?

91. Yes. In Israel we rate a regulated integrated power utility and a regulated gas transmission system operator (TSO). The power utility's relationship with its regulator is extremely poor in our view, which led to significant cash flow volatility in a stress scenario (when terrorists blew up the gas pipeline that was then Israel's main source of natural gas, the utility was unable to negotiate compensation for expensive alternatives in its regulated tariffs). We view the gas TSO's relationship with its regulator as very supportive and stable. Because we already reflected this in very different preliminary regulatory advantage assessments, we did not modify the preliminary assessments because the two regulatory environments in Israel differ and were not the result of the companies' respective business strategies.

How is regulatory advantage assessed for utilities that are a natural monopoly but are not regulated by a regulator or a specific regulatory framework, and do you use the regulatory modifier if they achieve favorable treatment from the government as an owner?

92. The four regulatory pillars remain the same. On regulatory stability we look at the stability of the setup, with more emphasis on the historical track record and our expectations regarding future changes. In tariff-setting procedures and design we look at the utility's ability to fully recover operating costs, investments requirements, and debt-service obligations. In financial stability we look at the degree of flexibility in tariffs to counter volume risk or commodity risk. The flexibility can also relate to the level of indirect competition the utility faces. For example, while Nordic district heating companies operate under a natural monopoly, their tariff flexibility is partly restricted by customers' option to change to a different heating source if tariffs are significantly increased. Regulatory independence and insulation is mainly based on the perceived risk of political intervention to change the setup that could affect the utility's credit profile. Although political intervention tends to be mostly negative, in certain cases political ties due to state ownership might positively influence tariff determination. We believe that the four pillars effectively capture the benefits from the close relationship between the utility and the state as an owner; therefore, we do not foresee the use of the regulatory modifier.

In table 1, when describing a "strong" regulatory advantage assessment, you mention that there is support of cash flows during construction of large projects, and preapproval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs. Would this preclude a "strong" regulatory advantage assessment in jurisdictions where those practices are absent?

93. No. The table is guidance as to what we would typically expect from a regulatory framework that we would assess as "strong." We would expect some frameworks with no capital support during construction to receive a "strong" regulatory advantage assessment if in aggregate the other factors we analyze support that conclusion.

RELATED CRITERIA AND RESEARCH

- Corporate Methodology, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, Nov. 19, 2013
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Nov. 19, 2013
- Collateral Coverage And Issue Notching Rules For ‘1+’ And ‘1’ Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities and Insurers, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

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Corporate Methodology: Ratios And Adjustments

*(**Editor's Note:** We originally published this criteria article on Nov. 19, 2013. We republished this article on Oct. 31, 2014, to clarify a term in paragraph 104. We republished this article following our periodic review completed on Oct. 16, 2014. We republished this article to add a section on frequently asked questions. We republished this article on April 10, 2014, to correct the first bullet point in paragraph 174 regarding the lease disclosure requirements under International Financial Reporting Standards, and the second bullet point in the same paragraph to add that CFO, as well as FFO, are increased by adding back the depreciation expense. These corrections have no impact on our ratings.)*

1. Standard & Poor's Ratings Services is updating its criteria for making analytical adjustments to companies' financial data, following its "Request for Comment: Corporate Criteria: Ratios And Adjustments," published on June 26, 2013, on RatingsDirect. This criteria update relates to our global corporate criteria "Corporate Methodology," published on Nov. 19, 2013, and to the criteria article "Principles Of Credit Ratings," published on Feb. 16, 2011.

2. This criteria article supersedes "2008 Corporate Criteria: Ratios And Adjustments," published on April 15, 2008, and other articles, as listed in the Appendix.

I. SCOPE OF THE CRITERIA

3. These criteria apply to nonfinancial corporate entities we rate globally. It excludes project finance entities and corporate securitizations because of their unique characteristics.

II. SUMMARY OF THE CRITERIA

4. The analytical adjustments that Standard & Poor's makes to the reported financial results of companies worldwide allow for globally consistent and comparable financial data.

5. These adjustments also enable better alignment of a company's reported figures with our view of underlying economic conditions. Moreover, they allow a more accurate portrayal of a company's ongoing business, for example, following acquisitions or disposals, through pro forma adjustments.

6. There are general analytical adjustments that apply across multiple industries, but some are industry specific. The general adjustments are described in this criteria article, whereas the details of industry-specific adjustments are in the relevant criteria articles, labeled "Key Credit Factors."

III. IMPACT ON OUTSTANDING RATINGS

7. The impact of the new corporate criteria on ratings is described in the criteria article "Corporate Methodology," published on Nov. 19, 2013.

IV. EFFECTIVE DATE AND TRANSITION

8. These criteria are effective immediately.

V. METHODOLOGY AND ASSUMPTIONS

A. Reasons For Analytical Adjustments

9. A company's financial statements are the starting point of our financial analysis. Our analysis of a company's financial statements begins with a review of the accounting features to determine whether the data in the statements accurately measure a company's performance and position relative to that of its peers and the larger universe of corporate entities.

10. Understanding accounting frameworks such as International Financial Reporting Standards (IFRS), U.S. generally accepted accounting principles (U.S. GAAP), and other local or statutory GAAP, is therefore crucial to our corporate rating methodology. It is equally important to understand the differences between the accounting standards and how those differences can affect the reporting of economically equivalent transactions.

11. Accounting rules often provide options for the treatment of certain items, making the comparison of data difficult, even among companies using the same accounting frameworks. Moreover, business transactions have become increasingly complex, and so have the related accounting rules and concepts, which often involve greater reliance on subjective estimates and judgments.

12. In addition, several fundamental shortcomings of reporting requirements could reduce the quality and quantity of information in financial statements. One example relates to recognition and measurement: What circumstances determine whether an item such as a special-purpose entity or a synthetic lease should be reflected on or off a company's balance sheet, and at what value? Another example concerns transparency: What should a company disclose about the nature of off-balance-sheet commitments, compensation arrangements, or related-party transactions?

13. To allow for globally consistent and comparable financial analyses, our rating analysis includes quantitative adjustments to companies' reported results. These adjustments also enable better alignment of a company's reported figures with our view of underlying economic conditions. Moreover, they allow a more accurate portrayal of a company's ongoing business, for example following acquisitions or disposals, through pro forma adjustments.

14. Although our adjustments revise certain amounts that companies report under applicable accounting principles, this does not imply that we challenge the company's application of those principles, the adequacy of its audit or financial reporting process, or the appropriateness of the accounting judgments made to fairly depict the company's financial position and results for other purposes.

15. Rather, the methodology seeks to address a fundamental difference between accounting and analysis. An accountant

puts figures together in the form of financial statements. An analyst, by definition, picks the numbers apart and considers the implications of their components as well as the reported totals. It is rarely possible to completely recast a company's financial statements (so we do not attempt to apply double-entry accounting), but adjustments improve the relevance and consistency of the financial ratios we use in our analysis.

B. How And When Adjustments Apply

16. Certain adjustments pertain broadly to all industries because they apply to many types of companies at all times. These include adjustments for operating leases and postretirement employee benefits. Other adjustments may pertain only to a certain industry. Industry-specific adjustments are in the relevant criteria articles labeled Key Credit Factors.

17. In rare circumstances, consistent with the principles underpinning our explicit adjustments, we may make nonstandard analytical adjustments to depict a transaction differently from the reported financial statements or simply to increase the comparability of financial data across industries. For example, we may treat certain cash-raising transactions as akin to borrowing if they do not follow the standard trade terms of an industry and are in lieu of conventional debt issuance.

18. Our use of analytical adjustments depends on whether events and items a company reports could have a material impact on our view of the company's creditworthiness. Therefore, we may not make certain adjustments if the related amounts are too small to be material to our analysis.

19. Additionally, the transparency or extent of a company's disclosure in its financial statements may preclude adjustments to reported figures. For example, in many industries there is insufficient disclosure to allow full adjustments to income for inventory figures that reflect the "last in first out" valuation method.

C. Adjusted Debt Principle

20. Many of the analytical adjustments we make result from our view of certain implicit financing arrangements as being debt-like. Our depiction of these transactions as debt, which is often contrary to how a company reports them, affects not only the quantification of debt but also the measures of earnings and cash flows we use in our analysis. Therefore, it is instructive to understand the principles underpinning our adjustments to debt.

21. In general, items that we add to reported debt include:

- Incurred liabilities that provide no future offsetting operating benefit (such as unfunded postretirement employee benefits and self-insurance reserves);
- On- and off-balance-sheet commitments for the purchase or use of long-life assets (such as lease obligations) or businesses (such as deferred purchase consideration) where the benefits of ownership are accruing to the company; and
- Amounts relating to certain instances when a company accelerates the monetization of assets in lieu of borrowing (such as through securitization or factoring of accounts receivable).

22. Many of the items that increase debt under the adjustments are probable future calls on cash, but not all future calls on

cash are forms of debt. We do not consider a company's future commitments to purchase goods or services it has not received as akin to debt. This is because these are executory contracts, which means a counterparty must still perform an action and the benefits of ownership have yet to accrue to the company.

23. Not all incurred liabilities are added to reported debt. The adjusted debt figure excludes short-term obligations, such as accounts payable and other accrued liabilities, because we regard them as trade credit rather than the incurrence of long-term debt. However, to the extent that a company defers payment beyond the term customary for its supply chain, we may add that amount to debt.

24. Additionally, we may exclude certain obligations a company reports as debt. This is, for example, because we perceive those obligations as equity rather than debt.

25. Companies' recognition and measurement of the numerous financing mechanisms vary. Some are reported at amortized cost (for example, issued debt), others at fair value (such as for contingent consideration), and others somewhere in between (as for pension obligations). Companies may also exclude certain financing from the balance sheet (such as operating leases). Ideally, we add to reported debt the amounts that approximate the amortized cost of commitments we consider to represent a debt, although from a practical standpoint this is not always possible.

26. Lastly, we may reduce the adjusted debt figure by netting surplus cash (see paragraphs 231-238).

D. Financial Ratios

27. The components of our ratios are derived from figures in companies' financial statements, subject to adjustments (subsequently referred to as "all applicable adjustments") defined in this criteria article and in the applicable Key Credit Factors articles. The definitions of the components are in the glossary (see paragraphs 248-263).

E. Analytical Adjustments

28. To calculate our financial ratios, we may make analytical adjustments related to the following:

- 1. Adjusted debt and interest

a) Accrued interest and dividends

b) Debt issuance costs

c) Debt at fair value

d) Fair-value hedging

e) Convertible debt

f) Foreign currency hedges of debt principal

g) Initial measurement of debt

- 2. Asset-retirement obligations
- 3. Capitalized development costs
- 4. Capitalized interest
- 5. Financial and performance guarantees
- 6. Hybrid capital instruments
- 7. Inventory accounting methods
- 8. Litigation
- 9. Multi-employer pension plans
- 10. Nonoperating activities and nonrecurring items
- 11. Leases
- 12. Postretirement employee benefits and deferred compensation
- 13. Scope of consolidation
- 14. Securitization and factoring
- 15. Seller-provided financing
- 16. Share-based compensation expenses
- 17. Surplus cash
- 18. Workers' compensation and self-insurance

1. Adjusted debt and interest

29. In reflecting reported debt in our metrics, our objective is to use an amortized cost method, consistent with the amortized cost method under accounting standards like IFRS and U.S. GAAP. This method reflects debt as the amount of the original proceeds, plus interest calculated using the effective interest rate, minus payments of principal and interest. The effective interest rate is equivalent to the yield to maturity of a bond and takes into account the compounding of interest. This rate is consistent over the term of a fixed-rate debt instrument. For variable-rate debt, the effective interest rate after issuance will vary each time the coupon rate is reset. Under the amortized cost method, interest expense is measured at the full cost of the borrowing.

30. However, companies do not always report debt in this manner. Several factors can distort the measurement of debt, such as the exclusion of accrued and unpaid interest, the inclusion of debt-issuance costs, reporting debt at fair value, applying fair-value hedge accounting, and the method of accounting for convertible instruments. The use of different measures for debt may also result in interest expense amounts that differ from those under the amortized cost method. We make adjustments to the measurement of reported debt and interest in certain circumstances as described in paragraphs 31 to 70.

a) Accrued interest and dividends

31. We reclassify as debt any accrued interest that is not already included in reported debt. This adjustment enables a more consistent comparison among companies' financial obligations, by eliminating the disparity arising from differences in the frequency of interest payments (for example, quarterly rather than annually) or in payment due dates (for example, Jan. 1 or Dec. 31).

32. Additionally, we treat accrued interest or dividends on hybrid securities as debt. Deferred cumulative interest--whether the deferral was optional or mandatory--is also treated as debt.

Adjustment procedures

33. Data requirements:

- Reported accrued interest on debt, and dividends on hybrid securities, as of the balance-sheet date.

34. Calculations:

- Debt: Add to reported debt any accrued interest on debt and any dividends on hybrid securities.

b) Debt issuance costs

35. Debt issuance costs are a form of prepaid interest, which companies record on the balance sheet and amortize as an interest expense over the term of the debt. We regard them as part of the total cost of borrowing and therefore do not deduct the amortization of debt issuance costs from reported interest.

36. However, there are different approaches to where these amounts are reported on the balance sheet. A company may either report debt issuance costs as a separate asset, or deduct them from reported debt as a "contra liability" (that is, a liability with a debit balance, rather than the typical credit balance). We look to exclude these prepaid amounts from debt, when reported as a contra liability, to attain comparability. Similarly, if a company deducts premiums paid for modifications or redemptions from debt, we exclude those amounts from debt if practicable.

Adjustment procedures

37. Data requirements:

- Amount of debt issuance costs or modification premiums reported as a contra liability, which reduces reported debt.

38. Calculations:

- Debt: Add to reported debt the amount of debt issuance costs or modification premiums reported as a contra liability.

c) Debt at fair value

39. In certain circumstances, a company may report debt at fair value instead of at amortized cost. In such cases, we adjust the reported figure to reflect the amortized cost method. If the amortized cost figure is not shown in the financial statements, we may estimate it, based on the amount originally received or the face value plus accrued but unpaid interest.

40. In addition, we seek to exclude gains or losses from the revaluation of debt at fair value from our measure of interest expense. However, from a practical standpoint, if a company does not disclose these figures, it is difficult to adjust interest expense for the difference between the reported figure and the effective rate achieved by the amortized cost method.

41. When this difference is material, we may make estimates to arrive at a figure that approximates interest expense, exclusive of mark-to-market effects. We would make such an estimate by, for example, multiplying the face value of the obligation by an interest rate estimated from other similar debt instruments.

Adjustment procedures

42. Data requirements:

- The amount of debt using the amortized cost method (from the financial statements) or, if this is not available, an estimate based on the amount originally received or the face value plus accrued but unpaid interest.
- The amount of any charge or benefit for debt reported at fair value and recorded as an interest expense.

43. Calculations:

- Debt: Increase or decrease reported debt by the difference between the reported amount and our estimate of the amortized cost.
- Interest expense: Increase or decrease reported interest expense by the amount of any charge or benefit for debt reported at fair value and recorded as an interest expense.

d) Fair-value hedging

44. A company may issue fixed-rate debt and at the same time enter a derivative contract to synthetically create a variable-rate debt instrument. If all necessary conditions are met, companies may elect to apply fair-value hedge accounting to such an arrangement. The effect of this accounting approach is that a company would report both the derivative instrument and the debt (but only the risk being hedged) at fair value. Changes in the fair values of both items from one reporting date to the next are netted off against each other in the income statement.

45. When a company applies fair-value hedge accounting to debt, we adjust the reported debt figure to reflect the amortized cost method.

46. It is not necessary to adjust interest expense in this case because the fair-value adjustments the company makes in the income statement generally offset each other, and settlements under the derivative are reported as an interest expense.

Adjustment procedures

47. Data requirements:

- The debt figure expressed as the amortized cost amount in the financial statements.
- If this is not available, we (1) determine the amount of the fair-value adjustment made to reported debt as a consequence of hedge accounting; or (2) estimate the adjustment amount using the fair value of the related derivative instrument; or (3) adjust debt to reflect the amount originally received as proceeds or the face value plus accrued and unpaid interest.

48. Calculations:

- Debt: Increase or decrease debt by the difference between the reported amount and our estimate of debt under the amortized cost method.

e) Convertible debt

49. Due to their complex nature, we take a slightly different approach to measuring convertible debt instruments that give the holder the option of converting the debt into shares. Because of this option, the coupon rate on such obligations is normally lower than market interest rates.

50. Under U.S. GAAP and IFRS the value of a convertible debt obligation is split into a debt component and an equity

component (following the split-accounting method).

51. The debt component is the fair value of a similar debt obligation without the conversion feature. This amount is accounted for under the amortized cost method and increases toward the face value of the convertible debt instrument until maturity or conversion.

52. The equity component (the value of the conversion feature) represents the difference between the debt component and the issue price of the convertible debt instrument. The value of the equity portion remains constant.

53. Although uncommon, we may regard a convertible debt instrument as having equity content in our analysis, depending on its terms and conditions and our view of the likelihood that the debt holder will convert it to equity (see "Hybrid Capital Handbook: September 2008 Edition," published on Sept. 15, 2008). If we consider such an instrument to have high equity content, we reclassify it as equity. If we consider that there is minimal equity content, we treat the instrument fully as debt.

54. We typically add to reported debt the unamortized value of the discount created by the conversion option, bringing the value of such an instrument back to par.

55. In our ratios, we seek to include the full effective cost of the obligation as interest. We believe the interest resulting from the split-accounting method achieves this goal and therefore no adjustment is necessary.

56. If a company does not use split accounting we estimate the cost of debt by increasing reported interest expense when the difference in value under the other method is material.

Adjustment procedures

57. Data requirements:

- The face value of convertible debt instruments or the remaining unamortized discount as of the balance-sheet date.
- The amount of interest expense reported in the period, if we consider the instruments to have high equity content.

58. Calculations:

- Debt: Increase reported debt by the amount necessary to bring an instrument back to par. If an instrument has high equity content according to our criteria, we deduct the reported amount from debt.
- Interest: Subtract from interest the amount of interest expense on convertible debt considered to have high equity content.

f) Foreign currency hedges of debt principal

59. Foreign-currency-denominated debt is typically included in consolidated debt on the balance sheet at the amount of foreign currency, translated at the spot rate on the balance-sheet date.

60. Many companies hedge the foreign currency exposure by entering into derivatives that fix the foreign exchange rate that will apply on the debt's repayment date. To better reflect the economics of such transactions, we adjust the reported amount of foreign-currency-denominated debt to reflect the net amount required for repayment as a result of the hedge.

61. We may not make this adjustment if other factors can neutralize the benefit of the derivative. These factors include

concerns about risk relating to the derivative counterparty (such as when a derivative counterparty has credit quality equivalent to 'BB+' or lower) and other derivative contracts that can offset the benefit of the derivative hedge.

62. The adjustment amount results from restating the hedged debt principal using the "locked-in" foreign exchange rate achieved through the derivative. The adjustment amount is broadly equivalent to the fair value of a derivative representing a foreign currency hedge of debt principal, but may differ for various reasons, such as because the derivative's fair value also reflects liquidity and counterparty risk.

63. We use the derivative's value as a proxy for our adjustment amount if retranslation of the debt balance is not practical because of insufficient information.

64. However, companies often hedge the foreign currency exposure related to debt principal and interest simultaneously. In this instance, we take care to adjust only for the fair value of the derivative that hedges the principal, and not the portion that hedges the interest.

Adjustment procedures

65. Data requirements:

- The amount of hedged foreign-currency-denominated debt (from the balance sheet); and
- The locked-in foreign exchange rate (or locked-in principal value of outstanding debt) achieved via the hedge transaction.
- Alternatively, the fair value of the derivative that applies only to the principal (that is, excluding any fair value associated with hedged interest payments).

66. Calculations:

- Debt: Retranslate foreign-currency-denominated debt using the locked-in foreign exchange rate (or adjust the balance-sheet value of debt to equal the locked-in principal value). Alternatively, add to or subtract from reported debt the fair value of the hedging instrument on the balance-sheet date.

g) Initial measurement of debt

67. We subscribe to amortized cost as the preferred method of measuring debt after debt is issued. However, in certain circumstances, we may take an alternative view toward a company's initial measurement, and therefore ongoing measurement, of a particular debt instrument, as described in the next paragraph.

68. Companies usually initially measure debt at an amount equal to the net proceeds received at issuance. However, there are other methods of initial measurement of debt that we believe can in certain instances distort the initial and ongoing carrying value of debt. This may include the methods applied to debt assumed in an acquisition, or debt that has been modified or is part of a distressed exchange. When our judgment about the initial measurement (and therefore ongoing measurement) of a debt instrument differs from a company's, we may adjust debt, funds from operations (FFO), and interest expense if practical and the effect is material.

Adjustment procedures

69. Data requirements:

- Initial measurement of the applicable debt instrument.

- Our assumed measurement of the applicable debt instrument.
- Interest expense associated with the applicable debt instrument that is reported during the period.
- Interest expense for the period, based on our assumed initial measurement of the applicable debt instrument.

70. Calculations:

- Debt: Increase or decrease debt by the difference between the reported amount of debt and our estimate of amortized cost based on our assumed initial measurement.
- Interest expense: Increase or decrease interest expense by the difference between reported interest expense and the estimated interest expense based on our assumed initial measurement.
- FFO: Increase or decrease FFO by the difference between reported interest expense and the estimated interest expense based on our assumed initial measurement.

2. Asset-retirement obligations

71. Asset-retirement obligations (AROs) are legal obligations associated with a company's retirement of tangible long-term assets. Examples of AROs include the cost of plugging and dismantling oil and gas wells, decommissioning nuclear power plants, and treating or storing spent nuclear fuel and capping and restoring mining and waste-disposal sites.

72. We treat AROs as debt-like obligations, although several characteristics distinguish them from conventional debt, including timing and measurement uncertainties.

73. A company's liability for AROs is independent from the amount and timing of the cash flows the associated assets generate. In certain situations, companies fund AROs by adding a surcharge to customer prices; or the AROs are paid by third parties, such as a state-related body. In these cases there would typically be no debt adjustment.

74. The measurement of AROs involves a subjective assessment and is therefore imprecise. We generally use the reported ARO figures, but we may make adjustments for anticipated reimbursements, asset-salvage value, or any of the company's assumptions we view as unrealistic. Those assumptions may include the ultimate cost of abandoning an asset, the timing of asset retirement, and the discount rate used to calculate the balance-sheet value.

75. Under most accounting standards, company balance sheets show the ARO figure before tax, and any expected tax benefits as a separate deferred tax asset on the balance sheet (because the associated ARO-related asset is subject to depreciation). Tax savings that coincide with settling ARO payments (as opposed to their provisioning), reduce the cash cost of the AROs, and we factor them into our analysis to the extent that we expect the company to generate taxable income in the same tax jurisdiction.

76. Our approach is to add AROs--after deducting any dedicated retirement-fund assets or provisions, salvage value, and anticipated tax savings--to debt. We generally adjust for the net aggregate funding position, even if some specific obligations are underfunded and others are overfunded. The adjustment amounts are tax effected (that is, adjusted for any tax benefit the company may receive) if the company will likely be able to use tax deductions.

77. The accretion of an ARO that reflects the time value of money is akin to noncash interest and similar to postretirement benefit interest charges. Accordingly, we reclassify the accretion (net of earnings on any dedicated funds), using a floor of zero for the net amount as interest expense, in analyzing the income and cash flow statements.

78. If dedicated funding is in place and the related returns are not entirely reflected in reported earnings and cash flows,

we add the unrecognized portion of the related returns to earnings and cash flows. We reclassify the recognized portion to interest expense and cash flow from operations (CFO).

79. We treat cash payments for the abandonment of assets and contributions to dedicated funds that exceed ARO interest costs (after deducting ARO fund earnings) as repayment of the ARO. We therefore add these amounts to FFO and CFO.

80. We treat cash payments for the abandonment of assets and contributions to dedicated funds that are less than the ARO interest costs (after deducting ARO fund earnings) as the incurrence of a debt obligation. We therefore deduct the shortfall in payments from FFO and CFO.

Adjustment procedures

81. Data requirements:

- The ARO figure (from the financial statements or Standard & Poor's estimate).
- Any associated assets or funds set aside for AROs.
- ARO interest costs irrespective of whether charged to operating or financing costs.
- The reported gain or loss on assets set aside for funding AROs.
- Any cash payments for AROs.

82. Calculations:

- Debt: Add net ARO to debt (net ARO equals the reported or estimated ARO minus any assets set aside to fund AROs, multiplied by 1 minus the tax rate).
- EBITDA: Add ARO interest costs included in operating costs.
- Interest: Deduct ARO interest costs (net of ARO fund earnings) from reported operating expenses, if included there, and add to interest expense.
- FFO: Our definition of FFO is EBITDA minus net interest expense minus current tax expense, after adjusting each of the three components according to our criteria. EBITDA and interest expense are adjusted as described in the previous two bullet points. The figure to adjust the current tax expense results from multiplying the applicable tax rate by the net result of (1) new provisions, plus (2) interest costs, minus (3) the actual return on funded assets, minus (4) fund contributions or ARO payments in the corresponding period. The net effect of these adjustments is that FFO is reduced by net ARO interest and adjusted for tax effects.
- CFO: Subtract the gain (or add the loss) on assets set aside for AROs from interest expense. Then compare the resulting amount with payments on the AROs to arrive at the excess contribution or shortfall to add to, or subtract from, CFO. Additionally, we adjust CFO for tax effects in a similar way as for FFO.

3. Capitalized development costs

83. In financial reporting, research costs are almost universally treated as an expense; however the treatment of development costs varies. U.S. GAAP, with limited exceptions (such as for software development costs in certain instances), requires companies to treat development costs as an expense, whereas IFRS allows such costs to be capitalized under certain conditions. In addition to these differences between accounting regimes, there is an element of subjectivity in determining when development costs are capitalized, which can lead to a disparity among companies' reported figures.

84. To enhance the comparability of data, we adjust reported financial statements when a company capitalizes

development costs, if the information is available and the amounts material. The adjustment aims to treat the capitalized development costs as if they had been expensed in the period incurred.

85. We aim to adjust EBITDA, FFO, and CFO for the amount of development costs capitalized during the year. This is because a company's position in its product life cycle has a great effect on its current spending relative to the amortization of previously capitalized development costs. However, in the absence of accurate figures, we use the annual amortization figure reported in the financial statements as a proxy for the current year's development costs. To the extent that the amortization of previously capitalized costs equals current development spending, there is no impact on operating expenses and EBIT because these amounts are after amortization. However, there is an impact on EBITDA, FFO, and CFO, which are calculated before amortization.

86. We do not carry through the adjustment to the cumulative asset (and equity) accounts, weighing the complexity of such adjustments against their typically limited impact on amounts that are secondary to our analysis.

87. We make one exception to this approach, and that is for capitalized development costs relating to internal-use software. Consistent with our goal of achieving comparability, we do not want to create a gap between companies that develop software for internal use and those that purchase software and capitalize equivalent products. We therefore attempt to exclude such costs from our adjustment.

Adjustment procedures

88. Data requirements:

- Amount of development costs incurred and capitalized during the period, excluding, if practical, capitalized development costs for internal-use software.
- Amortization amount for relevant capitalized costs.

89. Calculations:

- EBITDA, FFO, and CFO: Subtract the amount of net capitalized development costs or, alternatively, the amortization amount for that period.
- EBIT: Subtract (or add) the difference between the spending and amortization in the period.
- Capital expenditures: Subtract the amount capitalized in the period.

4. Capitalized interest

90. Under most major accounting regimes, financial statements show interest costs related to the construction of fixed assets as capitalized, that is, as a component of the historical cost of capital assets. This can obscure the total interest that has been incurred during the period, hindering comparisons of the interest burden of companies that capitalize and do not capitalize interest.

91. Under our methodology, interest costs that have been capitalized are adjusted and included as interest expense in the period in which the interest was incurred.

92. In the statement of cash flows, we reclassify any capitalized interest shown as an investing cash flow to operating cash flow. This adjustment reduces CFO and capital expenditures by the amount of interest capitalized in the period. Free operating cash flow remains unchanged.

93. We make no adjustment for the cumulative effect on the value of property, plant, and equipment resulting from any prior-year interest capitalization, tax effects, or depreciation, due to disclosure limitations and the minimal analytical benefit this would provide.

Adjustment procedures

94. Data requirements:

- The amount of capitalized interest during the period.

95. Calculations:

- Interest expense: Add amount of interest capitalized during the period.
- FFO: Our definition of FFO is EBITDA minus net interest expense minus current tax expense, after adjusting each of the three components according to our criteria. Net interest expense includes the interest capitalized during the period, as described in the previous bullet point. Therefore, FFO is reduced by the amount of interest capitalized in the period.
- CFO: Subtract the amount of capitalized interest recorded as an investing cash flow.
- Capital expenditures: Subtract the amount of capitalized interest recorded as an investing cash flow.

5. Financial and performance guarantees

a) Financial guarantees

96. A financial guarantee is a promise by one party to assume a liability of another party if that party fails to meet its obligations under the liability. A guarantee can be limited or unlimited. If a company has guaranteed liabilities of a third party or an unconsolidated affiliate, we may add the guaranteed amount to the company's reported debt.

97. We do not add the guaranteed amount to debt if the other party is sufficiently creditworthy (that is if the other party has credit quality equivalent to 'BBB-' or higher) in its own right, or we believe that the net amount payable if the guarantee were called would be lower than the guaranteed amount. This could happen, for example, if the company that has provided the guarantee has been counter-guaranteed by another party. In this case, we add the lower amount to debt. We do not adjust interest expense because the guarantor is only obliged to service interest if called upon to meet the guarantee.

b) Performance guarantees

98. A performance guarantee is a promise to provide compensation if a company does not complete a project or deliver a product or service according to the agreed terms. An insurance company or bank may issue such guarantees on a company's behalf. Construction companies often provide performance guarantees to meet a condition in a work contract. If the project, product, or service is not completed as agreed, the customer can call on the performance guarantee.

99. We do not regard performance guarantees as debt if a company is likely to maintain sufficient work or product quality to avoid making large payments under those guarantees.

100. A company's past record of payments under performance guarantees could indicate the likelihood of future payments under such guarantees. Only if this payment history suggests a high likelihood of future payments would we estimate a potential liability and add that amount to debt.

Adjustment procedures

101. Data requirements:

- The value of guarantees on and off the balance sheet, net of any tax benefit.

102. Calculations:

- Debt: Add to debt the amount of on- and off-balance-sheet debt-equivalent related to guarantees, net of any tax benefit.
- Equity: Subtract from equity the amount of off-balance-sheet debt-equivalent related to guarantees, net of any tax benefit.

6. Hybrid capital instruments

103. Hybrid capital instruments (or hybrids) have features of both debt and common equity. We classify a corporate hybrid as having minimal, intermediate, or high equity content depending on the specific terms and conditions of the instrument and our view of whether the issuer intends to maintain the instrument as loss-bearing capital. Our classification of equity content determines the type of adjustments we make to a company's reported figures.

104. A company's issuance of conventional hybrids, in an aggregate amount of up to 15% of capitalization, can be eligible for equity credit, which means that we exclude at least some of the hybrid instrument and its interest costs from our debt and interest measures (see "Hybrid Capital Handbook: September 2008 Edition," published on Sept. 15, 2008). We exclude bonds that are mandatorily convertible into shares from this calculation. Capitalization is equal to balance-sheet equity, plus debt and hybrids, after adjusting for goodwill and making all applicable adjustments. The capitalization calculation excludes any goodwill asset that exceeds 10% of total assets.

105. The treatment of hybrids for the purposes of our leverage and debt service ratio calculations depends on the equity content classification:

- Hybrids that have high equity content are treated as equity and the interest or dividends are treated as dividends.
- For hybrids with intermediate equity content, 50% of the principal is treated as debt and 50% as equity (excluding unpaid accrued interest or dividends, which are added to debt). Similarly, we treat one-half of the period's interest or dividends as dividends and one-half as interest. There is no adjustment to related taxes.
- Hybrids with minimal equity content are treated entirely as debt and all interest or dividends as interest.

106. In all cases, accrued coupon payments are treated as debt.

107. The criteria for adjustments related to convertible debt are in paragraphs 49-58 of this article and in "Hybrid Capital Handbook: September 2008 Edition," published on Sept. 15, 2008.

Adjustment procedures

108. Data requirements:

- Documentation for reported hybrid capital instruments.
- Amount of hybrids, debt, goodwill, and shareholders' equity on the balance sheet.
- Amount of associated interest or dividend expense and interest or dividend payments in the period.
- Amount of accrued unpaid interest or dividends.

109. Calculations:

- Hybrids reported as equity: (1) If we classify equity content as high, there is no adjustment to equity. (2) If we classify equity content as intermediate we deduct 50% of the value from equity and add it to debt. We also deduct 50% of the dividend accrued during the accounting period and add it to interest expense, thereby reducing FFO. Likewise, 50% of any dividends paid are deducted from CFO. (3) If we classify equity content as minimal, we deduct the full principal amount from equity and add it to debt. We add associated dividends to interest expense, thereby reducing FFO. Likewise dividends paid are added to interest paid, thereby reducing CFO.
- Hybrids reported as debt: (1) We deduct the value of hybrids with high equity content from debt and add it to equity. We also deduct the associated interest charge from interest expense and add it to dividends, thereby removing it from FFO. Likewise, interest paid is added to CFO and dividends. (2) If we classify equity content as intermediate, we deduct 50% of its value from debt and add it to equity. We also deduct 50% of the associated interest expense from interest expense and add it to dividends accrued, thereby increasing FFO. 50% of interest paid is added to CFO. (3) If equity content is minimal there is no adjustment because we treat such hybrids as debt.
- Debt: We add to debt the accrued and unpaid interest and dividends on all hybrids.

7. Inventory accounting methods

110. Accounting frameworks allow companies a choice of inventory accounting method, and this leads to reporting differences within industries and among regions. The disparity is more pronounced in inventory-intensive industries, particularly when the price of inventory (such as raw materials) fluctuates significantly. This is because the method a company uses influences the amount of inventory it can charge as an expense, and therefore also its taxable income. The inventory accounting methods under U.S. GAAP are "first in first out" (FIFO), "last in first out" (LIFO), weighted-average cost, and specific identification.

111. Similar costing methods exist in other generally accepted accounting principles. However, many frameworks, including IFRS, do not allow LIFO. The tax treatment is a key factor in a company's choice of inventory costing method and it varies significantly by jurisdiction. For example, LIFO is permitted for tax-reporting purposes in the U.S., and a company that uses it for tax purposes must also use it for preparing its financial statements.

112. The greatest potential disparity in financial results comes from using FIFO as opposed to LIFO. When inventory prices are rising, the LIFO method results in lower income than under FIFO because the most recent and higher cost of goods is transferred to the income statement, while the remaining inventory is shown at the older, lower cost on the balance sheet. Furthermore, LIFO results in improved cash flows for that period because income taxes are lower as a result of the lower taxable income.

113. Apart from hindering comparison between different companies, the different methods can also obscure a company's true performance record. For example, LIFO arguably allows for a more realistic depiction of current costs on the income statement, but showing inventory at older costs distorts the balance-sheet position. The FIFO method, on the other hand, provides a more up-to-date valuation of inventory on the balance sheet, but can significantly understate the cost of goods sold during a period of rising prices and overstate income.

114. We adjust the reported inventory figures if material to our analytical process. Companies that use LIFO have to disclose what the inventory valuation would be under FIFO, through an account called the LIFO reserve that represents the cumulative effect on gross profit from the use of the LIFO method. For such companies, we add the

balance in the LIFO reserve to the reported inventory. This enables us to reflect inventory balances at approximately the current market value. A corresponding adjustment, net of tax, is made to equity.

115. We do not adjust the income statement when a company uses LIFO because we believe the LIFO method results in costs of goods sold that closely reflect replacement-cost values.

116. Typically, there are no adjustments to the income statement for companies that use FIFO or the average cost method because the data are generally not available.

117. When a company using the LIFO method has inventory balances that decrease over a period of time, LIFO liquidation may result. This means that older layers of inventory are turned into cost of goods sold as a result ("older" refers to inventory in terms of their accounting and not necessarily in a physical sense). Assuming an inflationary environment, the cost of goods sold is reduced and, as a result, income increases because of LIFO liquidation gains. To capture the true sustainable profitability of a company, we generally exclude the gains generated from LIFO liquidation from our profitability measures.

Adjustment procedures

118. Data requirements:

- The balance of the LIFO reserve account.
- LIFO liquidation gains from the income statement.

119. Calculations:

- Assets: Add the LIFO reserve to inventory.
- Equity: Add the LIFO reserve (after tax) to equity.
- EBITDA, EBIT, and FFO: Deduct LIFO liquidation gains from EBITDA, EBIT, and FFO.

8. Litigation

120. If a company is a defendant in a major lawsuit, we may adjust its debt to account for the potential cost when an adverse outcome (payment of a cash settlement or damages) is probable or has materialized. If the estimated or known amount of the potential payment is material in relation to the company's cash flow or leverage ratios, we add that figure to reported debt. Before doing so, we may reduce the potential payment to reflect the expected reimbursement from legal insurance coverage, cash held in reserve, and extended payment dates; or add accruing interest penalties.

121. The adjusted debt figure therefore includes the present value of the net estimated payout, on an aftertax basis.

122. To achieve the difficult task of sizing the litigation exposure, we may use as a reference any resolved lawsuits that can serve as benchmarks. We also consider the company's reported litigation reserves and the different thresholds for their recognition under IFRS and U.S. GAAP.

123. Because the full financial effects of a lawsuit are difficult to quantify accurately, the analysis also involves techniques such as calculating ranges of outcomes or performing a sensitivity analysis. The results of these techniques can indicate, for example, what effect even higher potential payouts would have on a company's financial profile.

124. If, to allow for a possible adverse financial judgment, a company has placed cash in escrow with the courts or is

expected to do so; or if it had to provide a financial guarantee to the courts, we incorporate the impact of this actual or contingent commitment into the liquidity assessment.

Adjustment procedures

125. Data requirements:

- An estimate or actual amount of the litigation exposure.

126. Calculations:

- Debt: Add the estimated or actual amount of litigation exposure (net of any applicable tax deduction) to reported debt.
- Equity: Subtract the amount of estimated litigation exposure considered to be debt-like that exceeds the accrued litigation exposure, if any.

9. Multi-employer pension plans

127. Some companies in the U.S. participate in multi-employer, defined-benefit pension plans on behalf of their employees. Such companies are predominantly in the transportation, building, construction, manufacturing, hospitality, and grocery sectors. The pension plans are often are referred to as "Taft-Hartley" plans because they fall under the Taft-Hartley Labor Act (officially termed the "The Labor Management Relations Act") of 1947.

128. A multi-employer pension plan is forged by a collective bargaining agreement between companies that generally operate in the same sector and the union(s) that represent the sector's workers. These arrangements share many of the attributes of single-employer plans.

129. We regard the liability associated with a funding deficit on multi-employer pension plans as debt, as we do deficits on single-employer defined-benefit, postretirement obligations. For practical reasons, and because of a lack of pertinent data, we generally do not adjust cash flow measures in our analysis unless significant catch-up contributions are made; nor do we generally adjust our profitability measures.

a) Unique characteristics of multi-employer pension plans

130. Multi-employer pension plans pose some unique challenges, mainly because they are complex, and information about them in companies' financial statements is limited. For example, unlike for single-employer plans, there is generally no information on a company's potential share of a shortfall under a multi-employer plan, unless that company is withdrawing from the plan. Further, because the plans are collective, the sponsoring companies may become liable beyond their otherwise pro rata share of the obligation if another company becomes insolvent.

131. These challenges make it difficult to estimate the amount each company might have to pay to meet current and future obligations under such plans. It is therefore crucial to gather additional information that is timely and relevant, including the specific features of the plan and the collective bargaining process.

132. A company participating in a multi-employer plan faces problems that a company sponsoring a single-company pension plan does not, in particular if it wants to withdraw from such a plan. Companies that withdraw from an underfunded multi-employer plan may incur a withdrawal liability representing their pro rata shares of the total underfunded pension obligation. Determining the withdrawal liability amount accurately is difficult because statutes

provide several different ways to calculate it. Moreover, special rules in certain industries (such as construction, entertainment, and trucking) determine the withdrawal liability trigger points and the size of the obligation. For example, the withdrawal liability may be limited in cases such as a bona fide sale of substantially all of the employer's assets or the company's liquidation or dissolution.

133. A solvent company that exits an underfunded multi-employer pension plan generally continues to make payments for its share of the liabilities for as many years as the Employee Retirement Income Security Act specifies. However, if a company is insolvent, the other participating companies must assume all of its obligations. For single-employer plans, the sponsoring company is liable only for the underfunded portion of its own plan.

134. All of these factors make it difficult to estimate the amount of a company's potential liability under a multi-employer plan to add as debt. To do so, we consider the facts and circumstances associated with the plan. For example, instead of a pro rata share of the collective obligation, we may estimate a lower amount if we view it as plausible that the plan's trustees could reduce the plan's total liability over time by decreasing the level of future employee benefits. We primarily base this determination on information from the company and publicly available data.

b) Accounting and disclosure limitations

135. Under U.S. GAAP and IFRS, a company's withdrawal liability must be both probable and estimable for it to be recognized as a contingent liability in the financial statements. This obligation is therefore seldom accrued or disclosed.

136. Financial statement disclosure on multi-employer plans is typically limited to the significant plans an employer participates in, the company's annual contributions to each plan over the previous three years, and the relative financial health of the plans as indicated by regulatory guidelines.

137. Using publicly available tax and regulatory filings to approximate the funded status of a multi-employer pension is also problematic, considering filing delays. Plans must file Form 5500 (Annual Return/Report of Employee Benefit Plan) with the U.S. Department of Labor. This form provides useful data about a plan's overall financial health, its funding status, number of participants, and contribution levels. However, the form must be filed within 210 days after the end of the plan year (subject to a 75-day extension), and there may be an additional time lag before the Department of Labor publishes the information. The resulting data will therefore be somewhat out of date. In particular, in the period before the publication of the data, fluctuations in discount rates, market returns, and the terms of collective bargaining agreements, participation levels, and other actuarial assumptions may result in changes in the financial health of the plan that the filings do not reflect.

Adjustment procedures

138. Data requirements: Where material, obtain an estimate of the withdrawal liability for each plan a company participates in. If this figure is unavailable, we make an estimate of the company's pro rata share of the funded status based on the following information:

- The funded status of each of the multi-employer plans to which the company contributes. This information may be provided by the company for more recent years, or it may be obtained from the publicly available Form 5500s filed with the Department of Labor. To estimate the funded status, we use the Retirement Protection Act of 1994 liability, minus the fair value of assets as of the same date.

- The company's contributions to each of its multi-employer plans in the corresponding years.
- The total contributions to the multi-employer pension plan by all employers in the corresponding years.
- An applicable haircut for anticipated negotiations.

139. Calculations:

- Debt: Add the estimated withdrawal liability for all plans, net of tax, to debt. Alternatively, if not available, add to debt the estimate of the employer's share of the funded status of each plan (net of any applicable haircut and net of tax).

10. Nonoperating activities and nonrecurring items

140. We define our key income-statement-based metrics (EBITDA, EBIT, and FFO) in a particular fashion. However, the reported financials often do not conform to our views. Therefore it is necessary for us to adjust the reported financial information so that they fit in with our methodology.

a) Operating versus nonoperating items

141. Our decision to include or exclude an activity from a particular metric depends on whether we consider that activity to be operating or nonoperating in nature (see paragraphs 142-158). Independent of that decision, we consider whether an activity is recurring or nonrecurring (see paragraphs 159-164).

142. Our EBIT measure is a traditional view of profit that factors in capital intensity. We consider all income statement activity integral to EBIT, with the exception of interest and taxes. This includes all activity we consider nonoperating that is excluded from EBITDA.

143. Our definition of EBITDA is: Revenue minus operating expenses plus depreciation and amortization (including noncurrent asset impairment and impairment reversals). We include cash dividends received from investments accounted for under the equity method, and exclude the company's share of these investees' profits. This definition generally adheres to what EBITDA stands for: earnings before interest, taxes, depreciation, and amortization. However, it also excludes certain other income statement activity that we view as nonoperating.

144. Our definition of EBITDA aims to capture the results of a company's core operating activities before interest, taxes, and the impact on earnings of capital spending and other investing and financing activities. This definition links to the cash flow statement because we use EBITDA to calculate FFO, which we use as an accrual-based proxy for CFO (cash flow from operations).

145. Generally, this means that any income statement activity whose cash effects have been (or will be) classified as being from operating activities (excluding interest and taxes) are included in our definition of EBITDA.

146. Conversely, income statement activity whose cash effects have been (or will be) classified in the statement of cash flows as being from investing or financing activities is excluded from EBITDA.

147. We may however take alternative views about the classification of transactions to that presented in the statement of cash flows, and this would flow through to our other metrics.

148. Below are examples of how we apply this principle to various scenarios.

149. *Disposals:-* Under accounting standards, proceeds from the sale of a subsidiary are classified in the statement of cash flows as an investing cash flow rather than an operating cash flow. Moreover, we view the disposal of a subsidiary as outside core business operations. As such, we do not treat a gain or loss from the sale of a subsidiary as an operating activity and exclude this from our calculation of EBITDA and FFO.

150. The same rationale holds for the sale of property, plant, and equipment. The cash flows arising from such transactions are classified, under accounting standards, as investing activities in the statement of cash flows. Therefore, we would typically view any gains or losses on the sale of property, plant, and equipment as nonoperating items.

151. *Restructuring costs:-* We include restructuring costs in our calculation of EBITDA, consistent with their treatment in the cash flow statement as operating activities. Moreover, most companies need to restructure at some point, as the global economy is constantly evolving and businesses alter their operations to remain competitive and viable.

152. *Acquisition-related costs:-* These include advisory, legal, and other professional and administrative fees related to an acquisition. We include them in EBITDA, consistent with their treatment in the statement of cash flows as operating activities. Many businesses make acquisitions as part of their growth strategy; therefore it is important to factor these expenses into our metrics.

153. *Asset impairments/write-downs:-* Impairments on tangible and intangible noncurrent assets are akin to depreciation or amortization in that they represent a company's income-statement recognition of earlier capital expenditures. We therefore exclude them from our definition of EBITDA. Our definition of EBIT includes impairment charges or reversals. Our decision to exclude an impairment cost or reversal from EBIT would depend on whether we consider it to be recurring or nonrecurring (see paragraphs 159-164).

154. However, impairments on current assets, such as inventory and trade receivables, are included in our calculation of EBITDA. The charges for inventory represent a company's recognition in the income statement of cash that it has already spent, and those for trade receivables represent the reduction of income previously recognized, but which the company will not fully collect.

155. *Unrealized gains or losses on derivatives:-* If a company has not achieved the requirements of technical hedge accounting (even though an effective economic hedge may exist), it reports all mark-to-market gains or losses related to the fair-valuing of derivative contracts in the income statement. Although the nature of the underlying activity is often integral to EBITDA, FFO, or both, using mark-to-market accounting can distort these metrics because the derivative contract may be used to hedge several future periods.

156. Therefore, when we have sufficient information, we exclude the unrealized gains or losses not related to current-year activity, so that the income statement represents the economic hedge position achieved in the current financial year (that is, as if hedge accounting had been used). This adjustment is common in the utilities and oil and gas sectors.

157. *Foreign currency transaction gains and losses:-* Foreign currency transaction gains or losses arise from transactions denominated in a currency other than a company's functional currency (generally the currency in which it transacts most of its business). Examples include selling goods at prices denominated in a foreign currency, borrowing or lending in a foreign currency, or other contractual obligations denominated in a foreign currency.

158. Currency transaction gains and losses may be viewed as operating or nonoperating in nature. If gains or losses included in operating profit are operating in nature, we do not make adjustments. We may however adjust reported operating results for currency gains and losses that are nonoperating. For example, we may adjust (or exclude) foreign currency gains or losses resulting from the issuance of foreign-currency-denominated debt.

b) Nonrecurring items and pro forma figures

159. The relative stability or volatility of a company's earnings and cash flow is an important measure of credit risk that is embedded in our corporate criteria. For this reason, our use of nonrecurring or pro forma adjustments is limited to the extent that there has been some transformative change in a company's business. Examples of such changes are the divestment of part of the business or a fundamental change in operating strategy.

160. *Discontinued operations and business divestments:-* Companies typically segregate their profits or losses from discontinued operations from those of the continuing business; although the segregation of related cash flows is less consistent. We typically exclude profits, losses, and cash flows from discontinued operations from our metrics so that they more accurately reflect the company's ongoing operations.

161. *Pro forma accounts for intrayear acquisitions or irregular reporting periods:-* If an acquisition has taken place, the financial statements for the year of the acquisition include all the debt of the enlarged group in the year-end balance sheet, but less than the full year's results and cash flows of the enlarged group. This distorts debt-coverage ratios, which therefore do not accurately indicate the company's likely future performance.

162. A similar issue exists when companies have irregular accounting periods, such as after a change in their accounting year-end. In these cases, we may use pro forma financial statements to allow for a more representative measure of full-year performance and more meaningful ratios.

163. *Asset impairments and write-downs:-* We generally exclude impairment charges on long-life assets from our measure of EBIT if they are very large and irregular. Excluding a nonrecurring impairment from EBIT produces a better estimate of a company's ongoing profitability, but does not mean we ignore the impairment in our analysis. On the contrary, a significant impairment may indicate that a company's ability to generate future cash flows has diminished.

164. We rarely exclude impairments of operating assets, such as inventories and receivables, from our EBITDA and FFO metrics because we wish to capture this volatility. An exception might be a genuine nonrecurring impairment, such as inventory impairment resulting from damage caused by a fire.

Adjustment procedures

165. Data requirements:

- Amounts of income, expense, and cash flows to be reclassified. The amounts are based on our analytical judgment, using information from the company and our assessments.

166. Calculations:

- Add or subtract amounts from the respective measures--such as, revenue, operating income before and after depreciation and amortization (D&A), D&A, EBIT, EBITDA, CFO, and FFO--and reclassify them according to our view of the underlying activities.
- Because CFO and FFO are aftertax measures, they are also adjusted to reflect tax effects, where feasible.

167. Beyond the standard adjustment, additional insights may be gleaned by adjusting individual line items within cost of goods sold or selling, general, and administrative expense, if there is sufficient data to reflect adjustments at such levels.

11. Leases

168. Companies commonly use leases as a means of financing, and the accounting method for leases distinguishes between operating and finance leases. Finance leases (also known as capital leases) are accounted for in a manner similar to a debt-financed acquisition of an asset and as a balance-sheet liability. Conversely, many operating leases are not accounted for as a balance-sheet liability, but the lease cost is recorded in the profit and loss account in each accounting period.

169. We view this accounting distinction as substantially artificial because under both types of lease arrangements, a company signs a contract that allows it to use an asset, thereby entering into a debt-like obligation to make periodic rental payments.

170. For this reason, we treat operating and finance lease obligations as debt. Reclassifying leases as debt seeks to enhance comparability between companies that finance assets using operating or financing leases and those that do so by incurring debt to finance the purchase of the asset. This adjustment aims to bring companies' financial ratios closer to the underlying economics and to make them more comparable by taking into consideration all of a company's financial obligations, whether on or off the balance sheet.

171. The methodology does not replicate a scenario in which a company finances the acquisition of an asset with debt. Rather, the adjustment is narrower in scope: It attempts to capture only a debt-equivalent for a company's lease contracts. For example, when a company enters into a five-year lease for an asset with a 20-year productive life, the adjustment includes only payments relating to the contracted five-year lease period. We do not use alternative methodologies that fully capitalize the value of the asset, given disclosure and other limitations.

172. However, if we view the term of a lease as artificially short relative to the length of expected use of the leased asset, we may make adjustments to reflect a more economically appropriate depiction of the underlying lease obligation. An example of this approach is for sale-and-leaseback transactions, where if practical we capitalize the entire sale amount.

Adjustment procedures

173. Data requirements:

- Minimum lease payments: The schedule of noncancellable future lease payments over the next five years and beyond (and residual-value guarantees if not included in minimum lease payments).
- Reported annual lease-related operating expenses for the most recent year.
- Deferred gains on sale-and-leaseback transactions that created operating leases.
- We use a fixed discount rate of 7% for all corporate entities we rate. Theoretically, the discount factor could be calculated as the weighted average of the implicit interest rates (that is, the rates charged by the lessors) in each of the company's operating lease arrangements. This is not practicable, however, given accounting disclosure limitations.
- The annual operating-lease-related expense, which we estimate using the average of the first projected annual payment disclosed at the end of the most recent year and the previous year.

174. Calculations (operating leases):

- Debt: We add to debt the present value of future lease payments, calculated using a 7% discount rate. Since minimum lease payments beyond the fifth year are regularly disclosed in aggregate as "thereafter," our methodology assumes that payments beyond the fifth year equal the payment amount in year five, and that the number of years in the "thereafter" period equals the "thereafter" amount divided by the fifth-year amount, rounded to the nearest year. This assumption is capped at a total payment profile of 30 years. IFRS allow companies to disclose amounts payable in years two through five as a single combined amount, instead of separate amounts for each year. In this case, we assume a flat annual payment amount in years two through five, based on the total minimum lease payment disclosed for these four years. We consider future lease payments to be net of sublease rental income only if the lease and sublease terms match and the holder of the sublease is sufficiently creditworthy (that is, has credit quality equivalent to 'BBB-' or higher).

- Income statement and cash flow measures: The lease-related expense is allocated to interest and depreciation expense. EBITDA is increased by adding back the interest and depreciation expense. EBIT is increased by adding back the interest expense. FFO and CFO are increased by adding back the depreciation expense. Gains or losses on sale-and-leaseback transactions are excluded from these measures.
- Interest expense: Interest expense is increased by the product of the 7% discount rate multiplied by the average net present value of the lease payments for the current and previous years.
- Capital expenditures: Our base calculation of capital expenditures, and therefore free operating cash flow (FOCF), excludes any implied capital expenditures relating to operating leases. For lease-intensive sectors, we may use a separate FOCF measure, which includes a capital-expenditure operating lease adjustment, to compare companies' lease and purchase decisions. For this separate FOCF measure, the capital expenditures figure is increased by an implied amount of capital expenditures relating to leases, calculated as the year-over-year change in lease debt, plus annual operating lease depreciation. This amount cannot be negative.
- Property, plant, and equipment: We add the amount of operating leases we reclassify as debt to property, plant, and equipment to approximate the depreciated asset cost.

175. Calculations (finance leases):

- Debt: To the extent that they are not already included in reported debt, we add to debt, finance lease obligations and any obligation associated with failed sale-and-leaseback transactions.
- Capital expenditures: Our base calculation of capital expenditures, and therefore FOCF, excludes any implied capital expenditures relating to finance leases. For lease-intensive sectors, we may use a separate FOCF measure, which includes a capital-expenditure finance lease adjustment, to compare companies' lease and purchase decisions. For this separate FOCF measure, capital expenditures are increased by the value of assets acquired via finance leases during the period.

12. Postretirement employee benefits and deferred compensation

176. We include underfunded defined-benefit obligations for retirees, including pensions and health care coverage (collectively, postretirement benefits or PRB) in our measure of debt. These obligations also include other forms of deferred compensation like retiree lump-sum payment schemes and long-service awards. We include these obligations in our measure of debt because they represent financial obligations that must be paid over time.

177. The adjustments we make relate solely to existing obligations, rather than to potential future obligations.

178. Unlike debt, the measurement of PRB obligations is inherently uncertain: The amount of benefits payable and the value of any assets earmarked to fund those obligations fluctuate over time.

179. To simplify the numerical analysis, we aggregate all retiree benefit plan assets and liabilities for pension, health, and other obligations, netting the positions of a company's plans in surplus against those that are in deficit.

180. We tax-effect our PRB adjustment amounts (that is, give credit for associated tax benefits), unless the related tax benefits have already been, or are unlikely to be, realized. We use the tax rates applicable to the company's plans or, if this is unavailable, the current corporate rate, even though the actual effect of tax charges or benefits in the future may be different. In a typical situation, the company has credible prospects of generating sufficient future taxable income to take advantage of tax deductions related to PRB and so reduce future tax payments.

181. We do not tax-effect the adjustment amounts if we consider a company's ability to generate profits uncertain. Moreover, in such cases, our main focus is the company's liquidity, rather than its capitalization or debt-coverage levels.

a) Capital structure

182. We adjust capitalization for PRB effects by adjusting both debt and equity, where applicable. Debt is increased by the company's tax-effected unfunded PRB obligation. In the instances where equity does not reflect the full extent of the underfunded deficit, equity is adjusted by the difference between the amount accrued on the corporate balance sheet and the amount of net over- or underfunded obligation (net surplus or deficit), net of tax. Debt is not adjusted downward for net surpluses, so net overfunding (surplus) leaves debt unchanged. Equity can be adjusted upward (if the net recognized asset is less than the pretax surplus) or downward. We do not split the debt adjustment between short and long term.

b) Cash flow

183. With PRB and deferred compensation plans, companies are effectively compensating their employees by issuing debt. Our cash flow view is that companies are constructively borrowing from the employees and paying the employees an amount equal to service costs. Additionally, because there is an interest element to the amount borrowed, our cash flow measures assume that imputed interest is paid as incurred. This approach takes a normalized view of cash flows: That is, regardless of when the pension plan is funded over the life of the plan, service costs and net interest costs are paid when incurred.

184. With that in mind, if a company is funding postretirement obligations at a level that is below its net expense (service cost and net interest cost), we interpret this as a form of borrowing that artificially bolsters reported CFO. Conversely, we try to identify catch-up contributions made to reduce unfunded obligations, which would artificially depress reported CFO. We view these contributions as akin to debt amortization, which represents a financing cash flow rather than an operating cash flow.

c) Income statement

185. For the purposes of arriving at income statement measures, we disaggregate the periodic benefit cost into its component parts, allocate those amounts to operating and financing components, and eliminate components we believe are not indicative of the current year's activity. The period's current service cost--reflecting the present value of future benefits employees earned for services rendered during the period--is the sole item we keep as part of operating expenses. We view the interest expense as a finance charge and reclassify it as such if reported differently, such as within operating expenses.

186. Under U.S. GAAP, the expected return on plan assets represents management's subjective, long-range expectation about the performance of the investment portfolio. This concept has been abandoned under IFRS, which under revised

accounting standards, now calculates a net interest figure by multiplying the deficit (or surplus) on the PRB by the discount rate. For the purposes of global comparability, we make adjustments to the reported data of companies still incorporating an expected return element into their interest calculations, such as those reporting under U.S. GAAP, to mimic the IFRS method of calculating net interest. This measure of PRB interest, if a net expense, is added to reported interest. No adjustment is made if net interest is a net income item.

Adjustment procedures

187. Data requirements (for adjustments to income and cash flow items):

- Service cost;
- Interest cost;
- Expected return on pension plan assets, if applicable;
- Actuarial gains or losses (amortization or immediate recognition in earnings);
- Prior service costs (amount included in earnings);
- Other amounts included in earnings (such as special benefits, settlements, and curtailments of benefits);
- Total benefit costs; and
- The sum of employer contributions and direct payments to employees.

188. Data requirements (for adjustments to balance-sheet items):

- PRB-related assets on the balance sheet, including intangible assets, prepaid or noncurrent assets, or any other assets;
- Reported liabilities attributed to PRB, including current and noncurrent liabilities;
- Deferred tax assets related to PRB (or the tax rate applicable to related costs);
- Fair value of plan assets; and
- Total plan liabilities.

Note: Relevant pension and other PRB amounts are combined for all plans.

189. Calculations (income statement and cash flows):

- Operating income: Add to EBIT and EBITDA the total amount of PRB costs charged to operating income, less the current service cost.
- Interest: PRB interest is the net interest cost as reported by companies under IFRS, or as we estimate for companies reporting under U.S. GAAP and other companies using the expected-return approach. If PRB interest is a cost, we include it in adjusted interest expense (we do not reduce interest expense if PRB interest is an income item). This PRB interest is added to reported interest when the net benefit costs are included in operating income. If reported interest already includes an interest component for PRB we adjust it, if necessary, to ensure it reflects the amount of PRB interest.
- Tax expense: We add to, or subtract from, reported tax expenses any tax charge or benefit that results if a company makes additional contributions to postretirement plans or falls short of planned contributions for the current year.
- FFO: FFO equals EBITDA minus net interest expense, minus current tax, with our analytical adjustments applying to each of the three components. EBITDA is adjusted for PRB as described in the first bullet point of this paragraph, while the adjusted net interest expense includes the PRB net interest cost or credit. The current tax expense is adjusted to reflect any tax benefit or charge that the company has received through making excess or insufficient contributions. The net effect of this is that FFO is reduced by the sum of current service costs and net PRB interest, adjusting for tax effects.

- CFO: The adjustment to CFO starts with a calculation of excess contributions or PRB borrowing: Total employer cash contributions (including direct payments to retirees), minus current service costs, minus PRB interest yields the excess contribution if positive, or PRB borrowing if negative. The excess contribution or PRB borrowing is reduced by taxes at the rate applicable to PRB costs (that is, the figure multiplied by 1 minus the tax rate) to create the adjustment amount to CFO. The excess contribution or PRB borrowing is added to, or subtracted from, CFO.

190. Calculations (balance sheet):

- Debt: The net balance sheet asset or liability position (funded status) is calculated as the balance-sheet PRB assets minus PRB liabilities. For the adjustment to debt, if the net pension and postretirement funded status is positive, debt is not adjusted. If the net pension and postretirement funded status is negative, this amount is reduced by the expected tax shield, that is, the amount is multiplied by 1 minus the tax rate. The resulting net amount is added to debt.
- In some jurisdictions, the tax benefit is realized in advance of funding the deficit or paying benefits, for example, when the liability is accrued for tax purposes. The expected tax shield used in our calculation only takes into account amounts that have not yet been received. The adjustment to equity also considers existing balance-sheet amounts.
- Equity: We add to, or subtract from, equity the tax-effected difference (that is, after multiplying that figure by 1 minus the tax rate) between the deficit or surplus on the PRB plan and the reported net plan assets and liabilities.

13. Scope of consolidation

191. When analyzing the creditworthiness of a group, a first critical step is to determine the manner in which a company reports the results of its subsidiaries and affiliates (including their operations, cash flows, assets, and liabilities) in its financial statements. There are several accounting methods to reflect a company's relationship with another company: full consolidation, proportionate consolidation, equity-method consolidation, and deconsolidation (that is, accounted for as an investment).

192. Full consolidation of a subsidiary entails including 100% of each line item of its income, cash flows, assets, and liabilities in the group's financial statements. When a parent owns less than 100% of a subsidiary, the non-controlling-interest holder's share is shown on a separate line in the consolidated income statement and balance sheet.

193. Proportionate consolidation of an affiliate is when all line items of a parent's financial statements include its pro rata share of the affiliate's income, cash flows, assets, and liabilities. This method of consolidation is not common in accounting, but we use it from time to time if we believe that proportionate consolidation best reflects a company's business and financial ties with subsidiaries and affiliates.

194. The equity method of consolidation involves showing the parent's share of profits (or losses) on one line in the income statement, and the parent's investment (initial price paid plus the post-acquisition share of changes in the affiliate's net assets) on the balance sheet. Only cash dividends are reflected in the parent's cash flow statement.

195. Reporting as a nonconsolidated (or deconsolidated) investment means the parent company shows the value of the investment on its balance sheet, typically measured at cost or fair value. The parent does not include any of the income of that affiliate in its results, but reports cash dividends received in the cash flow statement.

196. Although most often the scope of consolidation we employ when analyzing a company is the same as that in the company's financial statements, we may use any consolidation method that in our opinion best reflects a company's business and financial ties with its subsidiaries and affiliates. The analytical adjustments would therefore serve to convert the reported figures to those consistent with our chosen method.

197. No single factor determines our analytical view of a company's relationship with a particular business venture. Rather, the decision will reflect an assessment of factors that, taken together, will lead to a particular characterization. These factors include:

- Strategic importance--integrated lines of business or critical supplier;
- Percentage of ownership (current and prospective);
- Management control;
- Shared name;
- Domicile in the same country;
- Common sources of capital and lending relationships;
- Financial capacity for providing support;
- Significance of the amount of investment;
- Investment relative to the amount of debt at the affiliate or project;
- Position of the other owners (whether strategic or financial investment) and their financial capacity;
- Management's stated stance toward the affiliate or project;
- Whether the creditors of the subsidiary or affiliate have recourse to the parent;
- Shared collective bargaining agreements;
- The bankruptcy-law regimes applicable to the parent and subsidiary;
- Track record of the parent company in similar circumstances; and
- The nature of potential risks.

Adjustment procedures

198. Because a company can use various consolidation methods, there is no standard adjustment procedure. We adjust the reported figures to reflect our quantitative view of the group.

14. Securitization and factoring

199. Securitization can be an important financing vehicle for many companies, potentially enhancing liquidity and enabling them to diversify their funding sources. An important factor is whether the assets and liabilities of a securitization are shown on a company's balance sheet, or deconsolidated and reported as an off-balance-sheet transaction.

200. We may reconsolidate a securitization that a company reports as off-balance-sheet financing. This is because securitizations do not ordinarily transform the risks or the underlying economic reality of the business activity, nor do they necessarily provide equity relief, which allows the company to retain less equity or incur more debt than would otherwise be the case, without affecting its credit quality.

201. If a securitization accomplishes true transfer of risk (contractual, legal, and reputation risk), as is the case with securitization of a tax asset, we regard the transaction as an asset sale and make no adjustments, subject to the considerations in paragraphs 202-206.

202. More commonly, a company retains risks related to the assets transferred under the securitization transaction. We

regard such transactions as being akin to secured financing and bring them back onto the balance sheet if the company has treated them as off-balance-sheet items. The analysis also indicates whether the securitization creates a disadvantage for a company's unsecured creditors that would affect our rating on unsecured debt issues.

203. For example, in our analysis, we treat as on-balance-sheet items, securitization of assets (such as trade receivables) that are regenerated in the ordinary course of business and financed on an ongoing basis. This is because the assets and trading relationships these assets represent are an integral part of a company's operations. Even if a transaction legally transferred risks related to a pool of assets and the company has no obligation to support failing securitizations, this does not mean the company would receive equity relief or that we would not reconsolidate the securitization in our analysis. If a company has a recurring need to finance similar assets, we do not presume it will have permanent access to the securitization market. The company may have to meet future funding needs by other means, and therefore have the requisite equity (and the equivalent level of borrowings) to do so.

204. We treat factoring (or invoice discounting) of trade receivables in a similar way, by including the trade receivable asset and the associated funding liability in the company's balance sheet.

205. Other key considerations for the adjustment of securitizations include:

- The riskiness of the securitized assets. If, as is often the case, a company securitizes its highest-quality or most liquid and therefore low-risk assets, this would limit the extent of any meaningful equity relief, and may create subordination of unsecured creditors, which if significant enough could have an impact on our rating on unsecured debt.
- First-loss exposure. A company may retain liability for a defined portion of loss from a securitization (known as "first-loss exposure"), thereby providing structural credit protection for the securitized asset, which would lower funding costs. The first-loss layer may absorb much of the risk of the securitized asset, and the total gain or loss from the securitization will vary depending on the performance of the assets. Often, only the risk of loss that exceeds the first-loss exposure is transferred to third-party investors.
- Moral recourse. This refers to the likelihood that a company will support a securitization although not legally obliged to do so. Our assessment of moral recourse reflects our view of how a company could behave if losses on the securitization reached catastrophic levels. There is evidence to suggest that companies often tend to bail out troubled securitization transactions (for example, by repurchasing problematic assets or replacing them with other assets) to preserve access to this funding source and, more broadly, to preserve their good name in the capital markets. Moral recourse is magnified when securitizations make up a significant portion of a company's total financing, or when a company remains linked to the securitized assets through the use of a shared corporate name or by continuing in the role of servicer or operator. If we regard the likelihood of moral recourse as significant, we regard the securitized asset and liability as part of the company's balance sheet.

206. The adjustments to a company's financial statements also depend on the extent of risk transfer resulting from a securitization:

- If a company retains most of the risk, our cash flow/leverage ratio calculations include the securitized debt, regardless of whether the securitized debt was reported as on-balance-sheet debt or accounted for as an off-balance-sheet transaction.
- If the company retains none of the risk, the securitized assets are not regenerated in the ordinary course of business, and there are no contingent or indirect liabilities resulting from the transaction, we view the securitization as

equivalent to an asset sale and exclude it from our analysis of the company. This means that if a company has consolidated such a transaction, we use adjustments to remove the securitization assets, debt, earnings, and cash flows from the reported consolidated results in our analysis. We also adjust shareholders' equity, including for the effect of deferred taxes and imputed (or assumed) interest.

207. Several factors limit our ability to make full adjustments for securitizations. When a company reports a securitization as an asset sale in its financial statements, this may create an upfront gain or loss on the sale. When we reconsolidate such a securitization, it is appropriate to reverse such gains because of the uncertainty about whether they will be realized and because they represent nonrecurring income. Likewise, we reverse any loss on the sale that reflects the discount on the sale, to prevent double counting the interest component of the transactions.

208. To calculate the imputed interest, we generally estimate an interest rate because of insufficient information. That rate approximates the interest rate on similar transactions.

209. It is impractical to fully recast the financial statements to consolidate off-balance-sheet securitizations because companies are not required to include pro forma schedules including the securitization transaction in their published accounts.

210. Under U.S. GAAP and IFRS, companies report cash inflows or outflows related to working-capital assets or liabilities, or finance receivables, as operating items on the statement of cash flows. Consequently, securitizations of assets such as receivables affect CFO, and the effect may be particularly significant in reporting periods when the securitizations are initiated or mature.

211. The reporting convention varies with the balance-sheet classification. If a company consolidates a securitization, the related borrowings are treated as a financing activity. If the securitization is off the balance sheet, the effect is akin to accelerated liquidation of the associated assets. There is no separate record of the incurrence of debt, either as an operating liability or a financing source of cash.

212. When our approach is to consolidate a securitization (or, in rare situations, to deconsolidate a securitization), we adjust the cash flow statement to smooth out the variations in CFO that can result from the treatment of a securitization as a sale, which can distort the pattern of recurring cash flow.

Adjustment procedures

213. Data requirements:

- The period-end amount and average outstanding amount of trade receivables sold or securitized that are not on the balance sheet and require adjustments according to our criteria.

214. Calculations:

- Debt and receivables: Add the amount of period-end trade receivables sold or securitized (that is, the uncollected receivables as of the balance-sheet date) to reported debt and receivables.
- Interest expense: Add to interest expense the amount of imputed interest, calculated using the average trade receivables sold over a two-year period (if the data are available) or the trade receivables sold as of the period-end date, at an appropriate benchmark interest rate.
- CFO: Deduct from CFO the proceeds from the securitization if the transaction results in large cash flow movements,

such as on the creation of a securitization or subsequent changes in amounts securitized. Rolling over an existing securitization requires no cash flow adjustment.

15. Seller-provided financing

215. Companies acquiring other companies sometimes finance a portion of the purchase price (or consideration), via seller-provided financing and/or entering into contingent consideration arrangements (that is, "earn outs"). We often view these transactions as a form of financing and therefore we make analytical adjustments to reflect this view. The accounting approach under U.S. GAAP is materially consistent with that under IFRS.

216. The most straightforward form of seller-provided financing is a loan reported at amortized cost plus interest. We include the reported debt amount and interest expense in our respective measures to the extent that they are not already reported as such. No adjustment is necessary on the statement of cash flows, apart from any interest reported under IFRS outside of CFO.

217. The reporting of contingent consideration is more convoluted given the complexity and variability of the instruments. Contingent consideration can take many forms: It can be paid in cash or shares, it can be contingently payable by the acquirer or prepaid and contingently returnable to the acquirer, or it can be contingent upon the recipient's continued employment with the acquirer after the acquisition. The nature and terms of an arrangement dictate the accounting for the arrangement and our analytical treatment.

218. Contingent consideration payable in shares is generally reported within equity and is not remeasured in reporting periods subsequent to the transaction. We do not add to debt an amount for the anticipated settlement of these transactions because we consider them to be prospective equity issuance.

219. Contingent consideration that is prepaid and contingently returnable to the acquiring entity results in an asset on the acquirer's balance sheet that is marked to market in each accounting period until settled. We make no adjustments for these arrangements because they are effectively receivables with no potential future cash outlay. However, we would adjust CFO if the acquirer reported any returned consideration within CFO.

220. Contingent arrangements that require continued employment are technically not part of the consideration paid for the acquisition under U.S. GAAP and IFRS. Rather, such transactions represent remuneration for services after the acquisition. As such, the company does not record the transaction as a liability or expense until the services are performed. We also view such arrangements as payment for services and generally make no analytical adjustments. The recognized expense is a component of our EBITDA and FFO, and its ultimate payment should reduce CFO. Additionally, we do not adjust the reported debt figure unless the original term of the liability was greater than 12 months.

221. Our primary focus is on contingent consideration that is payable in cash, or contracts to be settled in shares that do not qualify as equity. The most common example is a contract to be settled with a variable number of shares. Companies typically record such arrangements, initially, as a liability at fair value and subsequently mark them to market at the end of each accounting period via charges or credits to income until settled. We add to debt the reported value of the liability-classified contingent consideration on each reporting date, understanding that it is not at amortized cost.

222. Consistent with our view of cash flows, described in the next paragraph, we exclude the charges or credits to income from our measurement of EBITDA and FFO, on the basis that this recognition of measurement uncertainty in the income statement is not a core operating cost, but an additional cost of the acquisition. We generally do not attempt to make adjustments to interest expense; such adjustments are usually impractical because interest on the contingent consideration is typically not disclosed.

223. When a company ultimately pays the contingent consideration to the seller, it may report the cash outflow in several ways in the statement of cash flows. We regard these outflows as investing cash flows because they represent cash paid for the purchase of a business. Any cash settlements reported in other ways (for example, as operating or financing cash flows) will be adjusted to reflect this view.

Adjustment procedures

224. Data requirements:

- The carrying value of seller-financed debt or liability-classified contingent consideration on the balance-sheet date.
- Charges or credits included in reported EBITDA.
- Cash paid for or received from the settlement of contingent consideration reported either in cash flows from operating activities or cash flows from financing activities.

225. Calculations:

- Debt: Add to debt, to the extent not already reported as such, the carrying amount of seller-financed debt at amortized cost, as well as any liability-classified contingent consideration reported at fair value.
- EBITDA: If charges or credits from the change in fair value of contingent consideration are included in reported EBITDA, add them back to or subtract them from EBITDA.
- CFO: If cash settlements are reported in CFO, remove the outflow because we consider it an investing activity (acquisition of businesses).

16. Share-based compensation expenses

226. Most major accounting regimes require companies to report the fair value of equity-based grants (such as stock options and restricted share awards) as an expense in the income statement. This amount is generally expensed over the benefiting period, that is, the period over which the company estimates the employee is providing services in exchange for the award.

227. Our cash-flow measures, such as CFO, are not affected by share-based grants payable in shares, given their inherent noncash nature. Additionally, we add back stock-based compensation that is payable in shares to EBITDA and FFO. Our key cash flow/leverage ratios--FFO to debt and debt to EBITDA--therefore exclude stock option expense related to arrangements payable in shares.

228. Certain other share-based arrangements, unlike options or restricted share awards, are payable solely in cash. Examples are stock appreciation rights that are required to be settled in cash, which represent a future call on a company's cash flow. Because they are payable in cash, we do not add back the expense related to these arrangements to EBITDA and FFO. We treat obligations under these arrangements as debt.

Adjustment procedures

229. Data requirements:

- Total share-based compensation expense reported in the period that is payable in shares.
- In jurisdictions that do not require the expensing of such compensation, an estimate of the expense.

230. Calculations:

- EBITDA: If a company has accounted for noncash stock compensation costs as an expense, we add that figure back to EBITDA.
- Operating income, before and after D&A, and EBIT: In jurisdictions that do not require companies to report share-based compensation as expenses, we estimate an expense amount and deduct it from these measures.
- Debt: Add to debt share-based arrangements payable solely in cash.

17. Surplus cash

231. We apply a standard method of calculating surplus cash, which is the amount of cash and liquid investments that is subtracted from gross debt to calculate debt.

232. Standard & Poor's payback ratios are intended to capture the degree to which a company has leveraged its risk assets. Highly liquid financial assets are often low risk. Moreover, we consider that, in addition to cash flow generation, surplus cash is available to repay debt, providing additional flexibility that enhances a company's credit quality. Therefore, it is appropriate to evaluate debt net of surplus cash.

233. Our standard methodology for calculating surplus cash allows the netting of available cash and liquid investments if in our judgment they are highly liquid, and if they are accessible; that is, the cash and liquid investments are truly surplus and therefore could be used to repay debt immediately.

234. We analyze the specifics of a company's cash holdings to evaluate how much of its cash is immediately accessible to reduce debt. To calculate how much cash can be netted off from debt, and unless we get enough information or identify analytical reasons supporting either a lower or higher haircut, we will deduct 25% from the available cash (A), identified as "cash and liquid investments" in "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published on Nov. 19, 2013, to reflect cash that is inaccessible. If we apply the default 25% haircut, adjusted cash (B) available for netting from gross debt would be A x 0.75 = B.

235. We identify cash that might be inaccessible due, among other reasons, to:

- Being held in a nonconvertible currency to the currency of a company's borrowings;
- Distribution restrictions (for example, covenants or cash held in escrow);
- Cash trapped at subsidiaries;
- Tax effects on the repatriation of cash;
- Period-end timing differences unrelated to working capital; or
- Being held in a country whose country risk we assess as high (country risk score of 5) or very high (country risk score of 6), and is in a different currency from the currency of the company's borrowings.

236. If available information indicates greater or lesser accessibility to cash and liquid investments, the haircut would be raised or lowered. For example, the haircut would increase if a company holds a large proportion of cash abroad in a

nonconvertible currency, or if the marginal tax payable on repatriation would exceed 25%. On the other hand, the haircut percentage would be lowered if, for example, detailed analysis showed that the amount of cash and liquid investments accessible on short notice would be higher than our standard assumption, or if any tax payable on repatriation of the cash and liquid investments would be at a rate of less than 25% and we believed that no other factors make the cash and liquid investments inaccessible.

237. If we forecast that a company will generate negative cash flow available for debt repayment, our cash flow/leverage criteria places greater reliance on the current year and the first and second forecast years (see paragraph 117 in "Corporate Methodology," published on Nov. 19, 2013). Forecast negative cash flows could stem from operating activities as well as share buybacks, dividends, or acquisitions, if we forecast these uses of cash based on the company's track record.

238. We will generally not deduct surplus cash from debt if a company is (1) owned by a financial sponsor as defined in Section H.2 of "Corporate Methodology," published on Nov. 19, 2013, or (2) has a business risk profile assessment of "weak" or "vulnerable." However, we deduct surplus cash from debt even if a company meets either of these conditions, as long as:

- We believe that the company has surplus cash identified to retire maturing debt or other debt-like obligations; and
- We believe--typically from the company's track record, market conditions, or financial policy--that management will use the cash to pay off maturing debt or debt-like obligations.

18. Workers' compensation and self-insurance

239. Workers' compensation schemes provide compensation for employees injured in the course of employment. Although schemes differ across jurisdictions, provisions may be made for payments to employees in lieu of wages, compensation for economic losses (past and future), reimbursement for, or payment of, medical and similar expenses, general damages, and benefits payable to the dependents of workers killed during employment.

240. Workers' compensation coverage may be provided through insurance companies, and therefore is not a financial concern for the company. But, in certain instances and/or industries, employers assume direct responsibility for payments such as medical treatment or lost wages.

241. In these cases, under U.S. GAAP or IFRS, the company reports incurred liabilities on the balance sheet as "other liabilities," using an actuarially determined present value of known and estimated claims. Accordingly, these obligations represent a call on future cash flow, distinguishing them from many other less-certain contingencies. They are analogous to postretirement obligations, which we also add to debt.

242. Treating the workers' compensation liability as debt affects many line items on the financial statements. Ideally, if there is sufficient information in the statements, we would make full adjustments, using the same approach as for postretirement employee benefits (see paragraphs 176-190). In practice, the data is not available, so we reclassify these obligations, adjusted for tax, as debt. We may also treat similar self-insurance-type liabilities as debt.

Adjustment procedures

243. Data requirements:

- Net amount reported as a liability for workers' compensation obligations and self-insurance claims.

244. Calculations:

- Debt: Add to debt, the amount recognized for workers' compensation obligations (net of tax) and the net amount recognized for self-insurance claims (net of tax).

F. Index Of Key Ratios

245. Core debt-payback ratios:

- Funds from operations (FFO)/debt
- Debt/EBITDA

246. Supplemental debt-payback and debt-service ratios:

- Cash flow from operations (CFO)/debt
- Free operating cash flow (FOCF)/debt
- Discretionary cash flow (DCF)/debt
- (FFO + interest)/cash interest (FFO cash interest cover)
- EBITDA/interest

247. Profitability ratios:

- EBIT/revenues (EBIT margin)
- EBITDA/revenues (EBITDA margin)
- EBIT/average beginning-of-year and end-of-year capital (return on capital)

VI. GLOSSARY

248. *Capital:* Debt plus noncurrent deferred taxes plus equity (plus or minus all applicable adjustments).

249. *Capital expenditures:* Funds spent to acquire or develop tangible and certain intangible assets (plus or minus all applicable adjustments).

250. *Cash interest:* For the purposes of calculating the FFO cash-interest-cover ratio, "cash interest" includes only cash interest payments on gross financial debt (including bank loans, debt capital market instruments, finance leases, and capitalized interest). Cash interest does not include any Standard & Poor's-adjusted interest on debt-like obligations, such as postretirement benefit obligations or operating leases.

251. *CFO (cash flow from operations):* CFO is also referred to as operating cash flow. This measure reflects cash flows from operating activities (as opposed to investing and financing activities), including all interest received and paid, dividends received, and taxes paid in the period (plus or minus all applicable adjustments). For companies that do not use U.S. GAAP, we reclassify as CFO any dividends received, or interest paid or received, that a company reports as investing or financing cash flows.

252. *Current tax expense:* This is the amount of income taxes payable on taxable profit, or income tax recoverable from tax losses, in an accounting period (plus or minus all applicable adjustments). Current tax expense is to be distinguished from deferred tax expense.

253. *DCF (discretionary cash flow):* FOCF minus cash dividends paid on common stock and preferred stock (plus or minus all applicable adjustments).

254. *Debt:* Gross financial debt (including items such as bank loans, debt capital market instruments, and finance leases) minus surplus cash (plus or minus all applicable adjustments).

255. *Dividends:* Dividends paid to common and preferred shareholders and to minority interest shareholders of consolidated subsidiaries (plus or minus all applicable adjustments).

256. *EBIT:* A traditional view of profit that factors in capital intensity, but also includes interest income, the company's share of equity earnings of associates and joint ventures, and other recurring, nonoperating items (plus or minus all applicable adjustments).

257. *EBITDA:* A company's revenue minus operating expenses, plus depreciation and amortization expenses, including impairments on noncurrent assets and impairment reversals (plus or minus all applicable adjustments). Dividends (cash) received from affiliates, associates, and joint ventures accounted for under the equity method are added, while the company's share of profits and losses from these affiliates is excluded.

258. *Equity:* Common equity and equity hybrids and minority interests (plus or minus all applicable adjustments).

259. *FFO (funds from operations):* EBITDA, minus net interest expense minus current tax expense (plus or minus all applicable adjustments).

260. *FOCF (free operating cash flow):* CFO minus capital expenditures (plus or minus all applicable adjustments).

261. *Interest:* This is the reported interest expense figure, including noncash interest on conventional debt instruments (such as payment-in-kind, zero-coupon, and inflation-linked debt), minus any interest income derived from assets structurally linked to a debt instrument (plus or minus all applicable adjustments).

262. *Net interest expense:* This is the reported interest expense figure, including noncash interest on conventional debt instruments (such as payment-in-kind, zero-coupon, and inflation-linked debt), minus the sum of interest income and dividend income (plus or minus all applicable adjustments).

263. *Revenues:* Total sales and other revenues we consider to be operating (plus or minus all applicable adjustments).

VII. APPENDIX

264. This criteria article supersedes:

- "2008 Corporate Criteria: Ratios And Adjustments," published on April 15, 2008;
- "Methodology And Assumptions: Standard & Poor's Revises Key Ratios Used in Global Corporate Ratings Analysis," published on Dec. 28, 2011;
- "Recognizing The Settlement Obligation For Foreign-Currency Hedges Of Debt Principal," published on April 15, 2010;
- "Methodology And Assumptions: Recognizing The Sustainable Cash Cost Of Inflation-Linked Debt For Corporates," published on Feb. 10, 2009;
- "Calculating Adjusted Debt And Interest For Corporate Issuers," published on June 2, 2008;
- "Standard & Poor's Approach To Analyzing Employers' Participation In U.S. Multi-Employer Pension Plans," published on May 30, 2006;
- "Analytical Approach To Postretirement Liabilities of Japanese Companies," published on March 31, 2003; and

- "Camouflaged Share Repurchases: The Rating Implications Of Total-Return Swaps And Similar Equity Derivatives," published on Dec. 7, 2000.

265. This criteria article partly supersedes the section Accounting And Financial Reporting in "2008 Corporate Criteria: Analytical Methodology," published on April 15, 2008.

Frequently Asked Questions

A. Surplus cash

Is the 25% deduction from cash and liquid investments, as described in paragraph 234, the standard amount Standard & Poor's uses to arrive at surplus cash and calculate adjusted debt?

No. The 25% deduction from cash and liquid investments should only be used if we do not have information that would enable the calculation of a more precise amount. If available information indicates greater--or lesser--accessibility to cash and liquid investments than what is assumed by the 25% deduction, we'd lower or raise the amount of the deduction. The deduction should only represent cash at the balance sheet date that is inaccessible to pay interest or repay debt in case of need. Often, we would expect the deduction to be less than 25%.

Can it be appropriate to have a different deduction from cash and liquid investments in arriving at surplus cash each year?

Yes, a different deduction from cash and liquid investments each year is often appropriate. We deduct from cash and liquid investments the amount of cash and liquid investments we believe is, or will be, inaccessible. That amount may not remain constant so a different percentage in each year can better reflect reality.

When developing the deduction from cash and liquid investments to arrive at surplus cash, do you exclude a minimum amount of cash necessary to run the business from the deduction? Could such a minimum amount of cash qualify as "cash trapped at subsidiaries," as noted in paragraph 235?

Generally no. When calculating surplus cash, cash and liquid investments should not be reduced by the amount of expected working capital investment needs. This is because this would disadvantage companies that fund working capital from cash rather than by drawing down on bank lines. In addition, as working capital investment should be "self-extinguishing" or "self-liquidating"--as stock and debt (i.e. inventory and receivables) are converted into cash--it is not appropriate to increase debt for working capital investment needs by reducing cash and liquid investments in the calculation of surplus cash. However, to the extent that we believe that some of the company's working capital investment won't be "self-extinguishing"--due to factors such as stock write-offs, stock discounting, or bad debts--this would be captured in weaker profits in the base-case forecast, which would reduce cash flows and future cash balances. In addition, such working capital investment needs would not qualify as "cash trapped at subsidiaries." An exception to this approach could be where a company has indicated to us an operational cash requirement such that 'cash in the tills' is not practically accessible because it is needed to operate their business (examples include a supermarket who needs cash in tills, or a casino who needs to retain cash in cages). In such cases, we treat this cash need as part of the 'cash trapped at subsidiaries' condition (see paragraph 235).

Do you consider future events (e.g., large expected cash outflows related to capital expenditures, acquisitions, share buybacks and dividends, or lower forecasted earnings) in developing the haircut to gross cash and liquid investments in a particular period?

No. The haircut to gross cash and liquid investments is only for matters of inaccessibility, not future events or needs.

The expected cash outflow or reduced earnings should be included in the base-case forecasts. This will reduce forecast cash flows and period-end cash balances.

Should the haircut applied to liquid investments consider the taxes that would be incurred upon the sale of liquid investments?

Yes. The same principle we apply when tax-effecting cash held overseas should apply here. If the issuer needs to sell liquid investments to generate cash to pay interest or repay debt, the cash that would be received and would be available to pay interest and repay debt would be the net amount of cash after any taxes payable.

Paragraph 235 states that "We identify cash that might be inaccessible due, among other reasons, to...distribution restrictions (for example, covenants or cash held in escrow...)". Are there cases where Standard & Poor's could net off cash that is subject to distribution restrictions from gross debt to calculate debt? If so, do the qualitative preclusions to deducting surplus cash noted in paragraph 238 apply?

Yes, there can be situations where we net off cash that is subject to distribution restrictions from gross debt as part of the surplus cash adjustment--if the cash is restricted for the benefit of creditors with obligations that we include in debt. In these cases, the qualitative restrictions on giving surplus cash credit do not apply, just as they do not apply to netting off other committed assets such as pension assets. For example, if the purpose of the cash distribution restriction is to retain the cash for the benefit of counterparties to debt or debt-like obligations that are otherwise included in our adjusted debt metric, such restricted cash could be netted off gross debt. For example, cash held in escrow for the benefit of debtholders would be fully netted off from debt if the debt is included in Standard & Poor's debt calculation. Additionally, if the exclusion of restricted cash from cash and liquid investments in the calculation of surplus cash would run counter to one of our other analytical adjustments, the restricted cash could be netted off gross debt. An example of this is a cash-collateralized letter of credit facility whereby an issuer overfunds a term loan and places the excess funds in escrow as a backstop for letters of credit or performance guarantees. As long as we believe that the company will not have to make payments under the guarantee, such cash would be eligible for netting against gross debt. This is because, as paragraphs 99 and 100 state, "We do not regard performance guarantees as debt if a company is likely to maintain sufficient work or product quality to avoid making large payments under those guarantees. A company's past record of payments under performance guarantees could indicate the likelihood of future payments under such guarantees. Only if this payment history suggests a high likelihood of future payments would we estimate a potential liability and add that amount to debt."

If an issuer that Standard & Poor's classifies as volatile or highly volatile under the cash flow/leverage criteria has a large amount of surplus cash on hand during a favorable part of the industry cycle, but based on historical evidence you expect it will use most of that cash to meet operating needs during periods of stress, do you take this into account in the surplus cash analysis?

No. When calculating surplus cash, we would only haircut cash and liquid investments by the amount of any of the cash and liquid investments that are inaccessible. Any expected future uses of cash can be captured in the base-case forecast. If an issuer is assessed under the cash flow/leverage criteria to be volatile or highly volatile, then the cash flow/leverage assessment could be modified by one or two categories weaker (as per paragraph 124, section 5, of "Corporate Methodology," published Nov. 19, 2013).

B. Non-operating activities and non-recurring charges

What types of events constitute "transformative events" for the purpose of adjusting for non-recurring items? Is this the same threshold used in the cash/flow leverage criteria, and if so why is there a need to adjust if the weighted average is going to exclude history?

A transformative event is any event that could cause a material change in a company's financial profile. Examples of such changes are the divestment of part of the business or a fundamental change in operating strategy. The idea of a transformative event in these criteria is a similar concept to that contained in paragraph 112 of "Corporate Methodology." When transformative events have occurred and there is sufficient disclosure such that pro forma historical financials are representative of the ongoing entity, historical periods can be used in the cash flow leverage weighted average. Conversely, if the transformative event so alters the business or contorts the historical financials--such that analytical adjustments to historical financials cannot be reasonably employed to in effect pro forma the historical results to be representative of the ongoing entity--then adjustments will not be attempted. Instead, our cash flow leverage analysis will rely on the forecasted periods as described in paragraph 112 of "Corporate Methodology."

Do you adjust for certain accounting anomalies on a regular basis? Do these distortions for "measurement effects" or "accounting distortions," which can lead to misleading figures in the annual financial statements, qualify for adjustment under the non-recurring criteria despite not meeting the "transformative" threshold?

While such distortions are not transformative events per se, we do make adjustments for accounting distortions in certain circumstances for a similar reason: that is to arrive at more meaningful ratios (see paragraphs 140-167). The "nonoperating activities and nonrecurring items" section of the ratio and adjustments criteria gives examples of measurement effects and accounting distortions that we exclude from our financial measures, such as goodwill impairments or unrealized mark-to-market gains or losses on derivatives where a company has not achieved the requirements of technical hedge accounting, even though an effective economic hedge may exist. Other examples of measurement effects and accounting distortions that we exclude from our financial measures include:

- A change in the measurement of a material litigation provision that leads to very significant gains or losses in the year; and
- Fair valuation gains or losses on investment properties under IFRS.

C. Adjusted debt principle

The adjusted debt principle mentions that "to the extent that a company defers payment beyond the term customary for its supply chain, we may add that amount to debt." Under what circumstances would you apply this and how would it be calculated? And how does Standard & Poor's treat reverse factoring arrangements?

If we believe that an issuer's trade payable days are well beyond the range of what would be deemed normal trade terms for the industry, and the improvement to cash flow/leverage measures that results from the stretch in trade payables is deemed to be material, then we'd make an adjustment. In the case of reverse factoring--which we define as financing initiated by a company in order to help its suppliers finance their receivables--we may make a debt adjustment for the customer, if we believe that the trade payable days are well beyond the range of what would be deemed normal trade terms for the industry (see above). However, we would not make an adjustment to debt for the supplier if the supplier has no contractual commitment to meet the customer's obligations and we are confident there is no moral recourse or reputational risk to the supplier as part of the reverse factoring program.

Do structured settlements (e.g., tax settlements and tobacco settlements) qualify as debt under the adjusted debt principle?

Yes. The adjusted debt principle says that we add to debt "incurred liabilities that provide no future offsetting operating benefit." Structured settlements of dispute, whether with commercial or governmental entities, fit this principle and are added to debt (on a discounted basis if feasible).

Under the adjusted debt principle, do you treat a redeemable minority interest as debt?

Yes, but only when the redemption is outside of the control of the issuer (i.e., the minority interest holder has a put option on the subsidiary's shares as opposed to the issuer having a call option to repurchase the shares) and we fully consolidate the subsidiary in our analysis. The liability would be added to our adjusted debt figure based on the adjusted debt principle (see paragraph 21) since the subsidiary is fully consolidated into the parent's accounts and, therefore, the benefits of ownership are accruing to the issuer.

D. Litigation

How does Standard & Poor's capture the risk associated with a large legal settlement, if not quantitatively captured as part of an adjustment to debt?

As stated in paragraphs 191 and 192 of "Corporate Methodology," we consider as part of our Comparable Ratings Analysis factors that may not be already or fully captured elsewhere in our analysis, such as this type of risk. Such factors will generally reflect less frequently observed credit characteristics, may be unique, or may reflect unpredictability or uncertain risk attributes, both positive and negative. In particular, we could assign a negative assessment for Comparable Ratings Analysis, depending on how well (or not) a company identifies, manages, and reserves for contingent risk exposures that can arise if guarantees are called, derivative contract break clauses are activated, or substantial lawsuits are lost.

Related Criteria And Research

- Corporate Methodology, Nov. 19, 2013
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Nov. 19, 2013
- Methodology And Assumptions: Assigning Equity Content To Corporate Entity And North American Insurance Holding Company Hybrid Capital Instruments, April 1, 2013
- Criteria Clarification On Hybrid Capital Step-Ups, Call Options, And Replacement Provisions, Oct. 22, 2012
- Principles Of Credit Ratings, Feb. 16, 2011
- Methodology: Hybrid Capital Issue Features: Update On Dividend Stoppers, Look-Backs, And Pushers, Feb. 10, 2010
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

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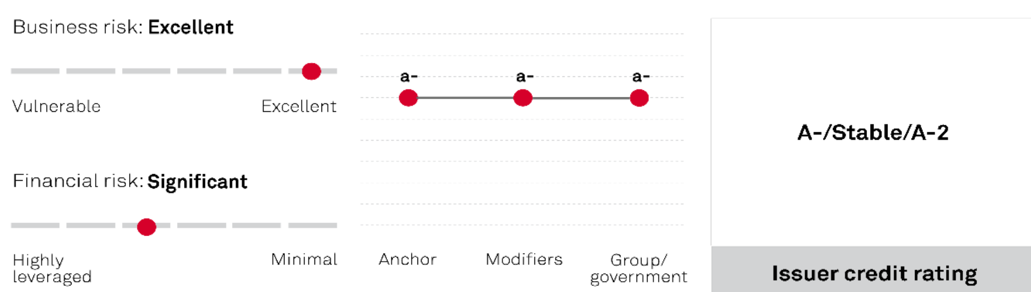

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Credit Highlights

Overview

Key strengths	Key risks
Fully regulated electric and natural gas utility strategy.	Climate change.
Large base of stable electric and natural gas customers.	Weakening regulatory jurisdiction.
Energy transition plan with an approved accelerated timeline.	Limited geographic and regulatory diversity.

We expect more class action lawsuits to be filed against Public Service Co. of Colorado's (PSCo) parent Xcel Energy Inc. Earlier this month, the Boulder County Sherriff's Office concluded its investigation into the cause and origin of the late 2021 Marshall Fire. The investigation stated that one of the two fires was most likely started by arcing power lines owned and managed by PSCo; however, the investigation found no evidence of criminally negligent or reckless system design or maintenance and instead pointed to the extraordinarily high winds that caused the lines to arc. More than 1,000 homes and commercial structures were damaged and two individuals died as a result of the 6,000-acre fire. Additional class action lawsuits have been filed against PSCo's parent, Xcel Energy, since the report was released on June 8, 2023.

Although we anticipate the legal process to be drawn out, total damages could be substantial if PSCo is found liable. Last October, Colorado's state insurance commission estimated the total economic financial loss from the wildfire to exceed $2 billion. It is our understanding that Colorado statute caps claims for noneconomic loss or injury at about $640,000 per claim, which may be increased by the court upon clear and convincing evidence to a maximum of $1.28 million per claim. We anticipate the legal process will be drawn out; our existing base case assumes the company's financial impact related to the fire is manageable. Should the legal process proceed in a manner that is unfavorable for the company, we would reevaluate our view of the company's business and financial risks.

PSCo has a cushion in its financial measures to weather weaker regulatory outcomes. We expect the utility's stand-alone financial measures, including funds from operations (FFO) to debt, to remain robust and support parent Xcel's consolidated FFO to debt. PSCO contributes roughly 37% of parent Xcel's EBITDA.

Colorado Senate Bill (SB) 291 transfers commodity price risk to the state's investor-owned utilities (IOUs), including PSCo. The legislation--which was introduced as a response to the large customer bill increases driven primarily by volatile fuel and purchased gas costs experienced in recent years--seeks to limit commodity cost volatility that is borne by ratepayers. The bill includes the following:

- The bill requires IOUs to file gas price risk management plans, which could include physical or financial hedging strategies to reduce this volatility, with the commission before Nov. 1, 2023;
- The bill mandates that the commission adopt rules by Jan. 1, 2025, to establish fuel-cost sharing mechanisms that could contain dead-bands. While allowing the company an opportunity to retain a benefit, these also limit the costs that may be recovered from ratepayers;
- The bill limits expenses related to business or legal consultants recovered by IOUs in rate cases;
- The bill restricts IOUs from charging gas customers for voluntarily terminating gas service; however, any costs associated with termination are eligible for recovery; and
- The bill mandates that an evaluation around the risk of stranded or underutilized gas infrastructure be conducted with the goal of limiting the rate impact of such infrastructure on customers.

We believe the legislative developments are mostly negative for credit quality, increasing the risk of commodity cost disallowance and reducing the flexibility that the regulatory framework provides in recovering unexpected costs when they arise. While the ability for IOUs to propose hedging strategies to potentially dampen commodity cost volatility is positive for credit quality, hedging contracts come with a significant cost.

Outlook

The stable rating outlook on PSCo reflects that of parent Xcel. Under our base case, we expect PSCo's stand-alone funds FFO to debt to be 20%-22% through 2025.

Downside scenario

We could lower the rating on PSCo over the next 24 months if we downgrade parent Xcel.

Upside scenario

We could raise PSCo's ratings over the next 24 months if we raise the ratings on parent Xcel.

Our Base-Case Scenario

Assumptions

- Gross margin grows an average of 5.5% annually through 2025, driven by the recovery of capital costs and robust volumetric growth in Colorado;
- Capital spending averages $2.4 billion per year through 2025;
- Dividends of $520 million-$710 million per year;
- Discretionary cash flow, or operating cash flow after capital spending and dividends that remain negative through 2025, requires external funding that could include debt financing or equity infusions from parent Xcel; and
- All debt maturities are refinanced.

Key metrics

Public Service Co. of Colorado--Key Metrics*

	2022a	2023e	2024f	2025f
Debt to EBITDA (x)	4.0	3.5-4.0	3.5-4.0	3.5-4.0
FFO to debt (%)	20.4	20.0-22.0	20.0-22.0	20.0-22.0
FFO cash interest coverage (%)	6.8	6.5-7.0	6.5-7.0	6.5-7.0

*All figures adjusted by S&P Global Ratings. a--Actual. f--Forecast. e--Estimate. FFO--Funds from operations.

Company Description

PSCo, a subsidiary of Xcel, operates as a vertically integrated electric and natural gas distribution utility in Colorado.

Peer Comparison

Public Service Co. of Colorado--Peer Comparisons

	Public Service Co. of Colorado	PacifiCorp	Black Hills Corp.	Evergy Kansas Central Inc.

Public Service Co. of Colorado--Peer Comparisons

Foreign currency issuer credit rating	A-/Stable/A-2	BBB+/Negative/A-2	BBB+/Stable/A-2	A-/Negative/A-2
Local currency issuer credit rating	A-/Stable/A-2	BBB+/Negative/A-2	BBB+/Stable/A-2	A-/Negative/A-2
Period	Annual	Annual	Annual	Annual
Period ending	2022-12-31	2022-12-31	2022-12-31	2022-12-31
Mil.	$	$	$	$
Revenue	5,708	5,679	2,552	3,056
EBITDA	1,977	2,291	718	1,189
Funds from operations (FFO)	1,618	2,065	559	932
Interest	309	441	172	214
Cash interest paid	280	411	158	178
Operating cash flow (OCF)	1,335	1,791	579	937
Capital expenditure	1,869	2,135	599	912
Free operating cash flow (FOCF)	(534)	(344)	(20)	25
Discretionary cash flow (DCF)	(1,025)	(444)	(194)	(430)
Cash and short-term investments	10	641	21	9
Gross available cash	10	641	21	9
Debt	7,925	9,309	4,759	5,343
Equity	9,230	10,740	3,090	4,507
EBITDA margin (%)	34.6	40.3	28.1	38.9
Return on capital (%)	6.4	6.5	6.0	6.8
EBITDA interest coverage (x)	6.4	5.2	4.2	5.5
FFO cash interest coverage (x)	6.8	6.0	4.5	6.2
Debt/EBITDA (x)	4.0	4.1	6.6	4.5
FFO/debt (%)	20.4	22.2	11.7	17.4
OCF/debt (%)	16.8	19.2	12.2	17.5
FOCF/debt (%)	(6.7)	(3.7)	(0.4)	0.5
DCF/debt (%)	(12.9)	(4.8)	(4.1)	(8.1)

Business Risk

Our assessment of PSCo's business risk profile reflects its low-risk, rate-regulated electric and gas utility business. The utility provides services to 3.1 million electric and natural gas customers in Colorado. Most customers are residential (89%), providing more stable revenue. The utility benefits from various regulatory mechanisms that mitigate regulatory lag and underearning, including rate surcharges that provide the recovery of expenses outside of the rate case, which we view as constructive for credit quality. We believe its broad customer base provides a greater opportunity to effectively manage the customer's bill.

We believe that consistency within Colorado's rate-making process has weakened, which is incorporated in our view of the jurisdiction compared with others. This reflects the authorization of below-average returns and the commission's reliance on an average cost rate base instead of the historically used original year-end cost rate base. Additionally, the commission has relied on historical test periods for rate-making purposes even when using forecast test periods is permitted by law. Further, authorized capital structure parameters, including return on equity, for IOUs have been below industry norms in recent proceedings. We view these actions as negative for credit quality because they exacerbate regulatory lag. Overall, we assess PSCo's effective management of regulatory risk as in line with peers, and we expect the company's effective management of regulatory risk to persist despite our belief that the regulatory environment in Colorado has weakened.

Furthermore, we believe that operating a natural gas system in Colorado continues to be challenging. The state's repeated interest in electrification is challenging the gas utility's growth prospects. We believe the heightened scrutiny of current and future systems may lower the predictability of investment recovery and increases the risk of stranded assets.

Our assessment also incorporates PSCo's exposure to coal generation, exposing it to heightened environmental risks, including the ongoing cost of operating older units in the face of disruptive technology advances and the potential for increased environmental regulations requiring significant capital investments. PSCo has about 1,700 megawatts of coal-fired operating capacity, representing over 25% of its total net generation capacity. However, the utility targets carbon emission reductions of 80% by 2030 and the retirement of its coal fleet by 2030.

Financial Risk

Our assessment of PSCo's financial risk profile incorporates a base-case scenario that includes S&P Global Ratings-adjusted FFO to debt of 20%-22% through 2025, above the midpoint of the benchmark range of the significant category. Further, we expect the supplemental ratio of FFO cash interest coverage to be 6.5x-7.0x, bolstering the financial risk profile assessment. In addition, we expect continued capital spending, combined with the utility's dividend, will result in negative discretionary cash flow through 2025. This negative cash flow will require funding such as debt issuances and equity injections from within the Xcel group to maintain credit quality. As a result, we expect debt leverage, as indicated by S&P Global Ratings-adjusted debt to EBITDA, to be 3.5x-4.0x, which is within the benchmark range for the financial risk profile.

We assess PSCo's financial measures using our medial volatility financial benchmark table. This reflects the company's steady cash flow and rate-regulated utility operations. These benchmarks are more relaxed than those we use for a typical corporate issuer.

Debt maturities

As of year-end 2022:

- 2023: $250 million
- 2024: $0
- 2025: $250 million
- 2026: $0
- 2027: $0
- Thereafter: $6.45 billion

Public Service Co. of Colorado--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.)	$	$	$	$	$	$

Public Service Co. of Colorado--Financial Summary

Revenues	4,043	4,086	4,237	4,183	4,815	5,708
EBITDA	1,422	1,422	1,528	1,540	1,782	1,977
Funds from operations (FFO)	1,205	1,075	1,290	1,282	1,519	1,618
Interest expense	226	245	263	262	269	309
Cash interest paid	210	231	232	235	249	280
Operating cash flow (OCF)	1,218	1,013	1,253	1,197	825	1,335
Capital expenditure	1,456	1,576	1,706	1,684	1,595	1,869
Free operating cash flow (FOCF)	(238)	(563)	(452)	(487)	(770)	(534)
Discretionary cash flow (DCF)	(572)	(938)	(910)	(1,318)	(1,237)	(1,025)
Cash and short-term investments	29	33	15	28	25	10
Gross available cash	28	33	15	28	25	10
Debt	5,404	6,070	6,241	6,720	7,378	7,925
Common equity	5,828	6,298	6,996	7,592	8,444	9,230
Adjusted ratios						
EBITDA margin (%)	35.2	34.8	36.1	36.8	37.0	34.6
Return on capital (%)	8.9	7.5	7.2	6.4	6.3	6.4
EBITDA interest coverage (x)	6.3	5.8	5.8	5.9	6.6	6.4
FFO cash interest coverage (x)	6.7	5.6	6.6	6.4	7.1	6.8
Debt/EBITDA (x)	3.8	4.3	4.1	4.4	4.1	4.0
FFO/debt (%)	22.3	17.7	20.7	19.1	20.6	20.4
OCF/debt (%)	22.5	16.7	20.1	17.8	11.2	16.8
FOCF/debt (%)	(4.4)	(9.3)	(7.2)	(7.3)	(10.4)	(6.7)
DCF/debt (%)	(10.6)	(15.5)	(14.6)	(19.6)	(16.8)	(12.9)

Reconciliation Of Public Service Co. of Colorado Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	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	7,154	9,230	5,708	1,842	994	260	1,977	1,255	491	1,880
Cash taxes paid	-	-	-	-	-	-	(79)	-	-	-
Cash interest paid	-	-	-	-	-	-	(250)	-	-	-
Lease liabilities	576	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	110	19	19	(19)	91	-	-

Reconciliation Of Public Service Co. of Colorado Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Accessible cash and liquid investments	(10)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	11	(11)	(11)	-	(11)
Asset-retirement obligations	376	-	-	19	19	19	-	-	-	-
Nonoperating income (expense)	-	-	-	-	20	-	-	-	-	-
Debt: other	(171)	-	-	-	-	-	-	-	-	-
EBITDA: other	-	-	-	6	6	-	-	-	-	-
D&A: other	-	-	-	-	(6)	-	-	-	-	-
Total adjustments	771	-	-	135	58	49	(359)	80	-	(11)
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	7,925	9,230	5,708	1,977	1,052	309	1,618	1,335	491	1,869

Liquidity

Our 'A-2' short-term rating on PSCo reflects our long-term issuer credit rating on the company. As of March 31, 2023, we assess the company's liquidity as adequate, with sources covering uses by 1.1x for the coming 12 months, even if forecast stand-alone EBITDA declines 10%. We use slightly less stringent thresholds to assess the utility's liquidity because we believe the regulatory framework under the Colorado Public Utilities Commission provides it with a manageable level of cash flow stability, even in times of economic stress.

Our assessment also reflects PSCo's generally prudent risk management--we expect the utility will manage its upcoming long-term debt maturities well in advance of their scheduled due dates--sound relationships with its banks, and satisfactory standing in the credit markets. In addition, we believe it could reduce its high capital spending during stressful periods, which limits the need to refinance under such conditions.

Overall, we believe PSCo will likely withstand the adverse market circumstances over the next 12 months while maintaining sufficient liquidity to meet its obligations. This is partially supported by its $700 million of committed credit facility capacity through 2027.

Principal liquidity sources

- Cash and liquid investments of $20 million;
- Credit facility availability of $700 million;
- Estimated cash FFO of $1.8 billion; and
- Working capital inflows of about $210 million.

Principal liquidity uses

- Capital spending of $1.6 billion;
- Debt maturities of about $360 million; and
- Dividends of $540 million.

Environmental, Social, And Governance

ESG Credit Indicators

E-1	**E-2**	E-3	E-4	E-5

S-1	**S-2**	S-3	S-4	S-5

G-1	G-2	G-3	G-4	G-5

Environmental	Social	Governance
- N/A	- N/A	- Transparency and reporting - Risk management, culture, and oversight

N/A—Not applicable. ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1-5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary "ESG Credit Indicator Definitions And Applications," published Oct. 13, 2021.

Governance factors are a positive consideration in our credit rating analysis of PSCo due to the execution of its strategic plan to invest in regulated utilities and manage regulatory risk.

Group Influence

Under our group rating methodology, we consider PSCo a core subsidiary of parent Xcel, reflecting our view that PSCo is highly unlikely to be sold, is integral to the overall group strategy, possesses a strong long-term commitment from senior management, and is closely linked to the parent's name and reputation. In our assessment, we align PSCo's issuer credit rating with Xcel's group credit profile of 'a-'.

Issue Ratings--Recovery Analysis

Key analytical factors

PSCo's first-mortgage bonds benefit from a first-priority lien on substantially all the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a '1+' recovery rating and an issue rating one notch above the issuer credit rating.

Rating Component Scores

Foreign currency issuer credit rating	**A-/Stable/A-2**
Local currency issuer credit rating	**A-/Stable/A-2**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Strong
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**a-**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Strong (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	**a-**

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of July 05, 2023)*

Public Service Co. of Colorado		
Issuer Credit Rating		A-/Stable/A-2
Commercial Paper		
Local Currency		A-2
Senior Secured		A
Issuer Credit Ratings History		
23-Jun-2010	*Foreign Currency*	A-/Stable/A-2
10-Jun-2009		BBB+/Positive/A-2
16-Oct-2007		BBB+/Stable/A-2
23-Jun-2010	*Local Currency*	A-/Stable/A-2
10-Jun-2009		BBB+/Positive/A-2
16-Oct-2007		BBB+/Stable/A-2
Related Entities		
Northern States Power Co.		
Issuer Credit Rating		A-/Stable/A-2
Commercial Paper		
Local Currency		A-2
Senior Secured		A
Northern States Power Wisconsin		
Issuer Credit Rating		A-/Stable/A-2
Commercial Paper		
Local Currency		A-2
Senior Secured		A
Southwestern Public Service Co.		
Issuer Credit Rating		A-/Stable/A-2
Commercial Paper		
Local Currency		A-2
Senior Secured		A
Senior Unsecured		A-
Xcel Energy Inc.		
Issuer Credit Rating		A-/Stable/A-2
Commercial Paper		
Local Currency		A-2
Senior Unsecured		BBB+

*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.

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Research Update:

Xcel Energy Inc. Outlook Remains Stable; PSCo Outlook Now Negative Amid Increasing Wildfire Risks; Ratings Affirmed

July 28, 2023

Rating Action Overview

- Legal complaints continue to be filed against Xcel Energy Inc. and its subsidiary Public Service Co. of Colorado (PSCo) related to the 2021 Marshall Fire in Colorado, which burned over 6,000 acres and destroyed or damaged over 1,000 structures.
- The growing cases follow the release of the June investigative report by the Boulder County Sheriff's Office that concluded the most probable cause of the second fire ("Trailhead Fire") was hot particles discharged from Xcel's powerlines.
- At the same time, Xcel benefits from sufficient cushion in its financial measures to weather incremental costs or weaker regulatory outcomes until such time as additional information on the pending legal risks become available.
- We therefore affirmed our ratings on Xcel and its subsidiaries, including Northern States Power Co. (NSP-M), Public Service Co. of Colorado (PSCo), Southwestern Public Service Co. (SPS), and Northern States Power Wisconsin (NSP-W). We revised the outlook on PSCo to negative from stable. The outlooks on Xcel and its remaining subsidiaries are stable.
- The stable outlook on Xcel reflects our expectation that the company will continue to reach constructive regulatory outcomes to avoid any significant increase in business risk, reflecting S&P Global Ratings-adjusted funds from operations (FFO) to debt that averages about 16% through 2025. The negative outlook on PSCo reflects the probability that managing regulatory risk could become more challenging for the company over the next 24 months as it navigates the legal proceedings related to the Marshall Fire.

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Rating Action Rationale

Xcel has roughly 100 basis points of cushion in its financial measures to weather incremental costs or weaker regulatory outcomes. Our base case assumes consolidated FFO to debt averages about 16% through 2025. This incorporates NSP-M's most recently authorized rate increase in Minnesota, Xcel's elevated capital spending program between $5 billion to $6.2 billon, and our assumption that Xcel's debt capitalization will continue to reflect 60% through 2025. We assess the consolidated financial risk profile using our medial volatility table, consistent with its regulated utility businesses.

As of today, eight complaints have been filed on behalf of plaintiffs relating to subsidiary PSCo's involvement in the Marshall Fire. Our base case assumes the legal issues will take time to bring to resolution and that Xcel's business risk will not materially increase due to adverse regulatory or legal developments as it navigates the legal proceedings related to the Marshall Fire. In addition, Xcel has $500 million in insurance coverage to cover any legal expenses or financial liabilities that may arise over the next 24 months. We will continue to assess any legal developments as they arise.

Managing regulatory risk in Colorado could become more challenging. We expect PSCo could implement more aggressive wildfire mitigation tactics, such as public safety power shut-offs, to proactively reduce the risk of causing a catastrophic wildfire. Should the frequency of these shut-offs increase, frustrated customers and adverse public opinion could negatively affect PSCo's ability to consistently manage regulatory risk. We believe the legislative response to PSCo's recovery of $508 million in extraordinary gas costs related to the February 2021 winter storm supports our view. SB 291, which was enacted in May 2023, limits commodity cost volatility that is borne by ratepayers by transferring commodity price risk to the state's investor-owned utilities (IOUs), including PSCo.

For additional analysis, please see our last publishing on PSCo, published July 5, 2023.

PSCo expects to file its fourth wildfire mitigation plan during the first quarter of 2024. Since 2020, PSCo has filed wildfire mitigation plans with its state regulator, the Colorado Public Utilities Commission (PUC), that detail its reporting of key performance indicators and capital and operating costs incurred over the previous year. The reports provide the PUC with a status update on the company's wildfire risk, activities, and associated costs the utility has undertaken over the past year that support its mitigation plan. PSCo's ratemaking authorizes through 2023 deferred accounting treatment of depreciation expense and interest associated with distribution capital additions incurred during the prior year, with carrying costs equal to the company's long-term cost of debt. We view PSCo's annual plan and implementation as supporting credit quality as wildfire mitigation reduces the company's operating risk and cost recovery supports financial health.

We believe climate change could make wildfires in Colorado more frequent. We are therefore revising our environmental score for our environmental, social, and governance (ESG) credit indicators on PSCo to E-3 from E-2, reflecting that environmental factors have a moderately negative influence on the ratings.

We revised downward our group status for PSCo to highly strategic from core. This reflects our view that PSCo is highly unlikely to be sold, constitutes a significant portion of Xcel's cash flows (approximately 38% of EBITDA) and is closely linked to the group's reputation and risk management. Furthermore, PSCo is important to the group's long-term strategy, has the strong long-term commitment from the group, and is reasonably successful at what it does. That said, in our opinion, because of ongoing wildfire risks in Colorado, there may be situations where extraordinary support from the group may be limited, supporting our decision to revise group status for PSCo.

We assess the cumulative value of the insulating measures in place as sufficient to rate NSP-M, PSCo, SPS, and NSP-W up to one notch higher than the group credit profile. Each utility benefits from the following key insulating measures:

- It is a separate stand-alone legal entity that functions independently--both financially and operationally--files its own rate cases, and is independently regulated by commissions in Colorado, Minnesota, New Mexico, Texas, and Wisconsin.
- It has its own records and books, including its stand-alone audited financial statements.
- It has its own funding arrangements, issues its own long-term debt, and has a separate committed credit facility for its short-term funding needs.
- It does not commingle funds, assets, or cash flows with its parent.
- It does not have any cross-default obligations, and a default by its parent would not directly lead to a default at the utility.

Consistent rate recovery is strengthening SPS' financial measures. We expect SPS' financial measures to reflect around the midpoint of the significant financial risk profile category through 2025. This incorporates stand-alone FFO to debt between 18%-19% through 2025. As a result, we revised our stand-alone credit profile (SACP) on SPS to 'a-' from 'bbb+' to reflect this strengthening.

Higher capital spending is expected to weaken NSP-W's financial measures. We expect NSP-W's stand-alone FFO to debt to average 22% through 2025. This leads to a downward revision in its financial risk profile category to significant from intermediate. However, the company's SACP remains unchanged at 'a-'.

Outlook

Xcel

The stable outlook on Xcel reflects our expectation that the company's business risk will not materially increase from any adverse regulatory or legal developments as it navigates the legal proceedings related to the Marshall Fire. Our base case incorporates consolidated FFO to debt that averages about 16% through 2025.

Downside scenario

We could lower the rating on Xcel if consolidated financial measures, including adjusted FFO to debt, weaken to consistently below 15%. This could occur if:

- The company faces adverse developments as it navigates the legal proceedings related to the Marshall Fire; or
- The company's utility subsidiaries receive weaker-than-expected regulatory outcomes that affect Xcel's financial performance.

Upside scenario

While unlikely during the next 24 months, absent an adverse regulatory outcome or negative development concerning subsidiary PSCo's wildfire risk, we could raise the rating on Xcel if consolidated financial measures consistently exceed our base-case forecast, reflecting FFO to debt consistently greater than 20%.

Outlook

PSCo

The negative outlook on PSCo reflects the probability that managing regulatory risk could become more challenging for the company over the next 24 months as it navigates the legal proceedings related to the Marshall Fire. Our base case incorporates PSCo's stand-alone adjusted FFO to debt of 20% through 2025.

Downside scenario

We could lower our ratings on PSCo over the next 24 months if its stand-alone FFO to debt weakens to consistently below 17%. This could occur if the company faces any adverse regulatory or legal developments as it navigates the legal proceedings related to the Marshall Fire and we believe the company's ability to effectively manage regulatory risk has deteriorated.

Upside scenario

We could revise the outlook to stable if the company navigates the legal proceedings related to the Marshall Fire in a credit-supportive manner and maintains its stand-alone financial performance.

Outlook

NSP-M

The stable outlook reflects our expectation that NSP-M will continue to file and receive balanced yet constructive rate outcomes on a consistent basis to avoid any meaningful increase in business risk. Our base case incorporates NSP-M's stand-alone FFO to debt between 21%-23% through 2025, which is at the upper end of our significant financial risk profile assessment.

Downside scenario

We could lower our ratings on NSP-M over the next 24 months if:

- We lower our ratings on Xcel; or
- NSP-M's stand-alone FFO to debt weakens to consistently below 21%.

Upside scenario

Although unlikely, we could raise our ratings on NSP-M if we upgrade Xcel and NSP-M's stand-alone financial measures strengthen, such that its FFO to debt is consistently above 25%.

Outlook

SPS

The stable outlook reflects our expectation that SPS will continue to file and receive balanced yet constructive rate outcomes on a consistent basis to avoid any meaningful increase in business risk. Our base case incorporates SPS' stand-alone FFO to debt between 18%-19% through 2025.

Downside scenario

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

- We lower our ratings on Xcel; and
- SPS' stand-alone FFO to debt weakens to consistently below 18%.

Upside scenario

Although unlikely, we could raise our ratings on SPS if we upgrade Xcel.

Outlook

NSP-W

The stable outlook reflects our expectation that NSP-W will continue to file and receive balanced yet constructive rate outcomes on a consistent basis to avoid any meaningful increase in business risk. Our base case incorporates NSP-W's stand-alone FFO to debt that averages 22% through 2025.

Downside scenario

We could lower our ratings on NSP-W over the next 24 months if:

- We lower our ratings on Xcel; and
- NSP-W's stand-alone FFO to debt weakens to consistently below 18%.

Upside scenario

Although unlikely, we could raise our ratings on NSP-W if we upgrade Xcel.

Company Description

Xcel is a holding company of regulated electric and natural gas utilities that serve 5.8 customers in eight states. The company owns over 20,650 MW of electricity generation capacity.

Our Base-Case Scenario

- Ongoing cost recovery through authorized mechanisms and periodic rate case filings.
- Operating expenses through 2025 that grow under 1% annually.
- Elevated capital spending between $5.4 billion and $6.2 billion per year.
- Dividend payout ratio between 60%-70%.
- Consolidated debt to capitalization that averages 60% through 2025.
- Negative discretionary cash flow indicates external funding needs.
- All debt maturities are refinanced.

Liquidity

We assess Xcel's liquidity as adequate as of March 31, 2023, which reflects sources covering uses by 1.1x for the coming 12 months, even if forecasted consolidated EBITDA declines 10%. We use slightly less stringent thresholds to assess Xcel's liquidity, as we believe its constructive regulatory frameworks provide a manageable level of cash flow stability even in times of economic stress.

Xcel maintains $3.55 billion in committed credit facilities through 2027. We believe the company can lower its high capital spending during stressful periods, which limits the need to refinance under such conditions. Furthermore, our assessment reflects the company's generally prudent risk management, sound relationships with its banks, and a satisfactory standing in the credit markets. Overall, we believe the company will likely withstand adverse market circumstances during the next 12 months with sufficient liquidity to meet its obligations. We expect Xcel to manage upcoming long-term debt maturities but refinance well in advance of scheduled due dates.

Principal liquidity sources

- Cash and liquid investments of $115 million.
- Credit facility availability of $3.55 billion.
- Working capital inflows of $280 million.
- Estimated cash FFO of $4.5 billion.

Principal liquidity uses

- Debt maturities, including outstanding commercial paper, of $1.98 billion.

- Capital spending of $4.35 billion.
- Dividends of $1.1 billion.

Environmental, Social, And Governance (For PSCo)

ESG credit indicators: To E-3, S-2, G-1 From E-2, S-2, G-1

Environmental factors are a moderately negative consideration. Climate change is increasing the frequency of wildfires in Colorado. Social factors remain neutral. Governance factors remain a positive consideration in our credit rating analysis of PSCo due to the execution of its strategic plan to invest in regulated utilities and manage regulatory risk.

Issue Ratings - Subordination Risk Analysis

Capital structure

Xcel's capital structure consists of roughly $24.7 billion of debt of which the majority is debt at its subsidiaries.

Analytical conclusions

We rate the unsecured debt at Xcel one notch below the issuer credit rating because priority debt exceeds 50% of the company's consolidated debt, such that Xcel's debt could be considered structurally subordinated.

Ratings Score Snapshot

Xcel Energy Inc.

Issuer credit rating: A-/Stable/A-2

Business risk: Excellent

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

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: a-

Modifiers

- Diversification/portfolio effect: Neutral (no impact)

- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Strong (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a-

ESG credit indicators: E-3, S-3, G-1

Northern States Power Co.

Issuer credit rating: A/Stable/A-1

Business risk: Excellent

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

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: a-

- Modifiers
- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Strong (no impact)
- Comparable rating analysis: Positive (+1 notch)

Stand-alone credit profile: a

- Group credit profile: a-
- Entity status within group: Insulated

ESG credit indicators: E-3, S-3, G-1

Public Service Co. of Colorado

Issuer credit rating: A-/Negative/A-2

Business risk: Excellent

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

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: a-

Modifiers

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

Stand-alone credit profile: a-

- Group credit profile: a-
- Entity status within group: Highly strategic

ESG credit indicators: E-3, S-2, G-1

Southwestern Public Service Co.

Issuer credit rating: A-/Stable/A-2

Business risk: Excellent

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

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: a-

Modifiers

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

Stand-alone credit profile: a-

- Group credit profile: a-
- Entity status within group: Core

ESG credit indicators: E-2, S-2, G-1

Northern States Power Co. Wisconsin

Issuer credit rating: A-/Stable/A-2

Business risk: Excellent

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

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: a-

Modifiers

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

Stand-alone credit profile: a-

- Group credit profile: a-
- Entity status within group: Core

ESG credit indicators: E-2, S-2, G-1

Environmental, social, and governance (ESG) credit factors for this change in credit rating/outlook and/or CreditWatch status:

- Physical risks

Related Criteria

- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

Ratings Affirmed	
Xcel Energy Inc.	
Southwestern Public Service Co.	
Northern States Power Wisconsin	
Issuer Credit Rating	A-/Stable/A-2
Northern States Power Co.	
Issuer Credit Rating	A/Stable/A-1

Ratings Affirmed; Outlook Action

	To	From
Public Service Co. of Colorado		
Issuer Credit Rating	A-/Negative/A-2	A-/Stable/A-2
Issue-Level Ratings Affirmed		
Xcel Energy Inc.		
Senior Unsecured	BBB+	
Commercial Paper	A-2	
Northern States Power Co.		
Senior Secured	A+	
Recovery Rating	1+	
Commercial Paper	A-1	
Northern States Power Wisconsin		
Senior Secured	A	
Recovery Rating	1+	
Commercial Paper	A-2	
Public Service Co. of Colorado		
Senior Secured	A	
Recovery Rating	1+	
Commercial Paper	A-2	
Southwestern Public Service Co.		
Senior Secured	A	
Recovery Rating	1+	
Senior Unsecured	A-	
Commercial Paper	A-2	

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

S&P Global
Ratings

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Tear Sheet:

Public Service Co. Of Colorado's Authorized Rate Increase Is In Line With Base Case

September 12, 2023

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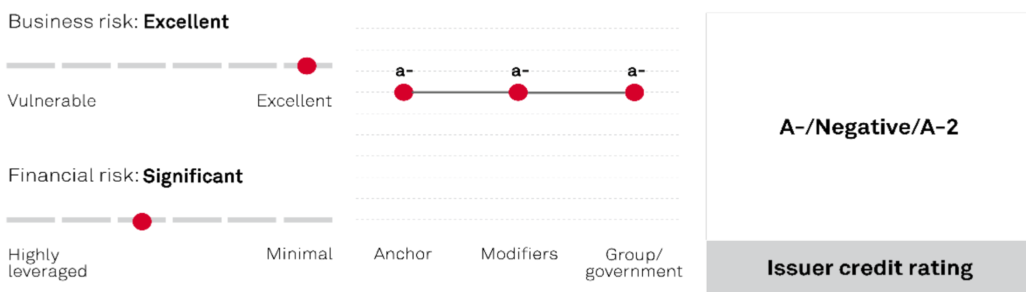
What's new: Xcel Energy Inc.'s subsidiary Public Service Co. of Colorado (PSCo) was recently authorized a $45 million electric base rate increase based on a 9.3% return on equity (55.69% of capital) and a 6.95% return on year-end rate base valued at about $10.6 billion for a calendar-2022 test year. This follows the utility’s last electric base rate increase of $298.8 million, which was authorized in March 2022.

Why it matters: This rate increase is in line with our base-case scenario and is reflected in our expectation of funds from operations (FFO) to debt of 20% through 2025. Although calculated using a historical test period, the combined rate increases since March 2022 support PSCo’s financial measures and help maintain its financial cushion.

Prospectively, PSCo has significant capital spending, and we believe the utility’s financial cushion could erode if the timeliness of cost recovery weakens, which includes aligning recovery with the company’s accelerated decarbonization plan. We expect PSCo’s capital and operating expenditure to increase from historical levels as the utility implements its decarbonization plan in the state and potentially implements more aggressive wildfire mitigation tactics to proactively reduce the risk of causing a catastrophic wildfire. In August 2022, the commission approved PSCo’s generation resource plan settlement that calls for the early retirements of Comanche 3 in 2031, Hayden 2 in 2027, and Hayden 1 in 2028; conversion of Pawnee to natural gas by 2026; and the addition of 2,400 megawatts (MW) of wind, 1,600 MW of solar, 400 MW of energy storage, 1,300 MW of dispatchable generation, and 1,200 MW of distributed solar resources.

Ratings Score Snapshot



Recent Research

Research Update: Xcel Energy Inc. Outlook Remains Stable; PSCo Outlook Now Negative Amid Increasing Wildfire Risks; Ratings Affirmed, July 28, 2023

Company Description

PSCo, a subsidiary of Xcel, operates as a vertically integrated electric and natural gas distribution utility in Colorado.

Outlook

The negative outlook on PSCo reflects the probability that managing regulatory risk could become more challenging for the company over the next 24 months as it navigates the legal proceedings related to the Marshall fire. Our base case incorporates PSCo's stand-alone adjusted FFO to debt of 20% through 2025.

Downside scenario

We could lower our ratings on PSCo over the next 24 months if its stand-alone FFO to debt weakens to consistently below 17%. This could occur if the company faces any adverse regulatory or legal developments as it navigates the legal proceedings related to the Marshall fire and we believe the company's ability to effectively manage regulatory risk has deteriorated.

Upside scenario

We could revise the outlook to stable if the company navigates the legal proceedings related to the Marshall Fire in a credit-supportive manner and maintains its stand-alone financial performance.

Key Metrics

Public Service Co. of Colorado--Key Metrics*

Mil. $	2021a	2022a	2023e	2024f	2025f
Debt to EBITDA (x)	4.1	4.0	4.0-4.5	4.0-4.5	4.0-4.5

Public Service Co. of Colorado--Key Metrics*

Mil. $	2021a	2022a	2023e	2024f	2025f
FFO to debt (%)	20.6	20.4	20.0-21.0	20.0-21.0	20.0-21.0
FFO interest coverage (x)	7.1	6.8	6.5-7.0	6.0-6.5	6.0-6.5

*All figures adjusted by S&P Global Ratings. a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations.

Financial Summary

Public Service Co. of Colorado--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.)	$	$	$	$	$	$
Revenues	4,043	4,086	4,237	4,183	4,815	5,708
EBITDA	1,422	1,422	1,528	1,540	1,782	1,977
Funds from operations (FFO)	1,205	1,075	1,290	1,282	1,519	1,618
Interest expense	226	245	263	262	269	309
Cash interest paid	210	231	232	235	249	280
Operating cash flow (OCF)	1,218	1,013	1,253	1,197	825	1,335
Capital expenditure	1,456	1,576	1,706	1,684	1,595	1,869
Free operating cash flow (FOCF)	(238)	(563)	(452)	(487)	(770)	(534)
Discretionary cash flow (DCF)	(572)	(938)	(910)	(1,318)	(1,237)	(1,025)
Cash and short-term investments	29	33	15	28	25	10
Gross available cash	28	33	15	28	25	10
Debt	5,404	6,070	6,241	6,720	7,378	7,925
Common equity	5,828	6,298	6,996	7,592	8,444	9,230
Adjusted ratios						
EBITDA margin (%)	35.2	34.8	36.1	36.8	37.0	34.6
Return on capital (%)	8.9	7.5	7.2	6.4	6.3	6.4
EBITDA interest coverage (x)	6.3	5.8	5.8	5.9	6.6	6.4
FFO cash interest coverage (x)	6.7	5.6	6.6	6.4	7.1	6.8
Debt/EBITDA (x)	3.8	4.3	4.1	4.4	4.1	4.0
FFO/debt (%)	22.3	17.7	20.7	19.1	20.6	20.4
OCF/debt (%)	22.5	16.7	20.1	17.8	11.2	16.8
FOCF/debt (%)	(4.4)	(9.3)	(7.2)	(7.3)	(10.4)	(6.7)
DCF/debt (%)	(10.6)	(15.5)	(14.6)	(19.6)	(16.8)	(12.9)

Peer Comparison

Public Service Co. of Colorado--Peer Comparisons

	Public Service Co. of Colorado	PacifiCorp	Black Hills Corp.	Evergy Kansas Central Inc.
Foreign currency issuer credit rating	A-/Negative/A-2	BBB+/Negative/A-2	BBB+/Stable/A-2	A-/Negative/A-2
Local currency issuer credit rating	A-/Negative/A-2	BBB+/Negative/A-2	BBB+/Stable/A-2	A-/Negative/A-2
Period	Annual	Annual	Annual	Annual
Period ending	2022-12-31	2022-12-31	2022-12-31	2022-12-31
Mil.	$	$	$	$
Revenue	5,708	5,679	2,552	3,056
EBITDA	1,977	2,291	718	1,189
Funds from operations (FFO)	1,618	2,065	559	932
Interest	309	441	172	214
Cash interest paid	280	411	158	178
Operating cash flow (OCF)	1,335	1,791	579	937
Capital expenditure	1,869	2,135	599	912
Free operating cash flow (FOCF)	(534)	(344)	(20)	25
Discretionary cash flow (DCF)	(1,025)	(444)	(194)	(430)
Cash and short-term investments	10	641	21	9
Gross available cash	10	641	21	9
Debt	7,925	9,309	4,759	5,343
Equity	9,230	10,740	3,090	4,507
EBITDA margin (%)	34.6	40.3	28.1	38.9
Return on capital (%)	6.4	6.5	6.0	6.8
EBITDA interest coverage (x)	6.4	5.2	4.2	5.5
FFO cash interest coverage (x)	6.8	6.0	4.5	6.2
Debt/EBITDA (x)	4.0	4.1	6.6	4.5
FFO/debt (%)	20.4	22.2	11.7	17.4
OCF/debt (%)	16.8	19.2	12.2	17.5
FOCF/debt (%)	(6.7)	(3.7)	(0.4)	0.5
DCF/debt (%)	(12.9)	(4.8)	(4.1)	(8.1)

Environmental, Social, And Governance

Environmental factors are a moderately negative consideration. Climate change is increasing the frequency of wildfires in Colorado. Social factors are neutral. Governance factors are a positive consideration in our credit rating analysis of PSCo due to the execution of its strategic plan to invest in regulated utilities and manage regulatory risk.

Rating Component Scores

Foreign currency issuer credit rating	A-/Negative/A-2
Local currency issuer credit rating	A-/Negative/A-2
Business risk	Excellent
Country risk	Very Low
Industry risk	Very Low
Competitive position	Strong
Financial risk	Significant
Cash flow/leverage	Significant
Anchor	a-
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Strong (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	a-

Related Criteria

- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
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MOODY'S
INVESTORS SERVICE

CREDIT OPINION
31 January 2023

Update

Send Your Feedback

RATINGS

Public Service Company of Colorado

Domicile	Colorado, United States
Long Term Rating	A3
Type	LT Issuer Rating
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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Public Service Company of Colorado

Update to credit analysis

Summary

Public Service Company of Colorado's (PSCO) credit profile reflects our view that it is a regulated vertically integrated electric and natural gas distribution utility operation in Colorado that benefits from a credit supportive regulatory environment and relationship with stakeholders, including the Colorado Public Utility Commission (CPUC).

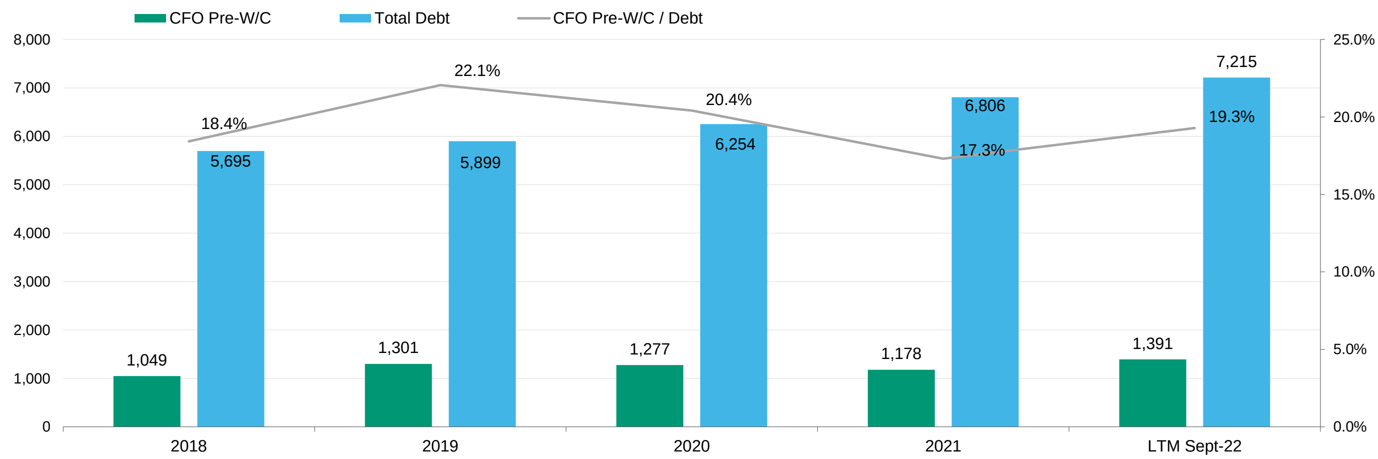
This view considers PSCO's access to several cost recovery mechanisms between rate cases, credit supportive outcomes of the utility's electric and natural gas rate cases completed in 2022 as well as its ability to enter into several multi-party agreements, including its revised Electric Resource Plan settlement (approved in August 2022). However, the timely implementation of some of these recovery mechanisms has faced some headwinds. Examples include PSCO's drawn-out proceeding (completed in July 2022) and less favorable outcome compared to peers for the recovery of sizeable extraordinary costs due to severe winter weather in February 2021. Also, its initiative to manage the impact of high commodity prices on customer bills will negatively affect its cash flow in early 2023. PSCO proposed to recover its electric operations' material under-recovered deferred balance of energy costs (as of October 2022: $123 million) over at least two quarters in 2023 (instead of one). The increased frequency of regulatory proceedings in the state could expose the utility to rate case fatigue.

We note the improvement in its financial metrics during the last twelve-month period (LTM) ended 3Q2022, including a ratio of CFO before changes in working capital (CFO pre-W/C) to debt of 19.3%, following a material deterioration in the ratio to 17.3% at year-end 2021. However, PSCO's financial flexibility is still limited given its credit metric downgrade threshold of 19%. PSCO's credit quality is dependent on continued credit-supportive regulatory outcomes that will allow it to report a ratio of CFO-pre W/C to debt that will range between 19-21%, on a sustained basis. Pending proceedings include its 2022 electric retail rate case, its ongoing 2021 Colorado Electric Resource Plan, Colorado's decarbonization policies that will drive its future capital investments, and carbon transition risk.

Recent Developments

In October 2022, parent company, Xcel Energy Inc (Baa1 stable) announced plans to completely exit coal-fired generation by the end of 2030. This updated target is in line with the terms of PSCO's Electric Resource Plan Settlement agreement, revised in April 2022, and approved by the CPUC in August 2022. This plan, also known as the 2021 Colorado Electric Resource Plan (Colorado ERP), includes PSCO's early retirement of its last coal-fired unit, Comanche Unit 3, by January 1, 2031. PSCO is seeking, through a request for proposals process launched in December 2022, third party bids (due in March 2023) for energy resources to meet its electric needs for the 2023-2028 period. These bids will be compared with PSCO's own proposals and submitted for the CPUC's review during the third quarter of 2023. The utility expects a final decision from the CPUC before year-end 2023. A separate solicitation process will be launched for the 2029-2030 resources.

Exhibit 1
Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt ($MM)



Source: Moody's Financial Metrics

Credit strengths

» Vertically integrated regulated utility in a credit-supportive regulatory environment

» Numerous riders and trackers reduce regulatory lag

» Part of the large and diverse Xcel corporate family

» Several initiatives help alleviate affordability concerns amid significant changes to energy-mix

Credit challenges

» Timely implementation of recovery mechanisms has faced headwinds

» Drawn out proceedings and lengthy recovery period for February 2021 storm costs

» Colorado's decarbonization policies and wildfires increase carbon transition and physical climate risk

» Uncertain size of investment program until implementation of the 2021 Colorado ERP

Rating outlook

PSCO's stable outlook is supported by our expectation that the regulatory environment will remain credit-supportive despite the unfavorable outcome of the regulatory proceeding for the recovery of the February 2021 extraordinary fuel costs. The stable outlook also reflects our view that PSCO's key credit metrics will recover from the low levels exhibited in 2021, including CFO pre-W/C to debt of at least 20% going forward.

Factors that could lead to an upgrade

The utility's ratings could experience positive momentum upon a material improvement in the credit supportiveness of the regulatory in Colorado or if higher than anticipated regulatory relief and/or cost savings allow it to generate CFO pre-W/C to debt above of 23%, on a sustained basis.

Factors that could lead to a downgrade

The ratings could be downgraded if there is a deterioration in the credit supportiveness of the regulatory environment or if its credit metrics remain weak; specifically, if its CFO pre-W/C to debt ratio stays below 19% on a sustained basis.

Key indicators

Exhibit 2
Public Service Company of Colorado

	Dec-18	Dec-19	Dec-20	Dec-21	LTM Sept-22
CFO Pre-W/C + Interest / Interest	5.7x	6.5x	6.2x	5.9x	6.6x
CFO Pre-W/C / Debt	18.4%	22.1%	20.4%	17.3%	19.3%
CFO Pre-W/C – Dividends / Debt	11.8%	14.3%	7.1%	10.4%	12.5%
Debt / Capitalization	41.7%	40.2%	39.8%	39.5%	39.6%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-financial Corporations.
Source: Moody's Financial Metrics

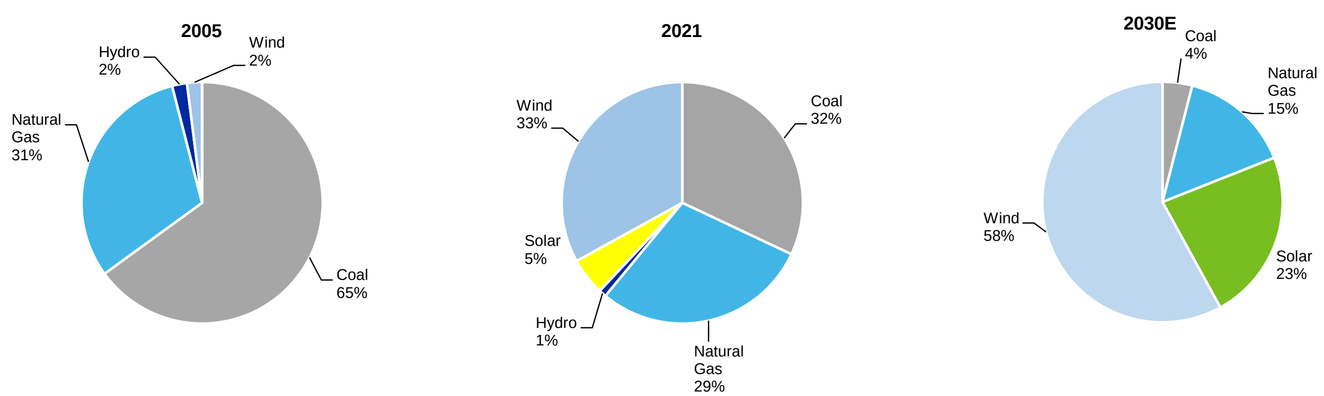
Profile

Public Service Company of Colorado (PSCO, A3 stable) is the largest integrated utility in Colorado, where it serves 1.5 million electric customers (2021 rate base: $9.7 billion) and 1.4 million natural gas customers (2021 rate base: $3.3 billion). The utility also renders transmission services in Colorado which, along with its wholesale operations, are subject to the Federal Energy Regulatory Commission's (FERC) purview (2021 rate base: $756 million). In January 2022, PSCO along with two additional Colorado utilities announced plans to join SPP's Western Energy Imbalance Service market in April 2023.

Our analysis of PSCO considers that its electric and natural gas retail operations, subject to the CPUC's oversight, represent the bulk of the utility's operations. The utility's wholesale and transmission services at SPP account in aggregate for under 10% of its total electric revenues at year-end 2021 which limits its exposure to FERC's regulatory framework. Revenues of PSCO's electric operations typically range between 70-75% of its total revenues.

At the end of 2021, its generation fleet's net summer capacity totaled 6,228 MW, on an ownership-adjusted basis.

Exhibit 3
2005-2030 expected development of PSCO's energy mixThe

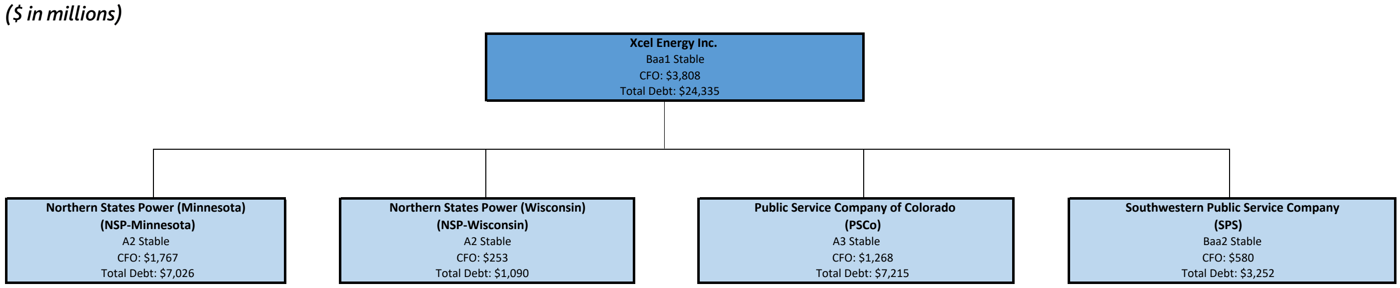


Source: Company presentations

The lower contribution of coal-fired generation to PSCO's energy mix at year-end 2021 (see Exhibit 3) is attributed to retirements (since 2021: 1,000 MW) as well as the relatively old vintage of PSCO's remaining coal-fired plants (year-end 2021 total capacity: 2,000 MW). The vast majority are more than 35 years old, except for the 750 MW co-owned Comanche Unit 3 (PSCO's share: 500 MW) that was completed in 2010 which faced extended forced outages in 2020 and 2022. At year-end 2021, PSCO's natural gas-fired fleet consisted of six facilities (capacity: around 2,900 MW) while it also has two windfarms (1,059 MW). The utility also procures power under different agreements (including 200 MW solar PPAs) that the utility estimates accounted for around 33% of its supplied power in 2021. Exhibit 3 also reflects the retirements of the 335 MW Comanche Unit 2 in 2025 (Unit 1 was retired in 2022) as well as the Craig Unit 1 (2025) and Unit 2 (2028).

As depicted in Exhibit 4, PSCO's parent, Xcel Energy Inc. (Xcel, Baa1 stable), is a holding company with utility operations in eight states serving around 3.7 million electric and about 2.1 million natural gas customers. PSCO is one of the largest subsidiaries in terms of regulated rate base and contributions to consolidated cash flow. We calculate that PSCO's funds from operations (FFO) accounted for between 35-38% of the subsidiaries' total generated FFO (before parent corporate expenses) during the 2020-LTM 3Q2022 period.

Exhibit 4
Xcel Energy Inc. Organizational Chart (LTM 3Q2022)
($ in millions)



Source: Xcel Energy Inc., Moody's Financial Metrics

Detailed credit considerations

Generally supportive cost recovery mechanisms but their application can face contentiousness

Our view that the regulatory environment in Colorado is credit supportive considers that the utility benefits from several rate adjustment mechanisms (see Exhibit 5) that allow it to adjust rates between rate cases, helping to reduce regulatory lag, a credit positive. These recovery mechanisms include a clause to recoup the book value associated with the early retirement costs of Comanche units 1 and 2, although this is subject to a cap of 1% of customers' bills. The framework allows for the implementation of interim rates if the CPUC's decisions exceed the statutory 210-day time frame for rate case outcomes in the state.

Exhibit 5
Summary of the key regulatory mechanisms available to PSCO in Colorado

	Multi-year Rate Plans	Forward Test Year	Interim Rates	Fuel Recovery Mechanism	Capacity Recovery Mechanism	Renwable Rider	Transmisison Rider	Pension Deferral Mechanism	Property Tax Deferral/True-up	Decoupling
PSCO	Allowed	Allowed	Allowed	√	√	√	√	√	√	√

Source: Xcel Energy Inc., regulatory filings

Despite these mechanisms, the utilities' financial performance and actual RoEs are not fully immune to the negative impact of regulatory lag as depicted in Exhibit 6.

Exhibit 6
Summary of PSCO's authorized and actual RoEs as well as applicable regulatory plans per type of operations

Jurisdisction		Authorized RoE	W/A Earned RoE (actual)				Regulatory Plan
			2018	2019	2020	2021	
PSCo	Electric - Co	9.30%	8.93%	7.62%	8.73%	8.48%	2022 FTY filed, rates effective April 2022
	NG- Co	9.10%	8.68%	6.81%	8.78%	8.10%	2022 CTY filed, rates effective November 2022
	Wholesale - PSCo	*	*	*	*	*	

*Authorized RoE for PSCo transmission and production formula = 9.72%
Source: Company presentations

In general, we deem the utilities' access to the decoupling mechanism as credit positive. However, PSCO's pilot electric decoupling, which became effective in April 2020 through 2023, is an example of contentiousness and drawn out proceedings, a credit negative. The mechanism applies to residential as well as small commercial and industrial (C&I) customers that pay no demand charges. The mechanism compares differences between a baseline of fixed cost recovery authorized by the CPCU and actual fixed costs recovered in base rates with annual adjustments to reflect in base rates the under- (over) recoveries of fixed costs through a surcharge (credit). However, the adjustment is limited to a +/-3% cap of the forecasted base rate revenues with the excess amounts eligible for recovery (refund) over subsequent years. At the end of September 2022, PSCO recorded a surcharge for C&I customers whose demand levels for the nine month period ended September 2022 and 2021 remained below the 2019 levels despite some recovery following the 6% contraction in 2020. In contrast, residential customers' electric demand, in 2021, remained relatively flat following the material spike of nearly 7% recorded in 2020 in the aftermath of the pandemic. The 3%-cap led the utility to report a regulatory liability (i.e. excess refundable amount) of around $50 million at the year-end 2021 and 2020. In October 2021, the utility entered into a multiparty partial settlement to address four outstanding regulatory matters, including customer refunds of $41 million associated with the decoupling mechanism. However, in May 2022, the CPUC found merits in the Colorado Office of the Utility Consumer Advocate's (UCA) protest that included issues with the 3%-cap components. The rate adjustments remain suspended, should have become effective in June 2022 according to PSCO's filing in April 2022, until a final regulatory decision. The Administrative Law Judge's recommendation is expected during the 1Q2023. This drawn out proceeding adds uncertainty around the application of the decoupling mechanism and the predictability of PSCO's cash flow, a credit negative.

Similar to its sister companies, PSCO's hedging strategy reflects the CPUC's authorized hedging policy. For its local natural gas distribution (LDC) operations, the authorized program allows the utility to hedge around 50% of estimated natural gas usage through a combination of physical storage and financial instruments. However, the utility does not hedge the fuel procured to generate power, a credit negative amid elevated commodity prices that began last year. The FERC-regulated wholesale rates allow for the most timely recovery because they are based on a forecasted formula rate subject to true-ups. The utility's electric and natural gas retail rates are subject to quarterly reviews through the commodity adjustments for electricity (ECA) and natural gas (GCA) clauses which reflect forecasted costs. PSCO's ECA also reflects the flow-through of tax credits to ratepayers, which currently consist of production tax credits (PTCs) generated by its wind assets, which the enactment of the Inflation Reduction Act (IRA) in August 2022 extended for at least ten years.

Despite these recovery mechanisms and flow-throughs, the utility's deferred electric fuel balance significantly increased during the third quarter of 2022. The reported regulatory asset increased to $91 million at the end of September 2022 from nearly $26 million at the end of June 2022. As a point of reference, the utility recorded fuel and purchased power costs of nearly $1.1 billion during the nine periods that ended on 30 September 2022. This amount was slightly higher than the costs recorded during the same period in 2021 which included around $220 million in extraordinary costs that PSCO's electric operations incurred in February 2021 driven by severe winter weather (around half of the total of approximately $610 million). We understand that the combination of elevated natural gas prices, along with PSCO's higher than usual reliance on natural gas generation in the aftermath of the extended forced outage at the coal-fired Comanche Unit 3 (from the end of January to mid-June 2022), helped to explain the material costs in 2022.

In its most recent ECA proceeding, for rates, effective January 2023, the utility updated its forecasted costs for the first quarter of 2023 and reported an ECA deferred balance of around $123 million at the end of October 2022. PSCO requested the authority to recoup half of this 2022 under-recovered amount during the first quarter of 2023 with the other half, along with any additional ECA balances, to be recovered during the second quarter. In addition, the utility requested a waiver to exclude from the deferred account balance the replacement energy costs incurred during the around 4.5 month forced outage at Comanche Unit 3 (total costs: $10 million). The utility's initiative to extend the recovery period and exclude portions of the costs incurred sought to mitigate the impact of high commodity prices on customer bills. This may help PSCO to manage its relationship with stakeholders in Colorado but it will also negatively impact the utility's cash flow.

February 2021 extraordinary commodity cost recovery proceeding is a material credit negative

This fuel recovery customer friendly initiative comes on the heels of the utility's agreement for the recovery of the aforementioned extraordinary electric and natural gas costs incurred in February 2021. The terms of the aforementioned settlement agreement (October 2021) also addressed these extraordinary costs recovery. The CPUC approved the settlement, with some modifications, in July 2022. Excluding what the utility will not recover as part of the settlement agreement and an additional $8 million CPUC disallowance, the utility's recoverable amount will aggregate $542 million, or nearly 90% of PSCO's initially submitted extraordinary costs. However, recovery only started in August 2022, a full 18 months after the costs were incurred. In the agreement, the parties agreed that PSCO's electric operations will recover $263 million of net natural gas fuel and purchased energy costs over 24 months, while its LDC operations' recovery of $287 million of net natural gas costs is expanding to over 30 months.

This drawn-out and contentious fuel cost recovery proceeding (with some parties requesting a material cost disallowance), the long recovery period, and the inability to recover carrying costs, are all credit negatives and stand as a notable exception to the historically credit supportive utility regulatory environment in Colorado. These cost recovery provisions compare much less favorably to the regulatory outcomes in most of the other jurisdictions affected by extraordinarily higher energy costs in February 2021, virtually all of which acted faster and more decisively to support their utilities.

Expectation of credit supportive outcomes of pending regulatory proceedings despite some risk of rate case fatigue

PSCO's A3 credit rating and stable outlook reflect our view that the Colorado regulatory environment remains credit supportive and that the aforementioned contentious proceedings regarding the February 2021 storm and decoupling do not indicate a negative trend in terms of the consistency and predictability of the regulatory environment. PSCO's rate cases completed during 2020 and 2022 are evidence of a regulatory environment that is general credit supportive, particularly compared to earlier proceedings that were subject to litigation and court appeals (examples include the PSCO's 2019 electric rate case and 2017 natural gas rate case). We also view PSCO's ability to enter into several multi-party settlement agreements during 2022 as credit positive. Examples include the settlements for the 2021 electric rate case (completed in 2022) and the Colorado 2021 ERP.

However, we also see a risk that more frequent rate case filings could expose the utility to the risk of rate case fatigue and some public backlash, particularly if commodity prices and inflation remain high and despite Xcel's track record of disciplined control operational and maintenance (O&M) costs. This view also factors in our estimation that, between August-December 2022, PSCO's electric and natural operations recovered in total around $90 million related to the aforementioned February 2021 incremental costs. Total recovery of around $220 million and $200 million will be embedded in the 2023 and 2024 electric and natural ratepayer bills. Nevertheless, PSCO's stable outlook reflects our expectation that continued credit-supportive outcomes will support its credit quality.

In November 2022, PSCO filed an electric retail rate case that comes shortly after new rates became effective in April 2022. The completion of this electric rate case (initiated in July 2021) in less than one year with new rates reflecting the CPUC's approval, without modifications, of PSCO's settlement agreement (January 2022) are credit supportive. The authorized net increase in electric rates of $177 million represented around 52% of the utility's initially requested increase of $343 million or 12.4%. The net increase excludes the transfer of amounts previously recovered through rider mechanisms ($122 million as per the agreement) to base rates, including the transmission rider (TCA) and some costs related to the Cheyenne Ridge windfarm that it previously collected through the ECA. The parties also agreed for PSCO to continue the property tax, qualified and non-qualified pension trackers. Drivers of the difference between the requested and authorized net revenue increase include that the parties agreed to maintain unchanged PSCO's ROE of 9.3%, compared to the utility's request to increase it to 10%. On a positive note, PSCO's authorized equity layer was increased to 55.69% which compares well with both the utility's request of 55.64% and its previous ratio of 55.61%. A robust equity layer is positive because it helps the utility to generate stronger financial metrics.

On a negative note, differences in the utilized rate base test year also contributed to the lower settled electric revenue increase that became effective in April 2022. In contrast to the utility's initial request that was premised on a future rate base for the year ended December 2022, the terms of the CPUC's authorized agreement used an average rate base for the calendar-2021 test year, except for certain items. These are related to investments associated with the advanced grid intelligence and security (AGIS) as well as the wildfire mitigation plan that were evaluated using a year-end 2021 approach. The utility was allowed to continue to apply deferred regulatory treatment to incremental investments related to its wildfire mitigation plan, with the ability to earn a debt return, as well as to the AGIS program, subject to an interest equivalent to PSCo's weighted average cost of capital.

The ability to earn carrying costs on those investments and access to riders including the transmission rider (subject to annual adjustments) amid its material investment to grow its transmission footprint are credit positives. However, the difference in the utilized test years still exposes the utility to regulatory lag which drove the utility to file another retail electric rate case in November 2022. PSCO asked for a net revenue increase of $262 million (net of $50 million in items already recovered through riders) effective September 2023. We estimate that the ask represents a 12.2% increase compared to PSCO's present base rate revenue of $2.1 billion while the utility disclosed an impact on the overall customer bills of approximately 8.2%.

Drivers of the request include incremental capital expenditures, increased O&M costs, amid the current high inflationary environment, but subject to excluding any increase in revenues owing to its load growth. PSCO's request is based on a test year ending December 31, 2023, including a rate base of $11.3 billion that reflects capex related to the AGIS, wildfire mitigation and cybersecurity programs. It also reflects investments in its distribution rate base to meet growing customer demand and in its transmission footprint to integrate new renewable assets into the grid. The request is premised on a slight increase in its current equity ratio to 55.7% but a material step-up in its authorized RoE to 10.25%, which would help to offset the impact of the current higher interest rate environment. Other items included in the request include PSCO's proposed continuation of certain trackers and deferrals, amortization of certain deferred costs and reset the baseline for its decoupling mechanism. It also includes the implementation of an earnings sharing adjustment (ESA) mechanism. In general, we view the implementation of this of mechanisms as credit supportive because they help utilities to manage their relationship with customers. For PSCO, our analysis will consider the mechanism's underlying details.

In a separate proceeding, in October 2022, the CPUC authorized a net increase of $64 million in PSCO's retail natural gas rates. This was a fully litigated rate case with the allowed increase equaling around 60% of the utility's requested net increase of $107 million in January 2022. Similar to PSCO's electric rate case, both amounts exclude the roll-in into PSCO's base rates of $108 million previously recovered from customers through the Pipeline System Integrity Adjustment (PSIA) rider. Investments to provide reliable, safe services and to meet the state's clean heat goals accounted for the bulk of the sought relief. Adjustments to the revenue requirements to reflect incremental O&M expenses and property taxes aggregated $22 million.

Similar to the electric rate case, key drivers of the gap between the requested and authorized net increase included differences in the underlying regulatory parameters along with the test year utilized to set the rate base and two credit negatives. According to the order, the subject is not to exceed a WACC of 6.7%, PSCO could choose the applicable Return on Equity (RoE) and equity layer that ranged between 9.2%-9.5% (RoE) and 52-55% (equity ratio). The utility determined that it will manage its natural gas operations based on an equity ratio of 55% and RoE of 9.1%. As a comparison, the utility requested to maintain its equity ratio of 55.66% (implemented in 2020) and to increase its allowed RoE to 10.25% (previous authorized RoE: 9.2%), the reduction is credit negative amid the rising interest rate environment. PSCO's ask was premised on a projected rate base of $3.6 billion for the year-end ended 2022. In contrast, the new rates, which became effective in November 2022, are premised on a historic test year with a year-end rate base.

In addition, the CPUC denied PSCO's request to authorize step revenue increases of $40 million (effective 1 November 2023) and $41 million (effective 1 November 2024). The combination of the use of the historic test year and the denied multi-year rate plan are credit negatives, particularly because PSCO's cash flow ceased to benefit from the PSIA rider. This surcharge was closed to new investments at the end of 2021, according to PSCO's settlement agreement with the Colorado Energy Office, which the CPCU approved in October 2021. Similar to PSCO's electric operations, we anticipate the utility will also file a new natural gas rate case to also reduce these operations' exposure to regulatory lag.

Regulatory proceedings, including investments under the 2021 Colorado ERP, will drive PSCO's financial flexibility

Exhibits 1 and 2 depict the improvement in PSCO's financial metrics during the LTM 3Q2022, including the ratio of CFO pre-W/C to debt that increased to 19.3% after dropping to around 17% at year-end 2021 following the material impact of the deferred balance of unrecovered fuel costs incurred in February 2021.

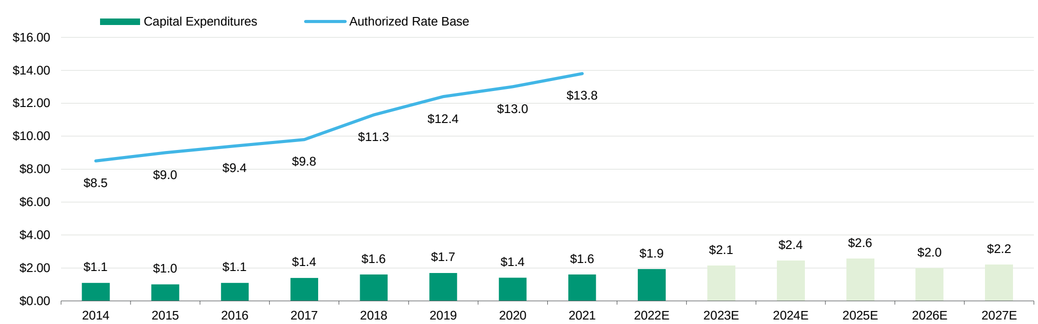
Nevertheless, the improvement in the utility's financial flexibility was limited given its financial metric threshold for a possible downgrade is 19%. During the LTM 3Q2022, PSCO's financial metrics benefited from the net revenue increases from its electric and natural gas rate cases authorized during 2022, including the step-up in the allowed equity layer of its electric operations, as well as further recovery of certain items under riders and a modest recovery of the February 2021 incremental costs of around $20 million. Also, we note that the utility's net dividend distributions aggregated around $10 million during the LTM 3Q2022, after excluding Xcel's capital contributions of $483 million. However, the positive impact of these factors was offset by the aforementioned headwinds faced in connection with the material increase in its deferred electric fuel balances during 2022 and incremental debt that approximated $410 million for the nine months ended September 2022. This included $165 million in short term borrowings under the group's money pool, to fund PSCO's capital requirements including its still material investments. For the LTM 3Q2022, PSCO's capital outlays represented 2.3x of its depreciation expense (compared to an average ratio of around 2.5x during the 2019-2021 period).

PSCO's A3 rating and stable outlook are based on our expectation that the utility will be able to report a ratio of CFO-pre W/C to debt that will range between 19-21%, on a sustained basis. The utility's financial flexibility will depend on the outcome of its pending regulatory proceedings, including the November 2022 electric rate case, and final investments associated with rate-based assets upon implementation of the 2021 Colorado ERP.

Colorado's decarbonization policies and wildfires increase carbon transition and physical climate risk

PSCO has disclosed that its base capex currently aggregates $11.3 billion during the 2023-2027 period (see Exhibit 6). It has earmarked the majority of these investments for its electric distribution (33% of the total) and transmission (29%) operations and natural gas distribution (23% of the total). Nearly 52% of the planned transmission investment of $3.3 billion embedded in this base capex program refers to the power pathway project. The CPUC's order, issued in June 2022, included a certificate of public convenience and necessity (CPCN) for this transmission project, approval of PSCO's cost estimate of around $1.7 billion with allowed recovery through the transmission rider, and a credit positive. The order modified some of the terms of PSCO's October 2021 settlement agreement related to this project, with the modifications largely related to the underlying details of the performance incentive mechanism that intends to foster the timely and on-budget delivery of the project. Additional investments of up to $1 billion in transmission are possible depending on whether additional network upgrades, voltage support, and interconnections are required upon the completion of the 2021 Colorado electric resource plan (ERP).

Exhibit 7
PSCO's rate base and 2013-2026 historical and projected capital expenditure plan
$ in billions



Source: Xcel Energy Inc.

The 2021 Colorado ERP, particularly the outcomes of the request for proposals for the 2023-2028 period (launched in December 2022) and 2029-2030 (future proceeding), will determine (i) the location and resource mix as well as (ii) PSCO's new rate based assets which would also increase its generation related investments going forward. These investments represented only around 6% of the aforementioned Capex plan, with updates pending CPUC's final approvals.

According to PSCO's 2021 Colorado ERP, which reflects the terms of the revised settlement agreement approved by the CPUC in August 2022, the utility expects that renewable sources will represent 80% of its total available energy mix by 2030. To that end, wind farms (2,400 MW), universal-scale solar (1,600 MW) and distributed solar resources (1,200 MW), storage (400 MW) as well as 1,300 MW of flexible, dispatchable generation will be added to the total energy mix, through a still unknown possible combination of rate-based and procured under PPAs. The 2021 Colorado ERP also includes a Clean Energy Plan (CEP) to reduce the company's carbon dioxide (CO2) emissions by a target of 85% by 2030 as compared to 2005 levels. To that end, the utility will (i) convert to natural gas the 505 MW Pawnee facility (by January 1, 2026) and (ii) accelerate the retirement of its remaining coal-fired facilities, specifically Hayden Unit 1 (to 2028 from 2030) and Unit 2 (to 2027 from 2036) as well as the aforementioned shutdown of Comanche Unit 3 (by January 1, 2031, from 2036). PSCO also agreed to reduce this unit's operations starting in 2025 which as mentioned earlier has faced forced outages in 2020 and 2022.

An aggressive implementation of the state's greenhouse emissions (GHG) reduction targets could increase PSCO's exposure to carbon transition risk, particularly in its LDC operations (around 25% of its rate base). PSCO's electric load should benefit from electrification initiatives as its electric and natural gas service territories largely overlap. However, they could also trigger challenges related to cost shifts across customers and affordability which could also negatively impact PSCO's regulatory relationship with stakeholders, and ability to timely recover other costs.

At the end of November 2022, the CPUC issued a final rule, to overhaul the planning for natural gas distribution systems, which we view as overall credit supportive. The rule requires that utilities with natural gas operations present several years of planned capital projects (for PSCO in excess of $3 million) related to safety, and reliability and to provide service to new customers for CPUC's approval every two years. We understand that PSCO will be the first utility to apply in 2023. These biannual gas infrastructure plans, and the requirement to attain a CPCN for projects (for PSCO: above $13 million), should reduce the utility's risk of cost disallowances going forward, particularly when compared to the CPUC's current approach. Revisions of the investments for cost recovery in rates currently take place only upon their completion. The utilities will be now also required to consider in their plans initiatives to reduce the expansion of natural gas consumption (such as pipeline extensions), and propose alternatives, so-called clean heat resources (including electric heating equipment, green hydrogen, renewable natural gas, and demand side strategies). The rule also established a clean heat standard that will require LDC operations to cut emissions 4% by 2025 and 22% by 2030 against a 2015 baseline, with future reductions to be determined by the CPUC. On a negative note, we also understand that some uncertainty remains as to whether the recoverability of the incremental costs associated with new development and growth will be further spread among the existing customer base or only born by the new customers serviced by the extensions, which could raise cost-shifting challenges.

We note that PSCO has a comprehensive wildfire mitigation plan in place. As mentioned earlier, the related expenditures are one of the key drivers of its electric operations' recent rate cases. The lack of application in Colorado of the inverse condemnation doctrine moderates its wildfire risk compared to California. However, the utility is not fully immune to the risk as wildfire victims can base their legal claim on negligence, which could also result in large damages. Examples include the class action filed in Boulder County, in March 2022, regarding the Marshall Fire that took place in PSCO's service territory in December 2021. In July 2022, PSCO filed a motion to dismiss the lawsuit. The utility maintains that there is no indication that its equipment ignited the fire, but in the remote event that it is found liable, it also discloses the damage could exceed its insurance coverage.

Several initiatives to help alleviate affordability concerns amid changes to energy-mix

PSCO's recovery of the book value of the retiring coal-fired facilities (Hayden, Craig, the coal portion of Pawnee, and Comanche Unit 3) remains uncertain after the CPCU decided to postpone the decision and address it in a separate proceeding. In August 2022, the CPUC directed PSCO to also add the use of securitization to its initial request that considered combinations of accelerated depreciation and regulatory asset with a full return, subject to an amortization period of around eight years. At the end of September 2022, PSCO reported the amount related to plants to be retired aggregated $1.3 billion following CPUC's approval of its 2021 Colorado ERP (year-end 2021: $182 million). The final amounts (net of additional depreciation) will decrease until the unit's retirement dates. However, the material amounts evidence the importance of the CPUC's decision for PSCO's cash flows going forward as well as the impact on customer bills of the implementation of the 2021 Colorado REP in terms of retired assets in addition to new investments.

That said, we also consider that certain items should help to mitigate the impact of the change in the energy mix on customer bills. These include the anticipated fuel cost reductions as renewable sources are expected to represent 80% of the total energy requirements and fixed cost savings from coal-fired assets retirements. Also, the enactment of the aforementioned IRA is credit positive from an affordability perspective. It extended the renewables tax credits, that flow through to ratepayers, and expanded their access to new technologies including solar and green hydrogen, while it also allowed their monetization through their transferability to third parties.

ESG considerations

PSCO's ESG Credit Impact Score is CIS-3 (Moderately Negative)

Exhibit 8
ESG Credit Impact Score

CIS-3
Moderately Negative

NEGATIVE IMPACT
POSITIVE IMPACT

For an issuer scored CIS-3 (Moderately Negative), its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. The negative influence of the overall ESG attributes on the rating is more pronounced compared to an issuer scored CIS-2.

Source: Moody's Investors Service

PSCO's ESG Credit Impact Score is moderately negative (**CIS-3**), where its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. PSCO's ESG **CIS-3** reflects moderate environmental and social risks along with neutral to low governance risks.

Exhibit 9
ESG Issuer Profile Scores

ENVIRONMENTAL	SOCIAL	GOVERNANCE
E-3	S-3	G-2
Moderately Negative	Moderately Negative	Neutral-to-Low

Source: Moody's Investors Service

Environmental
PSCO's exposure to environmental risk is moderately negative (**E-3** issuer profile score), reflecting moderate carbon transition risk due to its reliance on fossil fuels, with the output of its coal-fired and natural gas generation representing around 32% and 29% of the electric energy supply at the end of 2021, respectively. Its coal-fired facilities, as well as its natural gas distribution operations, also add risks of waste management and pollution, including manufactured gas plant environmental expenditures. Additionally, the **E-3** also reflects some exposure to physical climate risk such as wildfires.

Social
Exposure to social risks is moderately negative (**S-3** issuer profile score) reflecting the utility sector's fundamental risk that demographics and societal trends could trigger public affordability concerns that could lead to adverse regulatory or political intervention. These risks are balanced by neutral to low risks for human capital, customer relationships and responsible production.

Governance
Governance is broadly in line with other utilities and does not pose a particular risk (**G-2** issuer profile). For PSCO, it considers the G-IPS of its parent company, Xcel Energy, Inc, and factors in that the utility operates subject to the regulatory authorized capital structure. This is supported by neutral to low scores on financial strategy and risk management, management credibility and track record, organizational structure, compliance and reporting; despite high risk associated with board structure, policies and procedures driven by certain features, including a relatively low number of independent directors.

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

Liquidity analysis

In September 2022, Xcel and its utility subsidiaries, including PSCO, entered into amended five-year credit agreements that expire in September 2027 (with an option to request an extension for two additional one-year periods). The size of the bank facilities of PSCO ($700 million), SPS ($500 million), and NSP-Wisconsin ($150 million) remained the same. However, Xcel and NSP-Minnesota increased the size of their facilities to $1.5 billion (from $1.25 billion) and $700 million (from $500 million), respectively. The group's new credit facilities are subject to the same terms and conditions as the prior bank facilities that were scheduled to expire in June 2024.

PSCO's $700 million credit facility back-stops its same-sized commercial paper program. The facility provides for same-day funding and PSCO is not required to represent the lack of a material adverse change for future borrowings. We anticipate that the utility will remain comfortably in compliance with the one financial covenant embedded in the facility, a total debt-to-capitalization ratio below 65%. As of September 2022, we estimate the ratio was approximately 44%.

PSCO's facility was largely fully available at the end of September 2022 with availability of $674 million (year-end 2021: $552 million). In addition to its credit facility, PSCO participates in a regulated money pool with its affiliates in which it has a $250 million borrowing limit. This money pool allows for short-term loans among the utility subsidiaries and allows for short-term loans from Xcel to the utilities. However, it does not allow for loans from the utilities to Xcel. As of September 30, 2022, PSCO had borrowings of $165 million under the money pool compared to no borrowings at the end of 2021.

In May 2022, PSCO issued $300 million of 4.10% first mortgage bonds (FMB) due in June 2032 and $400 million of 4.50% FMB due June 2052. The utility used the net proceeds largely to fund the early repayment of a $300 million FMB that was scheduled to mature in September 2022 and repay outstanding short-term debt. PSCO's next debt maturities consist of $250 million of FMBs that are due in March 2023.

In 2023, we expect that PSCO will fund its capital requirements, including planned investments of approximately $2.1 billion in 2023, largely with internally generated cash flow and a combination of short- and long-term debt. Xcel has disclosed that PSCO plans to issue $700 million of FMBs during 2023. Xcel will further manage its equity contributions and PSCO's dividend policy to meet the regulatory capital structure of the utility's electric and natural gas operations. During the nine-month period ended September 3Q2022, PSCO received equity contributions from Xcel of $399 million (total at year-end 2021: $650 million) compared to dividend distributions of around $365 million (total at year-end 2021: $467 million). In January 2022, PSCO received a $40 million contribution to its defined pension fund (2021: $45 million). At year-end 2021, its defined pension fund was almost fully funded (under-funded position: $18 million).

Rating methodology and scorecard factors

Moody's evaluates PSCO's financial performance relative to the standard business risk grid under the Regulated Electric and Gas Utilities rating methodology published in June 2017. As depicted in the grid below, the company's scorecard indicated outcome based on projected average key credit metrics is A3, the same as its assigned senior unsecured rating.

Exhibit 10

Methodology Scorecard Factors

Public Service Company of Colorado

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 9/30/2022		Moody's 12-18 Month Forward View As of 12/20/2022 [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
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	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.4x	Aa	5.5x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	19.7%	Baa	19% - 22%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	10.7%	Baa	12% - 15%	Baa
d) Debt / Capitalization (3 Year Avg)	39.8%	A	39% - 41%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	0	0		
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned				A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2022(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
[4] Standard risk grid for financial strength.
Source: Moody's Financial Metrics

Appendix

Exhibit 11

Peer Comparison [1]

	Public Service Company of Colorado A3 (Stable)			Indiana Michigan Power Company A3 (Positive)			PacifiCorp A3 (Stable)		
(In US millions)	FYE Dec-20	FYE Dec-21	LTM Sept-22	FYE Dec-20	FYE Dec-21	LTM Sept-22	FYE Dec-20	FYE Dec-21	LTM Jun-22
Revenue	4,183	4,815	5,218	2,242	2,327	2,514	5,341	5,296	5,367
CFO Pre-W/C	1,277	1,178	1,391	920	803	914	1,605	1,799	1,710
Total Debt	6,254	6,806	7,215	3,287	3,393	3,447	8,879	8,806	8,799
CFO Pre-W/C + Interest / Interest	6.2x	5.9x	6.6x	8.7x	7.7x	8.3x	4.7x	5.2x	4.9x
CFO Pre-W/C / Debt	20.4%	17.3%	19.3%	28.0%	23.7%	26.5%	18.1%	20.4%	19.4%
CFO Pre-W/C – Dividends / Debt	7.1%	10.4%	12.5%	25.4%	16.3%	22.3%	18.1%	18.7%	16.6%
Debt / Capitalization	39.8%	39.5%	39.6%	46.3%	46.6%	45.6%	43.0%	40.9%	40.5%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Exhibit 12

Cash flow and credit metrics [1]

CF Metrics	Dec-18	Dec-19	Dec-20	Dec-21	LTM Sept-22
As Adjusted					
FFO	**1,082**	**1,348**	**1,217**	**1,413**	**1,482**
+/- Other	-33	-47	60	-235	-91
CFO Pre-WC	**1,049**	**1,301**	**1,277**	**1,178**	**1,391**
+/- ΔWC	-54	-44	-87	-425	-123
WC	995	1,257	1,190	753	1,268
WC	1,049	1,301	1,277	1,178	1,391
CFO	**995**	**1,257**	**1,190**	**753**	**1,268**
- Div	375	457	831	467	492
- Capex	1,564	1,706	1,674	1,624	1,910
FCF	**-944**	**-906**	**-1,315**	**-1,338**	**-1,134**
(CFO Pre-W/C) / Debt	18.4%	22.1%	20.4%	17.3%	19.3%
(CFO Pre-W/C - Dividends) / Debt	11.8%	14.3%	7.1%	10.4%	12.5%
FFO / Debt	19.0%	22.9%	19.5%	20.8%	20.5%
RCF / Debt	12.4%	15.1%	6.2%	13.9%	13.7%
Revenue	4,086	4,237	4,183	4,815	5,218
Interest Expense	221	235	245	238	251
Net Income	461	578	575	657	694
Total Assets	17,349	19,008	20,351	21,922	22,993
Total Liabilities	11,116	12,077	12,770	13,478	13,994
Total Equity	6,233	6,931	7,581	8,444	8,999

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Ratings

Exhibit 13

Category	Moody's Rating
PUBLIC SERVICE COMPANY OF COLORADO	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
Sr Unsec Bank Credit Facility	A3
Commercial Paper	P-2
PARENT: XCEL ENERGY INC.	
Outlook	Stable
Issuer Rating	Baa1
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured	Baa1
Commercial Paper	P-2

Source: Moody's Investors Service

REPORT NUMBER 1348673

MOODY'S
INVESTORS SERVICE

MOODY'S

Rating Action: Moody's affirms NSP-Minnesota's A2 ratings; stable outlook

12 Dec 2023

Approximately $8.7 billion of debt securities affected

New York, December 12, 2023 – Moody's Investors Service ("Moody's") affirmed today the ratings of Northern States Power Company (Minnesota) (NSP-Minnesota), including its A2 issuer rating and Aa3 senior secured debt rating. See a full list of affected debt toward the end of this press release. NSP-Minnesota's rating outlook remains stable.

RATINGS RATIONALE

"The affirmation of NSP-Minnesota's ratings assumes that the utility will continue to generate financial metrics that remain supportive of the A2 rating following the outcome of its electric rate case in Minnesota, which provides cash flow visibility through 2024" said Nati Martel, Vice President – Senior Analyst. Specifically, we expect the ratio of CFO before changes in working capital (CFO pre-W/C) to debt will range between 22-24% despite a possible increase in it base capital expenditures program. "Well positioned financial metrics help to offset our view that the utility's relationship with stakeholders has become more contentious, as evidenced by certain cost disallowances and the utility's appeal of the rate case decision to the Minnesota Court of Appeals", added Martel.

In July 2023, the Minnesota Public Utilities Commission (MPUC) approved a three-step increase in the utility's revenue requirements for the 2022-2024 period. NSP-Minnesota plans to appeal the order in courts, following the MPUC's denial of the company's request to reconsider certain aspects of its July 2023 electric rate order. This dynamic is credit negative because it points toward a less constructive relationship with the MPUC. Certain aspects of the order are also credit negative, including the implementation of a hard asymmetrical 3%-cap on the true-up mechanism for sales to non-decoupled customers. Further, the MPUC authorized a return on equity (RoE) that is less than peers in Minnesota and was below the March 2023 Administrative Law Judge's recommended ratio. This was the utility's first fully litigated electric general rate case since 2013 and resulted in an authorized revenue increase of around 62% of the utility's total ask, or roughly $130 million below the company's request.

NSP-Minnesota's A2 rating and stable outlook reflects some diversification benefits from its fully regulated utility profile, with integrated electric and natural gas distribution operations in Minnesota, its largest jurisdiction, as well as both Nort and South Dakota. The utility's access to several riders and surcharges, particularly in Minnesota, reduces its exposure to regulatory lag while the authorized equity ratio of 52.5% underpin our expectation that it will be able to generate financial metrics that remain commensurate with its A2 rating. In January 2024, the utility will start to credit customers $202 million of over-collected interim rates that began in January 2022. Even with these temporary credits, Moody's expects the company to generate CFO pre-W/C to debt above 22%.

FACTORS THAT COULD LEAD TO AN UPGRADE OR DOWNGRADE OF THE RATINGS

Factors that Could Lead to an Upgrade

The utility's ratings could experience positive momentum if there is greater than anticipated regulatory relief, cost savings, or a reduction in leverage, allowing it to generate a CFO pre-W/C to debt ratio above 25% on a sustained basis.

Factors that Could Lead to a Downgrade

The ratings could be downgraded if there is a further deterioration in the credit supportiveness of its regulatory environment in Minnesota or if there is an unexpected deterioration in its credit metrics. Specifically, downward pressure on the ratings could result if its CFO pre-W/C to debt ratio is below 22% for an extended period.

Affirmations:

..Issuer: Northern States Power Company (Minnesota)

.... Issuer Rating, Affirmed A2

....Senior Secured Shelf, Affirmed (P)Aa3

....Senior Secured First Mortgage Bonds, Affirmed Aa3

....Underlying Senior Secured First Mortgage Bonds, Affirmed Aa3

....Senior Unsecured Bank Credit Facility, Affirmed A2

....Senior Unsecured Commercial Paper, Affirmed P-1

Outlook Actions:

..Issuer: Northern States Power Company (Minnesota)

....Outlook, Remains Stable

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in June 2017 and available at https://ratings.moodys.com/rmc-documents/68547. Alternatively, please see the Rating Methodologies page on https://ratings.moodys.com for a copy of this methodology.

Headquartered in Minneapolis, NSP-Minnesota is a vertically integrated utility that provides electric services to approximately 1.5 million customers in Minnesota, North Dakota and South Dakota as well as natural gas local distribution (LDC) services to over 0.5 million customers in Minnesota and North Dakota. Minnesota, mostly around Minneapolis-St. Paul, accounts for the bulk of its operations (almost 90% of revenues) and rate base that aggregated

$14.5 billion at year-end 2022. The utility is subject to the regulatory overview of the MPUC, North Dakota Public Service Commission (NDPSC), South Dakota Public Utilities Commission (SDPUC) as well as Federal Energy Regulatory Commission (FERC). FERC oversees NSP-Minnesota's wholesale production and transmission services. NSP-Minnesota and its smaller sister company Northern States Power Company (Wisconsin) (NSP-Wisconsin, A2 stable) operate their electric production and transmission systems as an integrated system known as the NSP System. NSP-Minnesota is the legacy subsidiary of the holding company Xcel Energy Inc. (Xcel, Baa1 stable) with its rate base accounting for around 37% of the group's total rate base of $39 billion at year-end 2022.

REGULATORY DISCLOSURES

For further specification of Moody's key rating assumptions and sensitivity analysis, see the sections Methodology Assumptions and Sensitivity to Assumptions in the disclosure form. Moody's Rating Symbols and Definitions can be found on https://ratings.moodys.com/rating-definitions.

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Moody's downgrades Pinnacle West to Baa1 and Arizona Public Service to A3; outlook negative

Rating Action | *9 min read* | 17 Nov 2021 Moody's Investors Service

Approximately $6.5 billion of debt securities downgraded

New York, November 17, 2021 -- Moody's Investors Service ("Moody's") downgraded the long-term ratings of Pinnacle West Capital Corporation (Pinnacle) including its senior unsecured and Issuer ratings to Baa1 from A3. Pinnacle's short-term rating for commercial paper was affirmed at Prime-2. Concurrently, Moody's downgraded the ratings of utility subsidiary Arizona Public Service Company (APS) including its senior unsecured and Issuer ratings to A3 from A2 and its short-term rating for commercial paper to Prime-2 from Prime-1. The outlooks for both companies are negative. This concludes the review for downgrade initiated on 12 October 2021.

A complete list of rating actions appears below.

RATINGS RATIONALE

"The downgrades of Pinnacle and APS are prompted by the recent decline in Arizona regulatory environment following the conclusion of the utility's 2019 rate case as well as the organization's weakened credit metrics" stated Edna Marinelarena, Assistant Vice President. The rate case proceedings were highly contentious, and the final outcome will result in both companies sustaining credit metrics well below historical levels. We expect APS's cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio to range between 19% and 20% over the next several years while Pinnacle's CFO pre-WC to debt ratio is projected to be between 17% and 19% over the same period. This compares to CFO pre-WC to debt ratios that had historically been comfortably above 20% at both the utility and the parent company.

The rate case decision will result in a base rate decrease of $119.8 million and a substantive decline in the authorized ROE to 8.7% from 10%, which is well below the national average of 9.5%. Additionally, the Arizona Corporation Commission (ACC) voted to disallow $215.5 million of the utility's selective catalytic reduction (SCR) investments made at the Four Corners plant in 2018 and also disallowed a grid access fee charge. These results are indicative of a less credit supportive and predictable regulatory framework in Arizona compared to the rest of the country, materially increasing regulatory risk for both Pinnacle and

Related Entities

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Ocotillo plant upgrades. The CFO pre-WC to debt ratios have dropped significantly from the mid 20% range to a weak 17% for APS and 16% for Pinnacle at the end of 2020. We see the ratio remaining below 20% for both companies through 2021 as debt funded capital investments outpace cash flow. We expect credit metrics to marginally improve in 2022 as the company collects revenue associated with the Four Corners and Ocotillo plant investments that were authorized in the 2019 rate case; including the partial disallowance of the SCR, but they will not approach historical levels. We expect CFO pre-WC to debt to be about 20% for APS and 18% for Pinnacle in 2022.

APS plans to maintain its elevated capital spending amidst this period of higher regulatory risk. The company expects to invest about $1.5 billion annually, or a total of $4.7 billion, through 2024. Pinnacle plans to issue about $1 billion in debt to supporting capex at APS increasing its holding company debt to about 17% of consolidated debt from 7% at the end of 2020. We expect holding company debt to remain below 20% over the next several years. Although Arizona regulators have thus far not typically focused on the amount of debt issued at the holding company, given the recent negative regulatory developments, the higher debt levels at the holding company could fall under scrutiny.

Although we expect APS's and Pinnacle's credit metrics to improve slightly, the negative outlooks reflects the organization's limited financial flexibility to manage unforeseen events. Additionally, there is increased uncertainty over APS's ability to recovery its 100% of its future capital investments in a timely manner following the conclusion of the 2019 rate case. APS is now operating in a regulatory environment that is prioritizing customer bill impact and affordability concerns to the detriment of credit supportive cost recovery for the utility, unlike most other regulatory frameworks where utilities and their regulators have been more balanced and achieved both goals. The utility's future rate case filings will likely receive higher scrutiny, potentially leading to an increase in regulatory lag and disallowances of other mechanisms which could further pressure credit ratings going forward.

We note that APS's regulatory relationship had already become increasingly challenged for a number of reasons prior to the recent rate case outcome, including the utility's poor implementation of new rate plans in 2018, controversial disconnection policies during times of excessive heat in 2019, its provision of a faulty rate comparison tool to customers and the level of campaign contributions made by Pinnacle. These issues stressed the company's relationship with the ACC and led regulators to open an investigation into APS's earnings, require the utility to file a new rate case in 2019, and customer outreach programs. These issues plagued the company during the rate case proceedings despite several of these matters having been resolved separately. APS filed the recently concluded rate case just over two years ago, on 31 October 2019, originally requesting a $184 million (5.4%) revenue increase and a 10.15% ROE, and ultimately falling well short of its initial request.

ESG Considerations

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Pinnacle's exposure to environmental risk is moderate (E-3 issuer profile score) and driven by its moderately negative physical climate and water management risks, because the state of Arizona, Pinnacle's primary service territory, is exposed to heat and water stress. These risks are offset by neutral to low exposure to waste and pollution and natural capital.

The organization's exposure to social risk is highly negative (S-4 issuer profile score) driven by demographics and societal trends that could increase public concern over environmental, social or affordability issues that could lead to adverse regulatory or political decisions. While the ACC has been constructive and credit supportive historically, it has been less consistent and predictable more recently. Furthermore, as the owner and operator of the nation's largest nuclear facility, the Palo Verde Nuclear Generation Station, Pinnacle's risk of responsible production is heightened. Pinnacle also faces high risks associated with customer relations and a neutral to low risk related to health and safety and human capital.

Governance is broadly in line with other utilities and does not pose a particular risk (G-2 issuer profile score). For Pinnacle, the board structure primarily stands out as moderately negative due to having a less independent board and committees, however it is balanced by other aspects of governance strength that are derived in part by management credibility and track record as well as financial policy and risk management.

Rating Outlook

The negative outlook reflects increased regulatory risk, uncertainty over future rate case filings, and the lack of financial flexibility as credit metrics have fallen. APS is operating in a more challenging regulatory jurisdiction, could experience higher scrutiny over future investments and may face disallowances of other cost recovery mechanisms given the ACC's focus on customer affordability.

FACTORS THAT COULD LEAD TO AN UPGRADE OR DOWNGRADE OF THE RATINGS

Factors that could lead to an upgrade

A rating upgrade is unlikely over the next 12 to 18 months because of the negative outlook on both APS and Pinnacle. Both companies' outlooks could return to stable if there is evidence of a more constructive and credit supportive regulatory framework in Arizona. Longer term, greater regulatory predictability combined with stronger financial metrics, such that the CFO pre-WC to debt ratio is above 24% for APS and 23% for Pinnacle, could result in upward rating movement.

Factors that could lead to a downgrade

Pinnacle and APS's ratings could be downgraded if the Arizona regulatory environment deteriorates further, such as through additional cost recovery disallowances, prolonged rate case proceedings or

Related Entities

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Headquartered in Phoenix, AZ, Pinnacle is a holding company whose principal operating subsidiary, APS, is a regulated, vertically integrated electric utility providing electric service to more than 1.2 million customers in 11 of the 15 counties in Arizona. APS currently represents essentially all of Pinnacle's consolidated assets and revenues.

Affirmations:

..Issuer: Pinnacle West Capital Corporation

....Senior Unsecured Commercial Paper, Affirmed P-2

Downgrades:

..Issuer: Pinnacle West Capital Corporation

.... Issuer Rating, Downgraded to Baa1 from A3

....Senior Unsecured Bank Credit Facility, Downgraded to Baa1 from A3

....Senior Unsecured Regular Bond/Debenture, Downgraded to Baa1 from A3

..Issuer: Arizona Public Service Company

.... Issuer Rating, Downgraded to A3 from A2

....Senior Unsecured Bank Credit Facility, Downgraded to A3 from A2

....Senior Unsecured Commercial Paper, Downgraded to P-2 from P-1

....Senior Unsecured Regular Bond/Debenture, Downgraded to A3 from A2

....Senior Unsecured Shelf, Downgraded to (P)A3 from (P)A2

..Issuer: Maricopa Co. Pollution Control Corp., AZ

....Senior Unsecured Revenue Bonds, Downgraded to A3 from A2

....Senior Unsecured Revenue Bonds, Downgraded to P-2 from P-1

Outlook Actions:

..Issuer: Arizona Public Service Company

....Outlook, Changed To Negative From Rating Under Review

..Issuer: Pinnacle West Capital Corporation

....Outlook, Changed To Negative From Rating Under Review

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Levers to Managing Credit Quality: Illustrative Analysis

$ Millions

Xcel Energy

Summary

January, 2024

Analysis below attempts to provide an illustrative example of how a utility's credit quality can be managed via different levers. Modeled assumptions and figures are intentionally generic and meant to be representative of PSCo consolidated but vary from detailed specifics to provide simplification. Levers 1 - 3 attempt to improve the Reference Case's key credit metric CFO / Debt by 100 bps. In this example, equity ratio alone is approximately 4x cheaper than depreciation alone and approximately 6x cheaper than ROE alone.

Base Assumptions

Average Capitalization	18,000
Cash From Operations (excluding income)	930
Authorized ROE	9.3%
Regulatory Leakage / Lag	1.2%
Cost of Debt	4.0%
Composite Tax Rate	24.5%
Debt Adjustment (Period End & OBS)	500

Key Assumption Change

Item Description	Reference Case		1. Equity Ratio		2. Depreciation		3. Authorized ROE	
Average Equity	9,900	55.0%	10,193	56.6%	9,900	55.0%	9,900	55.0%
Average Debt	8,100	45.0%	7,807	43.4%	8,100	45.0%	8,100	45.0%
Average Capitalization	18,000		18,000		18,000		18,000	
Authorized ROE	9.30%		9.30%		9.30%		10.2%	
Embedded Leakage / Lag	-1.15%		-1.15%		-1.15%		-1.15%	
Earned Return on Equity	8.15%		8.15%		8.15%		9.02%	
Tax Rate	24.5%		24.5%		24.5%		24.5%	
Tax Gross-Up	1.3x		1.3x		1.3x		1.3x	
Return on Equity	807		831		807		893	
Interest Expense	324		312		324		324	
Added Book Depreciation	-		-		86		-	
Cash From Operations (excluding income)	930		930		930		930	
Taxes	261		269		261		289	
Revenue Requirement	2,322		2,342		2,408		2,436	
CFO	1,737		1,761		1,823		1,823	
Adjusted Debt	8,600		8,307		8,600		8,600	
CFO / Debt	20.2%		21.2%		21.2%		21.2%	
Credit Metric Improvement Over Reference			**1.00%**		**1.00%**		**1.00%**	
Rev Req Increase Over Reference Case			20		86		114	
RR Expense Factor Compared to Equity Ratio Alone					4.3x		5.7x	

S&P Global

RRA Regulatory Focus

November 1, 2023

Major energy rate case decisions in the US – January - September 2023

Quarterly update on pending rate cases

Lisa Fontanella, Research Director

Contributors: Brian Collins, Jim Davis, Russell Ernst, Lillian Federico, Monica Hlinka, Jason Lehmann, Dan Lowrey

Editor: Majda Shabbir

For detailed data

Access RRA's electric and gas rate case decisions through Sept. 30, 2023, data tables .

Averages calculated for the first nine months of 2023 show a modest upward trend in electric and gas authorized returns on equity.

To learn more or to request a demo, visit spglobal.com/marketintelligence.

Table of Contents

Executive Summary

Introduction

The average electric and gas authorized returns on equity for the first nine months of 2023 are modestly trending upward.

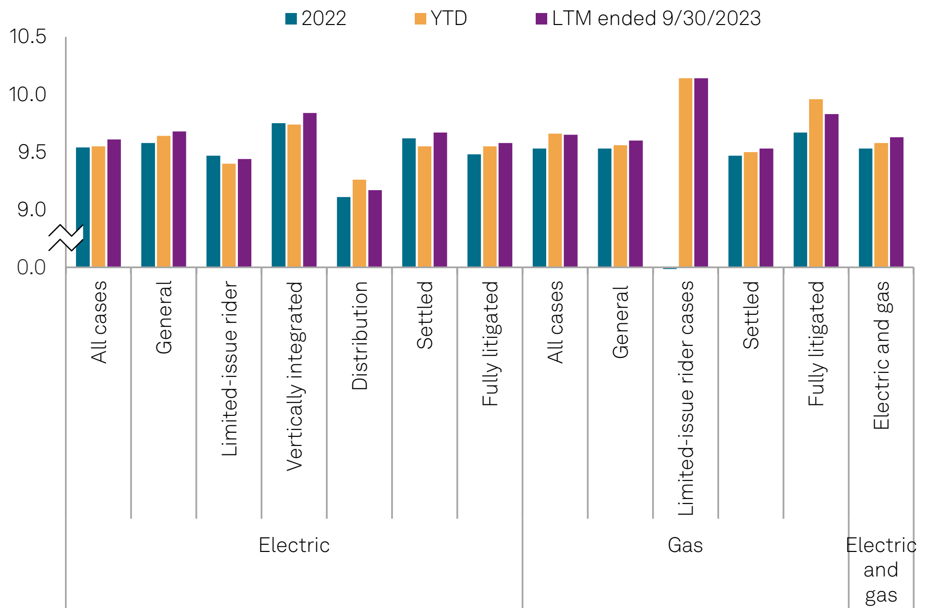
The average ROE authorized electric utilities was 9.55% in rate cases decided in the first nine months of 2023, modestly above the 9.54% average for full year 2022. There were 37 electric ROE authorizations in the first nine months of 2023 versus 53 in full year 2022.

The average ROE authorized gas utilities was 9.66% in cases decided in the first nine months of 2023 versus 9.53% in full year 2022. There were 17 gas cases that included an ROE determination in the first nine months of 2023 versus 33 in full year 2022.

Rate case activity remained elevated in 2022, with state public utility commissions issuing about 140 decisions. That level of activity, however, was down from 2021 — a record year with about 150 decisions rendered in electric and gas rate cases across the US.

While the reasons for a rate case filing are numerous, the main driver continues to be the recovery of capital expenditures. Energy utilities are investing in infrastructure to modernize transmission and distribution systems; build new natural gas, solar and wind generation; and deploy new technologies to accommodate the expansion of electric vehicles, battery storage and advanced metering infrastructure that facilitate the transition toward decarbonization. Other reasons for rate filings include rising expenses, revised cost-of-capital parameters, the impact of broader economic and sectorwide forces on operations, the need to address rate treatment to be accorded generation facilities being retired prior to the end of their planned service lives due to the energy transition, recovery of storm and severe-weather related costs, and regulatory approval for alternative regulatory mechanisms.

Average authorized ROE (%)



	2022	YTD	LTM ended 9/30/2023
Electric averages			
All cases	9.54	9.55	9.61
General rate cases	9.58	9.64	9.68
Limited-issue rider cases	9.47	9.40	9.44
Vertically integrated cases	9.75	9.74	9.84
Distribution cases	9.11	9.26	9.17
Settled cases	9.62	9.55	9.67
Fully litigated cases	9.48	9.55	9.58
Gas averages			
All cases	9.53	9.66	9.65
General rate cases	9.53	9.56	9.60
Limited-issue rider cases	--	10.14	10.14
Settled cases	9.47	9.50	9.53
Fully litigated cases	9.67	9.96	9.83
Composite electric and gas averages			
Electric and gas	9.53	9.58	9.63
US Treasury			
30-year bond yield	3.11	3.93	3.92

Data compiled Oct. 25, 2023.
ROE = return on equity; LTM = last 12 months; YTD = year to date (through Sept. 30, 2023).
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Department of the Treasury.

About this report

This quarterly report offers a detailed overview of electric and gas rate case decisions issued in the US during the first nine months of 2023 and select aggregated historical data. The information presented in this report utilizes the data compiled by Regulatory Research Associates for its rate case database, available on the S&P Capital IQ Pro platform. RRA endeavors to follow all "major" rate cases for investor-owned utilities nationwide, with "major" defined as a case in which the utility's request would result in a rate change of at least $5 million or in which the commission approves a rate change of at least $3 million. In addition to base rate cases, the rate case history database includes details regarding certain limited-issue rider proceedings, primarily those involving significant rate base additions recognized outside of a general rate case. In some of these cases, the rate change coverage criteria may not apply. Historical data in this report may not match earlier data provided in previous reports due to differences in presentation, including the treatment of withdrawn or dismissed cases and the addition of cases not previously included in RRA's coverage.

The Take

Averages calculated for the first nine months of 2023 show that electric and gas authorized returns on equity are modestly trending higher. In recent years, rate case activity for investor-owned electric and gas utilities in the US has been elevated, with state public utility commissions issuing about 140 decisions in 2022. This level of activity, however, is down from 2021, which was a record year with about 150 decisions rendered in electric and gas rate cases across the US. With rising interest rates, RRA anticipates rate case filings will remain robust.

For full year 2023, average authorized returns may edge slightly higher than the annual levels observed in 2022, as higher interest rates resulting from the US Federal Reserve's anti-inflation tightening policies will likely begin impacting authorized ROEs. The effect of interest rate increases on authorized returns will likely be limited, however, given that regulators are slower to adjust ROEs upward than downward, and affordability concerns persist, as regulators contend with customer rate increases stemming from significant but necessary capital investment in the energy transition during a period of high inflation.

Overview of electric and gas authorizations

The average electric and gas authorized returns on equity edged modestly higher per averages calculated for the first nine months of 2023.

The average ROE authorized for electric utilities was 9.55% for rate cases decided in the first nine months of 2023, above the 9.54% average observed in full year 2022. There were 37 electric ROE determinations reflected in the calculations for the first nine months of 2023 versus 53 in full year 2022.

The average ROE authorized for gas utilities was 9.66% for cases decided in the first nine months of 2023, above the 9.53% average observed in 2022. There were 17 gas rate case decisions decided in the first nine months of 2023 versus 33 in full year 2022.

The electric data set includes several limited-issue rider cases. Historically, the ROEs authorized in limited-issue rider cases were meaningfully higher than those approved in general rate cases, driven primarily by incentives allowed in Virginia for certain types of generation investment. These premiums have largely expired, however, narrowing the gap between the average ROE in the rider cases and general rate cases. Excluding rider cases, the average authorized ROE for electric cases was 9.64% in the first nine months of 2023 versus 9.58% in full year 2022.

Excluding the three rider cases, the average authorized ROE for gas cases was 9.56% in the first nine months of 2023. There were no rider cases with a gas-authorized ROE in 2022. For the most part, limited-issue riders have a limited impact on average ROEs in the gas sector, as most of the gas riders rely on ROEs approved in a previous base rate case.

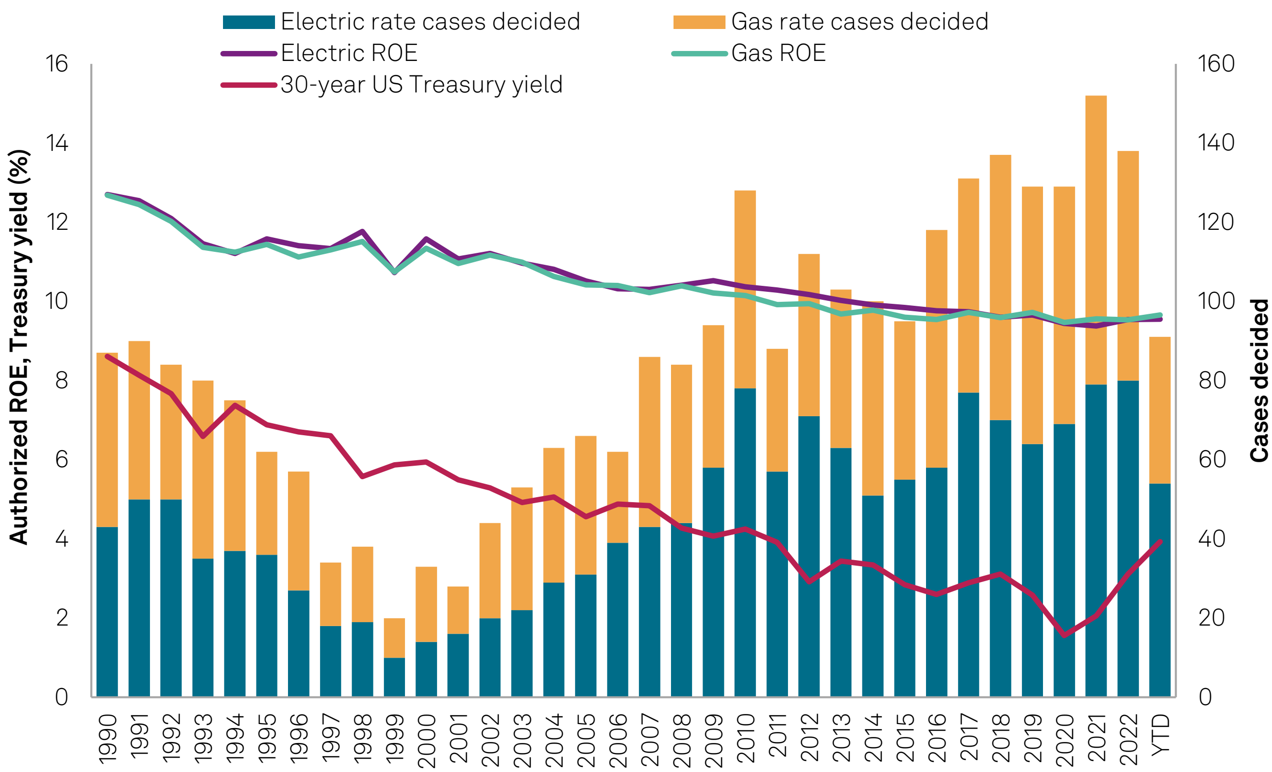
In the first nine months of 2023, the median ROE authorized in all electric utility rate cases was 9.35%, versus 9.50% in full year 2022; for gas utilities, the metric was 9.55% in the first nine months of 2023 and 9.60% in full year 2022.

Looking at the last 12 months ended Sept. 30, 2023, the average ROE authorized in all electric utility rate cases was 9.61%, and the median was 9.56%. For gas utilities during the same period, the average was 9.65%, and the median was 9.60%.

The full-year averages in recent years are at the lowest levels ever witnessed in the industry. ROE determinations in Illinois and Vermont, calculated using a formulaic approach tied to US Treasury bond yields, weighed down the electric ROE average in 2022. Excluding these ROE determinations, the average return authorized for electric utilities was 9.63% in 2022.

Looking longer-term, interest rates — as measured by the 30-year US Treasury bond yield — fell almost steadily between 1990 and 2020, placing downward pressure on authorized ROEs, which declined much less dramatically than Treasury yields. Between 1990 and 2020, Treasury yields fell more than 700 basis points, to 1.56% from 8.61%, while average authorized ROEs for electric and gas utilities combined fell less than 325 basis points, to 9.45% from 12.69%. The average authorized ROEs did not fall below 10% until 2011 for gas utilities and until 2014 for electric utilities. The calendar-year averages fell below 9.50% for the first time in 2020.

Average electric, gas authorized ROEs; number of rate cases decided



Data compiled Oct. 25, 2023.
ROE = return on equity; YTD = year to date (through Sept. 30, 2023).
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Department of the Treasury.

The decline in authorized ROEs has coincided with an upswing in rate case activity, with 100 or more cases adjudicated in 10 of the last 12 calendar years. This count includes electric and gas cases where no ROEs were specified, but it does not include withdrawn cases. At over 150 cases, rate case activity in 2021 was the most robust observed in any year during the 1990–2022 period. In 2022, about 140 cases were decided.

Absent the pandemic, increased costs associated with environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates, storm and disaster recovery, cybersecurity, early plant retirement and employee benefits have contributed to an active rate case agenda over the last decade.

Due to the COVID-19 pandemic and the challenging economic landscape, many utilities and state commissions sought to limit the immediate impact of rate hikes during 2020 by pushing rate changes into a future period or agreeing to forgo rate hikes and using accounting mechanisms, such as the accelerated recovery of excess accumulated deferred tax liabilities, to mitigate requested increases.

Amid the current high inflationary environment, the pace of rate case activity in the US is robust, with about 115 electric and gas rate cases currently pending.

With interest rates and authorized ROEs declining at different rates between 1990 and 2020, the spread between authorized ROEs and the average yield on 30-year US Treasuries somewhat widened over this period — from a little over 400 basis points in 1990 to peaking at just under 800 basis points in 2020.

This occurrence is attributable primarily to the regulators' often-unstated understanding that the drop in interest rates caused by the Fed intervention was unusual. Consequently, regulators did not necessarily fully reflect the interest rate drop in newly authorized ROEs in some instances; in others, regulators acknowledged that the changing dynamics of the industry and instability in the overall economy presented increased risks for investors, justifying a higher premium over interest rates.

In 2021, the spread narrowed slightly as Treasury yields rose, and in 2022, the spread fell to below 650 basis points.

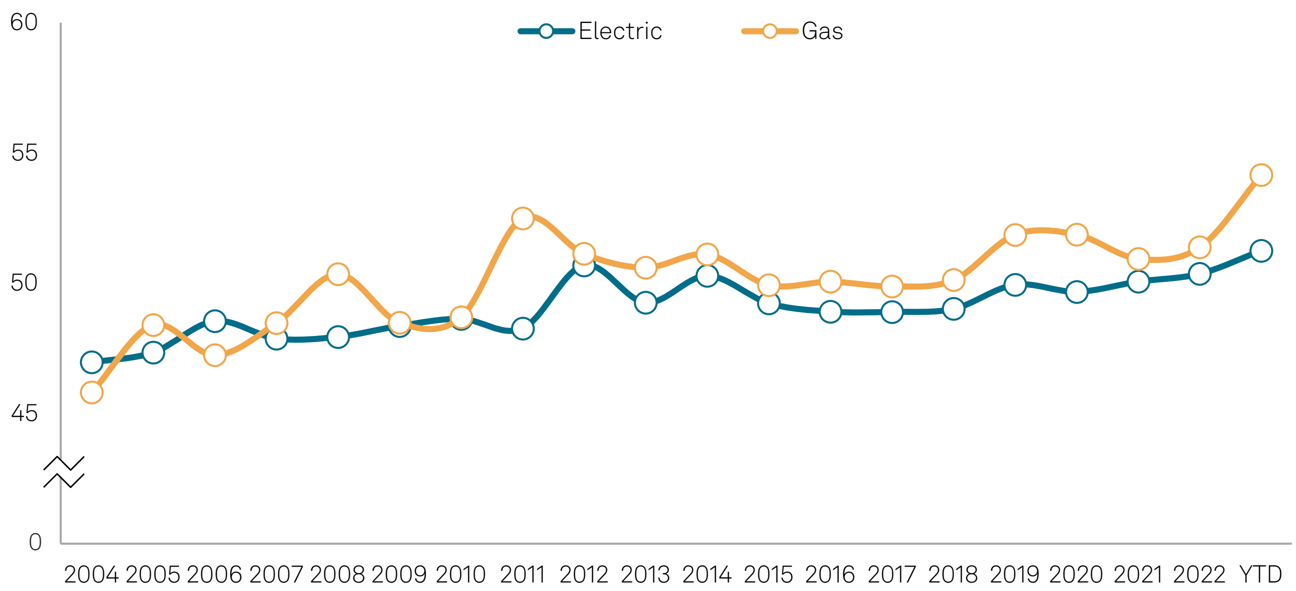
Nevertheless, with the uptick in interest rates, allowed returns may begin to edge slightly higher in 2023 as the Fed continues to raise interest rates as part of an aggressive effort to restrain inflation.

The effect of interest rate increases on authorized returns is unlikely to be dramatic, however, as authorized returns tend to be stickier on the upside than on the downside. In addition, affordability concerns will likely continue as regulators contend with inflationary pressures and stranded costs related to the energy transition. These considerations will be further complicated by several issues, including the overall macroeconomic picture and the record-high level of planned capital spending expected in the industry, particularly to fund the energy transition.

Capital structure trends

The negative cash flow impact of federal tax changes that took effect in 2018 raised concerns regarding utility liquidity and credit metrics. In response, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than those observed in 2018 and 2017.

Average authorized equity ratio (%)



Data compiled Oct. 25, 2023.
YTD = year to date (through Sept. 30, 2023).
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

For full years 2022, 2021, 2020, 2019, and 2018, the average equity ratios authorized in electric utility cases were 50.36%, 50.06%, 49.67%, 49.94%, and 49.02%, respectively. The average equity ratios authorized gas utilities for these years were 51.38%, 50.94%, 51.87%, 51.86% and 50.12%, respectively.

In the first nine months of 2023, the average authorized equity ratio for electric utility cases nationwide was 51.25%, while for gas utilities, it was 54.15%.

Taking a longer-term view, equity ratios have generally increased over the last several years — the average equity ratio approved in electric rate cases decided during 2004 was 46.96%, while the average for gas utilities was 45.81%. Many commissions began approving more equity-rich capital structures in the wake of the 2008 financial crisis. For the bulk of the period since 2004, allowed equity ratios for gas utilities have been above those authorized for electric utilities.

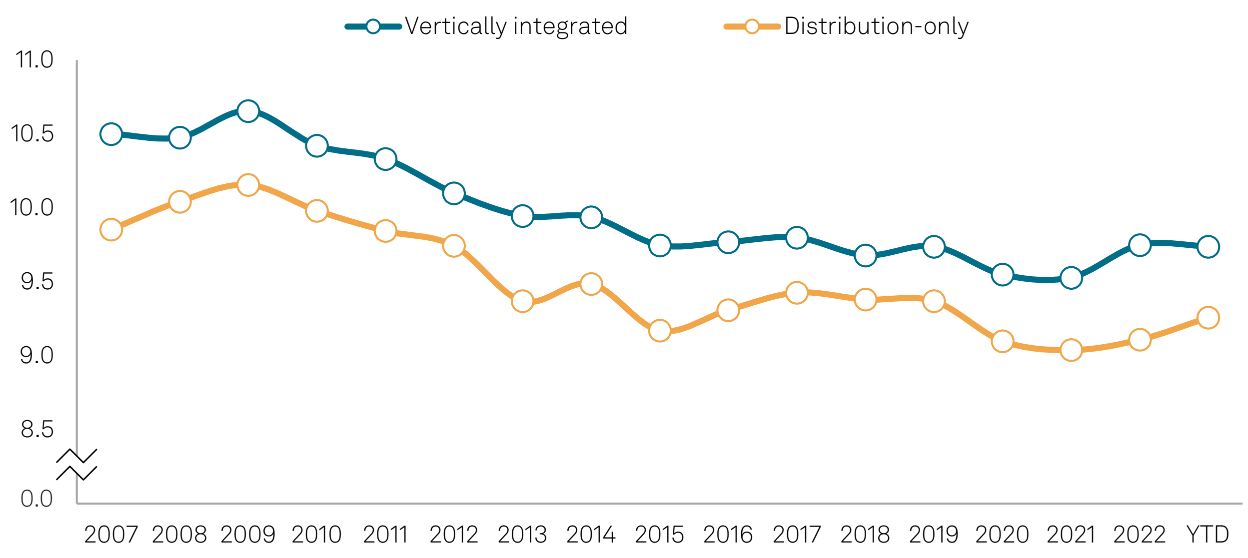
A more granular look at ROE trends

Thus far, the discussion has looked broadly at trends in authorized ROEs; the following sections provide a more granular view.

RRA has observed that there can be significant differences between average ROEs based on the types of proceedings/decisions in which these ROEs were established.

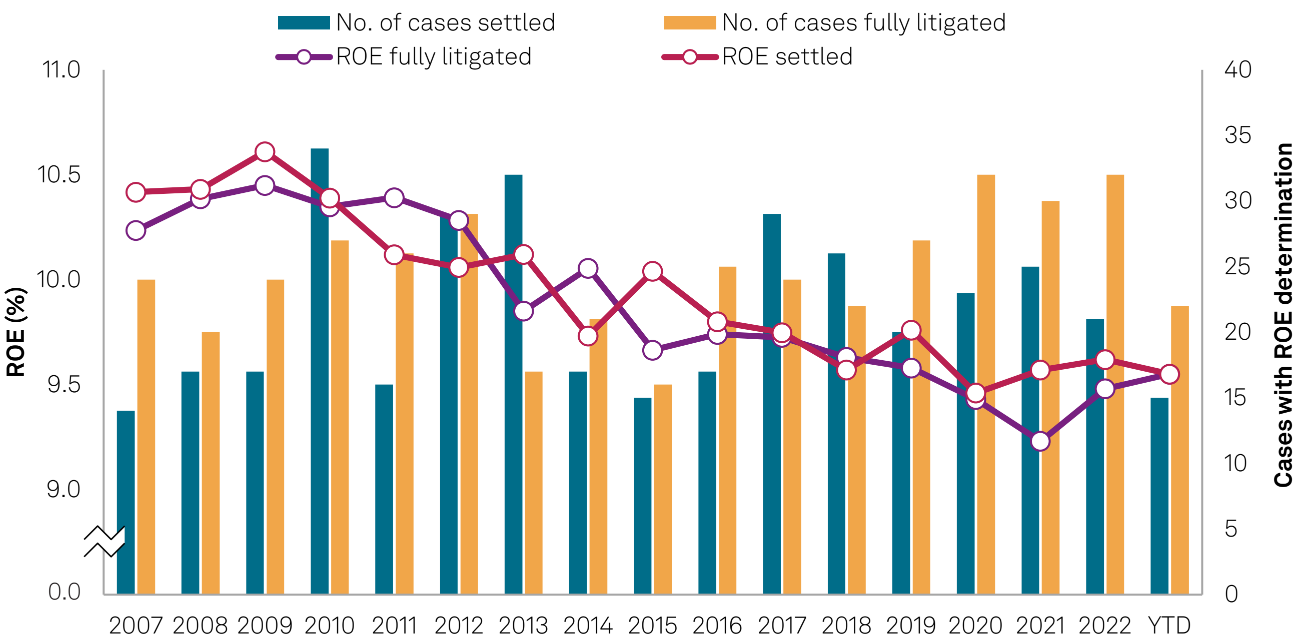
As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for distribution operations.

Average authorized electric ROEs (%)



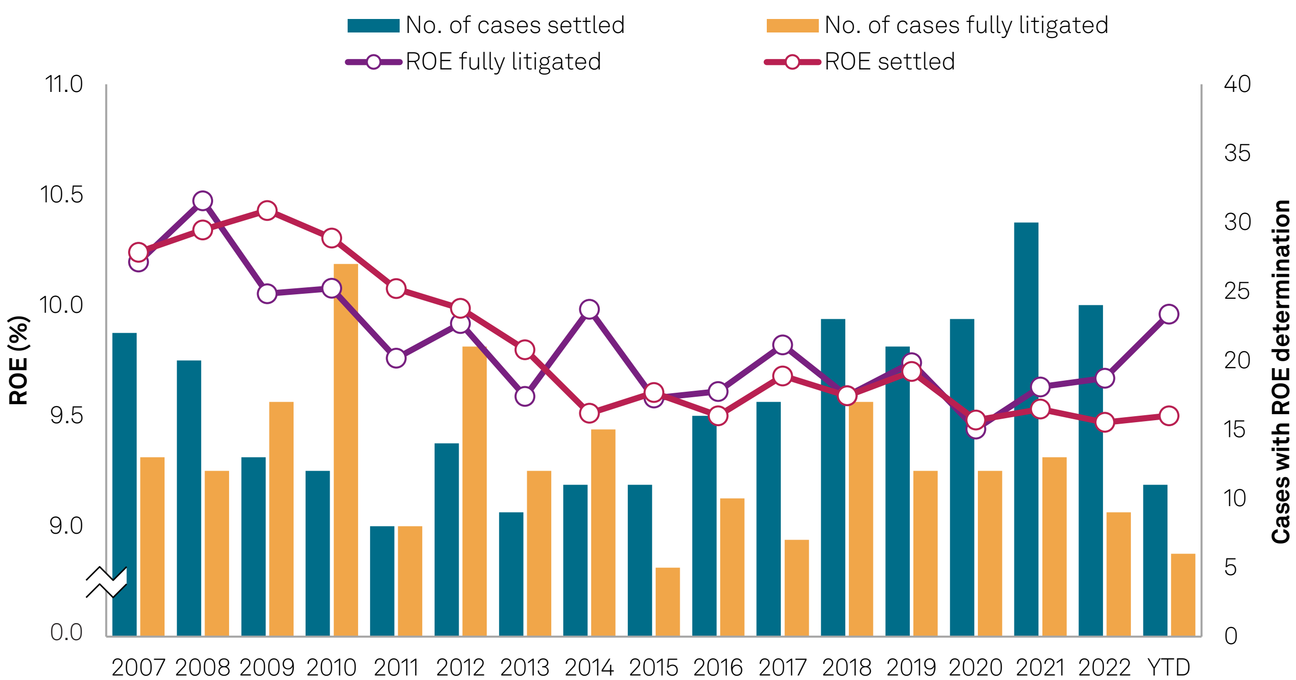
Data compiled Oct. 25, 2023.
ROE = return on equity; YTD = year to date (through Sept. 30, 2023).
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

Average authorized electric ROEs: settled vs. fully litigated cases



Data compiled Oct. 25, 2023.
ROE = return on equity; YTD = year to date (through Sept. 30, 2023).
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

Average authorized gas ROEs: settled vs. fully litigated cases



Data compiled Oct. 25, 2023.
YTD = year-to-date through Sep. 30, 2023.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

RRA finds that the annual average authorized ROEs in vertically integrated cases involving generation have been about 30–65 basis points higher than in distribution-only cases, arguably reflecting the increased risk associated with the ownership and operation of generation assets.

The industry average ROE for vertically integrated electric utilities was 9.74% in cases decided in the first nine months of 2023 versus the 9.75% average in full year 2022. For electric distribution-only cases, the industry average ROE was 9.26% in the first nine months of 2023 versus the 9.11% average in full year 2022.

Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are “black box” in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. Some states, however, preclude this type of treatment, and settlements must specify these values, if not the specific adjustments from which these values were derived.

For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, while in others, it was higher for settled cases.

The following discussion focuses on the corresponding tables available here .

Table 1 shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and quarterly since 2018, followed by the number of observations in each period. **Table 2** indicates the composite electric and gas industry data for all major cases, summarized annually since 2004 and quarterly since 2021.

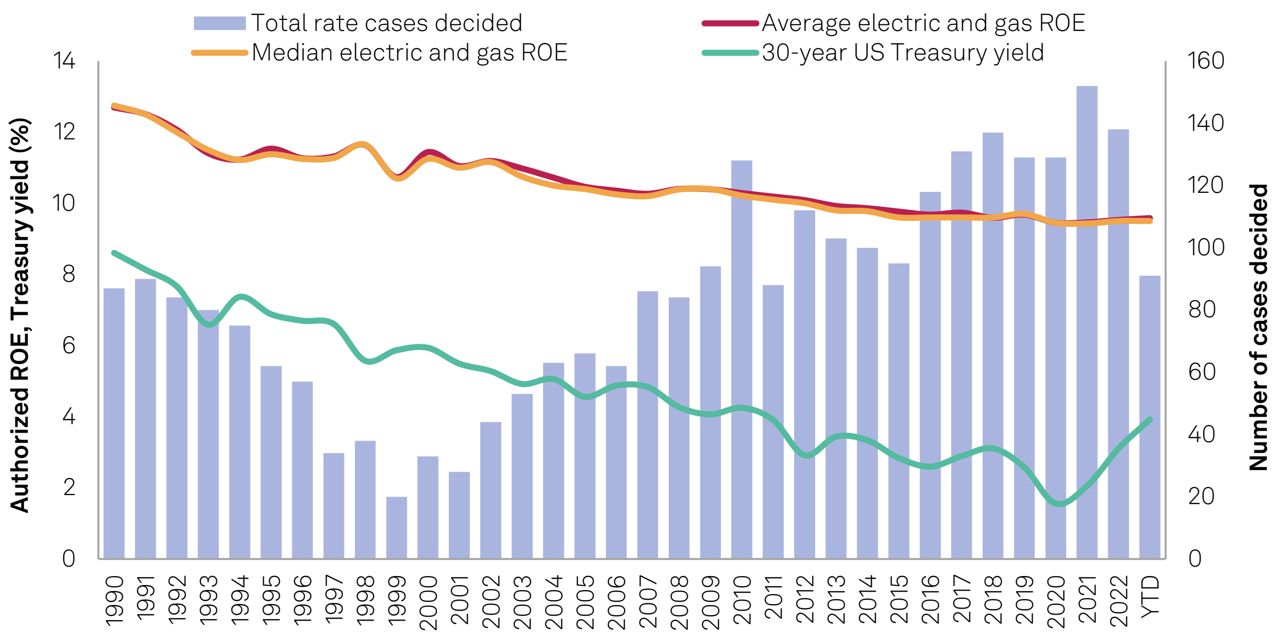
Tables 3 and 4 provide comparisons since 2007 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

The individual electric and gas cases decided in the first nine months of 2023 are listed in **Table 5**, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time the decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases decided during the specified time periods and are not necessarily representative of the average currently authorized ROEs for utilities industrywide or the returns earned by the utilities.

Table 6 and the graph below track the combined average and median equity return authorized for all electric and gas rate cases since 1990. As the table indicates, since 1990, authorized ROEs have generally trended downward, reflecting the significant decline in interest rates and capital costs over this time frame.

Composite electric, gas average authorized ROEs; total number of rate cases



Data compiled Oct. 25, 2023.
ROE = return on equity; YTD = year to date (through Sept. 30, 2023).
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Department of the Treasury.

Further Reading

The Commissions

State Regulatory Evaluations Energy

Major energy utility cases in progress in the US — Quarterly update on pending rate cases

The rate case process: a conduit to enlightenment

Rate base: It's more complicated than it sounds

Frequently Asked Questions

Intro to Water Utilities — Current Trends and Growth Drivers

An Overview of FERC Regulation

FERC Regulatory Review

Seismic shift in capex plans reported by utilities for 2023 through 2025

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Public Service Company of Colorado: PSCo Gas Case
Scenario 1. No Gas Rate Case
Dollars in Millions

Adjusted Credit Metrics

January, 2024

Moody's Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
CFO pre - WC / Debt	22.1%	20.4%	17.3%	21.2%	[redacted]		
CFO pre - WC + Interest / Interest	6.5x	6.2x	5.9x	6.9x			
CFO pre - WC - Dividends / Debt	14.3%	7.1%	10.4%	14.6%			
Debt / Book Capitalization	40.2%	39.8%	39.5%	39.6%			

S&P Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
FFO / Debt	20.7%	19.1%	20.6%	20.4%	[redacted]		
Debt / EBITDA	4.1x	4.4x	4.1x	4.0x			
FFO / Interest	5.9x	5.9x	6.7x	6.2x			
EBITDA / Interest	5.8x	5.9x	6.6x	6.4x			

Financial model below includes highly sensitive, forward-looking information including company earnings. This schedule should be considered "Restricted Confidential" and therefore should only be provided externally in direct response to an official information request.

Public Service Company of Colorado: PSCo Gas Case
Key Credit Metrics
Dollars in Millions

Xcel Energy®

Adjusted Credit Metrics Buildup

January, 2024

Moody's Adjusted Credit Metrics	2019A	2020A	2021A	2022A	
Cash Flow from Operations	$1,228	$1,174	$727	$1,255	[redacted]
Add pre-WC adjustment[2]	74	103	451	306	
Adjusted CFO pre-WC	**$1,302**	**$1,277**	**$1,178**	**$1,561**	
Interest Expense	224	224	234	260	
Add AFUDC Debt	0	14	0	0	
Add interest expense adjustment	11	7	4	4	
Adjusted Interest	**$235**	**$245**	**$238**	**$264**	
Dividends	457	831	467	491	
Debt	5,424	5,917	6,614	7,154	
Add debt adjustment	475	337	192	194	
Adjusted Debt	**$5,899**	**$6,254**	**$6,806**	**$7,348**	
Book Capitalization	14,271	15,406	17,018	18,367	
Add debt adjustment	410	323	192	194	
Adjusted Book Capitalization	**$14,681**	**$15,729**	**$17,210**	**$18,561**	
Moody's Key Metrics					
CFO pre - WC / Debt	22.1%	20.4%	17.3%	21.2%	
CFO pre - WC + Interest / Interest	6.5x	6.2x	5.9x	6.9x	
CFO pre - WC / Debt - Dividends / Debt	14.3%	7.1%	10.4%	14.6%	
Debt / Book Capitalization	40.2%	39.8%	39.5%	39.6%	

S&P Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Operating Income	$857	$823	$895	$994	[redacted]		
Add depreciation & amortization	602	655	744	848			
Add EBITDA adjustment	68	62	143	135			
Adjusted EBITDA	**$1,527**	**$1,540**	**$1,782**	**$1,977**			
Adjusted EBITDA	1,527	1,540	1,782	1,977			
Less Interest Paid	(224)	(224)	(234)	(260)			
Less Taxes Paid	(5)	(23)	(14)	(47)			
Less AFUDC Debt	(11)	(14)	(9)	(11)			
Add FFO adjustment	3	3	(6)	(41)			
Adjusted Funds from Operations	**$1,290**	**$1,282**	**$1,519**	**$1,618**			
Interest Expense	224	224	234	260			
Add AFUDC Debt	11	14	9	11			
Add interest expense adjustment	27	24	26	38			
Adjusted Interest	**$262**	**$262**	**$269**	**$309**			
Debt	5,424	5,917	6,614	7,154			
Add debt adjustment	818	803	764	771			
Adjusted Debt	**$6,242**	**$6,720**	**$7,378**	**$7,925**			
S&P's Key Metrics							
FFO / Debt	20.7%	19.1%	20.6%	20.4%			
Debt / EBITDA	4.1x	4.4x	4.1x	4.0x			
FFO / Interest	5.9x	5.9x	6.7x	6.2x			
EBITDA / Interest	5.8x	5.9x	6.6x	6.4x			

Public Service Company of Colorado: PSCo Gas Case
Financial Model: RESTRICTED CONFIDENTIAL
Dollars in Millions

Xcel Energy®

PSCo Financial Model

January, 2024

Income Statement	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Revenue	$4,237	$4,183	$4,815	$5,708	[redacted]		
COGS	(1,626)	(1,519)	(1,957)	(2,556)			
Gross Margin	**2,611**	**2,664**	**2,858**	**3,152**			
O&M	(810)	(811)	(831)	(905)			
CIP & DSM	(136)	(141)	(132)	(133)			
Property & Sales Taxes	(206)	(234)	(256)	(272)			
Depreciation & Amortization	(602)	(655)	(744)	(848)			
Operating Income	**857**	**823**	**895**	**994**			
AFUDC Equity / Other	25	34	32	30			
Interest	(224)	(224)	(234)	(260)			
Pretax Income	**658**	**633**	**693**	**764**			
Income Tax	(80)	(45)	(33)	(37)			
Net Income	**578**	**588**	**660**	**727**			

Cash Flow Statement	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Net Income	$578	$588	$660	$727	[redacted]		
Depreciation & Amortization	607	656	754	854			
Deferred Taxes	97	2	32	(10)			
AFUDC	(22)	(35)	(28)	(32)			
Pension	(47)	(41)	(53)	(13)			
Other	15	4	(638)	(271)			
Cash from Operations	**$1,228**	**$1,174**	**$727**	**$1,255**			
Capex	(1,691)	(1,671)	(1,604)	(1,880)			
Other Investments	0	0	0	0			
Cash Invested	**($1,691)**	**($1,671)**	**($1,604)**	**($1,880)**			
Equity from Parent	638	856	650	569			
Dividends Paid to Parent	(457)	(831)	(467)	(491)			
Change in Long Term Debt	528	335	737	386			
Change in Short Term Debt	(268)	154	(46)	146			
Cash from Financing	**$441**	**$514**	**$874**	**$610**			

Balance Sheet	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Cash	$11	$28	$25	$10	[redacted]		
Other Current Assets	970	1,061	1,478	1,990			
Net PP&E	16,155	17,470	18,444	19,652			
Other Assets	1,872	1,806	1,975	1,967			
Total Assets	**$19,008**	**$20,365**	**$21,922**	**$23,619**			
Short Term Debt	39	193	147	294			
Other Current Liabilities	1,247	1,235	1,332	1,544			
Deferred Taxes	1,851	1,897	1,960	1,983			
Other Liabilities	3,490	3,724	3,572	3,708			
Long Term Debt	5,385	5,724	6,467	6,860			
Equity	6,996	7,592	8,444	9,230			
Total Liabilities & Equity	**$19,008**	**$20,365**	**$21,922**	**$23,619**			

	2023	2024	2025
[redacted]			

Table 3

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2022--

Public Service Co. of Colorado reported amounts (mil. $)	**Debt**	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	7,154.0	1,842.0	994.0	260.0	1,977.0	1,255.0	1,880.0
S&P Global Ratings' adjustments							
Cash taxes paid	**--**	**--**	**--**	**--**	**(79.0)**	**--**	**--**
Cash interest paid	**--**	**--**	**--**	**--**			
Reported lease liabilities	**576.0**	**--**	**--**	**--**			
Operating leases	**--**	**110.0**	**18.8**	**18.8**			
Accessible cash and liquid investments	**(10.0)**	**--**	**--**	**--**			
Capitalized interest	**--**	**--**	**--**	**11.0**	**(11.0)**	**(11.0)**	**(11.0)**
Asset-retirement obligations	**376.0**	**19.0**	**19.0**	**19.0**	**--**	**--**	**--**
Nonoperating income (expense)	**--**	**--**	**20.0**	**--**	**--**	**--**	**--**
Debt: Other	**(171.0)**	**--**	**--**	**--**			
EBITDA: Other	**--**	**6.0**	**6.0**	**--**			
Depreciation and amortization: Other	**--**	**--**	**(6.0)**	**--**			
Total adjustments	**771.0**	**135.0**	**57.8**	**48.8**			

S&P Global Ratings' adjusted amounts	**Debt**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	7,925.0	1,977.0	1,051.8	308.8	1,618.2	1,335.2	1,869.0

Table 1

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2021--

Public Service Co. of Colorado reported amounts (mil. $)	**Debt**	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	6,614.0	1,639.0	895.0	234.0	1,782.0	727.0	1,604.0
S&P Global Ratings' adjustments							
Cash taxes paid	**--**	**--**	**--**	**--**	**(14.0)**	**--**	**--**
Cash interest paid	**--**	**--**	**--**	**--**	**(230.0)**	**--**	**--**
Reported lease liabilities	**560.0**	**--**	**--**	**--**	**--**	**--**	**--**
Operating leases	**--**	**117.0**	**9.6**	**9.6**	**(9.6)**	**107.4**	**--**
Accessible cash and liquid investments	**(25.0)**	**--**	**--**	**--**	**--**	**--**	**--**
Capitalized interest	**--**	**--**	**--**	**9.0**	**(9.0)**	**(9.0)**	**(9.0)**
Asset-retirement obligations	**333.4**	**16.0**	**16.0**	**16.0**	**--**	**--**	**--**
Nonoperating income (expense)	**--**	**--**	**26.0**	**--**	**--**	**--**	**--**
Debt: Other	**(104.0)**	**--**	**--**	**--**	**--**	**--**	**--**
EBITDA: Other	**--**	**10.0**	**10.0**	**--**	**--**	**--**	**--**
Depreciation and amortization: Other	**--**	**--**	**(10.0)**	**--**	**--**	**--**	**--**
Total adjustments	**764.4**	**143.0**	**51.6**	**34.6**	**(262.6)**	**98.4**	**(9.0)**

S&P Global Ratings' adjusted amounts	**Debt**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	7,378.4	1,782.0	946.6	268.6	1,519.4	825.4	1,595.0

Table 2

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2020--

Public Service Co. of Colorado reported amounts (mil. $)	**Debt**	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	5,917.0	1,478.0	823.0	224.0	1,540.0	1,174.0	1,671.0
S&P Global Ratings' adjustments							
Cash taxes paid	**--**	**--**	**--**	**--**	**(23.0)**	**--**	**--**
Cash interest paid	**--**	**--**	**--**	**--**	**(211.0)**	**--**	**--**
Reported lease liabilities	**662.0**	**--**	**--**	**--**	**--**	**--**	**--**
Operating leases	**--**	**12.0**	**2.4**	**2.4**	**(2.4)**	**9.6**	**--**
Postretirement benefit obligations/deferred compensation	**123.2**	**--**	**--**	**--**	**--**	**--**	**--**
Accessible cash and liquid investments	**(28.0)**	**--**	**--**	**--**	**--**	**--**	**--**
Capitalized interest	**--**	**--**	**--**	**14.0**	**(14.0)**	**(14.0)**	**(14.0)**
Power purchase agreements	**200.5**	**35.0**	**7.8**	**7.8**	**(7.8)**	**27.2**	**27.2**
Asset-retirement obligations	**315.2**	**14.0**	**14.0**	**14.0**	**--**	**--**	**--**
Nonoperating income (expense)	**--**	**--**	**37.0**	**--**	**--**	**--**	**--**
Debt: Other	**(470.0)**	**--**	**--**	**--**	**--**	**--**	**--**
EBITDA: Other	**--**	**1.0**	**1.0**	**--**	**--**	**--**	**--**
Depreciation and amortization: Other	**--**	**--**	**(1.0)**	**--**	**--**	**--**	**--**
Total adjustments	**803.0**	**62.0**	**61.2**	**38.2**	**(258.2)**	**22.8**	**13.2**

S&P Global Ratings' adjusted amounts	**Debt**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	6,720	1,540	884	262	1,282	1,197	1,684

Table 3

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2019--

Public Service Co. of Colorado reported amounts (mil. $)	**Debt**	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	5,423.7	1,459.2	856.8	224.2	1,527.6	1,227.9	1,690.7
S&P Global Ratings' adjustments							
Cash taxes paid	**--**	**--**	**--**	**--**	**(4.7)**	**--**	**--**
Cash interest paid	**--**	**--**	**--**	**--**	**(209.3)**	**--**	**--**
Reported lease liabilities	**742.2**	**--**	**--**	**--**	**--**	**--**	**--**
Operating leases	**--**	**13.1**	**2.7**	**2.7**	**(2.7)**	**10.4**	**--**
Postretirement benefit obligations/deferred compensation	**146.5**	**--**	**--**	**--**	**--**	**--**	**--**
Accessible cash and liquid investments	**(15.2)**	**--**	**--**	**--**	**--**	**--**	**--**
Capitalized interest	**--**	**--**	**--**	**11.2**	**(11.2)**	**(11.2)**	**(11.2)**
Power purchase agreements	**226.7**	**35.4**	**9.3**	**9.3**	**(9.3)**	**26.1**	**26.1**
Asset-retirement obligations	**256.0**	**15.3**	**15.3**	**15.3**	**--**	**--**	**--**
Nonoperating income (expense)	**--**	**--**	**32.0**	**--**	**--**	**--**	**--**
Debt: Other	**(538.5)**	**--**	**--**	**--**	**--**	**--**	**--**
EBITDA: Other	**--**	**4.6**	**4.6**	**--**	**--**	**--**	**--**
Depreciation and amortization: Other	**--**	**--**	**(4.6)**	**--**	**--**	**--**	**--**
Total adjustments	**817.7**	**68.4**	**59.3**	**38.5**	**(237.2)**	**25.3**	**14.9**

S&P Global Ratings' adjusted amounts	**Debt**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	6,241	1,528	916	263	1,290	1,253	1,706

Public Service Company of Colorado Final

Credit Opinion Ratios			12/31/22 (Annual) As Rep	Standard Adjustments Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	tk. Comp	Hybrids	uritization	LIFO	Unusual	Restricted Cash	Int and Div	Contingent Consideration	Non-Standard Adjustments	Total Adj.	12/31/22 (Annual) As Adj		
(CFO Pre-W/C) / Debt	Cash Flow From Operations		1,255	11	16															27	1,282		
	- Changes in Working Capital		299																		299		
	- Changes in Short Term Op. Assets & Liabs.	=	-20.00																		-20.00	=	1,561
	Short-term debt		294																		294		7,348
	+ Long-term Debt - Gross		6,860																	194	7,054		
			21.4%																				***21.2%***
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		1,255	11	16															27	1,282		
	- Changes in Working Capital		299																		299		
	- Changes in Short Term Op. Assets & Liabs.		-20.00																		-20.00		
	- Preferred Dividends		0.00																		0.00		
	- Common Dividends		-491.00																		-491.00		
	- Minority Dividends	=	0.00																		0.00	=	1,070
	Short-term debt		294																		294		7,348
	+ Long-term Debt - Gross		6,860	9	185															194	7,054		
			14.6%																				***14.6%***
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		1,255	11	16															27	1,282		
	- Changes in Working Capital		299																		299		
	- Changes in Short Term Op. Assets & Liabs.		-20.00																		-20.00		
	+ Interest Expense	=	260	0.73	3															4	264	=	1,825
	Interest Expense		260	0.73	3															4	264		264
			6.9x																				***6.9x***
Debt / Book Capitalization	Short-term debt		294																		294		
	+ Long-term Debt - Gross	=	6,860	9	185															194	7,054	=	7,348
	Short-term debt		294																		294		18,561
	+ Long-term Debt - Gross		6,860	9	185															194	7,054		
	+ Total Equity		9,230																		9,230		
	+ Deferred Income Taxes - Non-Current		1,983																		1,983		
	+ Minority Interest		0.00																		0.00		
			39.0%																				***39.6%***

Public Service Company of Colorado Final

Credit Opinion Ratios			12/31/21 (Annual) As Rep	Standard Adjustments																	12/31/21 (Annual) As Adj		
				Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	tk. Comp	Hybrids	ritization	LIFO	Unusual	Restricted Cash	Int and Div	Contingent Consideration	Non-Standard Adjustments	otal Adj.			
(CFO Pre-W/C) / Debt	Cash Flow From Operations		727	13	13															26	753		
	- Changes in Working Capital		138																		138		
	- Changes in Short Term Op. Assets & Liabs.	=	287																		287	=	1,178
	Short-term debt		147																		147		6,806
	+ Long-term Debt - Gross		6,467	18	174															192	6,659		
			17.4%																				***17.3%***
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		727	13	13															26	753		
	- Changes in Working Capital		138																		138		
	- Changes in Short Term Op. Assets & Liabs.		287																		287		
	- Preferred Dividends		0.00																		0.00		
	- Common Dividends		-467.00																		-467.00		
	- Minority Dividends	=	0.00																		0.00	=	711
	Short-term debt		147																		147		6,806
	+ Long-term Debt - Gross		6,467	18	174															192	6,659		
			10.4%																				***10.4%***
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		727	13	13															26	753		
	- Changes in Working Capital		138																		138		
	- Changes in Short Term Op. Assets & Liabs.		287																		287		
	+ Interest Expense	=	234	2	2															4	238	=	1,416
	Interest Expense		234	2	2															4	238		238
			5.9x																				***5.9x***
Debt / Book Capitalization	Short-term debt		147																		147		
	+ Long-term Debt - Gross	=	6,467	18	174															192	6,659	=	6,806
	Short-term debt		147																		147		17,210
	+ Long-term Debt - Gross		6,467	18	174															192	6,659		
	+ Total Equity		8,444																		8,444		
	+ Deferred Income Taxes - Non-Current		1,960																		1,960		
	+ Minority Interest		0.00																		0.00		
			38.9%																				***39.5%***

Public Service Company of Colorado Final

Credit Opinion Ratios			12/31/20 (Annual) As Rep	Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	k. Comp	Hybrids	uritization	LIFO	Unusual	Restricted Cash	Int and Div	Contingent Consideration	Non-Standard Adjustments	otal Adj.			12/31/20 (Annual) As Adj
				Standard Adjustments																			
(CFO Pre-W/C) / Debt	Cash Flow From Operations		1,174	20	10		-14.00													16	1,190		
	- Changes in Working Capital		105																		105		
	- Changes in Short Term Op. Assets & Liabs.	=	-18.00																		-18.00	=	1,277
	Short-term debt		193																		193		6,254
	+ Long-term Debt - Gross		5,724	145	192															337	6,061		
			21.3%																				***20.4%***
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		1,174	20	10		-14.00													16	1,190		
	- Changes in Working Capital		105																		105		
	- Changes in Short Term Op. Assets & Liabs.		-18.00																		-18.00		
	- Preferred Dividends		0.00																		0.00		
	- Common Dividends		-831.00																		-831.00		
	- Minority Dividends	=	0.00																		0.00	=	446
	Short-term debt		193																		193		6,254
	+ Long-term Debt - Gross		5,724	145	192															337	6,061		
			7.3%																				***7.1%***
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		1,174	20	10		-14.00													16	1,190		
	- Changes in Working Capital		105																		105		
	- Changes in Short Term Op. Assets & Liabs.		-18.00																		-18.00		
	+ Interest Expense	=	224	5	2		14													21	245	=	1,522
	Interest Expense		224	5	2		14													21	245		245
			6.6x																				***6.2x***
Debt / Book Capitalization	Short-term debt		193																		193		
	+ Long-term Debt - Gross	=	5,724	145	192															337	6,061	=	6,254
	Short-term debt		193																		193		15,729
	+ Long-term Debt - Gross		5,724	145	192															337	6,061		
	+ Total Equity		7,592				-11.06													-11.06	7,581		
	+ Deferred Income Taxes - Non-Current		1,897				-2.94													-2.94	1,894		
	+ Minority Interest		0.00																		0.00		
			38.4%																				***39.8%***

Public Service Company of Colorado Final

Credit Opinion Ratios			12/31/19 (Annual) As Rep	Standard Adjustments												Non-Standard Adjust				12/31/19 (Annual) As Adj
				Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	tk. Comp	Hybrids	uritization	LIFO	Unusual		otal Adj.			
(CFO Pre-W/C) / Debt	Cash Flow From Operations		1,228	20	10												31	1,259		
	- Changes in Working Capital		102															102		
	- Changes in Short Term Op. Assets & Liabs.	=	-58.41															-58.41	=	1,302
	Short-term debt		39															39		5,898
	+ Long-term Debt - Gross		5,385	206	204											65	475	5,859		
			23.4%																	***22.1%***
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		1,228	20	10												31	1,259		
	- Changes in Working Capital		102															102		
	- Changes in Short Term Op. Assets & Liabs.		-58.41															-58.41		
	- Preferred Dividends		0.00															0.00		
	- Common Dividends		-457.60															-457.60		
	- Minority Dividends	=	0.00															0.00	=	844
	Short-term debt		39															39		5,898
	+ Long-term Debt - Gross		5,385	206	204											65	475	5,859		
			15.0%																	***14.3%***
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		1,228	20	10												31	1,259		
	- Changes in Working Capital		102															102		
	- Changes in Short Term Op. Assets & Liabs.		-58.41															-58.41		
	+ Interest Expense	=	224	8	3												11	235	=	1,537
	Interest Expense		224	8	3												11	235		235
			6.7x																	***6.5x***
Debt / Book Capitalization	Short-term debt		39															39		
	+ Long-term Debt - Gross	=	5,385	206	204											65	475	5,859	=	5,898
	Short-term debt		39															39		14,680
	+ Long-term Debt - Gross		5,385	206	204											65	475	5,859		
	+ Total Equity		6,996													-65.00	-65.00	6,931		
	+ Deferred Income Taxes - Non-Current		1,851															1,851		
	+ Minority Interest		0.00															0.00		
			38.0%																	***40.2%***

S&P Capital IQ PRO

Public Service Company of Colorado | Income Statement (As Reported)

(MI KEY: 4057094; SPCIQ KEY: 298400)

Periods: Custom
Source SNL Financial

SNL Financial	*2019 FY*	*2020 FY*	*2021 FY*	*2022 FY*
As Of Date	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Source Document	12/31/2021	12/31/2022	12/31/2022	12/31/2022
Currency Code	USD	USD	USD	USD
(in millions)				
Operating revenues				
Electric	3,033	3,116	3,413	3,795
Natural gas	1,161	1,024	1,355	1,860
Other	43	43	47	53
Total operating revenues	4,237	4,183	4,815	5,708
Operating expenses				
Electric fuel and purchased power	1,083	1,132	1,336	1,485
Cost of natural gas sold and transported	526	374	606	1,053
Cost of sales - steam and other	17	13	15	18
Operating and maintenance expenses	810	811	831	905
Demand side management expenses	136	141	132	133
Depreciation and amortization	602	655	744	848
Taxes (other than income taxes)	206	234	256	272
Total operating expenses	3,380	3,360	3,920	4,714
Operating income	**857**	**823**	**895**	**994**
Other income (expense), net	3	(1)	4	(2)
Allowance for funds used during construction - equity	22	35	28	32
Interest charges and financing costs				
Interest charges - includes other financing costs	235	238	243	271
Allowance for funds used during construction - debt	(11)	(14)	(9)	(11)
Total interest charges and financing costs	224	224	234	260
Income before income taxes	658	633	693	764
Income tax expense	80	45	33	37
Net income	**578**	**588**	**660**	**727**

S&P Capital IQ PRO

Public Service Company of Colorado | Balance Sheet (As Reported)

(MI KEY: 4057094; SPCIQ KEY: 298400)

Periods: Custom
Source SNL Financial

SNL Financial	*2019 FY*	*2020 FY*	*2021 FY*	*2022 FY*
As Of Date	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Source Document	12/31/2020	12/31/2020	12/31/2022	12/31/2022
Currency Code	USD	USD	USD	
(in millions)				
Assets				
Current assets				
Cash and cash equivalents	11	28	25	10
Accounts receivable, net	304	342	374	562
Accounts receivable from affiliates	53	8	13	11
Accrued unbilled revenues	294	298	350	519
Inventories	192	189	245	319
Regulatory assets	64	121	353	411
Derivative instruments	7	21	39	65
Prepayments and other	56	82	104	103
Total current assets	981	1,089	1,503	2,000
Property, plant and equipment, net	16,155	17,470	18,444	19,652
Other assets				
Regulatory assets	1,038	1,059	1,293	1,277
Derivative instruments	0	16	27	22
Operating lease right-of-use assets	574	500	409	437
Other	260	231	246	231
Total other assets	1,872	1,806	1,975	1,967
Total assets	**19,008**	**20,365**	**21,922**	**23,619**
Liabilities and Equity				
Current liabilities				
Current portion of long-term debt	400	0	300	250
Borrowings under utility money pool	39	57	0	0
Short-term debt	0	136	147	294
Accounts payable	573	452	531	764
Accounts payable to affiliates	44	58	69	75
Regulatory liabilities	69	100	95	59
Taxes accrued	202	251	252	242
Accrued interest	53	61	58	59
Dividends payable to parent	112	105	104	120
Derivative instruments	9	27	30	30
Operating lease liabilities	86	97	84	80
Other	99	84	109	115
Total current liabilities	1,686	1,428	1,779	2,088
Deferred credits and other liabilities				
Deferred income taxes	1,851	1,897	1,960	1,983
Deferred investment tax credits	23	20	0	0
Regulatory liabilities	2,037	2,337	2,397	2,489
Asset retirement obligations	324	399	422	476
Derivative instruments	53	51	29	9
Customer advances	173	168	160	144
Pension and employee benefit obligations	212	161	23	13
Operating lease liabilities	518	432	351	379
Other	150	156	190	198
Total deferred credits and other liabilities	5,341	5,621	5,532	5,691
Capitalization				
Long-term debt	4,985	5,724	6,167	6,610
Common stock	0	0	0	0
Additional paid in capital	4,940	5,770	6,426	6,992
Retained earnings	2,083	1,846	2,040	2,260
Accumulated other comprehensive loss	(27)	(24)	(22)	(22)
Total common stockholder's equity	6,996	7,592	8,444	9,230
Total liabilities and stockholder's equity	**19,008**	**20,365**	**21,922**	**23,619**

Public Service Company of Colorado: PSCo Gas Case
Scenario 2. 10.25% ROE and 55% Equity Ratio
Dollars in Millions

Adjusted Credit Metrics

January, 2024

Moody's Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
CFO pre - WC / Debt	22.1%	20.4%	17.3%	21.2%	[redacted]		
CFO pre - WC + Interest / Interest	6.5x	6.2x	5.9x	6.9x			
CFO pre - WC - Dividends / Debt	14.3%	7.1%	10.4%	14.6%			
Debt / Book Capitalization	40.2%	39.8%	39.5%	39.6%			

S&P Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
FFO / Debt	20.7%	19.1%	20.6%	20.4%	[redacted]		
Debt / EBITDA	4.1x	4.4x	4.1x	4.0x			
FFO / Interest	5.9x	5.9x	6.7x	6.2x			
EBITDA / Interest	5.8x	5.9x	6.6x	6.4x			

Financial model below includes highly sensitive, forward-looking information including company earnings. This schedule should be considered "Restricted Confidential" and therefore should only be provided externally in direct response to an official information request.

Public Service Company of Colorado: PSCo Gas Case
Key Credit Metrics
Dollars in Millions

Adjusted Credit Metrics Buildup

January, 2024

Moody's Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Cash Flow from Operations	$1,228	$1,174	$727	$1,255	[redacted]		
Add pre-WC adjustment[2]	74	103	451	306			
Adjusted CFO pre-WC	**$1,302**	**$1,277**	**$1,178**	**$1,561**			
Interest Expense	224	224	234	260			
Add AFUDC Debt	0	14	0	0			
Add interest expense adjustment	11	7	4	4			
Adjusted Interest	**$235**	**$245**	**$238**	**$264**			
Dividends	457	831	467	491			
Debt	5,424	5,917	6,614	7,154			
Add debt adjustment	475	337	192	194			
Adjusted Debt	**$5,899**	**$6,254**	**$6,806**	**$7,348**			
Book Capitalization	14,271	15,406	17,018	18,367			
Add debt adjustment	410	323	192	194			
Adjusted Book Capitalization	**$14,681**	**$15,729**	**$17,210**	**$18,561**			
Moody's Key Metrics							
CFO pre - WC / Debt	22.1%	20.4%	17.3%	21.2%			
CFO pre - WC + Interest / Interest	6.5x	6.2x	5.9x	6.9x			
CFO pre - WC / Debt - Dividends / Debt	14.3%	7.1%	10.4%	14.6%			
Debt / Book Capitalization	40.2%	39.8%	39.5%	39.6%			

S&P Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Operating Income	$857	$823	$895	$994	[redacted]		
Add depreciation & amortization	602	655	744	848			
Add EBITDA adjustment	68	62	143	135			
Adjusted EBITDA	**$1,527**	**$1,540**	**$1,782**	**$1,977**			
Adjusted EBITDA	1,527	1,540	1,782	1,977			
Less Interest Paid	(224)	(224)	(234)	(260)			
Less Taxes Paid	(5)	(23)	(14)	(47)			
Less AFUDC Debt	(11)	(14)	(9)	(11)			
Add FFO adjustment	3	3	(6)	(41)			
Adjusted Funds from Operations	**$1,290**	**$1,282**	**$1,519**	**$1,618**			
Interest Expense	224	224	234	260			
Add AFUDC Debt	11	14	9	11			
Add interest expense adjustment	27	24	26	38			
Adjusted Interest	**$262**	**$262**	**$269**	**$309**			
Debt	5,424	5,917	6,614	7,154			
Add debt adjustment	818	803	764	771			
Adjusted Debt	**$6,242**	**$6,720**	**$7,378**	**$7,925**			
S&P's Key Metrics							
FFO / Debt	20.7%	19.1%	20.6%	20.4%			
Debt / EBITDA	4.1x	4.4x	4.1x	4.0x			
FFO / Interest	5.9x	5.9x	6.7x	6.2x			
EBITDA / Interest	5.8x	5.9x	6.6x	6.4x			

Public Service Company of Colorado: PSCo Gas Case
Financial Model: RESTRICTED CONFIDENTIAL
Dollars in Millions

PSCo Financial Model

January, 2024

Income Statement	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Revenue	$4,237	$4,183	$4,815	$5,708	[redacted]		
COGS	(1,626)	(1,519)	(1,957)	(2,556)			
Gross Margin	**2,611**	**2,664**	**2,858**	**3,152**			
O&M	(810)	(811)	(831)	(905)			
CIP & DSM	(136)	(141)	(132)	(133)			
Property & Sales Taxes	(206)	(234)	(256)	(272)			
Depreciation & Amortization	(602)	(655)	(744)	(848)			
Operating Income	**857**	**823**	**895**	**994**			
AFUDC Equity / Other	25	34	32	30			
Interest	(224)	(224)	(234)	(260)			
Pretax Income	**658**	**633**	**693**	**764**			
Income Tax	(80)	(45)	(33)	(37)			
Net Income	**578**	**588**	**660**	**727**			

Cash Flow Statement	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Net Income	$578	$588	$660	$727	[redacted]		
Depreciation & Amortization	607	656	754	854			
Deferred Taxes	97	2	32	(10)			
AFUDC	(22)	(35)	(28)	(32)			
Pension	(47)	(41)	(53)	(13)			
Other	15	4	(638)	(271)			
Cash from Operations	**$1,228**	**$1,174**	**$727**	**$1,255**			
Capex	(1,691)	(1,671)	(1,604)	(1,880)			
Other Investments	0	0	0	0			
Cash Invested	**($1,691)**	**($1,671)**	**($1,604)**	**($1,880)**			
Equity from Parent	638	856	650	569			
Dividends Paid to Parent	(457)	(831)	(467)	(491)			
Change in Long Term Debt	528	335	737	386			
Change in Short Term Debt	(268)	154	(46)	146			
Cash from Financing	**$441**	**$514**	**$874**	**$610**			

Balance Sheet	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Cash	$11	$28	$25	$10	[redacted]		
Other Current Assets	970	1,061	1,478	1,990			
Net PP&E	16,155	17,470	18,444	19,652			
Other Assets	1,872	1,806	1,975	1,967			
Total Assets	**$19,008**	**$20,365**	**$21,922**	**$23,619**			
Short Term Debt	39	193	147	294			
Other Current Liabilities	1,247	1,235	1,332	1,544			
Deferred Taxes	1,851	1,897	1,960	1,983			
Other Liabilities	3,490	3,724	3,572	3,708			
Long Term Debt	5,385	5,724	6,467	6,860			
Equity	6,996	7,592	8,444	9,230			
Total Liabilities & Equity	**$19,008**	**$20,365**	**$21,922**	**$23,619**			

	2023	2024	2025
[redacted]	[redacted]	[redacted]	[redacted]

Table 3

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2022--

Public Service Co. of Colorado reported amounts (mil. $)	Debt	EBITDA	Operating income	Interest expense	S&P Global Ratings' adjusted EBITDA	Cash flow from operations	Capital expenditure
	7,154.0	1,842.0	994.0	260.0	1,977.0	1,255.0	1,880.0
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(79.0)	--	--
Cash interest paid	--	--	--	--	(250.0)	--	--
Reported lease liabilities	576.0	--	--	--	--	--	--
Operating leases	--	110.0	18.8	18.8	(18.8)	91.2	--
Accessible cash and liquid investments	(10.0)	--	--	--	--	--	--
Capitalized interest	--	--	--	11.0	(11.0)	(11.0)	(11.0)
Asset-retirement obligations	376.0	19.0	19.0	19.0	--	--	--
Nonoperating income (expense)	--	--	20.0	--	--	--	--
Debt: Other	(171.0)	--	--	--	--	--	--
EBITDA: Other	--	6.0	6.0	--	--	--	--
Depreciation and amortization: Other	--	--	(6.0)	--	--	--	--
Total adjustments	771.0	135.0	57.8	48.8	(358.8)	80.2	(11.0)
S&P Global Ratings' adjusted amounts							
	Debt	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	7,925.0	1,977.0	1,051.8	308.8	1,618.2	1,335.2	1,869.0

Table 1

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2021--

Public Service Co. of Colorado reported amounts (mil. $)	Debt	EBITDA	Operating income	Interest expense	S&P Global Ratings' adjusted EBITDA	Cash flow from operations	Capital expenditure
	6,614.0	1,639.0	895.0	234.0	1,782.0	727.0	1,604.0
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(14.0)	--	--
Cash interest paid	--	--	--	--	(230.0)	--	--
Reported lease liabilities	560.0	--	--	--	--	--	--
Operating leases	--	117.0	9.6	9.6	(9.6)	107.4	--
Accessible cash and liquid investments	(25.0)	--	--	--	--	--	--
Capitalized interest	--	--	--	9.0	(9.0)	(9.0)	(9.0)
Asset-retirement obligations	333.4	16.0	16.0	16.0	--	--	--
Nonoperating income (expense)	--	--	26.0	--	--	--	--
Debt: Other	(104.0)	--	--	--	--	--	--
EBITDA: Other	--	10.0	10.0	--	--	--	--
Depreciation and amortization: Other	--	--	(10.0)	--	--	--	--
Total adjustments	764.4	143.0	51.6	34.6	(262.6)	98.4	(9.0)
S&P Global Ratings' adjusted amounts							
	Debt	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	7,378.4	1,782.0	946.6	268.6	1,519.4	825.4	1,595.0

Table 2

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2020--

Public Service Co. of Colorado reported amounts (mil. $)	Debt	EBITDA	Operating income	Interest expense	S&P Global Ratings' adjusted EBITDA	Cash flow from operations	Capital expenditure
	5,917.0	1,478.0	823.0	224.0	1,540.0	1,174.0	1,671.0
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(23.0)	--	--
Cash interest paid	--	--	--	--	(211.0)	--	--
Reported lease liabilities	662.0	--	--	--	--	--	--
Operating leases	--	12.0	2.4	2.4	(2.4)	9.6	--
Postretirement benefit obligations/deferred compensation	123.2	--	--	--	--	--	--
Accessible cash and liquid investments	(28.0)	--	--	--	--	--	--
Capitalized interest	--	--	--	14.0	(14.0)	(14.0)	(14.0)
Power purchase agreements	200.5	35.0	7.8	7.8	(7.8)	27.2	27.2
Asset-retirement obligations	315.2	14.0	14.0	14.0	--	--	--
Nonoperating income (expense)	--	--	37.0	--	--	--	--
Debt: Other	(470.0)	--	--	--	--	--	--
EBITDA: Other	--	1.0	1.0	--	--	--	--
Depreciation and amortization: Other	--	--	(1.0)	--	--	--	--
Total adjustments	803.0	62.0	61.2	38.2	(258.2)	22.8	13.2
S&P Global Ratings' adjusted amounts							
	Debt	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	6,720	1,540	884	262	1,282	1,197	1,684

Table 3

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2019--

Public Service Co. of Colorado reported amounts (mil. $)	Debt	EBITDA	Operating income	Interest expense	S&P Global Ratings' adjusted EBITDA	Cash flow from operations	Capital expenditure
	5,423.7	1,459.2	856.8	224.2	1,527.6	1,227.9	1,690.7
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(4.7)	--	--
Cash interest paid	--	--	--	--	(209.3)	--	--
Reported lease liabilities	742.2	--	--	--	--	--	--
Operating leases	--	13.1	2.7	2.7	(2.7)	10.4	--
Postretirement benefit obligations/deferred compensation	146.5	--	--	--	--	--	--
Accessible cash and liquid investments	(15.2)	--	--	--	--	--	--
Capitalized interest	--	--	--	11.2	(11.2)	(11.2)	(11.2)
Power purchase agreements	226.7	35.4	9.3	9.3	(9.3)	26.1	26.1
Asset-retirement obligations	256.0	15.3	15.3	15.3	--	--	--
Nonoperating income (expense)	--	--	32.0	--	--	--	--
Debt: Other	(538.5)	--	--	--	--	--	--
EBITDA: Other	--	4.6	4.6	--	--	--	--
Depreciation and amortization: Other	--	--	(4.6)	--	--	--	--
Total adjustments	817.7	68.4	59.3	38.5	(237.2)	25.3	14.9
S&P Global Ratings' adjusted amounts							
	Debt	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	6,241	1,528	916	263	1,290	1,253	1,706

Public Service Company of Colorado Final

Credit Opinion Ratios

Standard Adjustments

			12/31/22 (Annual) As Rep	Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	tk. Comp	Hybrids	uritization	LIFO	Unusual	Restricte d Cash	Int and Div	Continge nt Consider ation	Non-Standard Adjustments	Total Adj.	12/31/22 (Annual) As Adj		
(CFO Pre-W/C) / Debt	Cash Flow From Operations		1,255	11	16															27	1,282		
	- Changes in Working Capital		299																		299		
	- Changes in Short Term Op. Assets & Liabs.	=	-20.00																		-20.00	=	1,561
	Short-term debt		294																		294		7,348
	+ Long-term Debt - Gross		6,860	9	185															194	7,054		
			21.4%																				*21.2%*
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		1,255	11	16															27	1,282		
	- Changes in Working Capital		299																		299		
	- Changes in Short Term Op. Assets & Liabs.		-20.00																		-20.00		
	- Preferred Dividends		0.00																		0.00		
	- Common Dividends		-491.00																		-491.00		
	- Minority Dividends	=	0.00																		0.00	=	1,070
	Short-term debt		294																		294		7,348
	+ Long-term Debt - Gross		6,860	9	185															194	7,054		
			14.6%																				*14.6%*
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		1,255	11	16															27	1,282		
	- Changes in Working Capital		299																		299		
	- Changes in Short Term Op. Assets & Liabs.		-20.00																		-20.00		
	+ Interest Expense	=	260	0.73	3															4	264	=	1,825
	Interest Expense		260	0.73	3															4	264		264
			6.9x																				*6.9x*
Debt / Book Capitalization	Short-term debt		294																		294		
	+ Long-term Debt - Gross	=	6,860	9	185															194	7,054	=	7,348
	Short-term debt		294																		294		18,561
	+ Long-term Debt - Gross		6,860	9	185															194	7,054		
	+ Total Equity		9,230																		9,230		
	+ Deferred Income Taxes - Non-Current		1,983																		1,983		
	+ Minority Interest		0.00																		0.00		
			39.0%																				*39.6%*

Public Service Company of Colorado Final

Credit Opinion Ratios

Standard Adjustments

			12/31/21 (Annual) As Rep	Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	tk. Comp	Hybrids	uritization	LIFO	Unusual	Restrict ed Cash	Int and Div	Conting ent Conside ration	Non-Standard Adjust ments	otal Adj.	12/31/21 (Annual) As Adj		
(CFO Pre-W/C) / Debt	Cash Flow From Operations		727	13	13															26	753		
	- Changes in Working Capital		138																		138		
	- Changes in Short Term Op. Assets & Liabs.	=	287																		287	=	1,178
	Short-term debt		147																		147		6,806
	+ Long-term Debt - Gross		6,467	18	174															192	6,659		
			17.4%																				*17.3%*
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		727	13	13															26	753		
	- Changes in Working Capital		138																		138		
	- Changes in Short Term Op. Assets & Liabs.		287																		287		
	- Preferred Dividends		0.00																		0.00		
	- Common Dividends		-467.00																		-467.00		
	- Minority Dividends	=	0.00																		0.00	=	711
	Short-term debt		147																		147		6,806
	+ Long-term Debt - Gross		6,467	18	174															192	6,659		
			10.4%																				*10.4%*
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		727	13	13															26	753		
	- Changes in Working Capital		138																		138		
	- Changes in Short Term Op. Assets & Liabs.		287																		287		
	+ Interest Expense	=	234	2	2															4	238	=	1,416
	Interest Expense		234	2	2															4	238		238
			5.9x																				*5.9x*
Debt / Book Capitalization	Short-term debt		147																		147		
	+ Long-term Debt - Gross	=	6,467	18	174															192	6,659	=	6,806
	Short-term debt		147																		147		17,210
	+ Long-term Debt - Gross		6,467	18	174															192	6,659		
	+ Total Equity		8,444																		8,444		
	+ Deferred Income Taxes - Non-Current		1,960																		1,960		
	+ Minority Interest		0.00																		0.00		
			38.9%																				*39.5%*

Public Service Company of Colorado Final

Credit Opinion Ratios			12/31/20 (Annual) As Rep	Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	tk. Comp	Hybrids	uritization	LIFO	Unusual	Restricted Cash	Int and Div	Contingent Consideration	Non-Standard Adjustments	otal Adj.			12/31/20 (Annual) As Adj
				Standard Adjustments															Non-Standard				
(CFO Pre-W/C) / Debt	Cash Flow From Operations		1,174	20	10		-14.00													16	1,190		
	- Changes in Working Capital		105																		105		
	- Changes in Short Term Op. Assets & Liabs.	=	-18.00																		-18.00	=	1,277
	Short-term debt		193																		193		6,254
	+ Long-term Debt - Gross		5,724	145	192															337	6,061		
			21.3%																				***20.4%***
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		1,174	20	10		-14.00													16	1,190		
	- Changes in Working Capital		105																		105		
	- Changes in Short Term Op. Assets & Liabs.		-18.00																		-18.00		
	- Preferred Dividends		0.00																		0.00		
	- Common Dividends		-831.00																		-831.00		
	- Minority Dividends	=	0.00																		0.00	=	446
	Short-term debt		193																		193		6,254
	+ Long-term Debt - Gross		5,724	145	192															337	6,061		
			7.3%																				***7.1%***
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		1,174	20	10		-14.00													16	1,190		
	- Changes in Working Capital		105																		105		
	- Changes in Short Term Op. Assets & Liabs.		-18.00																		-18.00		
	+ Interest Expense	=	224	5	2		14													21	245	=	1,522
	Interest Expense		224	5	2		14													21	245		245
			6.6x																				***6.2x***
Debt / Book Capitalization	Short-term debt		193																		193		
	+ Long-term Debt - Gross	=	5,724	145	192															337	6,061	=	6,254
	Short-term debt		193																		193		15,729
	+ Long-term Debt - Gross		5,724	145	192															337	6,061		
	+ Total Equity		7,592				-11.06													-11.06	7,581		
	+ Deferred Income Taxes - Non-Current		1,897				-2.94													-2.94	1,894		
	+ Minority Interest		0.00																		0.00		
			38.4%																				***39.8%***

Public Service Company of Colorado Final

Credit Opinion Ratios			12/31/19 (Annual) As Rep	Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	tk. Comp	Hybrids	ritization	LIFO	Unusual	Non-Standard Adjust	otal Adj.			12/31/19 (Annual) As Adj
				Standard Adjustments																
(CFO Pre-W/C) / Debt	Cash Flow From Operations		1,228	20	10												31	1,259		
	- Changes in Working Capital		102															102		
	- Changes in Short Term Op. Assets & Liabs.	=	-58.41															-58.41	=	1,302
	Short-term debt		39															39		5,898
	+ Long-term Debt - Gross		5,385	206	204											65	475	5,859		
			23.4%																	*22.1%*
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		1,228	20	10												31	1,259		
	- Changes in Working Capital		102															102		
	- Changes in Short Term Op. Assets & Liabs.		-58.41															-58.41		
	- Preferred Dividends		0.00															0.00		
	- Common Dividends		-457.60															-457.60		
	- Minority Dividends	=	0.00															0.00	=	844
	Short-term debt		39															39		5,898
	+ Long-term Debt - Gross		5,385	206	204											65	475	5,859		
			15.0%																	*14.3%*
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		1,228	20	10												31	1,259		
	- Changes in Working Capital		102															102		
	- Changes in Short Term Op. Assets & Liabs.		-58.41															-58.41		
	+ Interest Expense	=	224	8	3												11	235	=	1,537
	Interest Expense		224	8	3												11	235		235
			6.7x																	*6.5x*
Debt / Book Capitalization	Short-term debt		39															39		
	+ Long-term Debt - Gross	=	5,385	206	204											65	475	5,859	=	5,898
	Short-term debt		39															39		14,680
	+ Long-term Debt - Gross		5,385	206	204											65	475	5,859		
	+ Total Equity		6,996													-65.00	-65.00	6,931		
	+ Deferred Income Taxes - Non-Current		1,851															1,851		
	+ Minority Interest		0.00															0.00		
			38.0%																	*40.2%*

S&P Capital IQ PRO

Public Service Company of Colorado | Income Statement (As Reported)

(MI KEY: 4057094; SPCIQ KEY: 298400)

Periods: Custom
Source SNL Financial

SNL Financial	*2019 FY*	*2020 FY*	*2021 FY*	*2022 FY*
As Of Date	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Source Document	12/31/2021	12/31/2022	12/31/2022	12/31/2022
Currency Code	USD	USD	USD	USD
(in millions)				
Operating revenues				
Electric	3,033	3,116	3,413	3,795
Natural gas	1,161	1,024	1,355	1,860
Other	43	43	47	53
Total operating revenues	4,237	4,183	4,815	5,708
Operating expenses				
Electric fuel and purchased power	1,083	1,132	1,336	1,485
Cost of natural gas sold and transported	526	374	606	1,053
Cost of sales - steam and other	17	13	15	18
Operating and maintenance expenses	810	811	831	905
Demand side management expenses	136	141	132	133
Depreciation and amortization	602	655	744	848
Taxes (other than income taxes)	206	234	256	272
Total operating expenses	3,380	3,360	3,920	4,714
Operating income	**857**	**823**	**895**	**994**
Other income (expense), net	3	(1)	4	(2)
Allowance for funds used during construction - equity	22	35	28	32
Interest charges and financing costs				
Interest charges - includes other financing costs	235	238	243	271
Allowance for funds used during construction - debt	(11)	(14)	(9)	(11)
Total interest charges and financing costs	224	224	234	260
Income before income taxes	658	633	693	764
Income tax expense	80	45	33	37
Net income	**578**	**588**	**660**	**727**

S&P Capital IQ PRO

Public Service Company of Colorado | Balance Sheet (As Reported)

(MI KEY: 4057094; SPCIQ KEY: 298400)

Periods: Custom
Source SNL Financial

SNL Financial	*2019 FY*	*2020 FY*	*2021 FY*	*2022 FY*
As Of Date	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Source Document	12/31/2020	12/31/2020	12/31/2022	12/31/2022
Currency Code	USD	USD	USD	
(in millions)				
Assets				
Current assets				
Cash and cash equivalents	11	28	25	10
Accounts receivable, net	304	342	374	562
Accounts receivable from affiliates	53	8	13	11
Accrued unbilled revenues	294	298	350	519
Inventories	192	189	245	319
Regulatory assets	64	121	353	411
Derivative instruments	7	21	39	65
Prepayments and other	56	82	104	103
Total current assets	981	1,089	1,503	2,000
Property, plant and equipment, net	16,155	17,470	18,444	19,652
Other assets				
Regulatory assets	1,038	1,059	1,293	1,277
Derivative instruments	0	16	27	22
Operating lease right-of-use assets	574	500	409	437
Other	260	231	246	231
Total other assets	1,872	1,806	1,975	1,967
Total assets	**19,008**	**20,365**	**21,922**	**23,619**
Liabilities and Equity				
Current liabilities				
Current portion of long-term debt	400	0	300	250
Borrowings under utility money pool	39	57	0	0
Short-term debt	0	136	147	294
Accounts payable	573	452	531	764
Accounts payable to affiliates	44	58	69	75
Regulatory liabilities	69	100	95	59
Taxes accrued	202	251	252	242
Accrued interest	53	61	58	59
Dividends payable to parent	112	105	104	120
Derivative instruments	9	27	30	30
Operating lease liabilities	86	97	84	80
Other	99	84	109	115
Total current liabilities	1,686	1,428	1,779	2,088
Deferred credits and other liabilities				
Deferred income taxes	1,851	1,897	1,960	1,983
Deferred investment tax credits	23	20	0	0
Regulatory liabilities	2,037	2,337	2,397	2,489
Asset retirement obligations	324	399	422	476
Derivative instruments	53	51	29	9
Customer advances	173	168	160	144
Pension and employee benefit obligations	212	161	23	13
Operating lease liabilities	518	432	351	379
Other	150	156	190	198
Total deferred credits and other liabilities	5,341	5,621	5,532	5,691
Capitalization				
Long-term debt	4,985	5,724	6,167	6,610
Common stock	0	0	0	0
Additional paid in capital	4,940	5,770	6,426	6,992
Retained earnings	2,083	1,846	2,040	2,260
Accumulated other comprehensive loss	(27)	(24)	(22)	(22)
Total common stockholder's equity	6,996	7,592	8,444	9,230
Total liabilities and stockholder's equity	**19,008**	**20,365**	**21,922**	**23,619**

S&P Capital IQ PRO

Public Service Company of Colorado | Cash Flow (As Reported)

(MI KEY: 4057094; SPCIQ KEY: 298400)

Periods: Custom
Source SNL Financial

SNL Financial	2019 FY	2020 FY	2021 FY	2022 FY
As Of Date	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Source Document	12/31/2021 10-	12/31/2021 10-	12/31/2021 10-	12/31/2022
Currency Code	USD	USD	USD	USD
(in millions)				
Operating activities				
Net income	578	588	660	727
Adjustments to reconcile net income to cash provided				
Depreciation and amortization	607	656	754	854
Deferred income taxes	97	2	21	(10)
Amortization of investment tax credits	0	0	11	0
Allowance for equity funds used during	(22)	(35)	(28)	(32)
Provision for bad debts	17	24	26	38
Net realized and unrealized hedging and	62	(14)	(44)	
Changes in operating assets and liabilities				
Accounts receivable	(22)	(51)	(58)	(227)
Accrued unbilled revenues	20	(5)	(52)	(169)
Inventories	(27)	(27)	(71)	(86)
Prepayments and other	(29)	(8)	(23)	12
Accounts payable	(44)	(14)	66	183
Net regulatory assets and liabilities	35	58	(526)	82
Other current liabilities	0	45	30	8
Pension and other employee benefit	(47)	(41)	(53)	(13)
Other, net	3	(4)	14	(112)
Net cash provided by operating activities	1,228	1,174	727	1,255
Investing activities				
Utility capital/construction expenditures	(1,691)	(1,671)	(1,604)	(1,880)
Investments in utility money pool arrangement	(641)	(122)	(273)	(45)
Repayments from utility money pool arrangement	641	122	273	45
Net cash used in investing activities	(1,691)	(1,671)	(1,604)	(1,880)
Financing activities				
Proceeds from (repayments of) short-term borrowings,	(307)	136	11	146
Borrowings under utility money pool arrangement	100	1,189	743	1,199
Repayments under utility money pool arrangement	(61)	(1,171)	(800)	(1,199)
Proceeds from issuance of long-term debt	928	735	737	686
Repayments of long-term debt	(400)	(400)	0	(300)
Capital contributions from parent	638	856	650	569
Dividends paid to parent	(457)	(831)	(467)	(491)
Net cash provided by financing activities	441	514	874	610
Net change in cash and cash equivalents	(22)	17	(3)	(15)
Cash, cash equivalents and restricted cash at beginning of	33	11	28	25
Cash, cash equivalents and restricted cash at end of period	11	28	25	10
Supplemental disclosure of cash flow information				
Cash paid for interest (net of amounts capitalized)	(209)	(211)	(230)	(250)
Cash paid for income taxes, net	(5)	(23)	(14)	(79)
Supplemental disclosure of non-cash investing and financing transactions				
Accrued property, plant and equipment additions	234	197	157	233
Inventory transfers to property, plant and equipment	32	35	10	12
Operating lease right-of-use assets	654	14	0	140
Allowance for equity funds used during construction	22	35	28	32

Public Service Company of Colorado: PSCo Gas Case
Scenario 3. 10.25% ROE 50% Equity Ratio
Dollars in Millions

Adjusted Credit Metrics

January, 2024

Moody's Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
CFO pre - WC / Debt	22.1%	20.4%	17.3%	21.2%	[redacted]		
CFO pre - WC + Interest / Interest	6.5x	6.2x	5.9x	6.9x			
CFO pre - WC - Dividends / Debt	14.3%	7.1%	10.4%	14.6%			
Debt / Book Capitalization	40.2%	39.8%	39.5%	39.6%			

S&P Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
FFO / Debt	20.7%	19.1%	20.6%	20.4%	[redacted]		
Debt / EBITDA	4.1x	4.4x	4.1x	4.0x			
FFO / Interest	5.9x	5.9x	6.7x	6.2x			
EBITDA / Interest	5.8x	5.9x	6.6x	6.4x			

Public Service Company of Colorado: PSCo Gas Case
Key Credit Metrics
Dollars in Millions

Xcel Energy®

Adjusted Credit Metrics Buildup

January, 2024

Moody's Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Cash Flow from Operations	$1,228	$1,174	$727	$1,255	[redacted]		
Add pre-WC adjustment[2]	74	103	451	306	[redacted]		
Adjusted CFO pre-WC	**$1,302**	**$1,277**	**$1,178**	**$1,561**	[redacted]		
Interest Expense	224	224	234	260	[redacted]		
Add AFUDC Debt	0	14	0	0	[redacted]		
Add interest expense adjustment	11	7	4	4	[redacted]		
Adjusted Interest	**$235**	**$245**	**$238**	**$264**	[redacted]		
Dividends	457	831	467	491	[redacted]		
Debt	5,424	5,917	6,614	7,154	[redacted]		
Add debt adjustment	475	337	192	194	[redacted]		
Adjusted Debt	**$5,899**	**$6,254**	**$6,806**	**$7,348**	[redacted]		
Book Capitalization	14,271	15,406	17,018	18,367	[redacted]		
Add debt adjustment	410	323	192	194	[redacted]		
Adjusted Book Capitalization	**$14,681**	**$15,729**	**$17,210**	**$18,561**	[redacted]		
Moody's Key Metrics					[redacted]		
CFO pre - WC / Debt	22.1%	20.4%	17.3%	21.2%	[redacted]		
CFO pre - WC + Interest / Interest	6.5x	6.2x	5.9x	6.9x	[redacted]		
CFO pre - WC / Debt - Dividends / Debt	14.3%	7.1%	10.4%	14.6%	[redacted]		
Debt / Book Capitalization	40.2%	39.8%	39.5%	39.6%	[redacted]		

S&P Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Operating Income	$857	$823	$895	$994	[redacted]		
Add depreciation & amortization	602	655	744	848	[redacted]		
Add EBITDA adjustment	68	62	143	135	[redacted]		
Adjusted EBITDA	**$1,527**	**$1,540**	**$1,782**	**$1,977**	[redacted]		
Adjusted EBITDA	1,527	1,540	1,782	1,977	[redacted]		
Less Interest Paid	(224)	(224)	(234)	(260)	[redacted]		
Less Taxes Paid	(5)	(23)	(14)	(47)	[redacted]		
Less AFUDC Debt	(11)	(14)	(9)	(11)	[redacted]		
Add FFO adjustment	3	3	(6)	(41)	[redacted]		
Adjusted Funds from Operations	**$1,290**	**$1,282**	**$1,519**	**$1,618**	[redacted]		
Interest Expense	224	224	234	260	[redacted]		
Add AFUDC Debt	11	14	9	11	[redacted]		
Add interest expense adjustment	27	24	26	38	[redacted]		
Adjusted Interest	**$262**	**$262**	**$269**	**$309**	[redacted]		
Debt	5,424	5,917	6,614	7,154	[redacted]		
Add debt adjustment	818	803	764	771	[redacted]		
Adjusted Debt	**$6,242**	**$6,720**	**$7,378**	**$7,925**	[redacted]		
S&P's Key Metrics					[redacted]		
FFO / Debt	20.7%	19.1%	20.6%	20.4%	[redacted]		
Debt / EBITDA	4.1x	4.4x	4.1x	4.0x	[redacted]		
FFO / Interest	5.9x	5.9x	6.7x	6.2x	[redacted]		
EBITDA / Interest	5.8x	5.9x	6.6x	6.4x	[redacted]		

Financial model below includes highly sensitive, forward-looking information including company earnings. This schedule should be considered "Restricted Confidential" and therefore should only be provided externally in direct response to an official information request.

Public Service Company of Colorado: PSCo Gas Case
Financial Model: RESTRICTED CONFIDENTIAL
Dollars in Millions

Xcel Energy®

PSCo Financial Model

January, 2024

Income Statement	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Revenue	$4,237	$4,183	$4,815	$5,708	[redacted]		
COGS	(1,626)	(1,519)	(1,957)	(2,556)	[redacted]		
Gross Margin	**2,611**	**2,664**	**2,858**	**3,152**	[redacted]		
O&M	(810)	(811)	(831)	(905)	[redacted]		
CIP & DSM	(136)	(141)	(132)	(133)	[redacted]		
Property & Sales Taxes	(206)	(234)	(256)	(272)	[redacted]		
Depreciation & Amortization	(602)	(655)	(744)	(848)	[redacted]		
Operating Income	**857**	**823**	**895**	**994**	[redacted]		
AFUDC Equity / Other	25	34	32	30	[redacted]		
Interest	(224)	(224)	(234)	(260)	[redacted]		
Pretax Income	**658**	**633**	**693**	**764**	[redacted]		
Income Tax	(80)	(45)	(33)	(37)	[redacted]		
Net Income	**578**	**588**	**660**	**727**	[redacted]		

Cash Flow Statement	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Net Income	$578	$588	$660	$727	[redacted]		
Depreciation & Amortization	607	656	754	854	[redacted]		
Deferred Taxes	97	2	32	(10)	[redacted]		
AFUDC	(22)	(35)	(28)	(32)	[redacted]		
Pension	(47)	(41)	(53)	(13)	[redacted]		
Other	15	4	(638)	(271)	[redacted]		
Cash from Operations	**$1,228**	**$1,174**	**$727**	**$1,255**	[redacted]		
Capex	(1,691)	(1,671)	(1,604)	(1,880)	[redacted]		
Other Investments	0	0	0	0	[redacted]		
Cash Invested	**($1,691)**	**($1,671)**	**($1,604)**	**($1,880)**	[redacted]		
Equity from Parent	638	856	650	569	[redacted]		
Dividends Paid to Parent	(457)	(831)	(467)	(491)	[redacted]		
Change in Long Term Debt	528	335	737	386	[redacted]		
Change in Short Term Debt	(268)	154	(46)	146	[redacted]		
Cash from Financing	**$441**	**$514**	**$874**	**$610**	[redacted]		

Balance Sheet	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Cash	$11	$28	$25	$10	[redacted]		
Other Current Assets	970	1,061	1,478	1,990	[redacted]		
Net PP&E	16,155	17,470	18,444	19,652	[redacted]		
Other Assets	1,872	1,806	1,975	1,967	[redacted]		
Total Assets	**$19,008**	**$20,365**	**$21,922**	**$23,619**	[redacted]		
Short Term Debt	39	193	147	294	[redacted]		
Other Current Liabilities	1,247	1,235	1,332	1,544	[redacted]		
Deferred Taxes	1,851	1,897	1,960	1,983	[redacted]		
Other Liabilities	3,490	3,724	3,572	3,708	[redacted]		
Long Term Debt	5,385	5,724	6,467	6,860	[redacted]		
Equity	6,996	7,592	8,444	9,230	[redacted]		
Total Liabilities & Equity	**$19,008**	**$20,365**	**$21,922**	**$23,619**	[redacted]		

	2023	2024	2025
[redacted]	[redacted]	[redacted]	[redacted]

Table 3

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2022--

Public Service Co. of Colorado reported amounts (mil. $)	Debt	EBITDA	Operating income	Interest expense	S&P Global Ratings' adjusted EBITDA	Cash flow from operations	Capital expenditure
	7,154.0	1,842.0	994.0	260.0	1,977.0	1,255.0	1,880.0
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(79.0)	--	--
Cash interest paid	--	--	--	--	(250.0)	--	--
Reported lease liabilities	576.0	--	--	--	--	--	--
Operating leases	--	110.0	18.8	18.8	(18.8)	91.2	--
Accessible cash and liquid investments	(10.0)	--	--	--	--	--	--
Capitalized interest	--	--	--	11.0	(11.0)	(11.0)	(11.0)
Asset-retirement obligations	376.0	19.0	19.0	19.0	--	--	--
Nonoperating income (expense)	--	--	20.0	--	--	--	--
Debt: Other	(171.0)	--	--	--	--	--	--
EBITDA: Other	--	6.0	6.0	--	--	--	--
Depreciation and amortization: Other	--	--	(6.0)	--	--	--	--
Total adjustments	771.0	135.0	57.8	48.8	(358.8)	80.2	(11.0)
S&P Global Ratings' adjusted amounts							
	Debt	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	7,925.0	1,977.0	1,051.8	308.8	1,618.2	1,335.2	1,869.0

Table 1

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2021--

Public Service Co. of Colorado reported amounts (mil. $)	Debt	EBITDA	Operating income	Interest expense	S&P Global Ratings' adjusted EBITDA	Cash flow from operations	Capital expenditure
	6,614.0	1,639.0	895.0	234.0	1,782.0	727.0	1,604.0
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(14.0)	--	--
Cash interest paid	--	--	--	--	(230.0)	--	--
Reported lease liabilities	560.0	--	--	--	--	--	--
Operating leases	--	117.0	9.6	9.6	(9.6)	107.4	--
Accessible cash and liquid investments	(25.0)	--	--	--	--	--	--
Capitalized interest	--	--	--	9.0	(9.0)	(9.0)	(9.0)
Asset-retirement obligations	333.4	16.0	16.0	16.0	--	--	--
Nonoperating income (expense)	--	--	26.0	--	--	--	--
Debt: Other	(104.0)	--	--	--	--	--	--
EBITDA: Other	--	10.0	10.0	--	--	--	--
Depreciation and amortization: Other	--	--	(10.0)	--	--	--	--
Total adjustments	764.4	143.0	51.6	34.6	(262.6)	98.4	(9.0)
S&P Global Ratings' adjusted amounts							
	Debt	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	7,378.4	1,782.0	946.6	268.6	1,519.4	825.4	1,595.0

Table 2

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2020--

Public Service Co. of Colorado reported amounts (mil. $)	Debt	EBITDA	Operating income	Interest expense	S&P Global Ratings' adjusted EBITDA	Cash flow from operations	Capital expenditure
	5,917.0	1,478.0	823.0	224.0	1,540.0	1,174.0	1,671.0
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(23.0)	--	--
Cash interest paid	--	--	--	--	(211.0)	--	--
Reported lease liabilities	662.0	--	--	--	--	--	--
Operating leases	--	12.0	2.4	2.4	(2.4)	9.6	--
Postretirement benefit obligations/deferred compensation	123.2	--	--	--	--	--	--
Accessible cash and liquid investments	(28.0)	--	--	--	--	--	--
Capitalized interest	--	--	--	14.0	(14.0)	(14.0)	(14.0)
Power purchase agreements	200.5	35.0	7.8	7.8	(7.8)	27.2	27.2
Asset-retirement obligations	315.2	14.0	14.0	14.0	--	--	--
Nonoperating income (expense)	--	--	37.0	--	--	--	--
Debt: Other	(470.0)	--	--	--	--	--	--
EBITDA: Other	--	1.0	1.0	--	--	--	--
Depreciation and amortization: Other	--	--	(1.0)	--	--	--	--
Total adjustments	803.0	62.0	61.2	38.2	(258.2)	22.8	13.2
S&P Global Ratings' adjusted amounts							
	Debt	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	6,720	1,540	884	262	1,282	1,197	1,684

Table 3

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2019--

Public Service Co. of Colorado reported amounts (mil. $)	Debt	EBITDA	Operating income	Interest expense	S&P Global Ratings' adjusted EBITDA	Cash flow from operations	Capital expenditure
	5,423.7	1,459.2	856.8	224.2	1,527.6	1,227.9	1,690.7
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(4.7)	--	--
Cash interest paid	--	--	--	--	(209.3)	--	--
Reported lease liabilities	742.2	--	--	--	--	--	--
Operating leases	--	13.1	2.7	2.7	(2.7)	10.4	--
Postretirement benefit obligations/deferred compensation	146.5	--	--	--	--	--	--
Accessible cash and liquid investments	(15.2)	--	--	--	--	--	--
Capitalized interest	--	--	--	11.2	(11.2)	(11.2)	(11.2)
Power purchase agreements	226.7	35.4	9.3	9.3	(9.3)	26.1	26.1
Asset-retirement obligations	256.0	15.3	15.3	15.3	--	--	--
Nonoperating income (expense)	--	--	32.0	--	--	--	--
Debt: Other	(538.5)	--	--	--	--	--	--
EBITDA: Other	--	4.6	4.6	--	--	--	--
Depreciation and amortization: Other	--	--	(4.6)	--	--	--	--
Total adjustments	817.7	68.4	59.3	38.5	(237.2)	25.3	14.9
S&P Global Ratings' adjusted amounts							
	Debt	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	6,241	1,528	916	263	1,290	1,253	1,706

Public Service Company of Colorado Final

Credit Opinion Ratios			12/31/22 (Annual) As Rep	Standard Adjustments Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	tk. Comp	Hybrids	uritization	LIFO	Unusual	Restricte d Cash	Int and Div	Continge nt Consider ation	Non-Standar d Adjustm ents	Total Adj.	12/31/22 (Annual) As Adj		
(CFO Pre-W/C) / Debt	Cash Flow From Operations		1,255	11	16															27	1,282		
	- Changes in Working Capital		299																		299		
	- Changes in Short Term Op. Assets & Liabs.	=	-20.00																		-20.00	=	1,561
	Short-term debt		294																		294		7,348
	+ Long-term Debt - Gross		6,860	9	185															194	7,054		
			21.4%																				*21.2%*
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		1,255	11	16															27	1,282		
	- Changes in Working Capital		299																		299		
	- Changes in Short Term Op. Assets & Liabs.		-20.00																		-20.00		
	- Preferred Dividends		0.00																		0.00		
	- Common Dividends		-491.00																		-491.00		
	- Minority Dividends	=	0.00																		0.00	=	1,070
	Short-term debt		294																		294		7,348
	+ Long-term Debt - Gross		6,860	9	185															194	7,054		
			14.6%																				*14.6%*
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		1,255	11	16															27	1,282		
	- Changes in Working Capital		299																		299		
	- Changes in Short Term Op. Assets & Liabs.		-20.00																		-20.00		
	+ Interest Expense	=	260	0.73	3															4	264	=	1,825
	Interest Expense		260	0.73	3															4	264		264
			6.9x																				*6.9x*
Debt / Book Capitalization	Short-term debt		294																		294		
	+ Long-term Debt - Gross	=	6,860	9	185															194	7,054	=	7,348
	Short-term debt		294																		294		18,561
	+ Long-term Debt - Gross		6,860	9	185															194	7,054		
	+ Total Equity		9,230																		9,230		
	+ Deferred Income Taxes - Non-Current		1,983																		1,983		
	+ Minority Interest		0.00																		0.00		
			39.0%																				*39.6%*

Public Service Company of Colorado Final

Credit Opinion Ratios			12/31/21 (Annual) As Rep	Standard Adjustments Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	tk. Comp	Hybrids	uritization	LIFO	Unusual	Restrict ed Cash	Int and Div	Conting ent Conside ration	Non-Standar d Adjust ments	otal Adj.	12/31/21 (Annual) As Adj		
(CFO Pre-W/C) / Debt	Cash Flow From Operations		727	13	13															26	753		
	- Changes in Working Capital		138																		138		
	- Changes in Short Term Op. Assets & Liabs.	=	287																		287	=	1,178
	Short-term debt		147																		147		6,806
	+ Long-term Debt - Gross		6,467	18	174															192	6,659		
			17.4%																				*17.3%*
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		727	13	13															26	753		
	- Changes in Working Capital		138																		138		
	- Changes in Short Term Op. Assets & Liabs.		287																		287		
	- Preferred Dividends		0.00																		0.00		
	- Common Dividends		-467.00																		-467.00		
	- Minority Dividends	=	0.00																		0.00	=	711
	Short-term debt		147																		147		6,806
	+ Long-term Debt - Gross		6,467	18	174															192	6,659		
			10.4%																				*10.4%*
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		727	13	13															26	753		
	- Changes in Working Capital		138																		138		
	- Changes in Short Term Op. Assets & Liabs.		287																		287		
	+ Interest Expense	=	234	2	2															4	238	=	1,416
	Interest Expense		234	2	2															4	238		238
			5.9x																				*5.9x*
Debt / Book Capitalization	Short-term debt		147																		147		
	+ Long-term Debt - Gross	=	6,467	18	174															192	6,659	=	6,806
	Short-term debt		147																		147		17,210
	+ Long-term Debt - Gross		6,467	18	174															192	6,659		
	+ Total Equity		8,444																		8,444		
	+ Deferred Income Taxes - Non-Current		1,960																		1,960		
	+ Minority Interest		0.00																		0.00		
			38.9%																				*39.5%*

Public Service Company of Colorado Final

Credit Opinion Ratios			12/31/20 (Annual) As Rep	Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	tk. Comp	Hybrids	uritization	LIFO	Unusual	Restricted Cash	Int and Div	Contingent Consideration	Non-Standard Adjustments	otal Adj.	12/31/20 (Annual) As Adj		
				Standard Adjustments																			
(CFO Pre-W/C) / Debt	Cash Flow From Operations		1,174	20	10		-14.00													16	1,190		
	- Changes in Working Capital		105																		105		
	- Changes in Short Term Op. Assets & Liabs.	=	-18.00																		-18.00	=	1,277
	Short-term debt		193																		193		6,254
	+ Long-term Debt - Gross		5,724	145	192															337	6,061		
			21.3%																				***20.4%***
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		1,174	20	10		-14.00													16	1,190		
	- Changes in Working Capital		105																		105		
	- Changes in Short Term Op. Assets & Liabs.		-18.00																		-18.00		
	- Preferred Dividends		0.00																		0.00		
	- Common Dividends		-831.00																		-831.00		
	- Minority Dividends	=	0.00																		0.00	=	446
	Short-term debt		193																		193		6,254
	+ Long-term Debt - Gross		5,724	145	192															337	6,061		
			7.3%																				***7.1%***
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		1,174	20	10		-14.00													16	1,190		
	- Changes in Working Capital		105																		105		
	- Changes in Short Term Op. Assets & Liabs.		-18.00																		-18.00		
	+ Interest Expense	=	224	5	2		14													21	245	=	1,522
	Interest Expense		224	5	2		14													21	245		245
			6.6x																				***6.2x***
Debt / Book Capitalization	Short-term debt		193																		193		
	+ Long-term Debt - Gross	=	5,724	145	192															337	6,061	=	6,254
	Short-term debt		193																		193		15,729
	+ Long-term Debt - Gross		5,724	145	192															337	6,061		
	+ Total Equity		7,592				-11.06													-11.06	7,581		
	+ Deferred Income Taxes - Non-Current		1,897				-2.94													-2.94	1,894		
	+ Minority Interest		0.00																		0.00		
			38.4%																				***39.8%***

Public Service Company of Colorado Final

Credit Opinion Ratios			12/31/19 (Annual) As Rep	Standard Adjustments												Non-Standard Adjust				12/31/19 (Annual) As Adj
				Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	tk. Comp	Hybrids	uritization	LIFO	Unusual		otal Adj.			
(CFO Pre-W/C) / Debt	Cash Flow From Operations		1,228	20	10												31	1,259		
	- Changes in Working Capital		102															102		
	- Changes in Short Term Op. Assets & Liabs.	=	-58.41															-58.41	=	1,302
	Short-term debt		39															39		5,898
	+ Long-term Debt - Gross		5,385	206	204											65	475	5,859		
			23.4%																	***22.1%***
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		1,228	20	10												31	1,259		
	- Changes in Working Capital		102															102		
	- Changes in Short Term Op. Assets & Liabs.		-58.41															-58.41		
	- Preferred Dividends		0.00															0.00		
	- Common Dividends		-457.60															-457.60		
	- Minority Dividends	=	0.00															0.00	=	844
	Short-term debt		39															39		5,898
	+ Long-term Debt - Gross		5,385	206	204											65	475	5,859		
			15.0%																	***14.3%***
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		1,228	20	10												31	1,259		
	- Changes in Working Capital		102															102		
	- Changes in Short Term Op. Assets & Liabs.		-58.41															-58.41		
	+ Interest Expense	=	224	8	3												11	235	=	1,537
	Interest Expense		224	8	3												11	235		235
			6.7x																	***6.5x***
Debt / Book Capitalization	Short-term debt		39															39		
	+ Long-term Debt - Gross	=	5,385	206	204											65	475	5,859	=	5,898
	Short-term debt		39															39		14,680
	+ Long-term Debt - Gross		5,385	206	204											65	475	5,859		
	+ Total Equity		6,996													-65.00	-65.00	6,931		
	+ Deferred Income Taxes - Non-Current		1,851															1,851		
	+ Minority Interest		0.00															0.00		
			38.0%																	***40.2%***

S&P Capital IQ PRO

Public Service Company of Colorado | Income Statement (As Reported)

(MI KEY: 4057094; SPCIQ KEY: 298400)

Periods: Custom
Source SNL Financial

SNL Financial	***2019 FY***	***2020 FY***	***2021 FY***	***2022 FY***
As Of Date	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Source Document	12/31/2021	12/31/2022	12/31/2022	12/31/2022
Currency Code	USD	USD	USD	USD
(in millions)				
Operating revenues				
Electric	3,033	3,116	3,413	3,795
Natural gas	1,161	1,024	1,355	1,860
Other	43	43	47	53
Total operating revenues	4,237	4,183	4,815	5,708
Operating expenses				
Electric fuel and purchased power	1,083	1,132	1,336	1,485
Cost of natural gas sold and transported	526	374	606	1,053
Cost of sales - steam and other	17	13	15	18
Operating and maintenance expenses	810	811	831	905
Demand side management expenses	136	141	132	133
Depreciation and amortization	602	655	744	848
Taxes (other than income taxes)	206	234	256	272
Total operating expenses	3,380	3,360	3,920	4,714
Operating income	**857**	**823**	**895**	**994**
Other income (expense), net	3	(1)	4	(2)
Allowance for funds used during construction - equity	22	35	28	32
Interest charges and financing costs				
Interest charges - includes other financing costs	235	238	243	271
Allowance for funds used during construction - debt	(11)	(14)	(9)	(11)
Total interest charges and financing costs	224	224	234	260
Income before income taxes	658	633	693	764
Income tax expense	80	45	33	37
Net income	**578**	**588**	**660**	**727**

S&P Capital IQ PRO

Public Service Company of Colorado | Balance Sheet (As Reported)
(MI KEY: 4057094; SPCIQ KEY: 298400)

Periods: Custom
Source SNL Financial

SNL Financial	*2019 FY*	*2020 FY*	*2021 FY*	*2022 FY*
As Of Date	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Source Document	12/31/2020	12/31/2020	12/31/2022	12/31/2022
Currency Code	USD	USD	USD	
(in millions)				
Assets				
Current assets				
Cash and cash equivalents	11	28	25	10
Accounts receivable, net	304	342	374	562
Accounts receivable from affiliates	53	8	13	11
Accrued unbilled revenues	294	298	350	519
Inventories	192	189	245	319
Regulatory assets	64	121	353	411
Derivative instruments	7	21	39	65
Prepayments and other	56	82	104	103
Total current assets	981	1,089	1,503	2,000
Property, plant and equipment, net	16,155	17,470	18,444	19,652
Other assets				
Regulatory assets	1,038	1,059	1,293	1,277
Derivative instruments	0	16	27	22
Operating lease right-of-use assets	574	500	409	437
Other	260	231	246	231
Total other assets	1,872	1,806	1,975	1,967
Total assets	**19,008**	**20,365**	**21,922**	**23,619**
Liabilities and Equity				
Current liabilities				
Current portion of long-term debt	400	0	300	250
Borrowings under utility money pool	39	57	0	0
Short-term debt	0	136	147	294
Accounts payable	573	452	531	764
Accounts payable to affiliates	44	58	69	75
Regulatory liabilities	69	100	95	59
Taxes accrued	202	251	252	242
Accrued interest	53	61	58	59
Dividends payable to parent	112	105	104	120
Derivative instruments	9	27	30	30
Operating lease liabilities	86	97	84	80
Other	99	84	109	115
Total current liabilities	1,686	1,428	1,779	2,088
Deferred credits and other liabilities				
Deferred income taxes	1,851	1,897	1,960	1,983
Deferred investment tax credits	23	20	0	0
Regulatory liabilities	2,037	2,337	2,397	2,489
Asset retirement obligations	324	399	422	476
Derivative instruments	53	51	29	9
Customer advances	173	168	160	144
Pension and employee benefit obligations	212	161	23	13
Operating lease liabilities	518	432	351	379
Other	150	156	190	198
Total deferred credits and other liabilities	5,341	5,621	5,532	5,691
Capitalization				
Long-term debt	4,985	5,724	6,167	6,610
Common stock	0	0	0	0
Additional paid in capital	4,940	5,770	6,426	6,992
Retained earnings	2,083	1,846	2,040	2,260
Accumulated other comprehensive loss	(27)	(24)	(22)	(22)
Total common stockholder's equity	6,996	7,592	8,444	9,230
Total liabilities and stockholder's equity	**19,008**	**20,365**	**21,922**	**23,619**

S&P Capital IQ PRO

Public Service Company of Colorado | Cash Flow (As Reported)

(MI KEY: 4057094; SPCIQ KEY: 298400)

Periods: Custom
Source SNL Financial

SNL Financial	*2019 FY*	*2020 FY*	*2021 FY*	*2022 FY*
As Of Date	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Source Document	12/31/2021 10-	12/31/2021 10-	12/31/2021 10-	12/31/2022
Currency Code	USD	USD	USD	USD
(in millions)				
Operating activities				
Net income	578	588	660	727
Adjustments to reconcile net income to cash provided				
Depreciation and amortization	607	656	754	854
Deferred income taxes	97	2	21	(10)
Amortization of investment tax credits	0	0	11	0
Allowance for equity funds used during	(22)	(35)	(28)	(32)
Provision for bad debts	17	24	26	38
Net realized and unrealized hedging and	62	(14)	(44)	
Changes in operating assets and liabilities				
Accounts receivable	(22)	(51)	(58)	(227)
Accrued unbilled revenues	20	(5)	(52)	(169)
Inventories	(27)	(27)	(71)	(86)
Prepayments and other	(29)	(8)	(23)	12
Accounts payable	(44)	(14)	66	183
Net regulatory assets and liabilities	35	58	(526)	82
Other current liabilities	0	45	30	8
Pension and other employee benefit	(47)	(41)	(53)	(13)
Other, net	3	(4)	14	(112)
Net cash provided by operating activities	1,228	1,174	727	1,255
Investing activities				
Utility capital/construction expenditures	(1,691)	(1,671)	(1,604)	(1,880)
Investments in utility money pool arrangement	(641)	(122)	(273)	(45)
Repayments from utility money pool arrangement	641	122	273	45
Net cash used in investing activities	(1,691)	(1,671)	(1,604)	(1,880)
Financing activities				
Proceeds from (repayments of) short-term borrowings,	(307)	136	11	146
Borrowings under utility money pool arrangement	100	1,189	743	1,199
Repayments under utility money pool arrangement	(61)	(1,171)	(800)	(1,199)
Proceeds from issuance of long-term debt	928	735	737	686
Repayments of long-term debt	(400)	(400)	0	(300)
Capital contributions from parent	638	856	650	569
Dividends paid to parent	(457)	(831)	(467)	(491)
Net cash provided by financing activities	441	514	874	610
Net change in cash and cash equivalents	(22)	17	(3)	(15)
Cash, cash equivalents and restricted cash at beginning of	33	11	28	25
Cash, cash equivalents and restricted cash at end of period	11	28	25	10
Supplemental disclosure of cash flow information				
Cash paid for interest (net of amounts capitalized)	(209)	(211)	(230)	(250)
Cash paid for income taxes, net	(5)	(23)	(14)	(79)
Supplemental disclosure of non-cash investing and financing transactions				
Accrued property, plant and equipment additions	234	197	157	233
Inventory transfers to property, plant and equipment	32	35	10	12
Operating lease right-of-use assets	654	14	0	140
Allowance for equity funds used during construction	22	35	28	32

Public Service Company of Colorado: PSCo Gas Case
Scenario 4. 10.25% ROE 40% Equity Ratio
Dollars in Millions

Adjusted Credit Metrics

January, 2024

Moody's Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
CFO pre - WC / Debt	22.1%	20.4%	17.3%	21.2%	[redacted]		
CFO pre - WC + Interest / Interest	6.5x	6.2x	5.9x	6.9x			
CFO pre - WC - Dividends / Debt	14.3%	7.1%	10.4%	14.6%			
Debt / Book Capitalization	40.2%	39.8%	39.5%	39.6%			

S&P Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
FFO / Debt	20.7%	19.1%	20.6%	20.4%	[redacted]		
Debt / EBITDA	4.1x	4.4x	4.1x	4.0x			
FFO / Interest	5.9x	5.9x	6.7x	6.2x			
EBITDA / Interest	5.8x	5.9x	6.6x	6.4x			

Financial model below includes highly sensitive, forward-looking information including company earnings. This schedule should be considered "Restricted Confidential" and therefore should only be provided externally in direct response to an official information request.

Public Service Company of Colorado: PSCo Gas Case
Key Credit Metrics
Dollars in Millions

Adjusted Credit Metrics Buildup

January, 2024

Moody's Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Cash Flow from Operations	$1,228	$1,174	$727	$1,255	[redacted]		
Add pre-WC adjustment[2]	74	103	451	306	[redacted]		
Adjusted CFO pre-WC	**$1,302**	**$1,277**	**$1,178**	**$1,561**	[redacted]		
Interest Expense	224	224	234	260	[redacted]		
Add AFUDC Debt	0	14	0	0	[redacted]		
Add interest expense adjustment	11	7	4	4	[redacted]		
Adjusted Interest	**$235**	**$245**	**$238**	**$264**	[redacted]		
Dividends	457	831	467	491	[redacted]		
Debt	5,424	5,917	6,614	7,154	[redacted]		
Add debt adjustment	475	337	192	194	[redacted]		
Adjusted Debt	**$5,899**	**$6,254**	**$6,806**	**$7,348**	[redacted]		
Book Capitalization	14,271	15,406	17,018	18,367	[redacted]		
Add debt adjustment	410	323	192	194	[redacted]		
Adjusted Book Capitalization	**$14,681**	**$15,729**	**$17,210**	**$18,561**	[redacted]		
Moody's Key Metrics					[redacted]		
CFO pre - WC / Debt	22.1%	20.4%	17.3%	21.2%	[redacted]		
CFO pre - WC + Interest / Interest	6.5x	6.2x	5.9x	6.9x	[redacted]		
CFO pre - WC / Debt - Dividends / Debt	14.3%	7.1%	10.4%	14.6%	[redacted]		
Debt / Book Capitalization	40.2%	39.8%	39.5%	39.6%	[redacted]		

S&P Adjusted Credit Metrics	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Operating Income	$857	$823	$895	$994	[redacted]		
Add depreciation & amortization	602	655	744	848	[redacted]		
Add EBITDA adjustment	68	62	143	135	[redacted]		
Adjusted EBITDA	**$1,527**	**$1,540**	**$1,782**	**$1,977**	[redacted]		
Adjusted EBITDA	1,527	1,540	1,782	1,977	[redacted]		
Less Interest Paid	(224)	(224)	(234)	(260)	[redacted]		
Less Taxes Paid	(5)	(23)	(14)	(47)	[redacted]		
Less AFUDC Debt	(11)	(14)	(9)	(11)	[redacted]		
Add FFO adjustment	3	3	(6)	(41)	[redacted]		
Adjusted Funds from Operations	**$1,290**	**$1,282**	**$1,519**	**$1,618**	[redacted]		
Interest Expense	224	224	234	260	[redacted]		
Add AFUDC Debt	11	14	9	11	[redacted]		
Add interest expense adjustment	27	24	26	38	[redacted]		
Adjusted Interest	**$262**	**$262**	**$269**	**$309**	[redacted]		
Debt	5,424	5,917	6,614	7,154	[redacted]		
Add debt adjustment	818	803	764	771	[redacted]		
Adjusted Debt	**$6,242**	**$6,720**	**$7,378**	**$7,925**	[redacted]		
S&P's Key Metrics					[redacted]		
FFO / Debt	20.7%	19.1%	20.6%	20.4%	[redacted]		
Debt / EBITDA	4.1x	4.4x	4.1x	4.0x	[redacted]		
FFO / Interest	5.9x	5.9x	6.7x	6.2x	[redacted]		
EBITDA / Interest	5.8x	5.9x	6.6x	6.4x	[redacted]		

Public Service Company of Colorado: PSCo Gas Case
Financial Model: RESTRICTED CONFIDENTIAL
Dollars in Millions

PSCo Financial Model

January, 2024

Income Statement	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Revenue	$4,237	$4,183	$4,815	$5,708	[redacted]		
COGS	(1,626)	(1,519)	(1,957)	(2,556)	[redacted]		
Gross Margin	**2,611**	**2,664**	**2,858**	**3,152**	[redacted]		
O&M	(810)	(811)	(831)	(905)	[redacted]		
CIP & DSM	(136)	(141)	(132)	(133)	[redacted]		
Property & Sales Taxes	(206)	(234)	(256)	(272)	[redacted]		
Depreciation & Amortization	(602)	(655)	(744)	(848)	[redacted]		
Operating Income	**857**	**823**	**895**	**994**	[redacted]		
AFUDC Equity / Other	25	34	32	30	[redacted]		
Interest	(224)	(224)	(234)	(260)	[redacted]		
Pretax Income	**658**	**633**	**693**	**764**	[redacted]		
Income Tax	(80)	(45)	(33)	(37)	[redacted]		
Net Income	**578**	**588**	**660**	**727**	[redacted]		

Cash Flow Statement	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Net Income	$578	$588	$660	$727	[redacted]		
Depreciation & Amortization	607	656	754	854	[redacted]		
Deferred Taxes	97	2	32	(10)	[redacted]		
AFUDC	(22)	(35)	(28)	(32)	[redacted]		
Pension	(47)	(41)	(53)	(13)	[redacted]		
Other	15	4	(638)	(271)	[redacted]		
Cash from Operations	**$1,228**	**$1,174**	**$727**	**$1,255**	[redacted]		
Capex	(1,691)	(1,671)	(1,604)	(1,880)	[redacted]		
Other Investments	0	0	0	0	[redacted]		
Cash Invested	**($1,691)**	**($1,671)**	**($1,604)**	**($1,880)**	[redacted]		
Equity from Parent	638	856	650	569	[redacted]		
Dividends Paid to Parent	(457)	(831)	(467)	(491)	[redacted]		
Change in Long Term Debt	528	335	737	386	[redacted]		
Change in Short Term Debt	(268)	154	(46)	146	[redacted]		
Cash from Financing	**$441**	**$514**	**$874**	**$610**	[redacted]		

Balance Sheet	2019A	2020A	2021A	2022A	2023E	2024E	2025E
Cash	$11	$28	$25	$10	[redacted]		
Other Current Assets	970	1,061	1,478	1,990	[redacted]		
Net PP&E	16,155	17,470	18,444	19,652	[redacted]		
Other Assets	1,872	1,806	1,975	1,967	[redacted]		
Total Assets	**$19,008**	**$20,365**	**$21,922**	**$23,619**	[redacted]		
Short Term Debt	39	193	147	294	[redacted]		
Other Current Liabilities	1,247	1,235	1,332	1,544	[redacted]		
Deferred Taxes	1,851	1,897	1,960	1,983	[redacted]		
Other Liabilities	3,490	3,724	3,572	3,708	[redacted]		
Long Term Debt	5,385	5,724	6,467	6,860	[redacted]		
Equity	6,996	7,592	8,444	9,230	[redacted]		
Total Liabilities & Equity	**$19,008**	**$20,365**	**$21,922**	**$23,619**	[redacted]		

	2023	2024	2025
[redacted]			

Table 3

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2022--

Public Service Co. of Colorado reported amounts (mil. $)	Debt	EBITDA	Operating income	Interest expense	S&P Global Ratings' adjusted EBITDA	Cash flow from operations	Capital expenditure
	7,154.0	1,842.0	994.0	260.0	1,977.0	1,255.0	1,880.0
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(79.0)	--	--
Cash interest paid	--	--	--	--	(250.0)	--	--
Reported lease liabilities	576.0	--	--	--	--	--	--
Operating leases	--	110.0	18.8	18.8	(18.8)	91.2	--
Accessible cash and liquid investments	(10.0)	--	--	--	--	--	--
Capitalized interest	--	--	--	11.0	(11.0)	(11.0)	(11.0)
Asset-retirement obligations	376.0	19.0	19.0	19.0	--	--	--
Nonoperating income (expense)	--	--	20.0	--	--	--	--
Debt: Other	(171.0)	--	--	--	--	--	--
EBITDA: Other	--	6.0	6.0	--	--	--	--
Depreciation and amortization: Other	--	--	(6.0)	--	--	--	--
Total adjustments	771.0	135.0	57.8	48.8	(358.8)	80.2	(11.0)

S&P Global Ratings' adjusted amounts	Debt	EBITDA	EBIT	Interest expense	Funds from operations	Cash flow from operations	Capital expenditure
	7,925.0	1,977.0	1,051.8	308.8	1,618.2	1,335.2	1,869.0

Table 1

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2021--

Public Service Co. of Colorado reported amounts (mil. $)	Debt	EBITDA	Operating income	Interest expense	S&P Global Ratings' adjusted EBITDA	Cash flow from operations	Capital expenditure
	6,614.0	1,639.0	895.0	234.0	1,782.0	727.0	1,604.0
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(14.0)	--	--
Cash interest paid	--	--	--	--	(230.0)	--	--
Reported lease liabilities	560.0	--	--	--	--	--	--
Operating leases	--	117.0	9.6	9.6	(9.6)	107.4	--
Accessible cash and liquid investments	(25.0)	--	--	--	--	--	--
Capitalized interest	--	--	--	9.0	(9.0)	(9.0)	(9.0)
Asset-retirement obligations	333.4	16.0	16.0	16.0	--	--	--
Nonoperating income (expense)	--	--	26.0	--	--	--	--
Debt: Other	(104.0)	--	--	--	--	--	--
EBITDA: Other	--	10.0	10.0	--	--	--	--
Depreciation and amortization: Other	--	--	(10.0)	--	--	--	--
Total adjustments	764.4	143.0	51.6	34.6	(262.6)	98.4	(9.0)

S&P Global Ratings' adjusted amounts	Debt	EBITDA	EBIT	Interest expense	Funds from operations	Cash flow from operations	Capital expenditure
	7,378.4	1,782.0	946.6	268.6	1,519.4	825.4	1,595.0

Table 2

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2020--

Public Service Co. of Colorado reported amounts (mil. $)	Debt	EBITDA	Operating income	Interest expense	S&P Global Ratings' adjusted EBITDA	Cash flow from operations	Capital expenditure
	5,917.0	1,478.0	823.0	224.0	1,540.0	1,174.0	1,671.0
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(23.0)	--	--
Cash interest paid	--	--	--	--	(211.0)	--	--
Reported lease liabilities	662.0	--	--	--	--	--	--
Operating leases	--	12.0	2.4	2.4	(2.4)	9.6	--
Postretirement benefit obligations/deferred compensation	123.2	--	--	--	--	--	--
Accessible cash and liquid investments	(28.0)	--	--	--	--	--	--
Capitalized interest	--	--	--	14.0	(14.0)	(14.0)	(14.0)
Power purchase agreements	200.5	35.0	7.8	7.8	(7.8)	27.2	27.2
Asset-retirement obligations	315.2	14.0	14.0	14.0	--	--	--
Nonoperating income (expense)	--	--	37.0	--	--	--	--
Debt: Other	(470.0)	--	--	--	--	--	--
EBITDA: Other	--	1.0	1.0	--	--	--	--
Depreciation and amortization: Other	--	--	(1.0)	--	--	--	--
Total adjustments	803.0	62.0	61.2	38.2	(258.2)	22.8	13.2

S&P Global Ratings' adjusted amounts	Debt	EBITDA	EBIT	Interest expense	Funds from operations	Cash flow from operations	Capital expenditure
	6,720	1,540	884	262	1,282	1,197	1,684

Table 3

Public Service Co. of Colorado--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

--Fiscal year ended Dec. 31, 2019--

Public Service Co. of Colorado reported amounts (mil. $)	Debt	EBITDA	Operating income	Interest expense	S&P Global Ratings' adjusted EBITDA	Cash flow from operations	Capital expenditure
	5,423.7	1,459.2	856.8	224.2	1,527.6	1,227.9	1,690.7
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(4.7)	--	--
Cash interest paid	--	--	--	--	(209.3)	--	--
Reported lease liabilities	742.2	--	--	--	--	--	--
Operating leases	--	13.1	2.7	2.7	(2.7)	10.4	--
Postretirement benefit obligations/deferred compensation	146.5	--	--	--	--	--	--
Accessible cash and liquid investments	(15.2)	--	--	--	--	--	--
Capitalized interest	--	--	--	11.2	(11.2)	(11.2)	(11.2)
Power purchase agreements	226.7	35.4	9.3	9.3	(9.3)	26.1	26.1
Asset-retirement obligations	256.0	15.3	15.3	15.3	--	--	--
Nonoperating income (expense)	--	--	32.0	--	--	--	--
Debt: Other	(538.5)	--	--	--	--	--	--
EBITDA: Other	--	4.6	4.6	--	--	--	--
Depreciation and amortization: Other	--	--	(4.6)	--	--	--	--
Total adjustments	817.7	68.4	59.3	38.5	(237.2)	25.3	14.9

S&P Global Ratings' adjusted amounts	Debt	EBITDA	EBIT	Interest expense	Funds from operations	Cash flow from operations	Capital expenditure
	6,241	1,528	916	263	1,290	1,253	1,706

Public Service Company of Colorado Final

Credit Opinion Ratios			12/31/22 (Annual) As Rep	Standard Adjustments Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	tk. Comp	Hybrids	uritization	LIFO	Unusual	Restricted Cash	Int and Div	Contingent Consideration	Non-Standard Adjustments	Total Adj.	12/31/22 (Annual) As Adj		
(CFO Pre-W/C) / Debt	Cash Flow From Operations		1,255	11	16															27	1,282		
	- Changes in Working Capital		299																		299		
	- Changes in Short Term Op. Assets & Liabs.	=	-20.00																		-20.00	=	1,561
	Short-term debt		294																		294		7,348
	+ Long-term Debt - Gross		6,860	9	185															194	7,054		
			21.4%																				***21.2%***
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		1,255	11	16															27	1,282		
	- Changes in Working Capital		299																		299		
	- Changes in Short Term Op. Assets & Liabs.		-20.00																		-20.00		
	- Preferred Dividends		0.00																		0.00		
	- Common Dividends		-491.00																		-491.00		
	- Minority Dividends	=	0.00																		0.00	=	1,070
	Short-term debt		294																		294		7,348
	+ Long-term Debt - Gross		6,860	9	185															194	7,054		
			14.6%																				***14.6%***
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		1,255	11	16															27	1,282		
	- Changes in Working Capital		299																		299		
	- Changes in Short Term Op. Assets & Liabs.		-20.00																		-20.00		
	+ Interest Expense	=	260	0.73	3															4	264	=	1,825
	Interest Expense		260	0.73	3															4	264		264
			6.9x																				***6.9x***
Debt / Book Capitalization	Short-term debt		294																		294		
	+ Long-term Debt - Gross	=	6,860	9	185															194	7,054	=	7,348
	Short-term debt		294																		294		18,561
	+ Long-term Debt - Gross		6,860	9	185															194	7,054		
	+ Total Equity		9,230																		9,230		
	+ Deferred Income Taxes - Non-Current		1,983																		1,983		
	+ Minority Interest		0.00																		0.00		
			39.0%																				***39.6%***

Public Service Company of Colorado Final

Credit Opinion Ratios			12/31/21 (Annual) As Rep	Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	k. Comp	Hybrids	uritization	LIFO	Unusual	Restricted Cash	Int and Div	Contingent Consideration	Non-Standard Adjustments	otal Adj.			12/31/21 (Annual) As Adj
(CFO Pre-W/C) / Debt	Cash Flow From Operations		727	13	13															26	753		
	- Changes in Working Capital		138																		138		
	- Changes in Short Term Op. Assets & Liabs.	=	287																		287	=	1,178
	Short-term debt		147																		147		6,806
	+ Long-term Debt - Gross		6,467	18	174															192	6,659		
			17.4%																				***17.3%***
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		727	13	13															26	753		
	- Changes in Working Capital		138																		138		
	- Changes in Short Term Op. Assets & Liabs.		287																		287		
	- Preferred Dividends		0.00																		0.00		
	- Common Dividends		-467.00																		-467.00		
	- Minority Dividends	=	0.00																		0.00	=	711
	Short-term debt		147																		147		6,806
	+ Long-term Debt - Gross		6,467	18	174															192	6,659		
			10.4%																				***10.4%***
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		727	13	13															26	753		
	- Changes in Working Capital		138																		138		
	- Changes in Short Term Op. Assets & Liabs.		287																		287		
	+ Interest Expense	=	234	2	2															4	238	=	1,416
	Interest Expense		234	2	2															4	238		238
			5.9x																				***5.9x***
Debt / Book Capitalization	Short-term debt		147																		147		
	+ Long-term Debt - Gross	=	6,467	18	174															192	6,659	=	6,806
	Short-term debt		147																		147		17,210
	+ Long-term Debt - Gross		6,467	18	174															192	6,659		
	+ Total Equity		8,444																		8,444		
	+ Deferred Income Taxes - Non-Current		1,960																		1,960		
	+ Minority Interest		0.00																		0.00		
			38.9%																				***39.5%***

Public Service Company of Colorado Final

Credit Opinion Ratios

			12/31/20 (Annual) As Rep	Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	k. Comp	Hybrids	uritization	LIFO	Unusual	Restrict ed Cash	Int and Div	Conting ent Conside ration	Non-Standard Adjustments	otal Adj.			12/31/20 (Annual) As Adj
				Standard Adjustments																			
(CFO Pre-W/C) / Debt	Cash Flow From Operations		1,174	20	10		-14.00													16	1,190		
	- Changes in Working Capital		105																		105		
	- Changes in Short Term Op. Assets & Liabs.	=	-18.00																		-18.00	=	1,277
	Short-term debt		193																		193		6,254
	+ Long-term Debt - Gross		5,724	145	192															337	6,061		
			21.3%																				***20.4%***
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		1,174	20	10		-14.00													16	1,190		
	- Changes in Working Capital		105																		105		
	- Changes in Short Term Op. Assets & Liabs.		-18.00																		-18.00		
	- Preferred Dividends		0.00																		0.00		
	- Common Dividends		-831.00																		-831.00		
	- Minority Dividends	=	0.00																		0.00	=	446
	Short-term debt		193																		193		6,254
	+ Long-term Debt - Gross		5,724	145	192															337	6,061		
			7.3%																				***7.1%***
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		1,174	20	10		-14.00													16	1,190		
	- Changes in Working Capital		105																		105		
	- Changes in Short Term Op. Assets & Liabs.		-18.00																		-18.00		
	+ Interest Expense	=	224	5	2		14													21	245	=	1,522
	Interest Expense		224	5	2		14													21	245		245
			6.6x																				***6.2x***
Debt / Book Capitalization	Short-term debt		193																		193		
	+ Long-term Debt - Gross	=	5,724	145	192															337	6,061	=	6,254
	Short-term debt		193																		193		15,729
	+ Long-term Debt - Gross		5,724	145	192															337	6,061		
	+ Total Equity		7,592				-11.06													-11.06	7,581		
	+ Deferred Income Taxes - Non-Current		1,897				-2.94													-2.94	1,894		
	+ Minority Interest		0.00																		0.00		
			38.4%																				***39.8%***

Public Service Company of Colorado Final

Credit Opinion Ratios			12/31/19 (Annual) As Rep	Pensions	Op Leases	Fin Leases	Cap. Int.	Cap. Dev. Costs	Int Exp - Disc	Cap Maint Costs	k. Comp	Hybrids	uritization	LIFO	Unusual	Non-Standard Adjust	otal Adj.			12/31/19 (Annual) As Adj
				Standard Adjustments																
(CFO Pre-W/C) / Debt	Cash Flow From Operations		1,228	20	10												31	1,259		
	- Changes in Working Capital		102															102		
	- Changes in Short Term Op. Assets & Liabs.	=	-58.41															-58.41	=	1,302
	Short-term debt		39															39		5,898
	+ Long-term Debt - Gross		5,385	206	204											65	475	5,859		
			23.4%																	***22.1%***
(CFO Pre-W/C - Dividends) / Debt	Cash Flow From Operations		1,228	20	10												31	1,259		
	- Changes in Working Capital		102															102		
	- Changes in Short Term Op. Assets & Liabs.		-58.41															-58.41		
	- Preferred Dividends		0.00															0.00		
	- Common Dividends		-457.60															-457.60		
	- Minority Dividends	=	0.00															0.00	=	844
	Short-term debt		39															39		5,898
	+ Long-term Debt - Gross		5,385	206	204											65	475	5,859		
			15.0%																	***14.3%***
(CFO Pre-W/C + Interest) / Interest Expense	Cash Flow From Operations		1,228	20	10												31	1,259		
	- Changes in Working Capital		102															102		
	- Changes in Short Term Op. Assets & Liabs.		-58.41															-58.41		
	+ Interest Expense	=	224	8	3												11	235	=	1,537
	Interest Expense		224	8	3												11	235		235
			6.7x																	***6.5x***
Debt / Book Capitalization	Short-term debt		39															39		
	+ Long-term Debt - Gross	=	5,385	206	204											65	475	5,859	=	5,898
	Short-term debt		39															39		14,680
	+ Long-term Debt - Gross		5,385	206	204											65	475	5,859		
	+ Total Equity		6,996													-65.00	-65.00	6,931		
	+ Deferred Income Taxes - Non-Current		1,851															1,851		
	+ Minority Interest		0.00															0.00		
			38.0%																	***40.2%***

S&P Capital IQ PRO

Public Service Company of Colorado | Income Statement (As Reported)

(MI KEY: 4057094; SPCIQ KEY: 298400)

Periods: Custom
Source SNL Financial

SNL Financial	*2019 FY*	*2020 FY*	*2021 FY*	*2022 FY*
As Of Date	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Source Document	12/31/2021	12/31/2022	12/31/2022	12/31/2022
Currency Code	USD	USD	USD	USD
(in millions)				
Operating revenues				
Electric	3,033	3,116	3,413	3,795
Natural gas	1,161	1,024	1,355	1,860
Other	43	43	47	53
Total operating revenues	4,237	4,183	4,815	5,708
Operating expenses				
Electric fuel and purchased power	1,083	1,132	1,336	1,485
Cost of natural gas sold and transported	526	374	606	1,053
Cost of sales - steam and other	17	13	15	18
Operating and maintenance expenses	810	811	831	905
Demand side management expenses	136	141	132	133
Depreciation and amortization	602	655	744	848
Taxes (other than income taxes)	206	234	256	272
Total operating expenses	3,380	3,360	3,920	4,714
Operating income	**857**	**823**	**895**	**994**
Other income (expense), net	3	(1)	4	(2)
Allowance for funds used during construction - equity	22	35	28	32
Interest charges and financing costs				
Interest charges - includes other financing costs	235	238	243	271
Allowance for funds used during construction - debt	(11)	(14)	(9)	(11)
Total interest charges and financing costs	224	224	234	260
Income before income taxes	658	633	693	764
Income tax expense	80	45	33	37
Net income	**578**	**588**	**660**	**727**

S&P Capital IQ PRO

Public Service Company of Colorado | Balance Sheet (As Reported)

(MI KEY: 4057094; SPCIQ KEY: 298400)

Periods: Custom
Source SNL Financial

SNL Financial	*2019 FY*	*2020 FY*	*2021 FY*	*2022 FY*
As Of Date	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Source Document	12/31/2020	12/31/2020	12/31/2022	12/31/2022
Currency Code	USD	USD	USD	
(in millions)				
Assets				
Current assets				
Cash and cash equivalents	11	28	25	10
Accounts receivable, net	304	342	374	562
Accounts receivable from affiliates	53	8	13	11
Accrued unbilled revenues	294	298	350	519
Inventories	192	189	245	319
Regulatory assets	64	121	353	411
Derivative instruments	7	21	39	65
Prepayments and other	56	82	104	103
Total current assets	981	1,089	1,503	2,000
Property, plant and equipment, net	16,155	17,470	18,444	19,652
Other assets				
Regulatory assets	1,038	1,059	1,293	1,277
Derivative instruments	0	16	27	22
Operating lease right-of-use assets	574	500	409	437
Other	260	231	246	231
Total other assets	1,872	1,806	1,975	1,967
Total assets	**19,008**	**20,365**	**21,922**	**23,619**
Liabilities and Equity				
Current liabilities				
Current portion of long-term debt	400	0	300	250
Borrowings under utility money pool	39	57	0	0
Short-term debt	0	136	147	294
Accounts payable	573	452	531	764
Accounts payable to affiliates	44	58	69	75
Regulatory liabilities	69	100	95	59
Taxes accrued	202	251	252	242
Accrued interest	53	61	58	59
Dividends payable to parent	112	105	104	120
Derivative instruments	9	27	30	30
Operating lease liabilities	86	97	84	80
Other	99	84	109	115
Total current liabilities	1,686	1,428	1,779	2,088
Deferred credits and other liabilities				
Deferred income taxes	1,851	1,897	1,960	1,983
Deferred investment tax credits	23	20	0	0
Regulatory liabilities	2,037	2,337	2,397	2,489
Asset retirement obligations	324	399	422	476
Derivative instruments	53	51	29	9
Customer advances	173	168	160	144
Pension and employee benefit obligations	212	161	23	13
Operating lease liabilities	518	432	351	379
Other	150	156	190	198
Total deferred credits and other liabilities	5,341	5,621	5,532	5,691
Capitalization				
Long-term debt	4,985	5,724	6,167	6,610
Common stock	0	0	0	0
Additional paid in capital	4,940	5,770	6,426	6,992
Retained earnings	2,083	1,846	2,040	2,260
Accumulated other comprehensive loss	(27)	(24)	(22)	(22)
Total common stockholder's equity	6,996	7,592	8,444	9,230
Total liabilities and stockholder's equity	**19,008**	**20,365**	**21,922**	**23,619**

S&P Capital IQ PRO

Public Service Company of Colorado | Cash Flow (As Reported)

(MI KEY: 4057094; SPCIQ KEY: 298400)

Periods: Custom
Source SNL Financial

SNL Financial	*2019 FY*	*2020 FY*	*2021 FY*	*2022 FY*
As Of Date	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Source Document	12/31/2021 10-	12/31/2021 10-	12/31/2021 10-	12/31/2022
Currency Code	USD	USD	USD	USD
(in millions)				
Operating activities				
Net income	578	588	660	727
Adjustments to reconcile net income to cash provided				
Depreciation and amortization	607	656	754	854
Deferred income taxes	97	2	21	(10)
Amortization of investment tax credits	0	0	11	0
Allowance for equity funds used during	(22)	(35)	(28)	(32)
Provision for bad debts	17	24	26	38
Net realized and unrealized hedging and	62	(14)	(44)	
Changes in operating assets and liabilities				
Accounts receivable	(22)	(51)	(58)	(227)
Accrued unbilled revenues	20	(5)	(52)	(169)
Inventories	(27)	(27)	(71)	(86)
Prepayments and other	(29)	(8)	(23)	12
Accounts payable	(44)	(14)	66	183
Net regulatory assets and liabilities	35	58	(526)	82
Other current liabilities	0	45	30	8
Pension and other employee benefit	(47)	(41)	(53)	(13)
Other, net	3	(4)	14	(112)
Net cash provided by operating activities	1,228	1,174	727	1,255
Investing activities				
Utility capital/construction expenditures	(1,691)	(1,671)	(1,604)	(1,880)
Investments in utility money pool arrangement	(641)	(122)	(273)	(45)
Repayments from utility money pool arrangement	641	122	273	45
Net cash used in investing activities	(1,691)	(1,671)	(1,604)	(1,880)
Financing activities				
Proceeds from (repayments of) short-term borrowings,	(307)	136	11	146
Borrowings under utility money pool arrangement	100	1,189	743	1,199
Repayments under utility money pool arrangement	(61)	(1,171)	(800)	(1,199)
Proceeds from issuance of long-term debt	928	735	737	686
Repayments of long-term debt	(400)	(400)	0	(300)
Capital contributions from parent	638	856	650	569
Dividends paid to parent	(457)	(831)	(467)	(491)
Net cash provided by financing activities	441	514	874	610
Net change in cash and cash equivalents	(22)	17	(3)	(15)
Cash, cash equivalents and restricted cash at beginning of	33	11	28	25
Cash, cash equivalents and restricted cash at end of period	11	28	25	10
Supplemental disclosure of cash flow information				
Cash paid for interest (net of amounts capitalized)	(209)	(211)	(230)	(250)
Cash paid for income taxes, net	(5)	(23)	(14)	(79)
Supplemental disclosure of non-cash investing and financing transactions				
Accrued property, plant and equipment additions	234	197	157	233
Inventory transfers to property, plant and equipment	32	35	10	12
Operating lease right-of-use assets	654	14	0	140
Allowance for equity funds used during construction	22	35	28	32

Scotiabank

Xcel Energy

Indicative New Issue Spreads

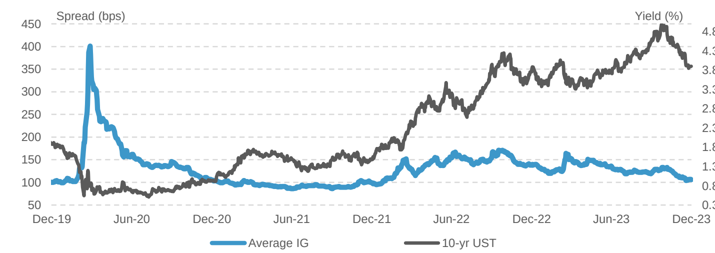
Wednesday, December 27, 2023

New Issue Spreads	3 Year	5 Year	10 Year	30 Year
UST Reference Bond	4.375 12/26	4.375 11/28	4.500 11/33	4.125 08/53
Reference Yield	4.01%	3.82%	3.82%	4.00%
Xcel Energy Inc. (Baa1/BBB+)				
Indicative Spread	**+75 area**	**+95 area**	**+125 area**	**+150 area**
Indicative Coupon	4.76%	4.77%	5.07%	5.50%
Swapped to US$ SOFR	S+95	S+120	S+157	S+214
Northern States Power - Minnesota (Aa3/A)				
Indicative Spread	**+40 area**	**+60 area**	**+90 area**	**+105 area**
Indicative Coupon	4.41%	4.42%	4.72%	5.05%
Swapped to US$ SOFR	S+61	S+86	S+123	S+170
Northern States Power - Wisconsin (Aa3/A)				
Indicative Spread	**+40 area**	**+60 area**	**+90 area**	**+105 area**
Indicative Coupon	4.41%	4.42%	4.72%	5.05%
Swapped to US$ SOFR	S+61	S+86	S+123	S+170
Public Service Company of Colorado (A1/A)				
Indicative Spread	**+60 area**	**+80 area**	**+110 area**	**+130 area**
Indicative Coupon	4.61%	4.62%	4.92%	5.30%
Swapped to US$ SOFR	S+80	S+105	S+142	S+194
Southwestern Public Service (A3/A)				
Indicative Spread	**+70 area**	**+90 area**	**+120 area**	**+145 area**
Indicative Coupon	4.71%	4.72%	5.02%	5.45%
Swapped to US$ SOFR	S+90	S+115	S+152	S+209

Recent Transactions

Date	Issuer	Ratings	Amt	Maturity	Spread
18-Dec	Ameren Corp	Baa1/BBB	$700M	Jan-29	+110
11-Dec	ONE Gas	A3/A-	$300M	Apr-29	+87
11-Dec	Vistra Operations (Add-On)	Baa3/BBB-	$400M	Oct-33	+240
6-Dec	American Electric Power Company	Baa2/BBB+	$1,000M	Jan-29	+113
4-Dec	Edison International	Baa3/BB+	$450M	Jun-54	+366
28-Nov	Oglethorpe Power	Baa1/BBB+	$400M	Dec-53	+175
20-Nov	Consolidated Edison Co of NY	A3/A-	$600M	Mar-34	+115
20-Nov	Consolidated Edison Co of NY	A3/A-	$900M	Nov-53	+138

Average IG Credit Spreads & 10-yr UST Yield



IG Market Stats

This Week's IG Issuance	$0.00 B
2023 YTD IG Issuance:	$1,221.72 B
This Week's P&U Issuance	$0.00 B
2023 YTD P&U Issuance:	$105.02 B
Average IG Index:	+ 106 bps

Economic Data Releases (01/01/24 - 01/05/24)

Monday:	
Tuesday:	S&P Global US Manufacturing PMI, Construction Spending
Wednesday:	ISM Manufacturing & Prices Paid
Thursday:	ADP Employment Change, S&P Global US Services & Composite PMI
Friday:	Nonfarm/Manufact. Payrolls, Unemployment Rate, Factory Orders
	ISM Services Index, Durable Goods Orders, Durables Ex Transportation

Scotiabank Debt Capital Markets 212-225-5501

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