Direct Testimony and Schedules
Sarah W. Soong

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-20-723
Exhibit___(SWS-1)

Capital Structure, Overall Rate of Return
And Investor Relations

November 2, 2020

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Sarah W. Soong. I am Vice President and Treasurer of Xcel Energy Services, Inc., the service company subsidiary of Xcel Energy Inc. (Xcel Energy or XEI).

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

A. I am testifying on behalf of Northern States Power Company (NSPM or the Company), d/b/a Xcel Energy.

Q. PLEASE BRIEFLY OUTLINE YOUR RESPONSIBILITIES AS VICE PRESIDENT AND TREASURER.

A. As Vice President 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. A description of my qualifications, duties, and responsibilities is included in this testimony as Exhibit ___(SWS-1), Schedule 1.

Q. PLEASE STATE THE PURPOSE OF YOUR TESTIMONY.

A. In my testimony, I discuss a number of topics related to the Company's cost of capital. In particular, I:

- Discuss financial integrity, its importance to NSPM and its stakeholders, and the need for NSPM to demonstrate stable overall financial health in order to access capital in varied economic conditions and raise debt capital for utility investments at low costs;

- Discuss the criteria the ratings agencies use to measure financial integrity;
- Provide a current assessment of NSPM's financial integrity and describe the impact that regulatory decisions, changes in cash flow and the timely recovery of prudent utility costs have on NSPM's financial integrity;
- Present and support the capital structure and overall cost of capital proposed by the Company for the term of the Multi-Year Rate Plan (MYRP), 2021-2023; and
- Discuss the importance of the Company's Investor Relations efforts.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present my testimony in the following sections:

- Section II provides a Summary and Overview of NSPM's proposed Capital Structure, Cost of Debt, and Rate of Return (ROR) for the time period covered by this rate case.
- Section III identifies the Commission's standards for review of capital structure and explains the purpose of, and how the Company determines, the capital structure.
- Section IV describes the Company's historical and planned financing and investment activities, explains the importance of the regulatory environment to the credit rating agencies' and investors' perceptions of the regulatory risk and to the Company's ability to carry out its capital expenditure plans. This section also includes a discussion of the credit rating agencies' criteria and NSPM's current credit ratings and financial metrics.
- Section V provides a detailed description of the components of NSPM's capital structure and costs of long-term debt (LTD) and short-term debt

(STD) for 2021 through 2023.

- Section VI discusses the need for and importance of the Company's Investor Relations expenses.
- Section VII includes a Summary and Recommendations.

II. SUMMARY AND OVERVIEW

Q. WHAT DO YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section, I provide an overview of the Company's recommended capital structure for 2021 through 2023.

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED CAPITAL STRUCTURE, COSTS OF DEBT AND EQUITY, AND ROR FOR 2021, 2022 AND 2023.

A. The Company's proposed capital structure for the 2021 test year, including costs of STD, LTD, and Common Equity, is included on Exhibit___(SWS-1), Schedule 2, Page 1 of 3, and are summarized below.[1] These proposed capital structures will allow the Company to continue to raise capital competitively in order to keep costs low for customers, will support the credit ratings guidance provided by the three recognized credit rating agencies and will help maintain the Company's financial integrity, which I discuss further in Section IV.

[1] Schedule 2 and the Tables presented here incorporate July 2020 actuals. As noted in his testimony, the final revenue requirements for 2021 through 2023 supported by Company witness Mr. Benjamin Halama used July forecast data. The forecast data and actual data lead to the same Weighted Average Cost of Capital (WACC) for 2021 and 2023 but lead to a one basis point difference in the cost of capital for 2022. The Company will provide a rebuttal adjustment to update the WACC for purposes of calculating revenue requirements accordingly.

Table 1

2021 Test Year

Recommended Capital Structure Ratios and Costs

	Percent of Total Capital	**Cost**	**Weighted Cost**
Short-Term Debt	0.78%	0.81%	0.01%
Long-Term Debt	46.72%	4.24%	1.98%
Common Equity	52.50%	10.20%	5.36%
Total Capital	100.00%		7.35%

The Company's proposed capital structure for the 2022 plan year is included on Exhibit___(SWS-1), Schedule 2, Page 2 of 3, and can be summarized as follows:

Table 2

2022

Recommended Capital Structure Ratios and Costs

	Percent of Total Capital	**Cost**	**Weighted Cost**
Short-Term Debt	0.32%	1.83%	0.01%
Long-Term Debt	47.18%	4.21%	1.98%
Common Equity	52.50%	10.20%	5.36%
Total Capital	100.00%		7.35%

The Company's proposed capital structure for the 2023 plan year is included on Exhibit___(SWS-1), Schedule 2, Page 3 of 3, and can be summarized as follows:

Table 3

2023

Recommended Capital Structure Ratios and Costs

	Percent of Total Capital	**Cost**	**Weighted Cost**
Short-Term Debt	0.75%	1.03%	0.01%
Long-Term Debt	46.75%	4.19%	1.96%
Common Equity	52.50%	10.20%	5.36%
Total Capital	100.00%		7.33%

Q. HOW DOES THE USE OF A 52.50 PERCENT EQUITY RATIO IN EACH OF THE YEARS OF THE COMPANY'S MYRP COMPARE TO RECENTLY AUTHORIZED CAPITAL STRUCTURES FOR NSPM?

A. The Company's recommended capital structure of 52.50 percent equity for the 2021 test year and for the 2022 and 2023 plan years remains unchanged from the 52.50 percent equity ratio authorized by the Commission in rate cases dating back to 2013. The Company's authorized equity ratio has ranged between 52.47 percent and 52.56 percent over the last several electric general rate case proceedings dating back to 2009. In each of those cases, the Commission has agreed with the reasonableness of the Company's proposed capital structure. Throughout this time, the Company has been consistent and transparent in managing its capital structure to ensure the Company's financial integrity. The Company is following those same principles in this proceeding.

Q. DO YOU BELIEVE THE RECOMMENDED RORS RESULTING FROM YOUR PROPOSED CAPITAL STRUCTURES ARE REASONABLE AND APPROPRIATE?

A. Yes. The Company's recommended RORs for 2021 through 2023 are reasonable, as discussed in Mr. D'Ascendis direct testimony, and reflect a decrease from the cost of LTD and STD used in the Commission approved Settlement of the Company's 2015 rate case.

The cost of LTD for the 2021 through 2023 time frame ranges from 4.19 to 4.24 percent as compared to 4.75 to 4.81 percent used in the last Settlement. The cost of STD for 2021 through 2023 ranges from 0.81 to 1.83 percent as compared to 1.84 to 4.81 percent used in the last Settlement. It should be noted that while the cost of debt has decreased, this is largely due to the current low interest rate environment in which the Company operates. The recommended Return on Equity (ROE) of 10.20 percent is supported in the Direct Testimony of Company Witness Mr. Dylan D'Ascendis.

III. STANDARDS AND FUNDAMENTAL CONSIDERATIONS FOR THE NSPM CAPITAL STRUCTURE

Q. PLEASE SUMMARIZE THE MOST SIGNIFICANT POINTS YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY.

A. I discuss the following points:

- The basic regulatory standard for reviewing a utility's capital structure is one of reasonableness.
- NSPM's capital structure satisfies the Commission's reasonableness criteria, and provides long-term customer benefits, including access to capital to finance capital expenditures that allow NSPM to serve its customers safely and reliably and to invest in carbon-free renewable generation to meet Minnesota energy policy and societal goals and customer expectations at a competitive cost.
- The Company's management of its capital structure is based on long-

term considerations, including credit ratings, future financing plans, the relative capital structures of other utilities, and overall financial market conditions.

Q. WHAT STANDARD HAS THE COMMISSION USED TO EVALUATE CAPITAL STRUCTURES FOR SETTING UTILITY RATES?

A. The Commission has used a reasonableness standard in making capital structure decisions. To determine whether a company's actual capital structure is reasonable, the Commission has considered:

- How the debt and equity ratios for the utility compare to those of similarly situated utility companies;
- Whether the utility's capital structure is an actual capital structure based on market forces, or is an internal accounting capital structure;
- Whether the capital structure supports long-term credit quality given the utility's capital investment forecast, future financing requirements, and the need to access public capital markets; and
- Whether the capital structure provides long-term cost benefits to customers.

Q. DOES NSPM'S PROPOSED CAPITAL STRUCTURE MEET THE COMMISSION'S STANDARDS AND CRITERIA FOR REASONABLENESS?

A. Yes. NSPM's proposed capital structure meets the Commission's standards and criteria. NSPM's capital structure is within a reasonable range of equity ratios for the Utility Proxy Group[2], as Mr. D'Ascendis's analysis shows. Further, NSPM's proposed capital structure is an actual, market-based capital structure

[2] Exhibit DWD-1, Schedule 2, Pages 3-5

and is comparable to its historical capital structure, which has provided long-term benefits to customers in the form of reasonable costs of capital over time and sufficient access to capital markets in all market conditions to finance capital investments. Finally, the Commission has consistently found the Company's recommended capital structures to be reasonable and the requested equity ratio in this case is identical to the equity ratio approved in Docket No. E002/GR-13-868 and utilized in the Settlement of the 2015 rate case, and is in line with the approved equity ratio in the three cases prior to those proceedings (Docket Nos. E002/GR-12-961, E002/GR-10-971, and E002/GR-08-1065).

Q. HOW DOES THE COMPANY'S 52.50 PERCENT EQUITY RATIO COMPARE WITH THE EQUITY RATIOS OF COMPANIES IN MR. D'ASCENDIS'S PROXY GROUP?

A. The Company's 52.50 equity ratio is well within the ranges of the operating utilities in Mr. D'Ascendis's proxy group, as Mr. D'Ascendis explains in his Direct Testimony. As shown on pages 3 and 4 of Exhibit___(DWD-1), Schedule 2, common equity ratios of the utilities range from 35.73 percent to 58.04 percent for fiscal year 2019. As Mr. D'Ascendis concludes, our proposal is consistent with these proxy group companies' equity ratios.

Q. WHEN YOU DESCRIBE NSPM'S CAPITAL STRUCTURE AS AN ACTUAL AND MARKET-BASED CAPITAL STRUCTURE, WHAT DOES THAT MEAN?

A. NSPM is a separate, stand-alone legal Minnesota corporation that manages its own separate capital structure consistent with the regulatory and financial risk prevailing at the operating company level and within its respective jurisdictions. Moody's, Fitch and Standard and Poor's (S&P) all assign credit ratings to NSPM as a corporate entity and to each one of its individual bond issuances. NSPM files its own quarterly and annual financial statements with the Securities and

Exchange Commission (SEC) which credit rating agencies and investors use to analyze the company. In addition, debt to support capital expenditures and operations of NSPM is issued specifically by the NSPM legal entity.

It is important to note that although the Commission may view the Electric and Gas Departments as different entities, from a financial statement perspective, these are both under the umbrella of one company. Both long-term and short-term debt are issued by NSPM, which is the sole entity recognized by the SEC, credit rating agencies and fixed-income investors.

Q. WHAT FACTORS ARE CONSIDERED IN PLANNING AND MANAGING THE CAPITAL STRUCTURE FOR NSPM?

A. The Company considers a number of factors, including:

- Credit rating evaluations that reflect rating agency assessments of NSPM's business and financial risk;
- NSPM's position in relation to its long-term construction cycle and the scale of its capital investments relative to earnings;
- Capital structures of other vertically-integrated, regulated utilities;
- The long-term stability of the capital structure being appropriately matched with the long lives of the Company's asset investments;
- The current macroeconomic outlook and associated risk factors affecting the utility sector and capital markets generally; and
- The need to manage the maturities of LTD to avoid excessive refinancing risk in any given year.

Q. DO YOU HAVE A TARGET FOR MANAGING NSPM'S EQUITY RATIO?

A. Yes. NSPM continues to target a regulated capital structure having an equity ratio of 52.50 percent, which the Company considers appropriate to support NSPM's current credit ratings and projected cost of long-term and short-term debt, as well as providing continued access to capital markets in all market conditions.

Q. WHY IS THAT TARGET EQUITY RATIO APPROPRIATE?

A. NSPM's target equity ratio supports its current S&P A- and Moody's A2 corporate credit ratings and is consistent with the Company's plan to maintain its credit ratings, which provides access to financing at a competitive cost while the Company continues to make significant capital investments in the utility in order to provide safe and reliable service to customers and support carbon reduction goals. The target regulated equity ratio of 52.50 percent is also consistent with other utility capital structures, as shown by the equity ratios of the utilities in Mr. D'Ascendis's proxy group.

Q. HOW DO CUSTOMERS BENEFIT FROM NSPM'S CAPITAL STRUCTURE AND EQUITY RATIO?

A. NSPM's capital structure and equity ratio have a significant effect on its financial integrity. NSPM's financial integrity is essential to: (i) its ability to finance its investments and operations at a competitive cost in all market conditions; and (ii) its credit ratings. NSPM's capital structure has allowed it to simultaneously finance its ongoing investments and maintain access to capital at competitive rates while also maintaining its credit ratings. NSPM's S&P, Moody's and Fitch's corporate credit ratings have remained stable for over a decade. In addition, NSPM has maintained its financial strength to ensure consistent access to capital markets under a range of economic conditions and enable NSPM to raise the capital required to efficiently fund its future investments, such as its investments in renewable energy.

Q. WHAT DOES THE TERM "FINANCIAL INTEGRITY" MEAN?

A. Financial integrity refers to a company's financial strength and its ability to attract capital to support operations and infrastructure investment in all economic conditions. The ability to attract capital at a competitive cost in all economic conditions is integral to a utility's obligation to provide safe, reliable and affordable utility service to customers. Financial integrity ensures that the utility will have the flexibility to withstand unanticipated macroeconomic events outside of its control.

Q. WHAT FACTORS CONTRIBUTE TO A UTILITY'S FINANCIAL INTEGRITY?

A. The financial integrity of a regulated utility is largely a function of its capital structure, ROE, and cash flow, but can be impacted by other factors as well. To maintain a strong financial profile, a utility needs to have the opportunity to recover all prudently-incurred utility costs in a timely manner, which includes not only the costs for capital investments and operations and maintenance expense, but also the costs of servicing debt and providing a fair return for equity investors. This is why constructive regulatory decisions on capital structure, ROE and the recovery of prudent utility costs are vitally important to NSPM.

IV. NSPM'S CAPITAL EXPENDITURE PLAN, CREDIT RATINGS AND THE REGULATORY ENVIRONMENT

Q. PLEASE SUMMARIZE THE KEY POINTS YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY.

A. The key points are as follows:

- To date, NSPM's significant capital expenditure program has resulted in corresponding issuances of debt by NSPM as well as equity infusions from Xcel Energy Inc.
- NSPM has and will continue to make significant capital investments in Minnesota, which requires future access to capital at favorable rates.
- Regulatory decisions are very important to both debt and equity investors, rating agencies, and financial analysts.
- NSPM's credit ratings remain strong, but they are dependent on NSPM's business and financial risk ratings, which can be affected by unfavorable regulatory decisions.

A. NSPM Capital Expenditures and Financial Implications

Q. PLEASE SUMMARIZE THE HISTORICAL CONTEXT FOR NSPM'S CAPITAL EXPENDITURES PROGRAM.

A. Over the past several years, the Company has engaged in a large scale capital expenditure program for necessary investments in its system as well as investment in carbon-free renewable generation to meet Minnesota energy policy and societal goals and customer expectations. As shown on Exhibit___(SWS-1), Schedule 3, during the period 2010 through 2019, NSPM made capital expenditures of approximately $12.4 billion in its combined gas and electric utility business, with approximately $2.1 billion in forecasted capital expenditures in 2020. As examples, the Company's investments in wind generation and new transmission projects required significant capital investment during this period. In addition, the Company has been making ongoing investments to modernize and support its distribution and transmission infrastructure, as discussed by Company witnesses Ms. Kelly

Bloch and Mr. Ian Benson.

These and other ongoing investments make it critical that the Company maintain a strong financial position, so that it can access the capital markets at competitive rates, as needed. Investors and credit rating agencies are aware of the equity ratio and ROE decision trends that have accompanied the Company's significant capital expenditures, and this pattern provides a context against which investors and credit rating agencies will evaluate the results of this proceeding.

Q. HOW DO FORECAST CAPITAL EXPENDITURE LEVELS COMPARE TO PRIOR YEARS?

A. Exhibit___(SWS-1), Schedule 3 shows that NSPM's forecasted capital expenditures for 2020 through 2023 are approximately $6.8 billion (82 percent of which is for the electric operations) or an average of approximately $1.7 billion ($1.4 billion for electric) per year. This level of forecasted capital expenditures is slightly higher than the historical average during 2015 through 2019 due to the projects noted earlier. As discussed by Company witnesses Mr. Gregory Chamberlain and Ms. Kimberly Randolph, the Company is making significant investments in wind resources over the term of the MYRP as it continues to transition its generation fleet to carbon free resources.

Q. HOW DOES THE COMPANY'S CAPITAL EXPENDITURE FORECAST AFFECT THE COMPANY'S FINANCING PLANS AND INVESTOR EXPECTATIONS?

A. To fund its forecasted capital expenditures, the Company will need to access the capital markets in each year 2021 through 2023. It is therefore important for the Company to meet investor expectations and maintain its current credit ratings to continue to be able to obtain financing at competitive rates. To do so, it is important that the Company receives timely recovery of the costs of its investments and a reasonable overall cost of capital.

Q. HAS NSPM RECENTLY ISSUED LTD, AND WILL NSPM NEED TO ISSUE LTD IN THE 2021 TO 2023 TIME PERIOD?

A. Yes. NSPM issued a $700 million "Green" First Mortgage Bond on June 15, 2020. NSPM is projected to issue debt in each of the years 2021 through 2023. The precise size, timing and tenor of debt issuances will depend on prevailing financial market conditions and trends at the time of issuance. The forecast included in Schedules 4, 5 and 6 reflect the most recent forecast information available.

Q. WHAT IS A "GREEN" FIRST MORTGAGE BOND?

A. A green first mortgage bond is a type of fixed-income instrument that is earmarked to raise money for climate and environmental projects. In NSPM's case, each of the green bonds issued (one in 2019 and 2020) has been tied to financing expenditures for wind projects.

Q. WHY DID NSPM ELECT TO ISSUE A "GREEN" FIRST MORTGAGE BOND VERSUS A STANDARD FIRST MORTGAGE BOND?

A. The main benefit of issuing green bonds is to diversify NSPM's investor base and directly attract environmentally-focused investors (also referred to as ESG investors). This leads to increased investor demand during a bond issuance. More demand puts added pressure on investors to accept a lower price which can lead to tighter spreads for the issuer (e.g., NSPM) and therefore, a lower coupon and lower overall long-term interest costs incurred by NSPM customers. The green bond format of the June 2020 issuance helped attract and retain a high quality order book when pricing started to tighten, contributing to the overall success of the issuance. The order book included 17 ESG investors.

NSPM customers want renewable energy and Xcel Energy strives to deliver carbon-free options reliably and at a reasonable cost to our customers, as discussed further by Company witness Mr. Gregory Chamberlain. These green bonds bring global attention to the advances Minnesota has made in implementing wind energy into our grid.

Q. WHAT ARE THE COMPANY'S OBJECTIVES WHEN ISSUING LONG-TERM DEBT?

A. The primary objectives of the Company's debt financing strategy are to minimize debt costs and exposure to potential adverse market conditions in the future, maximize financing flexibility, maintain a strong liquidity profile and maintain an adequate investment grade credit rating.

Q. WHY DOES MAINTAINING FINANCIAL INTEGRITY BENEFIT NSPM'S CUSTOMERS?

A. Financial integrity directly affects both NSPM's ability to access capital to invest in infrastructure necessary to continue to provide safe and reliable utility service as well as its cost of that capital, which is ultimately included in the Company's overall rates. Attracting competitively priced capital in all market conditions, including unexpected macroeconomic events outside the Company's control, such as the COVID-19 pandemic, is also critical to maintaining the ability to invest in the infrastructure necessary for NSPM to provide safe and reliable utility service to its customers.

It is important to note, however, that the question of a utility's financial integrity is not necessarily binary (i.e., does a utility have financial integrity or not); rather, the degree of financial integrity and therefore, the cost of capital available to a utility, lies on a spectrum. Weaker financial integrity at a utility increases the issued cost of debt and the implied cost of equity, which increases the overall WACC and the ultimate financing costs paid by customers. Strong financial integrity has the opposite effect, which in turn provides a direct benefit to customers.

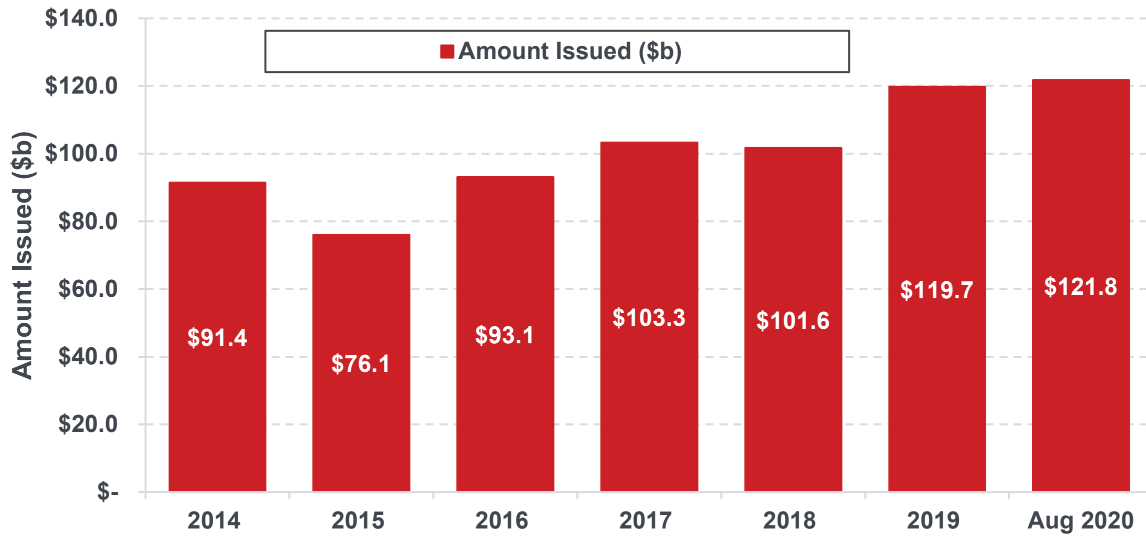
B. Importance of Credit Ratings and a Healthy Regulatory Environment

Q. CAN YOU EXPLAIN CREDIT RATINGS IN MORE DETAIL?

A. Yes. 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 help debt investors differentiate between utilities – all of whom are competing (with companies within and outside the utility sector) 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. 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 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.

During the period 2014 to August 2020, debt investors have provided approximately $707 billion of capital investment to the U.S. utility sector. Capital provided from these investors allows utilities to fund a portion of their capital investment programs. See Chart 1 below.

Chart 1: 2014-August 2020 Debt Amount Issued to the U.S. Utility Sector[3]



In order to attract capital at favorable rates in a competitive environment, protecting and maintaining NSPM's credit ratings is critical. This point becomes even more true in a volatile market environment, as recently evidenced during the COVID-19 pandemic. Utilities with higher credit ratings are associated with reduced risk, which attract investors at a lower cost of debt (e.g., lower average credit spreads) and favorably position 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 less the Company will need to pay in fees and interest 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

[3] Source: Bloomberg

substantially – for those companies rated near the bottom of or below investment grade. Credit ratings take on greater importance when economic conditions worsen and credit becomes more difficult to obtain. As credit availability tightens, investors become increasingly selective with respect to the companies which qualify for their investment. Therefore, lower credit ratings reduce access to capital markets and increase the expense of obtaining capital.

Equity investors also look at credit ratings as a source of information 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.

Ultimately, customers of the higher-rated utility benefit from the lower capital costs as these costs are ultimately borne by customers.

Q. DO CREDIT RATINGS AFFECT NSPM'S COST OF CAPITAL?

A. Yes. Long-term debt is priced based on the underlying Treasury rate plus a credit spread, which is primarily based on NSPM's credit rating. In general, the lower the credit rating, the higher the credit spread. Issuing debt at a higher rate will increase the long-term cost of debt for NSPM and ultimately increase the cost of debt paid for by NSPM's customers.

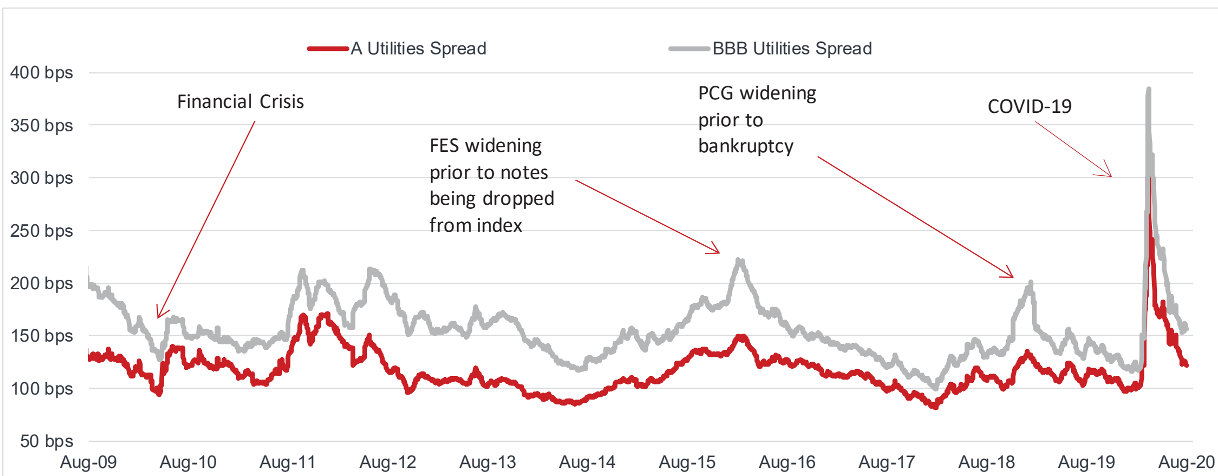
Q. DO CREDIT SPREADS DIFFER BASED ON CREDIT RATINGS?

A. Yes. As discussed above, lower credit ratings are seen as riskier and therefore investors demand a higher spread. Chart 2 below[4] shows that the credit spreads of BBB rated utility companies are historically wider than those of A

[4] Source: Bloomberg

rated utility companies, especially in times of market volatility. This chart demonstrates that although in current market conditions the credit spread between A and BBB ratings is approximately 30 basis points, in periods of market volatility, such as June 2009, the credit spread increased dramatically, at an average spread of 100 basis points. More recently, in March 2020, due to the market volatility related to the COVID-19 pandemic, the credit spread increased dramatically at an average spread of 75 basis points.

Chart 2:
A vs. BBB Rated Utility Spreads



Q. HAVE NSPM'S FINANCIAL STRENGTH AND CREDIT RATINGS HAD A POSITIVE EFFECT ON ITS COST OF LTD AND ITS RECENT LTD ISSUANCES?

A. Yes. NSPM's historical financial strength and credit ratings have had a positive effect on both NSPM's weighted cost of LTD and the rates for its recent LTD issuances. These effects confirm that customers and investors have a common interest in maintaining NSPM's financial strength. Maintaining a strong balance sheet and credit metrics, and otherwise meeting expectations of the investor community, has enabled NSPM to secure more favorable borrowing costs, which lowers overall costs for customers and provides substantial long run benefits to ratepayers.

Q. HOW IS A CREDIT RATING ESTABLISHED?

A. The analysis centers on two main areas of analysis: qualitative analysis and quantitative analysis. The qualitative side is the assessment of business risk, which is comprised of the broad macro environment risks prevailing at the country and industry level. For a utility, regulatory risk is the most significant overall business risk, as I describe below. The issuer's more specific risk within its business and economic environment is then determined. The quantitative side of the analysis examines financial ratios to analyze the financial risk of the issuer.

Business risk and financial risk can be viewed as complementary sides of 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 rating. Because utilities are tightly regulated on financial matters that limit how much financial metrics tend to vary over time, qualitative analysis – specifically, regulatory risk – is a key consideration in ratings outcomes.[5]

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.[6] Both focus on the basic regulatory

[5] Schedule 7 at 4 and Schedule 8 at 4.

[6] Schdule 9 at 4 (Regulatory Framework (25%) plus Ability to Cover Costs and Earn Returns (25%) plus Diversification (10%) and Schedule 10 at 6,9 (Competitive Advantage (60%) plus Scale, Scope and Diversity (20%).

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. Then they examine the mechanics of regulation, particularly the rate-setting process.

Q. ARE THE FRAMEWORK AND THE MECHANICS OF REGULATION THE ONLY CONSIDERATIONS THAT GO INTO DETERMINING REGULATORY RISK?

A. No. Rating agencies also place high value on transparency, predictability, and consistency in regulation.[7] 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 over the longest timeframe as possible. Utilities ultimately fund capital expenditures primarily with long-dated maturities to match the long-lived 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 naturally be accorded 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. HAVE CREDIT RATING AGENCIES COMMENTED ON THE IMPORTANCE OF THE REGULATORY FRAMEWORK IN EVALUATING A UTILITY'S FINANCIAL INTEGRITY?

[7] Schedule 9 at 10 and Schedule 10 at 6-8

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."[8] S&P observes further that "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."[9] The same document contains an extensive discussion regarding the importance of the regulatory environment in which the utility operates.

Q. HOW CAN THE COMMISSION'S SUPPORT BE SEEN AS FAVORABLE TO INVESTOR'S VIEWS OF THE COMPANY'S REGULATORY RISK?

A. As noted earlier, the rating agencies have emphasized that balanced, constructive outcomes in utility rate proceedings are indicative of a supportive regulatory environment and underpin a utility's financial integrity. Such regulatory outcomes convey to the rating agencies the positive relationships between companies and commissions, which in turn may lower the perceived risk for external investors. Approving NSPM's proposed capital structure and ROE recommendations will be viewed as credit supportive by the rating agencies and will allow NSPM to maintain its current credit ratings and competitive position in issuing debt securities.

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

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[8] Schedule 10 at 6.
[9] Schedule 10 at 6.

A. Credit analysis is distinguished by its emphasis on cash flow. Recognizing that servicing debt requires not just earnings but actual cash, credit analysts strive to understand the cash-flow dynamics of a company's financial results as much as or more than the earnings. A recent example of this is the effect of tax reform on utilities, which has placed downward pressure on utility ratings because of its negative cash-flow impact despite relatively neutral earnings implications. The primary measure that rating agencies use as a base for most cash-flow metrics is cash from operations (CFO) or some derivation of it.[10] The other major element of financial risk to a credit analyst is the total amount of debt or debt-like obligations on the issuer's balance sheet. Items that the rating agencies regard as debt-like include lease liabilities, long-term power purchase obligations, pension obligations, and asset-retirement obligations. These debt-like obligations are also oftentimes referred to as imputed or off-balance sheet obligations.

Credit metrics are calculated for both historical periods and future forecasts. Credit metrics are often used to calculate two different types of ratios: leverage and coverage ratios. Leverage ratios attempt to assess the relative burden of debt and other fixed-income obligations as compared to the financial responsibility borne by shareholders. Coverage ratios are more focused on the near-term cash flow of the company and gauge how much cash flow is available to service debt obligations. Credit agencies use both ratios to assess the probability of financial distress.

[10] For Moody's, their derivation of the CFO measurement is "CFO pre-working capital." S&P refers to this measure as funds from operations (FFO). Both Moody's and S&P compare there derivation of CFO to the overall debt burden.

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: (i) the ratio of funds from operations or cash from operations to total debt (FFO/Total Debt or CFO/Debt); (ii) the ratio of funds from operations or cash from operations to interest (FFO/Interest or CFO/Interest) and; (iii) the ratio of debt to earnings before interest, taxes, depreciation, and amortization (Debt/EBITDA). These financial metrics are a composite measure of the utility's ability to manage its debt burden over time and to meet its financial obligations when they are due. The greater the *business* risk of a particular company, the stronger these financial metrics must be to provide sufficient 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 amounts for on-balance sheet obligations such as finance and operating leases, as well as off-balance sheet obligations. Off-balance sheet obligations are payment obligations (such as long term purchase power obligations, pension obligations, and asset retirement obligations) that do not appear on the balance sheet as debt, but rating agencies may treat them as debt because the utility has little or no discretion whether to pay for these obligations.[11]

[11] See Schedules 9, 10, and 11 for a discussion of adjustments for off-balance sheet obligations.

Because rating agencies include off-balance sheet obligations in their capital structures for utilities, the rating agency results will always reflect additional downward pressure on a company's credit metrics as compared to an authorized regulatory capital structure, which does not include the off-balance sheet obligations.

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

A. The ratios help 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 the rating agencies rely upon. This will also cause a lower equity ratio, assuming the total equity return is held constant, which in turn will generate less cash flow. In general, the higher the proportion of debt in a capital structure, the more pressure on cash flow metrics, credit ratings, and cost of capital to the utility and its customers.

Q. DO CAPITAL EXPENDITURE PLANS ALSO AFFECT HOW RATING AGENCIES EVALUATE CREDIT METRICS?

A. Yes. When a utility undertakes a substantial capital investment plan relative to the amount of internally generated funds that are available to support that plan, the utility becomes subject to greater capital market risk because it needs to raise external capital regardless of the financial market conditions. Credit rating agencies expect companies that need significant amounts of external capital to maintain a strong credit profile, not just a profile that is marginal for the current credit rating, because these companies are inevitably exposed to external financial market risks and may need to raise capital under any financial market condition.

Q. PLEASE EXPLAIN THE RATING AGENCY SCALES.

A. Credit rating agencies provide ratings for both the business entity as a whole 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 through the use of pluses or minuses to show a company's relative standing within the categories, while Moody's uses numbers to show a company's standing within a category. The highest investment-grade rating is AAA; the lowest investment-grade rating is BBB-. Debt rated BB+ or below is considered speculative grade.

Q. WHAT ARE THE COMPANY'S CURRENT CREDIT RATINGS?

A. The Company's current credit ratings are:

Table 4
NSPM Current Credit Ratings

	Fitch	Moody's	Moody's S&P Equivalent	S&P	S&P SACP*
Corporate Rating	A-	A2	A-	A-	A
Senior Secured	A+	Aa3	A	A	N/A

* A Stand Alone Credit Profile (SACP) refers to S&P's opinion of an issuer's creditworthiness, in the absence of intervention from its parent.

There have been no changes in the credit ratings since the last MYRP filing.

Q. How do the Company's credit metrics compare to the S&P and Moody's criteria?

A. Exhibit___(SWS-1), Schedule 12, Page 1, shows NSPM's forecasted credit metrics as compared to S&P guidelines. The metrics are within the target ranges for NSPM's current credit ratings. Exhibit___(SWS-1), Schedule 12, Page 2, shows NSPM's forecasted credit metrics as compared to Moody's guidelines. The main metrics are generally within these target ranges. Overall, the Company expects that its recommended capital structure and the forecasted financial metrics will continue to support its current credit ratings over the 2021 to 2023 time period.

Q. Why is it important for NSPM to maintain its A- corporate rating?

A. Earlier in my Direct Testimony I demonstrated that the credit spreads between an A rated company and a BBB rated company can be significant, especially during times of market volatility or distress. This is a real cost that affects what rates the customers pay. To further support this position, Dr. Roger Morin, a noted expert on regulatory finance, analyzes the optimal capital structure for utilities in his book *New Regulatory Finance*. Based on that analysis, Dr. Morin concludes that an A rated utility is in the best interest of the customers and utilities:

> "The message from the model is clear: over the long run, a strong A bond rating will minimize the pre-tax cost of capital to ratepayers. Long term achievement of at least an A rating is in the electric utility company's and ratepayers' best interests.
>
> The model results show that on an incremental cost basis, a strong A bond rating generally results in the lowest pre-tax cost of capital for

> electric utilities, especially under adverse economic conditions, which are far more relevant to the question of capital structure."[12]

Q. WHAT IS THE SIGNIFICANCE OF RATEMAKING-RELATED FINANCIAL METRICS SUCH AS ROE, EQUITY RATIO/CAPITAL STRUCTURE, AND TIMELINESS AND RELIABILITY OF COST RECOVERY?

A. I will address each component in turn:

- First, the authorized ROE and equity ratio affect public service's earnings and directly affect its ability to fund capital investment with internally generated cash flow. In addition to credit ratings, investors also assess the capital structure and ROE when making judgements about the credit quality of a regulatory jurisdiction. As such, the ROE/equity ratio combination is a powerful and effective communication tool to underscore the interest of regulators in attracting capital to provide safe, reliable and environmentally sound electric service in this state.
- Second, the capital structure and authorized costs directly affect all of the utility's key credit metrics because either total debt, interest expense, or cash flow is a component of each of the primary credit metrics that rating agencies analyze. The credit rating agencies also evaluate the relative amounts of debt and equity in the capital structure to determine whether the company is appropriately capitalized given its business risk profile and to determine whether the company has the ability to make interest payments, repay existing debt and to issue additional new debt to fund its utility capital expenditures. The credit rating agencies are very concerned with a company's liquidity to meet its short-term capital needs

[12] Roger A. Morin, *New Regulatory Finance* 515 (2006).

under conditions of financial stress, and they factor in the debt portfolio maturity schedule and other future obligations as part of this assessment.

- Third, debt and equity investors expect NSPM to be able to recover its costs in a timely manner and to have a reasonable opportunity to earn its authorized ROE. Investors and rating agencies track the decisions of regulatory agencies relating to capital structure, cost of debt, ROE, and forward-looking cost recovery mechanisms, and they categorize the state regulatory environments in their assessment of the relative risks of different utility investment opportunities.
- Finally, for regulated utilities, investors tend to prefer stable regulatory environments (so long as they are constructive) because this simplifies pricing risk and enables investors to generate predictable returns.

Q. CAN YOU FURTHER EXPLAIN WHY THE COMMISSION'S DECISIONS FOR NSPM ARE PARTICULARLY IMPORTANT TO THE INVESTOR COMMUNITY?

A. Investors – both debt and equity – and credit rating agencies understand the importance of the regulatory environment on the business risks of utilities. Credit rating agencies and investors also know that NSPM has investments weighted heavily toward its electric business and that NSPM's customers are concentrated in Minnesota, making the Minnesota retail electric jurisdiction NSPM's primary jurisdiction. Finally, rating agencies and bond and equity investors know that the Commission is fully informed about NSPM's investment plans through the various dockets before the Commission. As a result, these agencies and investors will likely consider the Commission's decisions regarding the financial components of the overall ROR and electric rates as a reflection of the level of support for the Company's investment plans, including the investments necessary to meet the Company's stated carbon reduction goals. Therefore, the Commission's decisions not only have an important impact on the Company's ability to maintain its financial integrity and allow us to access low cost capital, they will impact the Company's ability to achieve its broader business and environmental goals.

V. PROPOSED CAPITAL STRUCTURE, COST OF DEBT, AND RATE OF RETURN

Q. PLEASE SUMMARIZE THE MOST SIGNIFICANT POINTS YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY.

A. The most significant points I discuss include the following:

- The components of LTD, STD, and common equity for 2021, 2022 and 2023 have been determined using the same approaches that have been used in prior rate cases.
- NSPM's proposed capital structures for 2021, 2022 and 2023 are very similar to the capital structure adopted in the last rate case.
- The costs of LTD and STD have also been determined using the same approaches that have been used in prior cases.
- The size of NSPM's short term credit facility is reasonable and has not changed since the last MYRP.
- The Utility Money Pool provides public interest benefits to NSPM's customers.

Q. PLEASE SUMMARIZE THE COMPONENTS OF THE COMPANY'S RECOMMENDED CAPITAL STRUCTURE AND ROR.

A. The Company's proposed 2021, 2022 and 2023 capital structures include LTD, STD, and common equity. The Company's proposed revenue requirement for

2021 reflects an overall cost of capital or ROR of 7.35 percent, which includes the Company's average common equity ratio of 52.50 percent and a 10.20 percent ROE as recommended in Mr. D'Ascendis's Direct Testimony. The Company's proposed ROR for 2022 is 7.35 percent and for 2023 is 7.33 percent, again including the Company's average common equity ratio of 52.50 percent and the 10.20 percent ROE recommended by Mr. D'Ascendis.

Q. HOW DO THE COMPANY'S 2021, 2022 AND 2023 CAPITAL STRUCTURES COMPARE WITH THE CAPITAL STRUCTURES REFLECTED IN PAST RATE CASES?

A. The capital structures for all three years are comparable to the capital structure approved by the Commission in the Company's 2013 rate case (Docket No. E002/GR-13-868) and those reflected in the Settlement approved by the Commission in the 2015 rate case. The proposed 52.50 percent equity ratio for all three years match the equity ratios approved in those cases. The LTD ratios for years 2021 through 2023 range from 46.72 to 47.18 percent, compared to 2013 and 2015 rate case LTD ratios ranging from 45.60 to 46.41 percent. Finally, the STD ratios of 0.32 to 0.78 percent are also lower than the 2013 and 2015 ratios, which ranged from 1.09 to 1.90 percent. The lower cost of LTD and STD reflect the current low interest rate environment.

Q. WHAT METHODOLOGY DID THE COMPANY USE TO DEVELOP BALANCES AND COSTS FOR THE VARIOUS COMPONENTS OF CAPITAL STRUCTURE?

A. The Company's methodology in this case is consistent with the calculations used and approved by the Commission in prior rate cases. Key points are identified below:

- 2021 and 2022 future long and short-term debt interest rates are based on the average between July 2020 Global Insight forecast and August

2020 Bloomberg forward curve with an added credit spread (which is based on the current credit rating and reflects current market information). 2023 future long and short-term debt interest rates are based on July 2020 Global Insight forecast with an added credit spread. The July 2020 Global Insight forecast and August 2020 Bloomberg forward curve is attached as Exhibit___(SWS-1), Schedule 13.

- For forecast purposes, STD is in the form of commercial paper.
- STD balances are based on the average of month-end balances for the 12 months in the respective year.
- LTD balances are based on the average of month-end balances for the 12 months in the respective year and include forecasted LTD issuances and retirements during that period.
- LTD costs include the coupon rate on all bonds expected to be outstanding for each month of the respective year. In addition to the interest expense, the cost of LTD also includes amortization expense for debt issuance costs, discounts or premiums, losses on reacquired debt, gains and losses from hedging transactions, and the annual amortization of the upfront fees associated with the Company's multi-year credit agreement.
- Common equity balances represent the average of 13 month-end equity balances from December of the prior year through December of the year analyzed. The common equity balance averages the accounting month-end balances consistent with Generally Accepted Accounting Principles (GAAP) and eliminates the non-regulated investments.

1. *Long-Term Debt*

Q. WHAT ARE THE COMPANY'S RECOMMENDED 2021-2023 LTD BALANCES AND COSTS?

A. See the Company's recommended LTD balances and costs for 2021 through 2023 included in Table 5, as shown on Exhibit___(SWS-1), Schedules 4, 5 and 6, respectively, Page 1 of 1.

Table 5

Recommended 2021 through 2023 LTD Balances and Costs

	LTD Balance	LTD Cost
2021 Test Year	$6.1 billion	4.24%
2022 Plan Year	$6.4 billion	4.21%
2023 Plan Year	$6.6 billion	4.19%

Q. ARE THERE ISSUANCES OR RETIREMENTS OF LTD PLANNED FOR 2021 THROUGH 2023?

A. Yes, NSPM plans to issue $400 million of new long-term debt in 2021, $450 million in 2022 and $750 million in 2023. NSPM has a $300 million debt retirement scheduled in 2022 and a $400 million debt retirement scheduled in 2023.

Q. HOW DOES THE COMPANY DETERMINE ITS LTD ISSUANCES?

A. NSPM forecasts its financing needs over a multi-year period. NSPM generally issues LTD in years when an existing long-term bond is maturing or if existing higher coupon debt can be refinanced at a lower interest rate. In addition, NSPM will issue LTD to replace STD when the STD levels consistently approach or remain above an "index-eligible" bond size of $300 million. All of these factors can affect the amount and timing of a specific bond offering.

When determining the maturity of a new bond, the Company considers the existing debt portfolio maturity profile, market conditions, investor demand, the life of the underlying asset portfolio, and the effects on the cost of LTD. The Company reviews the existing debt portfolio maturity profile and identifies potential years where maturities are not already scheduled to occur. The Company staggers new LTD maturities to mitigate the risk of having large future maturities in any one year that could be exposed to capital market volatility and the associated interest rate risk.

Q. PLEASE EXPLAIN THE TERM "INDEX ELIGIBLE" AND WHY IT IS IMPORTANT.

A. To be included in the Barclays Capital Aggregate Bond Index, a bond must be a minimum size of $300 million. Bonds that trade as a component of the index are more liquid and will generally be priced at a lower credit risk premium over prevailing U.S. Treasury rates than less liquid bonds, resulting in lower cost to customers.

Q. DOES THE COMPANY CONSIDER THE POSSIBILITY OF EARLY RETIREMENT OF COMPONENTS OF ITS LTD PORTFOLIO?

A. Yes. For example, in 2020, NSPM retired a bond that had provisions that allowed the Company to "call" the bonds without incurring significant added financial obligations known as "make whole" redemption obligations. The bonds currently in the NSPM debt portfolio either: (i) have no call options; (ii) are only callable at par value 3 to 6 months prior to maturity; or (iii) have make whole redemption provisions that are too expensive to exercise because they result in very large premium payments to existing debt holders. The Company continues to monitor its LTD portfolio to take advantage of refinancing opportunities that could result in lower customer costs.

Q. HOW DO THE PROJECTED LTD BALANCE AND COSTS COMPARE TO THE LAST ELECTRIC RATE CASE?

A. The projected $6.1 billion average LTD balance for the 2021 test year is approximately $1.5 billion higher than the LTD balance in the Company's 2016 test year in its last rate case, reflecting increased capital investment levels. The 4.24 percent rate for 2021 is 57 basis points lower than the cost in the 2016 test year. NSPM has benefited from a lower interest rate environment over the last several years and its financial strength and strong credit ratings have also contributed to this significant decline.

2. Short-Term Debt

Q. WHAT IS THE COMPANY'S RECOMMENDED 2021 THROUGH 2023 STD BALANCES AND ASSOCIATED COSTS?

A. See the Company's recommended STD balances and costs for 2021 through 2023 included in Table 6, as also shown on Exhibit__(SWS-1), Schedule 14, 15 and 16, respectively, Page 1 of 1.

Table 6

Recommended 2021 through 2023 STD Balances and Costs

	STD Balance	STD Cost
2021 Test Year	$101.8 million	0.81%
2022 Plan Year	$43.1 million	1.83%
2023 Plan Year	$106.7 million	1.03%

Q. HOW WAS THE 2021 THROUGH 2023 COST OF STD DETERMINED?

A. The cost of STD includes interest expense for commercial paper and the monthly financing fee associated with the Company's June 2019 "Amended and Restated Credit Agreement" for its participation in the credit facility, which provides the back-up liquidity required for its commercial paper program. See the Company's Exhibit__(SWS-1), Schedule 14, 15 and 16, respectively, Page 1 of 1 for a break-out of the STD cost between monthly interest expense relating to commercial paper and the monthly fee expense relating to the credit facility fees.

Q. HOW DOES THE PROJECTED 2021 STD COST COMPARE TO THE LAST ELECTRIC RATE CASE?

A. The 2021 STD cost is forecasted at 0.81 percent. The STD cost from the 2016 case was 1.84 percent. The decrease is largely driven by the recent decline in short term interest rates.

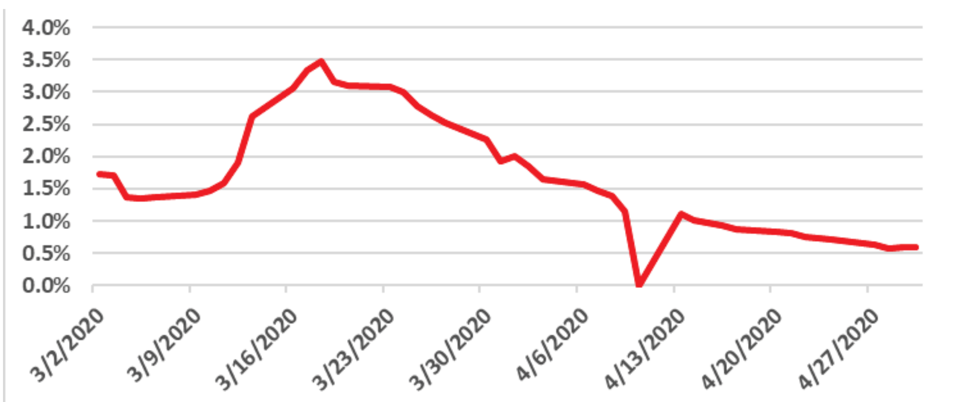
Q. HAS THE SIZE OF THE CREDIT FACILITY CHANGED SINCE THE PRIOR CASE?

A. No. NSPM's credit facility remains at the $500 million level. To determine the size of NSPM's credit facility, the Company considers factors that significantly impact liquidity requirements to evaluate the amount of short term credit capacity required, such as: (i) the total capital commitments over the life of the revolving credit agreement, including projected capital investment and scheduled LTD maturities; (ii) the projected level and volatility of fuel purchase requirements; and (iii) the liquidity required to manage variability in operating cash flow due to changes in sales and operating expenses. Currently, these factors support the sizing of the credit facility at $500 million; however, the size of the credit facility may need to be reassessed if these factors change.

Q. DOES NSPM'S USE OF COMMERCIAL PAPER REDUCE THE REQUIRED LEVEL OF NSPM'S CREDIT FACILITY?

A. No. NSPM expects to have continued access to the capital and commercial paper markets, but it is necessary to have adequate back up liquidity in the event of a capital market disruption. For example, the 2008 capital market crisis caused commercial paper to become unavailable for a period of time. In a more recent example, during March 2020, as a result of the COVID-19 pandemic, commercial paper markets became very volatile and the cost of commercial paper increased dramatically as shown in Chart 3 below. If comparable events occurred again, or commercial paper required unreasonable terms or costs, NSPM would be reliant on its credit facility for its liquidity needs.

Chart 3: A2/P2 Overnight Commercial Paper Rates
March-April 2020[13]



A credit facility is required in order to backstop commercial paper facilities. In other words, if NSPM was not able to repay its maturing commercial paper, it would be required to draw down its credit facility in order to meet that obligation. Commercial paper is almost always used instead of direct drawing on the credit facility because of its lower cost. Since the credit facility is a backstop to commercial paper, the amount of commercial paper issued cannot exceed the limit of the credit facility. Any outstanding commercial paper

[13] Source: www.federalreserve.gov

reduces the amount available to draw under the credit facility.

Q. DOES NSPM PARTICIPATE IN A UTILITY MONEY POOL WITH OTHER OPERATING UTILITY SUBSIDIARIES OF XEI?

A. Yes. The Utility Money Pool is a short-term intercompany revolving credit facility that allows for coordination and provision of some short-term cash and working capital for NSPM, Public Service Company of Colorado (PSCo) and Southwestern Public Service Company (SPS).

Q. HAS THE COMMISSION REVIEWED AND APPROVED NSPM'S PARTICIPATION IN THE UTILITY MONEY POOL?

A. Yes. The Commission's July 9, 2004 Order in Docket No. E002/AI-04-100 approved participation in the Utility Money Pool and required NSPM to demonstrate in future rate cases that NSPM's participation in the Utility Money Pool continues to be consistent with the public interest. NSPM has submitted the required information in this case and in all prior rate cases since 2004. NSPM also submits information regarding its participation in the Utility Money Pool for Commission review and approval in its annual capital structure filings.

Q. IS THE UTILITY MONEY POOL CONSISTENT WITH THE PUBLIC INTEREST?

A. Yes. The Utility Money Pool provides additional flexibility and allows for potential cost savings and efficiencies without limiting access to existing financing. Participants are not obligated to lend to or borrow from the Utility Money Pool. However, it is available for use when it is most efficient, in situations when it provides benefits such as a lower cost of borrowing, or more flexibility regarding the terms of borrowing. NSPM's lending limits are also subject to approval by both the Commission and the Federal Energy Regulatory

Commission.

Q. Does the Utility Money Pool provide a substitute for the NSPM credit facility in relation to needed liquidity?

A. No. Since there is no obligation for any participant to provide funds to the Utility Money Pool, it does not provide the assurance of available cash that is needed by NSPM, and thus does not provide a substitute source of liquidity for NSPM's credit facility and commercial paper program.

Q. Does NSPM's participation in the Utility Money Pool impose risks on NSPM?

A. No. The borrowings under the Utility Money Pool are payable on demand. If anything, NSPM's participation in the Utility Money Pool provides additional access to liquidity (and usually at more favorable rates) and thus, reduces risk that may be caused by various macroeconomic events.

Q. Have you prepared a schedule showing borrowing and lending between NSPM and the Utility Money Pool?

A. Yes. Exhibit___(SWS-1), Schedule 17, provides a record of Utility Money Pool activity, including lending to and borrowing from the Utility Money Pool from January 2018 through June 2020.

3. Common Equity

Q. How did you determine NSPM's 2021 through 2023 common equity balances?

A. Consistent with prior rate case methodology, the proposed 2021 test year and 2022 and 2023 plan years' common equity balances reflect the average of 13 month-end equity balances from December of the previous year through December of the respective year and eliminates the non-regulated investments. See the Company's recommended common equity balances by month for 2021 through 2023 by referencing Exhibit___(SWS-1), Schedules 18, 19 and 20, respectively.

Q. How does the 2021 common equity balance compare to the balance in the last rate case?

A. The nearly $6.9 billion common equity balance for 2021 is approximately $1.7 billion greater than the $5.2 billion balance in the test year of the last rate case.

Q. Has XEI issued common stock in the last few years?

A. Yes. In September 2018, XEI issued approximately $225 million of common stock through a $300 million SEC-registered "At the Market" program under which XEI issued common stock to the public from time to time at then-prevailing market prices. XEI entered into a forward equity agreement for approximately $460 million in November 2018, which was settled on August 29, 2019. Additionally, in November 2019, XEI entered into forward sales agreements in connection with a completed $743 million public offering of 11.8 million shares of Xcel Energy common stock. XEI may settle the agreements at any time up to the maturity date of December 31, 2020.

Q. Have you provided information regarding flotation costs for public and non-public equity issuances by XEI?

A. Yes. Information regarding flotation costs for public and non-public offerings by XEI is included in Exhibit___(SWS-1), Schedule 21. This information was used by Mr. D'Ascendis in his testimony regarding his flotation cost adjustment.

VI. INVESTOR RELATIONS EXPENSES

Q. CAN YOU PLEASE ALSO DISCUSS THE COMPANY'S INVESTOR RELATIONS EFFORTS AND THE EXPENSES YOU EXPECT TO INCUR IN THE 2021 TEST YEAR AND IN THE 2022 AND 2023 PLAN YEARS?

A. Yes. The Company will incur investor relations expenses in 2021 through 2023 due to the need to keep the credit rating agencies fully informed regarding NSPM's business and financing plans and to maintain strong investor demand for NSPM's LTD securities. The Investor Relations team also incurs costs for shareholder services. These efforts will enable NSPM to issue LTD securities at favorable costs, as evidenced by NSPM's very low cost of LTD. Additionally, the Investor Relations group will continue to support the Company's equity program, and customers receive the benefit of improved proceeds as a result of obtaining favorable prices from the issuance of stock.

Q. ARE THESE DISCRETIONARY EXPENSES?

A. No. A company with publicly-traded equity must engage in investor relations activities, including but not limited to: (i) the listing of shares of XEI on the National Association of Securities Dealers Automated Quotations (NASDAQ); (ii) stock transfer agent services associated with the issuance of new common shares to investors, providing shareholders online access to accounts, and maintaining the list of registered shareholders; and (iii) an annual shareholders meeting.

Q. IS IT APPROPRIATE TO INCLUDE THESE EXPENSES AS PART OF THE COMPANY'S COST OF PROVIDING ELECTRIC SERVICE TO MINNESOTA RATEPAYERS?

A. Yes. These are unavoidable, just and reasonable expenses that should be included in the Company's cost of service for ratemaking purposes. The Company incurs these expenses as a necessary part of providing cost-effective service to its customers; they are not expenses incurred to benefit shareholders.

Q. BUT ISN'T THE COMPANY REQUESTING RECOVERY OF ONLY HALF OF THESE EXPENSES?

A. Yes. Company witness Mr. Benjamin C. Halama's testimony, and the Company's rate request, reflects recovery of only 50 percent of these expenses in this case. As Mr. Halama discusses in his direct testimony, schedules and supporting workpapers, the total investor relations expenses allocated to the Minnesota electric jurisdiction are approximately $1.9 million for the period 2021-2023. The Company has removed 50 percent of these expenses, given past Commission decisions on this topic and due to the desire to minimize controversy in this proceeding. However, the Company continues to view these as just, reasonable and necessary expenses.

VII. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend that the Commission approve NSPM's proposed 2021 test year capital structure with 52.50 percent common equity and an overall rate of return of 7.35 percent, as follows:

2021 Test Year

Recommended Capital Structure Ratios and Costs

(as presented in Table 1 on Page 4)

	Percent of Total Capital	Cost	Weighted Cost
Short-Term Debt	0.78%	0.81%	0.01%
Long-Term Debt	46.72%	4.24%	1.98%
Common Equity	52.50%	10.20%	5.36%
Total Capital	100.00%		7.35%

I also recommend that the Commission approve a proposed 2022 capital structure with 52.50 percent common equity and an overall rate of return of 7.35 percent, as follows:

2022

Recommended Capital Structure Ratios and Costs

(as presented in Table 2 on Page 4)

	Percent of Total Capital	Cost	Weighted Cost
Short-Term Debt	0.32%	1.83%	0.01%
Long-Term Debt	47.18%	4.21%	1.98%
Common Equity	52.50%	10.20%	5.36%
Total Capital	100.00%		7.35%

And lastly, I recommend that the Commission approve a proposed 2023 capital structure with 52.50 percent common equity and an overall rate of return of 7.33 percent, as follows:

2023

Recommended Capital Structure Ratios and Costs

(as presented in Table 3 on Page 5)

	Percent of Total Capital	Cost	Weighted Cost
Short-Term Debt	0.75%	1.03%	0.01%
Long-Term Debt	46.75%	4.19%	1.96%
Common Equity	52.50%	10.20%	5.36%
Total Capital	100.00%		7.33%

The Company's proposed capital structures and overall costs of capital are reasonable and meet the Commission general standards of reasonableness used in decision making. The capital structures reflect the actual capital structure NSPM uses to fund its utility investment. These capital structures are market based and consistent with prior Commission decisions for NSPM and with capital structures of other comparable companies. The capital structures will support the Company's financial integrity as demonstrated through strong bond ratings and lower costs of debt, while simultaneously enabling NSPM to make substantial capital investments in the utility infrastructure, including renewable energy. Finally, the Company has not materially changed its capital structure since 2009 and the Commission has reviewed and approved its equity ratio in the past four electric rate case proceedings.

I also recommend that the Commission allow partial recovery of investor relations costs in rates as the Company has proposed.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Schedule 1

Sarah W. Soong

Education:

Master of Business Administration, Finance – 1997

The Wharton School, University of Pennsylvania

Master of Arts – Western European and French Studies - 1997

Lauder Institute, University of Pennsylvania

Bachelor of Arts, Government – 1992

College of William and Mary

Employment:

Xcel Energy Inc., Minneapolis, MN **2018- Present**
Vice President and Treasurer

ONCOR Electric Delivery Company, LLC, Dallas, TX **2017-2018**
Vice President and Treasurer

Hunt Consolidated Inc., Dallas TX **2005 – 2017**

2012 - 2017 *Vice President, Project Finance*

2010 – 2012 *Director, Project Finance*

2005 – 2010 *Manager, Project Finance*

The Neiman Marcus Group Inc., Dallas TX **2004- 2005** *Manager, Corporate Finance*

Exodus Energy, LLC., Houston, TX **2003**
Director

Enron Corporation, Houston, TX **1997 - 2002**
Manager, Global Finance and Treasury

ABN Amro Bank, Netherlands, Czech Republic **1993 - 1995**
Relationship Manager, Global Clients

N.M. Rothschild and ČESKOSLOVENSKÁ OBCHODNÍ BANKA (ČSOB), Prague, Czech Republic **1993**
Financial Advisor and Consultant to N.M. Rothschild on behalf Of ČSOB

PROPOSED TEST YEAR 2021 COST OF CAPITAL

Capitalization:	($000's) Amount	Percent of Total Capitalization	Cost of Capital	Weighted Cost of Capital*
Long-Term Debt	$6,130,539	46.72%	4.24%	1.98%
Short-Term Debt	$101,814	0.78%	0.81%	0.01%
Total Debt	$6,232,353	47.50%		1.99%
Net Common Equity	$6,888,650	52.50%	10.20%	5.36%
Total Capitalization	$13,121,003	100.00%		7.35%

Short Term Debt and Long Term Debt Amounts are 12 Month Average Balances.
Equity Amounts are 13 Month Average Balances.

PROPOSED ADDITIONAL TEST YEAR 2022 COST OF CAPITAL

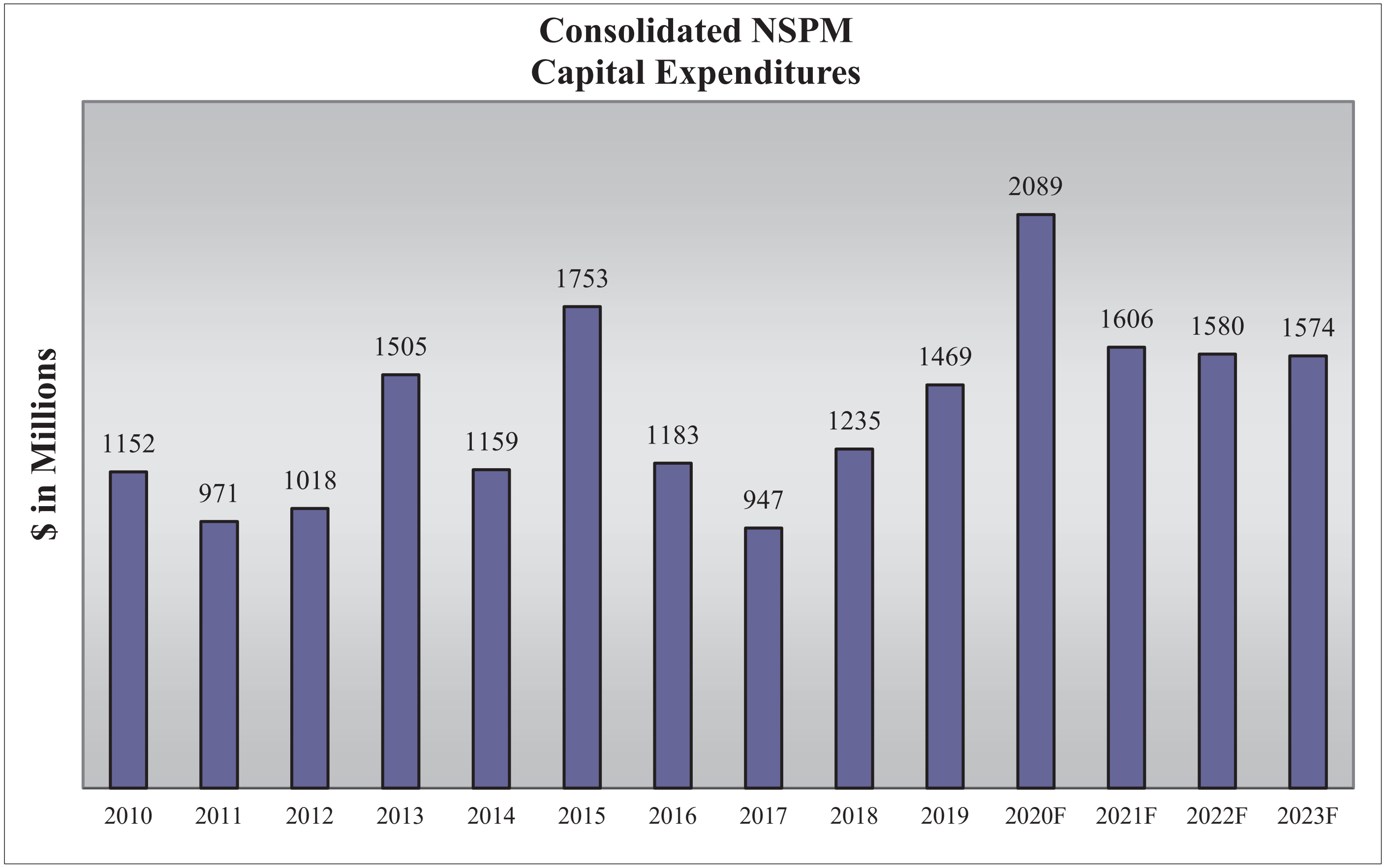
Capitalization:	($000's) Amount	Percent of Total Capitalization	Cost of Capital	Weighted Cost of Capital*
Long-Term Debt	$6,403,032	47.18%	4.21%	1.98%
Short-Term Debt	$43,078	0.32%	1.83%	0.01%
Total Debt	$6,446,110	47.50%		1.99%
Net Common Equity	$7,125,058	52.50%	10.20%	5.36%
Total Capitalization	$13,571,169	100.00%		7.35%

Short Term Debt and Long Term Debt Amounts are 12 Month Average Balances.
Equity Amounts are 13 Month Average Balances.

PROPOSED ADDITIONAL TEST YEAR 2023 COST OF CAPITAL

Capitalization:	**($000's) Amount**	**Percent of Total Capitalization**	**Cost of Capital**	**Weighted Cost of Capital***
Long-Term Debt	$6,645,745	46.75%	4.19%	1.96%
Short-Term Debt	$106,740	0.75%	1.03%	0.01%
Total Debt	$6,752,485	47.50%		1.97%
Net Common Equity	$7,462,817	52.50%	10.20%	5.36%
Total Capitalization	$14,215,303	100.00%		7.33%

Short Term Debt and Long Term Debt Amounts are 12 Month Average Balances.
Equity Amounts are 13 Month Average Balances.



(a) 2010 - 2019 actual 10 year expenditures = $12.4B, average spend per year = $1.239B

(b) 2015 - 2019 actual 5 year expenditures = $6.6B, average spend per year = $1.317B

(c) 2020 - 2023 forecast 4 year expenditures = $6.8B, average spend per year = $1.712B

($000's)

2021 FORECASTED LONG TERM DEBT AND COST
as of 8/25/20

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(3) Capital Employed	Total Bond Cost: (4) Interest Charge	Total Bond Cost: Premium/ Hedge Amortization	Total Bond Cost: Discount Amortization	Total Bond Cost: Expense Amortization	Total Bond Cost: LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	307	250		249,442	17,813	-	78	63		17,953	7.20%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	389	326		149,285	9,750	-	59	49		9,858	6.60%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	226	1,416		248,358	13,125	-	16	101		13,242	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	8,106	696	2,417		404,993	25,000	545	47	162		24,665	6.09%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	1,057	2,306		346,637	21,700	-	66	144		21,911	6.32%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,958)	348	2,537		295,156	16,050	(107)	19	139		16,315	5.53%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	450	1,920		247,630	12,125	-	24	101		12,249	4.95%
Series Due August 15, 2022 (FMB)	2.1500	Aug-12	Aug-22	300,000	-	49	334		299,617	6,450	-	46	309		6,805	2.27%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(31,566)	2,684	4,409		461,341	17,000	(1,496)	127	209		18,833	4.08%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	134	829		399,037	10,400	-	73	453		10,927	2.74%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	664	2,909		296,427	12,375	-	29	127		12,531	4.23%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,931	3,129		292,940	12,000	-	163	130		12,293	4.20%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,735	4,482		343,783	12,600	-	70	180		12,850	3.74%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	5,216	7,674	7,302	579,808	22,200	-	199	293	279	22,971	3.96%
Series Due Mar 1, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	10,871	8,202		580,926	17,400	-	380	286		18,066	3.11%
Series Due Jun 1, 2051 (FMB)	2.6000	Jun-20	Jun-51	700,000	-	12,712	9,434		677,854	18,200	-	425	316		18,941	2.79%
Series Due May 1, 2051 (FMB) (1)	2.9000	May-21	May-51	266,667	-	-	3,950		262,717	7,733	-	-	134		7,867	2.99%
Other Debt																
Right of Way Notes	var	var	var	286	-	-	-		286	-	-	-	-		-	0.00%
TOTAL DEBT				6,266,953	(25,419)	41,468	56,524	7,302	6,136,239	251,921	(1,059)	1,820	3,198	279	258,277	4.21%
Unamortized Loss on Reacquired Debt									(5,700)						1,217	
Fees on 5-year Credit Facility (2)									-						379	
GRAND TOTAL and COST OF DEBT									6,130,539						259,872	4.24%

(1) NSPM 2021 issuance of $400M 30 year bond, balance is 8 of 12 months.
(2) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
(3) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.
(4) Interest Expense is a Straight Interest Expense calculation.

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-Term Debt
($000's)

2022 FORECASTED LONG TERM DEBT AND COST
as of 8/25/20

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost (5) Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	230	187		249,583	17,813	-	78	63		17,953	7.19%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	330	277		149,393	9,750	-	59	49		9,858	6.60%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	210	1,314		248,475	13,125	-	16	101		13,242	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	7,561	649	2,255		404,657	25,000	545	47	162		24,665	6.10%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	991	2,162		346,848	21,700	-	66	144		21,911	6.32%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,851)	329	2,398		295,421	16,050	(107)	19	139		16,315	5.52%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	426	1,819		247,754	12,125	-	24	101		12,249	4.94%
Series Due August 15, 2022 (FMB) (2)	2.1500	Aug-12	Aug-22	175,000	-	8	52		174,940	3,763	-	28	191		3,982	2.28%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(30,069)	2,556	4,200		463,174	17,000	(1,496)	127	209		18,833	4.07%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	61	375		399,564	10,400	-	73	453		10,927	2.73%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	635	2,782		296,583	12,375	-	29	127		12,531	4.23%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,767	2,999		293,233	12,000	-	163	130		12,293	4.19%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,665	4,302		344,033	12,600	-	70	180		12,850	3.74%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	5,017	7,381	7,023	580,579	22,200	-	199	293	279	22,971	3.96%
Series Due Mar 1, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	10,492	7,916		581,592	17,400	-	380	286		18,066	3.11%
Series Due Jun 1, 2051 (FMB)	2.6000	Jun-20	Jun-51	700,000	-	12,286	9,118		678,595	18,200	-	425	316		18,941	2.79%
Series Due May 1, 2051 (FMB)	2.9000	May-21	May-51	400,000	-	-	5,758		394,242	11,600	-	-	200		11,800	2.99%
Series Due Jun 1, 2052 (FMB) (1)	3.2000	Jun-22	Jun-52	262,500	-	-	3,894		258,606	8,400	-	-	132		8,532	3.30%
Other Debt																
Right of Way Notes	var	var	var	286	-	-	-		286	-	-	-	-		-	0.00%
TOTAL DEBT				6,537,786	(24,360)	39,652	59,190	7,023	6,407,561	261,500	(1,059)	1,803	3,278	279	267,918	4.18%
Unamortized Loss on Reacquired Debt									(4,529)						1,020	
Fees on 5-year Credit Facility (3)									-						379	
GRAND TOTAL and COST OF DEBT									6,403,032						269,317	4.21%

(1) NSPM 2022 issuance of $450M 30 year bond, balance is 7 of 12 months.
(2) NSPM 2012 issuance of $300M 10 year bond, balance is 7 of 12 months.
(3) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
(4) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.
(5) Interest Expense is a Straight Interest Expense calculation.

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-Term Debt
($000's)

2023 FORECASTED LONG TERM DEBT AND COST
as of 8/25/20

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost: (5) Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	152	124		249,724	17,813	-	78	63		17,953	7.19%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	272	227		149,501	9,750	-	59	49		9,858	6.59%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	194	1,213		248,593	13,125	-	16	101		13,242	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	7,016	602	2,092		404,322	25,000	545	47	162		24,665	6.10%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	924	2,017		347,058	21,700	-	66	144		21,911	6.31%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,744)	310	2,260		295,686	16,050	(107)	19	139		16,315	5.52%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	403	1,719		247,879	12,125	-	24	101		12,249	4.94%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(28,573)	2,429	3,991		465,007	17,000	(1,496)	127	209		18,833	4.05%
Series Due May 15, 2023 (FMB) (2)	2.6000	May-13	May-23	133,333	-	4	24		133,305	3,467	-	27	166		3,660	2.75%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	606	2,655		296,739	12,375	-	29	127		12,531	4.22%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,604	2,870		293,526	12,000	-	163	130		12,293	4.19%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,595	4,122		344,283	12,600	-	70	180		12,850	3.73%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	4,818	7,088	6,744	581,350	22,200	-	199	293	279	22,971	3.95%
Series Due Mar 1, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	10,112	7,630		582,258	17,400	-	380	286		18,066	3.10%
Series Due Jun 1, 2051 (FMB)	2.6000	Jun-20	Jun-51	700,000	-	11,861	8,803		679,336	18,200	-	425	316		18,941	2.79%
Series Due May 1, 2051 (FMB)	2.9000	May-21	May-51	400,000	-	-	5,558		394,442	11,600	-	-	200		11,800	2.99%
Series Due Jun 1, 2052 (FMB)	3.2000	Jun-22	Jun-52	450,000	-	-	6,497		443,503	14,400	-	-	225		14,625	3.30%
Series Due May 1, 2033 (FMB) (1)	2.2000	May-23	May-33	250,000	-	-	3,608		246,392	5,500	-	-	377		5,877	2.39%
Series Due May 1, 2053 (FMB) (1)	3.4000	May-23	May-53	250,000	-	-	3,703		246,297	8,500	-	-	126		8,626	3.50%
Other Debt																
Right of Way Notes	var	var	var	286	-	-	-		286	-	-	-	-		-	0.00%
TOTAL DEBT				6,783,619	(23,301)	37,886	66,201	6,744	6,649,487	270,804	(1,059)	1,728	3,395	279	277,266	4.17%
Unamortized Loss on Reacquired Debt									(3,742)						700	
Fees on 5-year Credit Facility (3)									-						379	
GRAND TOTAL and COST OF DEBT									6,645,745						278,344	4.19%

(1) NSPM 2023 issuance of $375M 10 year bond, balance is 8 of 12 months.
NSPM 2023 issuance of $375M 30 year bond, balance is 8 of 12 months.
(2) NSPM 2013 issuance of $400M 10 year bond, balance is 4 of 12 months.
(3) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
(4) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.
(5) Interest Expense is a Straight Interest Expense calculation.

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
13 December 2019

Update

Rate this Research

RATINGS

Northern States Power Company (Minnesota)

Domicile	Minneapolis, Minnesota, United States
Long Term Rating	A2
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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Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Northern States Power Company (Minnesota)

Update to credit analysis

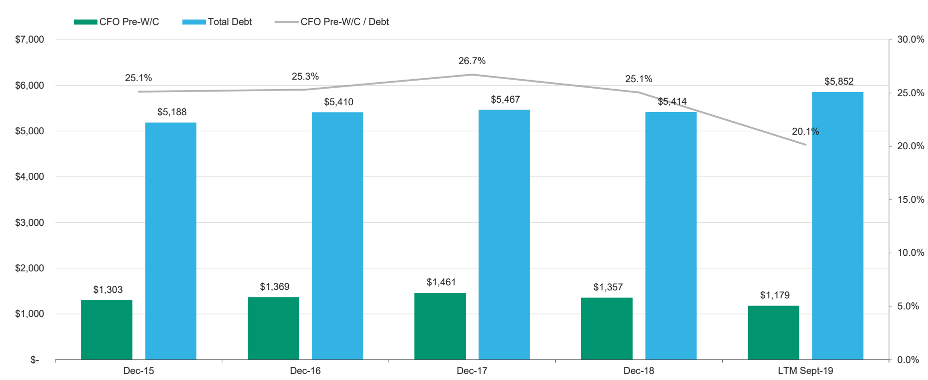
Summary

The credit profile of Northern States Power Company (Minnesota) (NSP-Minnesota) reflects the fully regulated nature of its vertically integrated electric and natural gas distribution operations in Minnesota (nearly 90% of its rate base), North and South Dakota (each accounts for less than 10% of its rate base). The profile reflects our view that these regulatory environments are generally credit supportive. NSP-Minnesota ranks as one of the larger subsidiaries in the Xcel Energy Inc. (Xcel, Baa1 stable) family in terms of rate base (2019 estimated: 37%) as well as earnings before interest, taxes, depreciation and amortization (EBITDA) and cash flow contribution (40%-45%). The credit profile also recognizes that NSP-Minnesota's state regulators indirectly restrict dividends that the utility is allowed to upstream to parent Xcel by requiring NSP-Minnesota to maintain an equity-to-total capitalization ratio ranging between 47.1% to 57.5%.

NSP-Minnesota's credit is tempered by the recent deterioration of its financial metrics due primarily to the implementation of the Tax Cuts and Jobs Act (TCJA). However, the credit reflects our assumption that going forward, the utility will produce a ratio of cash flow from operations excluding changes in working capital (CFO pre-W/C) to debt at or above 22%.

Exhibit

Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt ($ in millions)



Source: Moody's Financial Metrics

Credit strengths

» Rate base of approximately $11.2 billion by year-end 2019

» Vertically integrated regulated utility operations in overall credit supportive regulatory environments

» Dividend distributions are subject to the commissions' indirectly imposed restrictions regarding capital structure

Credit challenges

» Moderate exposure to carbon transition risk

» Pending rate case uncertainty following the expiration of multi-year rate plan in Minnesota but expectation of credit supportive outcome

» Declining, albeit still adequate, financial credit metrics amid some capex moderation

Rating outlook

NSP-Minnesota's stable outlook is supported by the predictable nature of the utility's operations, and the expectation that, although lower than previous highs, its key credit metrics will remain adequate for its credit, including CFO pre-W/C to debt of around 22%. The outlook considers Xcel's group-wide O&M-cost control initiatives, overall timely recovery of costs, as well as some moderation in the utility's base case capex.

Factors that could lead to an upgrade

» While not expected in the near term, the utility's ratings could experience positive momentum if greater than anticipated regulatory relief or cost savings, or a reduction in leverage, allow it to record CFO pre-W/C to debt in the high 20%.

Factors that could lead to a downgrade

» The ratings could be downgraded if we perceive a deterioration in the credit supportiveness of its regulatory environments, or if its credit metrics deteriorate further; specifically, downward pressure on the ratings could result if its CFO pre-W/C to debt ratio falls to the low 20% range, for an extended period.

Key indicators

Exhibit 2
Northern States Power Company - Minnesota

	Dec-15	Dec-16	Dec-17	Dec-18	LTM Sept-19
CFO Pre-W/C + Interest / Interest	6.8x	6.7x	7.0x	6.6x	5.9x
CFO Pre-W/C / Debt	25.1%	25.3%	26.7%	25.1%	20.1%
CFO Pre-W/C – Dividends / Debt	20.1%	18.0%	17.5%	16.6%	14.1%
Debt / Capitalization	40.6%	40.3%	44.0%	43.0%	43.4%

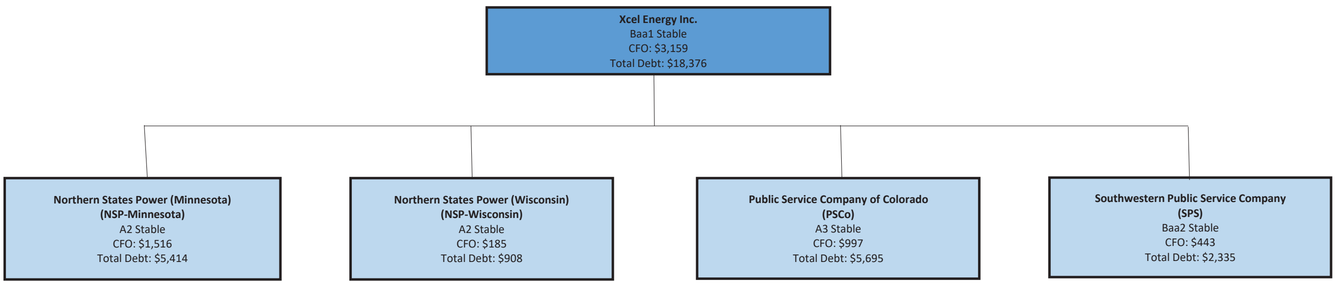
[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

NSP-Minnesota is a vertically integrated utility that provides electric services to 1.5 million customers in Minnesota, North Dakota and South Dakota as well as natural gas services to 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).

As depicted in Exhibit 3, NSP-Minnesota is the legacy subsidiary of parent Xcel Energy Inc. (Xcel, Baa1 stable), a holding company with utility operations in eight states servicing around 3.6 million electric customers and about 2 million natural gas customers. It is the second largest subsidiary in terms of regulated rate base (2019 year-end estimate: $11.2 billion) after Public Service Company of Colorado (PSCO, A3 stable; 2019 year-end estimate: 12.4 billion), with each contributing between 35-45% to Xcel's consolidated net income. NSP-Minnesota and its smaller neighboring sister company Northern States Power (Wisconsin) (NSP-Wisconsin, A2 stable) operate their electric production and transmission systems as an integrated system known as the NSP-System.

Exhibit 3
Xcel Energy Inc. Organizational Chart (year-end 2018)
($ in millions)



Source: Xcel Energy Inc., Moody's Financial Metrics

Detailed credit considerations

LIMITED DIVERSIFICATION BENEFITS; BULK OF OPERATIONS ARE IN MINNESOTA

NSP-Minnesota's credit quality reflects limited geographic diversification benefits because Minnesota accounts for the majority of its operations while North and South Dakota (electric only) each represent around 6% of the total. At the same time, the Federal Energy Regulatory Commission's (FERC) oversight of NSP-Minnesota's wholesale production (around 4.3% of the utility's 2018 total electric revenues) and transmission services modestly enhances its regulatory diversity.

OVERALL CREDIT SUPPORTIVE STATE REGULATORY ENVIRONMENTS

Riders reduce regulatory lag

Our view of the credit supportiveness of the state's regulatory frameworks in which NSP-Minnesota operates considers that the utility's cash flows benefit from a broad group of rider mechanisms that allow for the timely recovery of costs and investments between rate cases, and the ability to implement multi-year rate plans in all three states. The utility also benefits from the ability to implement interim rates until final tariff decisions are made, automatic fuel and purchase power cost recovery mechanisms (subject to monthly adjustments) and transmission riders. However, the number of automatic recovery mechanisms is more extensive in Minnesota (including distribution and decoupling) followed by North Dakota. This drives our view that these regulatory frameworks are above-average in terms of credit supportiveness compared to most other states, including South Dakota.

Exhibit 4
Summary of key regulatory mechanisms available in NSP-Minnesota's jurisdictions

	Multi-year Rate Plans	Forward Test Year	Interim Rates	Fuel Recovery Mechanism	Renewable Rider	Transmission Rider	Distribution Recovery Mechanism	Infrastructure Rider	Pension Deferral Mechanism	Property Tax Deferral/True-up	Decoupling
NSP-M	√	√ MN & ND	√	√	√ MN & ND	√ MN & ND	√ MN	√ SD	√ MN	√ MN	√ MN

Source: Xcel Energy Inc., regulatory filings

In South Dakota, rates are based on historical test periods which along with a limited number of riders have contributed to the utility's volatile actual return on equities (RoEs) (see Exhibit 5). In Minnesota, NSP-Minnesota benefits from a decoupling mechanisms (implemented in January 2016) for for electric residential end-users, as well as small commercial and industrial (C&I) customers, although their annual increases are capped at 3%. In addition, revenues from all non-decoupled electric customers are also subject to sales true-ups. That said, this mechanism does not fully insulate the utility's cash flows from the declining electricity sales volumes in its service territory despite its modestly growing electric customer base (FY2018 and nine month period ended in September 2019: +0.8%). For example, end of September 2019, the utility reported a reduction in its electric margin of around $17 million owing to a drop in its electricity sales by 2.3%, on a weather adjusted basis. In contrast, the utility's natural gas sales (September 2019: +1.3%; FY 2018:+1%) and customer base (September 2019: +1%; FY 2018: +1.1%) continue to grow. All these factors help to explain the differences in the development of the utility's actual RoE.

Exhibit 5
Summary of key financial parameters including authorized and actual RoEs and applicable regulatory plans

		Authorized RoE	W/A Earned RoE (actual)			Regulatory Plan
			2016	2017	2018	
NSP-Minnesota	Electric-Mn	9.20%	9.35%	9.66%	8.88%	2016-2019 multi-year plan (MYP); filed MYP in 2019
	NG-Mn	10.09%	8.12%	9.16%	9.81%	
	Electric - ND	10.25%	9.60%	10.91%	9.93%	TCJA Settlement 2019-20
	NG-ND	10.75%	6.00%	8.75%	10.32%	TCJA Settlement 2019-20
	Electric - SD	Blackbox	8.91%	6.91%	6.79%	TCJA Settlement 2019-20

*(w/a is weather-adjusted)
Source: Xcel Energy Inc., Regulatory filings

Our analysis also considers the mixed outcomes of the regulatory decisions regarding refunds due to the ratepayers following the re-evaluation of the accumulated deferred income tax (ADIT) at the lower corporate tax rate of 21% after the implementation of the TCJA in December 2017. At year-end 2018, the balance approximated $1.5 billion (with the protected portion accounting for the majority). We view the decisions of the North and South Dakota Commissions (NDPSC and SDPUC) as credit supportive as they authorized settlement agreements that provided for one-time refunds in 2018 (total refund in both states: $21 million) but also allowed the utility to retain the amounts due to the electric customers in 2019 and 2020 in exchange for a two-year rate case freeze. The two-year moratorium and the riders provide some cash flow visibility, particularly as the utility's 2013-2017 electric rate plans in both states expired at the end of 2017. In North Dakota, NSP-Minnesota was allowed to use the refundable amounts due to natural gas customers to amortize (annually: $1 million) the regulatory assets related to unrecovered remediation manufactured gas plant site expenses in Fargo. In contrast, the Minnesota Public Utilities Commission (MPUC) ordered NSP-Minnesota to refund $141 million to its electric and natural gas customers, including $2 million to fund low income program. This refund equates to around 95% of the utility's total estimated impact of the implementation of the TCJA on its 2018 revenue requirements.

Expectation of credit supportive outcomes of the next regulatory proceeding in Minnesota

Following the expiration of its four year electric plan (approved in June 2017) for the 2016-2019 period, NSP-Minnesota filed a three-year electric rate case with the MPUC in November 2019. The requested increase aggregates $466 million (+15.1%) over the three year period; $201 million in 2020 (43%), $146 million in 2021 and $118 million in 2022. NSP-Minnesota's request was premised on its currently authorized equity layer of 52.5% but a higher RoE of 10.2% (current allowed: 9.2%). However, as part of the proceeding the utility also proposed to stay out until 2020 but adjust its base rates to reflect true-up mechanisms for example related to sales (around $90 million) as well as defer the increase in the nuclear decommissioning accruals (around $30 million). In December 2019, the MPUC approved, NSP-Minnesota's stay-out provision. As a result, the utility deferred its rate case filing by one year to November 2020. This could also be a multi-year plan which we view to be credit positive because they enhance the visibility of the utility's cash flow and they provide incentives for the utility to implement cost saving initiatives which will be eventually shared with end-users in the next rate case proceeding.

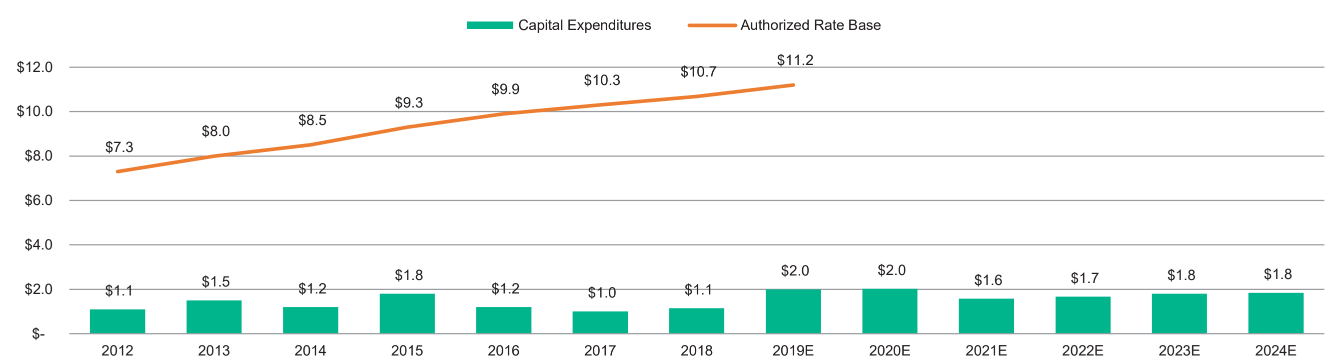
The credit supportiveness of the FERC's regulatory framework still ranks above-average

The FERC's decision, in November 2019, to lower the base RoE for Midcontinent Independent System Operator (MISO) transmission owners to 9.88%, with a cap of 12.24% (including RoE incentive adders) is credit negative for NSP-Minnesota and NSP-Wisconsin. This reduction of the RoE results from a series of inquiries and rulings emanating from a complaint filed in 2013 (a subsequent complained was filed in 2015) by a group of transmission customers under section 206 of the Federal Power Act. The customers alleged that MISO transmission owners were earning a base RoE that was unjust and unreasonable. At the time of the complaints, MISO base RoE was 12.38% (capped at 15.96%). In September 2016, FERC reduced the base RoE to 10.32% (capped to 11.35%) but, in a November 2018 order, it made preliminary determinations that the base RoE should be 10.28% for the first complaint period. In its November 2019 order, that set the final base RoE at 9.88%, FERC opted to use a two-step discounted cash flow (DCF) and capital asset pricing model (CAPM) for the new base RoE methodology (instead of considering the four-model approach proposed by the transmission owners). The change in the methodology limits the transparency of the process while the lower RoE will result in some refunds to customers and reduce the cash flows of NSP-Minnesota and NSP-Wisconsin going forward. However, we understand the cash impact of the refunds will be limited as they will represent less than 2% of the companies' aggregated cash flows. Our view of the credit supportiveness of the FERC regulatory environment recognizes that tariffs continue to be set on a forward-looking basis utilizing formulaic rate recovery mechanisms and true-ups, as well as robust (60%) equity layers, all of which serve to enhance the utility's cash flow and its predictability..

CAPITAL FOCUSED ON REGULATED TRANSMISSION, DISTRIBUTION AND GENERATION INVESTMENTS

For the 2020-2024 period, NSP-Minnesota's investment plan averages around $1.8 billion a year and totals approximately $8.9 billion, with the bulk of the investments remaining earmarked to expand the transmission, distribution and generation regulated footprint. The updated forecast exceeds the company's historical annual capital outlays (around $6.4 billion for the 2014-2018 period, or about $1.3 billion annually). However, in the updated plan for the 2020-2024 period, on average, capital investments will represent around 1.6x the utility's depreciation expense during this five year-period (compared to nearly 1.9x in average during the 2014-2018 period). The combination of these factors help to explain some moderation in the utility's rate base growth.

Exhibit 6
NSP-Minnesota's rate base and 2012-2024 historical and projected capital expenditure plan
($ in billions)



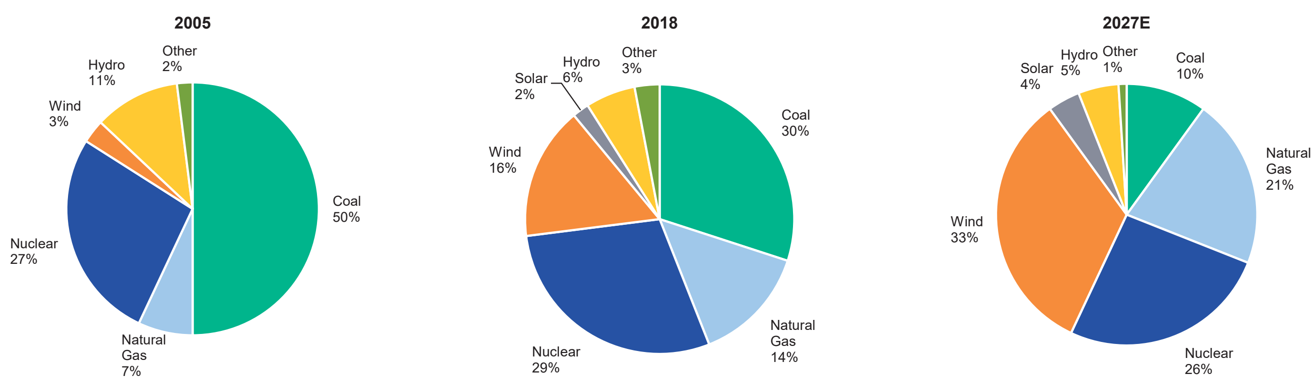
Source: Xcel Energy Inc.

NSP-Minnesota and its sister company NSP-Wisconsin share the costs of operating their integrated production and transmission systems (NSP-System) according to FERC's approved Interchange Agreement (IA). The IA separates costs into energy-related and demand-related costs (for the coincident monthly peak demand). NSP-Minnesota operates the NSP-System while NSP-Wisconsin is responsible for around 15% of the demand related costs. Generally, the associated interchange revenues received from NSP-Wisconsin represent around 10% of NSP-Minnesota's total revenues.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE CONSIDERATIONS

Environmental considerations incorporated into our credit analysis of NSP-Minnesota factors in the utility's goal of reducing, by 2030, carbon dioxide emissions 80% below the 2005 levels, which is in line with Xcel's goal that also aims to produce 100% carbon-free energy by 2050. These goals incorporate the output from NSP-Minnesota's nuclear fleet (1,657 MW) as the utility is seeking authorization to extend the life of the Monticello nuclear plant to 2040 from 2030 and to maintain operations at the Prairie Island nuclear units until 2033 and 2034 (end of their lives). The approved early retirement of NSP-Minnesota's 1,362 MW Sherco Unit 2 (2023) and Unit 1 (2026) will reduce the contribution of the coal-fired facilities to the utility's energy mix to 1,028 MW (expected contribution to the utility's energy mix in 2027: around 10%). However this contribution could drop to 0% if the MPUC approves NSP-Minnesota's Resource Plan (filed in July 2019) for the period ending 2034. In the plan, the utility proposed the retirement of the 511 MW King facility and the 517 MW Sherco Unit 3 in 2028 and 2030, respectively. MPUC's decision on the plan expected in late 2020 or early 2021.

Exhibit 7
2005-2027 planned development of NSP-Minnesota's energy mix



Source: Xcel Energy Inc.

NSP-Minnesota's Resource Plan also includes the construction of the Sherco combined cycle natural gas plant (CCGT; peak investment in 2026; CoD: 2028) while the MPUC recently denied the utility's request to add to its rate base the existing 760 MW CCGT Mankato Energy Center due the uncertainty regarding the transaction's estimated customer benefits before fully reviewing the utility's Resource Plan. Xcel still plans to acquire this plant that will remain contracted with the utility. The plan also includes demand side Management (DSM) initiatives such as energy efficiency programs (annual savings through 2034 around 780 GWh), and 400 MW of incremental demand response by 2023 (total by 2034: over 1,500 MW).

In the Resource Plan, the utility also proposed the addition of around 1,700 MW of firm peaking resources between 2031 and 2034, and around 5,200 MW of renewable assets. The latter consists of 4,000 MW of utility scale solar assets (first in 2025) and 1,200 MW in wind-farms by 2034 which will also replace wind assets that are expected to retire during that period.

In 2020 and 2021, a material portion of the utility's aforementioned investments are related to the completion of five wind-farms under construction (total installed capacity: 1,100 MW; 2019: 250MW). These new projects will grow the utility's wind-farm capacity to nearly 2.2 GW (2018: 840 MW). In addition, the MPUC approved NSP-Minnesota's acquisition of the 70 MW Longroad Energy wind-farm (acquisition price: $135 million) while a decision regarding the purchase of the 99 MW Mower wind facility is pending (expected decision after the anticipated repowering of the wind-farm in 2020).

NSP-Minnesota anticipates that the completion of the majority of its wind projects before year-end 2020 will allow them to quality for 100% of Production Tax Credits (PTCs) while the 300 MW Dakota Range (COD: 2021) is expected to quality for 80% of PTCs. The flow back to customers of the tax benefits, along with the saved fuel costs, and the termination of power purchase agreements (that are subject to elevated contracted prices), along with the group-wide focus on reducing O&M-expenses and credit back to customers of the tax credits (PTCs and ITCs) are key elements of the group-wide's strategy to limit the impact of the utilities' material investment on the end-users' bills. As per the Resource plan, NSP-Minnesota's goal is to keep the annual cost increases below the rate of inflation.

We assume that, upon their retirement, the utility will be able to recover the remaining rate base of its coal-fired facilities (all more than 35 years old). We assume that this rate base is relatively small, and largely reflects environmental compliance investments. This expectation contributes to our view that the utility's exposure to carbon transition risk is moderate.

Social risks are primarily related to demographic and societal trends as well as customer and regulatory relations. Corporate governance considerations include financial policy and we note that a strong financial position is an important characteristic for managing environmental and social risks amid the group's significant capital expenditure program.

WEAKENING FINANCIAL METRICS

As depicted under Exhibit 2, NSP-Minnesota's historical credit metrics were historically well positioned for the credit profile, including CFO pre-W/C to debt that consistently exceeded 25% during the 2015-2018 period. However, for the last twelve month (LTM) period ending 30 September 2019, NSP-Minnesota's ratio of CFO pre-W/C to debt was around 20%. The cash leakage that results from the implementation of the TCJA (mainly due to the aforementioned refunds of the ADIT, the PTCs pass-through and the expiration of bonus depreciation) is contributing to this deterioration of credit metrics. We calculate that during the 2014-2017 period, the deferred tax payments contributed to around 15% of NSP-Minnesota's operational cash flows. The relative contribution is lower than the average recorded by its sister companies (SPS: 27%; PSCO:21%) during the same period but not negligible.

Going forward, we assume that the anticipated moderation in the utility's base capital expenditure (capex) program along with a credit supportive outcome of the utility's next regulatory proceedings, particularly in Minnesota, will help the utility to record credit metrics that will remain adequate for the credit profile. For example, we anticipate a ratio of CFO pre-W/C to debt of at or above 22% over the foreseeable future. NSP-Minnesota's dividend distributions is subject to the utility recording an equity-to-total capitalization ratio that ranges between 47.1% and 57.1% (2018: 52.3%).

Liquidity analysis

Similar to its sister companies, NSP-Minnesota has its own separate committed credit facility. Following the group's amendment of the facilities, in June 2019, they are now scheduled to mature in June 2024 (previously: June 2021). This facility back-stops the utility's same-sized $500 million CP-program (Prime-1). The facility provides for same day funding and borrowings are not subject to conditionality. We anticipate the utility will be able to continue to comfortably comply with the only financial covenant embedded in the facility, namely a total Debt/Capitalization ratio below 65% (2018: 48%). At the end of September 2019, the utility had $481 million available under this credit facility (letter of credits outstanding: $19 million) as well as $329.5 million of cash on hand. Furthermore, in March 2019, NSP-Minnesota entered into a $75 million one-year uncommitted bilateral credit agreement, which is used to support letters of credit (available at the end of September 2019: $55 million).

NSP-Minnesota also participates in a regulated money pool with its sister companies PSCO and SPS. As of 30 September 2019 , NSP-Minnesota's $250 million borrowing limit was fully available. This money pool allows for short-term loans among those utility subsidiaries and allows for short-term loans from Xcel to the utilities. However, it does not permit loans from the utilities to Xcel. NPS-Minnesota's next debt maturity consists of $300 million first mortgage bonds (FMB) due in August 2020.

Xcel has publicly disclosed that the utility will issue $550 million FMB in 2020 following the 30-year 2.90% $600 million FMB issuance completed in September 2019. We anticipate that the utility will fund the rest of its capital requirements next year, including investments (2020: $2.025 billion), largely with internally generated cash flows (LTM September 2019: nearly $1.3 billion) and short and long-term debt financing. We also anticipate that Xcel will continue to manage NSP-Minnesota's dividend policy (LTM September 2019: $357 million) and equity contributions to the utility (LTM September 2019: $294 million) so as to meet its regulatory capital structure (that is a aforementioned range of equity-to-total capitalization ratio). In January 2019, Xcel contributed $150 million across the four pension plans (NSP-Minnesota's contribution: $47 million; 2018: $63 million).

Rating methodology and scorecard factors

Moody's evaluates NSP-Minnesota's financial performance relative to the Regulated Electric and Gas Utilities rating methodology published in June 2017. As depicted in the grid below, the company's indicated rating under this methodology based on historical as well as projected average key credit metrics is A2, the same as its assigned senior unsecured rating.

Exhibit 8

Northern States Power Company (Minnesota)

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 9/30/2019		Moody's 12-18 Month Forward View As of Date Published [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%) [4]				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.6x	Aa	6x - 6.5x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	24.4%	A	22% - 24%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	16.5%	Baa	15% - 17%	Baa
d) Debt / Capitalization (3 Year Avg)	42.1%	A	38% - 40%	A
Rating:				
Scorecard-indicated Outcome Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching				
a) Scorecard-indicated Outcome		A2		A2
b) Actual Rating Assigned		(P)A2		(P)A2

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2019(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 9

Peer Comparison [1]

	Northern States Power Company (Minnesota) (P)A2 Stable			Northern States Power Company (Wisconsin) (P)A2 Stable			ALLETE, Inc. Baa1 Stable			Otter Tail Power Company A3 Stable		
(in US millions)	FYE Dec-17	FYE Dec-18	LTM Sept-19	FYE Dec-17	FYE Dec-18	LTM Sept-19	FYE Dec-17	FYE Dec-18	LTM Sept-19	FYE Dec-17	FYE Dec-18	LTM Jun-19
Revenue	$5,102	$5,122	$5,152	$1,006	$1,022	$1,009	$1,419	$1,499	$1,384	$435	$450	$454
EBITDA	$1,811	$1,684	$1,708	$280	$304	$290	$444	$438	$434	$147	$143	$146
CFO Pre-W/C / Debt	26.7%	25.1%	20.1%	23.3%	23.5%	22.9%	23.6%	22.7%	19.5%	22.6%	18.9%	20.5%
CFO Pre-W/C – Dividends / Debt	17.5%	16.6%	14.1%	15.6%	13.4%	10.3%	17.4%	16.0%	12.9%	15.9%	11.6%	13.1%
Debt / EBITDA	3.0x	3.2x	3.4x	2.9x	3.0x	3.2x	3.9x	3.9x	4.2x	4.1x	4.1x	4.1x
Debt / Capitalization	44.0%	43.0%	43.4%	42.4%	42.9%	43.2%	43.3%	41.8%	42.8%	47.9%	45.3%	45.5%
EBITDA / Interest Expense	7.5x	7.0x	7.1x	7.7x	7.4x	6.8x	5.8x	5.7x	6.0x	5.3x	4.9x	5.0x

Source: Moody's Financial Metrics

Exhibit 10
Cash flow and credit metrics [1]

CF Metrics	Dec-15	Dec-16	Dec-17	Dec-18	LTM Sept-19
As Adjusted					
EBITDA	**1,498**	**1,689**	**1,811**	**1,684**	**1,708**
FFO	**1,283**	**1,395**	**1,485**	**1,421**	**1,421**
- Div	259	396	507	456	357
RCF	**1,024**	**999**	**978**	**965**	**1,064**
FFO	1,283	1,395	1,485	1,421	1,421
+/- ΔWC	19	(42)	(158)	159	159
+/- Other	20	(26)	(24)	(65)	(242)
CFO	**1,322**	**1,327**	**1,302**	**1,516**	**1,338**
- Div	259	396	507	456	357
- Capex	1,830	1,178	984	1,148	1,459
FCF	**(766)**	**(247)**	**(188)**	**(89)**	**(478)**
Debt / EBITDA	3.5x	3.2x	3.0x	3.2x	3.4x
EBITDA / Interest	6.7x	7.0x	7.5x	7.0x	7.1x
FFO / Debt	24.7%	25.8%	27.2%	26.3%	24.3%
RCF / Debt	19.7%	18.5%	17.9%	17.8%	18.2%
Revenue	4,757	4,900	5,102	5,122	5,152
Cost of Good Sold	1,909	1,795	1,939	2,058	2,006
Interest Expense	224	240	242	240	240
Net Income	406	490	523	476	461
Total Assets	17,093	17,917	18,005	18,525	19,857
Total Liabilities	12,058	12,691	12,664	13,024	13,948
Total Equity	5,035	5,226	5,341	5,500	5,910

[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 11

Category	Moody's Rating
NORTHERN STATES POWER COMPANY (MINNESOTA)	
Outlook	Stable
Issuer Rating	A2
First Mortgage Bonds	Aa3
Senior Secured Shelf	(P)Aa3
Sr Unsec Bank Credit Facility	A2
Senior Unsecured Shelf	(P)A2
Commercial Paper	P-1
PARENT: XCEL ENERGY INC.	
Outlook	Stable
Issuer Rating	Baa1
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured	Baa1
Subordinate Shelf	(P)Baa2
Pref. Shelf	(P)Baa3
Commercial Paper	P-2

Source: Moody's Investors Service

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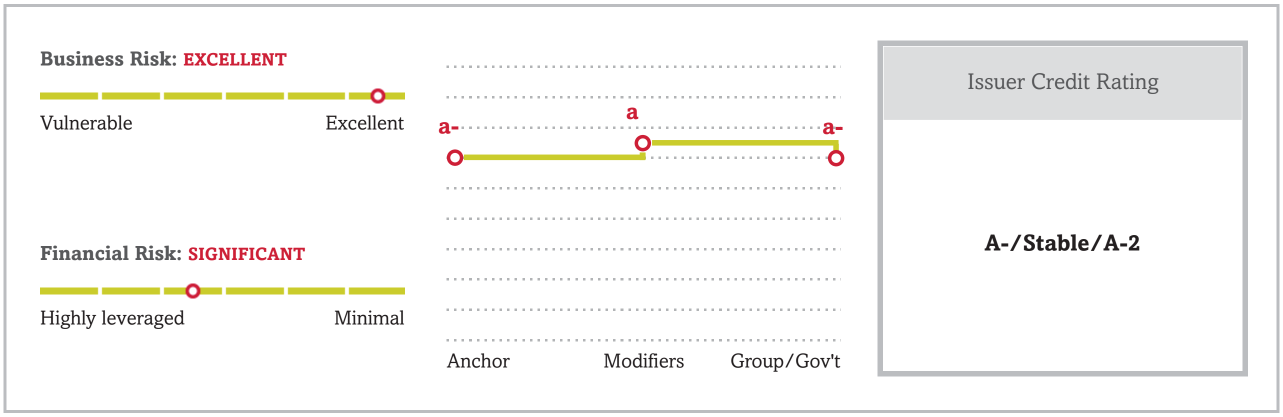
Northern States Power Co.



Credit Highlights

Overview	
Key Strengths	**Key Risks**
Low-risk vertically integrated electric utility.	Operational and environmental risks associated with nuclear and coal generation.
Large, mostly residential customer base.	Geographic diversity largely limited to Minnesota.
Steady utility operating cash flow.	Negative discretionary cash flow, indicating external funding needs.

The effects of U.S. tax reform and elevated capital spending expected to weaken financial measures. S&P Global Ratings expects the effects of U.S. tax reform and heightened capital spending (including the acquisitions of existing natural-gas and wind power plants) to weaken Northern States Power Co.'s (NSP's) financial measures.

We expect the company to maintain credit measures that are consistent with its current rating. Our base-case scenario assumes NSP will maintain adjusted funds from operations (FFO) to debt in the 18%-20% range, at or modestly above the midpoint of the financial risk profile benchmark range.

Outlook: Stable

The stable outlook on NSP reflects that on parent Xcel Energy Inc. (Xcel). We base the outlook on our expectation that Xcel's management will continue to reach constructive regulatory outcomes to avoid any significant rise in business risk for the regulated utilities. Specifically, our base-case forecast includes adjusted FFO to debt of about 16% and assumes the company will continue to fund its capital investments in a balanced manner to support its capital structure.

Downside scenario

We could lower the rating on Xcel and its subsidiaries, including NSP, if Xcel's financial ratios weaken and consistently reflect adjusted FFO to debt at or below 15%. This would most likely occur if rate-case outcomes are weaker than expected and capital spending materially rises.

Upside scenario

We could raise the ratings if Xcel improves its collective ability to manage regulatory risk across its jurisdictions, resulting in a consistent improvement to its business risk. We could also raise the rating if the company's consolidated financial measures consistently exceed our baseline forecast, including adjusted FFO to debt of greater than 20%.

Our Base-Case Scenario

Assumptions

- Continued cost recovery through various regulatory mechanisms;
- Annual gross margin in the 60%-62% range;
- Annual capital spending averaging about $1.9 billion through 2021;
- Annual dividends averaging about $420 million;
- Negative discretionary cash flow indicates external funding needs; and
- All debt maturities are refinanced.

Key Metrics

	2019E	2020E	2021E
Adjusted FFO to Debt (%)	21-23	19.5-20.5	19.5-20.5
Adjusted debt to EBITDA (x)	3.5-3.9	3.7-4	3.9-4.2
Adjusted FFO to cash interest(x)	6.1-6.5	5.4-5.7	5.4-5.7

*E--Expected. FFO--Funds from operations.

Company Description

Minneapolis-based NSP is a vertically-integrated electric and natural gas distribution utility operating in Minnesota, North Dakota, and South Dakota.

Business Risk: Excellent

NSP's stand-alone business risk profile incorporates its low-risk rate-regulated electric and natural gas operations that are providing service to about two million electric and natural gas customers in Minnesota, North Dakota, and South Dakota. Although NSP operates in three states, there is limited geographic and regulatory diversity since NSP earns about 90% of its revenue in Minnesota. Revenue stability is supported with a customer base that is 85% residential. NSP has been able to implement multiyear rate plans and benefits from infrastructure riders that are credit supportive. As the majority of NSP's generation capacity is nuclear-powered and coal-fired, the higher operating risk associated with nuclear-power generation and potential environmental risks from coal generation marginally weakens the company's business risk profile.

Peer comparison

Table 1

Northern States Power Co. -- Peer Comparison

Industry Sector: Electric

	Northern States Power Co.	Wisconsin Electric Power Co.	Consumers Energy Co.	Union Electric Co. d/b/a Ameren Missouri
	--Fiscal year ended Dec. 31, 2018--			
(Mil. $)				
Revenue	5,121.9	3,625.0	6,430.1	3,589.0
EBITDA	1,738.3	901.7	2,147.4	1,429.0
Funds from operations (FFO)	1,580.5	671.7	1,654.9	1,088.6
Interest expense	356.9	220.7	360.5	243.4
Cash interest paid	246.8	212.3	336.5	212.4
Cash flow from operations	1,477.6	998.1	1,522.9	1,235.6
Capital expenditure	1,158.8	628.8	1,910.1	952.0
Free operating cash flow (FOCF)	318.8	369.3	(387.2)	283.6
Discretionary cash flow (DCF)	(137.5)	58.7	(918.2)	(94.4)
Cash and short-term investments	50.0	20.2	39.0	0.0
Debt	5,661.7	7,155.6	7,854.3	4,085.3
Equity	5,573.1	3,476.0	6,920.0	4,229.0
Adjusted ratios				
EBITDA margin (%)	33.9	24.9	33.4	39.8
Return on capital (%)	8.3	4.8	7.9	10.2
EBITDA interest coverage (x)	4.9	4.1	6.0	5.9
FFO cash interest coverage (x)	7.4	4.2	5.9	6.1

Table 1

Northern States Power Co. -- Peer Comparison (cont.)

Industry Sector: Electric

	Northern States Power Co.	Wisconsin Electric Power Co.	Consumers Energy Co.	Union Electric Co. d/b/a Ameren Missouri
Debt/EBITDA (x)	3.3	7.9	3.7	2.9
FFO/debt (%)	27.9	9.4	21.1	26.6
Cash flow from operations/debt (%)	26.1	13.9	19.4	30.2
FOCF/debt (%)	5.6	5.2	(4.9)	6.9
DCF/debt (%)	(2.4)	0.8	(11.7)	(2.3)

Financial Risk: Significant

Our stand-alone financial risk profile for NSP incorporates a base-case scenario that includes adjusted FFO to debt weakening toward 19.5%, above the midpoint of the benchmark range of the significant category. Supporting the financial risk profile determination is the supplemental ratio of adjusted FFO cash interest coverage in the 5.4x-6.5x range. In addition, we expect the utility's elevated capital spending, when combined with the utility's dividend, will result in discretionary cash flow that is negative. To offset the negative cash flow, we expect external funding, such as debt issuances and cash injections within the Xcel Energy group. We do expect debt leverage, as indicated by debt to EBITDA, to rise and remain in the 3.5x-4.2x range over the next few years. Reflecting the company's steady cash flow and rate-regulated utility operations, we base our risk assessment on our medial table benchmarks. These are more relaxed benchmarks as compared to those used for a typical corporate issuer.

Financial summary

Table 2

Northern States Power Co.--Financial Summary

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2018	2017	2016	2015	2014
Rating history	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2
(Mil. $)					
Revenues	5,121.9	5,102.0	4,900.3	4,756.8	4,988.5
EBITDA	1,738.3	1,852.7	1,807.8	1,459.9	1,437.9
Funds from operations	1,580.5	1,524.3	1,524.7	1,286.4	1,193.0
Interest Expense	356.9	378.6	372.3	346.4	307.8
Cash Interest Paid	246.8	257.5	244.1	226.7	211.3
Cash flow from operations	1,477.6	1,256.1	1,290.4	1,310.8	1,134.0
Capital expenditures	1,158.8	988.5	1,186.4	1,837.7	1,230.4
Free operating cash flow	318.8	267.6	103.9	(526.9)	(96.4)
Discretionary cash flow	(137.5)	(239.0)	(292.0)	(786.1)	(355.9)
Cash and short-term investments	50.0	43.8	52.8	42.6	56.4
Gross available cash	50.0	43.8	47.6	42.6	56.4

Table 2

Northern States Power Co.--Financial Summary (cont.)

Industry Sector: Electric					
	--Fiscal year ended Dec. 31--				
	2018	**2017**	**2016**	**2015**	**2014**
Debt	5,661.7	5,605.4	5,885.9	5,734.7	5,122.7
Equity	5,573.1	5,475.6	5,355.6	5,167.1	4,703.2
Adjusted ratios					
EBITDA margin (%)	33.9	36.3	36.9	30.7	28.8
Return on capital (%)	8.3	9.4	9.9	8.4	9.5
EBITDA interest coverage (x)	4.9	4.9	4.9	4.2	4.7
FFO cash interest coverage (x)	7.4	6.9	7.2	6.7	6.6
Debt/EBITDA (x)	3.3	3.0	3.3	3.9	3.6
FFO/debt (%)	27.9	27.2	25.9	22.4	23.3
Cash flow from operations/debt (%)	26.1	22.4	21.9	22.9	22.1
Free operating cash flow/debt (%)	5.6	4.8	1.8	(9.2)	(1.9)
Discretionary cash flow/debt (%)	(2.4)	(4.3)	(5.0)	(13.7)	(6.9)

Liquidity- Adequate

We assess the company's stand-alone liquidity as adequate because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even with a 10% decline in EBITDA. The assessment also reflects our view of the company's generally prudent risk management, sound relationship with banks, and a generally satisfactory standing in credit markets.

Principal Liquidity Sources

- Cash and liquid investments of about $40 million
- Credit facility availability of about $500 million
- Estimated cash FFO of roughly $1.3 billion
- Parental equity infusion of around $450 million

Principal Liquidity Uses

- Debt maturities including outstanding commercial paper of about $455 million
- Capital spending of about $1.2 billion
- Dividends of around $385 million

Debt maturities

- 2019: nil
- 2020: $600 million
- 2021: nil

- 2022: $1.2 billion
- 2023: $2.0 billion

Other Credit Considerations

The stand-alone credit profile on NSP reflects a one-notch positive adjustment based on our expectation that the financial measures in our base-case scenario will consistently be around the higher end of the range for its financial risk profile category.

Environmental, Social, And Governance

Governance and social factors for the company are consistent with what we see across the industry for other publicly traded utilities.

Parent Xcel's reliance on coal-fired generation exposes it to the ongoing cost of operating older units in the face of disruptive technological advances and the potential for more environmental regulations requiring significant capital investments. However, the company is trying to reduce its carbon footprint; its near-term plans are to retire 1,400 MW of coal-fueled generation in the upper Midwest of the U.S. that will subsequently be replaced with a $3 billion investment in a combined cycle natural gas plant and 1,850 MW of wind generation. Also in Colorado, the company plans to retire additional coal-based generation and invest in wind, solar, and existing natural gas resources, as well as add 275 MW of large-scale battery storage. By pursuing greater renewable generation, the company is meeting customer demand for greener energy. Additionally, Xcel operates two nuclear plants, expected to remain open through 2034, that generate around 1,700 MW of power. Although carbon-free, the company's nuclear generation portfolio increases operating risk and exposes it to longer-term nuclear waste storage risks.

Group Influence

Under our group rating methodology, we consider NSP as a core subsidiary of parent Xcel, reflecting our view that NSP 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. We assess NSP's issuer credit rating to be in line with Xcel's group credit profile of 'a-'.

Issue Ratings - Subordination Risk Analysis

We base the short-term rating on NSP on the issuer credit rating on the company.

Issue Ratings - Recovery Analysis

NSP's first mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Reconciliation

Table 3

Reconciliation Of Northern States Power Co. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. $)

	--Fiscal year ended Dec. 31, 2018--						
Northern States Power Co. reported amounts							
	Debt	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	5,087.2	1,458.1	716.5	214.3	1,738.3	1,482.2	1,149.7
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	89.0	--	--
Cash taxes paid - Other	--	--	--	--	--	--	--
Cash interest paid	--	--	--	--	(207.4)	--	--
Operating leases	59.5	10.8	4.1	4.1	(4.1)	6.6	--
Postretirement benefit obligations/deferred compensation	213.3	--	--	--	--	--	--
Accessible cash & liquid investments	(50.0)	--	--	--	--	--	--
Capitalized interest	--	--	--	12.5	(12.5)	(12.5)	(12.5)
Power purchase agreements	324.7	44.3	22.7	22.7	(22.7)	21.6	21.6
Asset retirement obligations	61.5	103.2	103.2	103.2	--	--	--
Nonoperating income (expense)	--	--	83.6	--	--	--	--
U.S. decommissioning fund contributions	--	--	--	--	--	(20.3)	--
Debt - Other	(34.6)	--	--	--	--	--	--
EBITDA - Other income/(expense)	--	121.9	121.9	--	--	--	--
D&A - Other	--	--	(121.9)	--	--	--	--
Total adjustments	574.5	280.2	213.7	142.6	(157.8)	(4.6)	9.1
S&P Global Ratings' adjusted amounts							
	Debt	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditures**
	5,661.7	1,738.3	930.2	356.9	1,580.5	1,477.6	1,158.8

Ratings Score Snapshot

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:** Positive (+1 notch)

Stand-alone credit profile : a

- **Group credit profile:** a-
- **Entity status within group:** Core (-1 notch from SACP)

Related Criteria

- 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
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, 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 And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of November 25, 2019)*

Northern States Power Co.		
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

*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.

MOODY'S
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RATING METHODOLOGY

Regulated Electric and Gas Utilities

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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.

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	$1.5 \le x < 2.5$
Aa2	$2.5 \le x < 3.5$
Aa3	$3.5 \le x < 4.5$
A1	$4.5 \le x < 5.5$
A2	$5.5 \le x < 6.5$
A3	$6.5 \le x < 7.5$
Baa1	$7.5 \le x < 8.5$
Baa2	$8.5 \le x < 9.5$
Baa3	$9.5 \le x < 10.5$

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 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.

* 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

38. 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.

266 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 back stop 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.

STANDARD AND POOR'S (S&P) CREDIT METRICS

NSPM
As of September 2020
Dollars in Millions

	Projected Year End[3] 2020	Projected Year End[3] 2021	Projected Year End[3] 2022	Projected Year End[3] 2023
Adjusted Funds from Operations	$1,585	$1,731	$1,864	$1,943
Interest Expense				
Interest Charges and Financing Costs	$235	$247	$259	$266
AFUDC-Debt	$13	$12	$10	$11
Imputed Interest for Operating Leases(1)	$4	$4	$4	$3
Imputed Interest for PPAs(2)	$22	$20	$18	$16
Imputed Interest for Other Adjustments	$108	$108	$108	$108
Adjusted Interest Expense	$383	$391	$399	$405
EBITDA				
Operating Income	$807	$797	$819	$865
Depreciation & Amortization	$920	$1,037	$1,119	$1,152
EBITDA	$1,727	$1,835	$1,938	$2,017
Depreciation and Interest Adjustments for Operating Leases(1)	$8	$8	$12	$7
Depreciation and Interest Adjustments for PPAs(2)	$47	$48	$49	$49
Interest Adjustment for Other Adjustments	$108	$108	$108	$108
Adjusted EBITDA	$1,890	$1,999	$2,107	$2,181
Capitalization				
Short-Term Debt	$177	$127	$258	$192
Long-Term Debt (Includes Current Portion)	$5,917	$6,317	$6,466	$6,810
Total Balance Sheet Debt	$6,094	$6,445	$6,724	$7,003
Off-Balance Sheet Debt for Operating Leases (1)	$60	$57	$53	$45
Off-Balance Sheet Debt for PPAs (2)	$302	$277	$248	$215
Off-Balance Sheet Debt for Other Adjustments	$132	$105	$79	$53
Adjusted Total Debt	$6,588	$6,883	$7,104	$7,315
Common Equity from Balance Sheet	$6,699	$7,072	$7,392	$7,689
Adjusted Ratios: S&P Methodology				
FFO/Debt (%)	24.1	25.2	26.2	26.6
FFO/Interest (x)	5.1	5.4	5.7	5.8
Debt/EBITDA (x)	3.5	3.4	3.4	3.4
Total Debt/Total Capitalization (%)	49.6	49.3	49.0	48.8
Total Equity/Total Capitalization (%)	50.4	50.7	51.0	51.2

1.) The present value of operating leases and the imputed interest expense for operating leases are based on the operating subsidiaries' SEC Form 10-K following S&P's methodology for operating lease adjustments.

2.) The imputed debt, interest expense and depreciation for PPAs are based on internal forecasts, following S&P's methodology for power purchase adjustments.

3.) The financial data for the Projected Year End 2020 - 2023 is from Treasury Forecasting Model.

MOODY'S CREDIT METRICS

NSPM
As of September 2020
Dollars in Millions

	Projected Year End[1] 2020	Projected Year End[1] 2021	Projected Year End[1] 2022	Projected Year End[1] 2023
Adjusted Cash from Operations Pre Working Capital	$1,450	$1,599	$1,734	$1,794
Interest Expense				
Interest Charges and Financing Costs	$235	$247	$259	$266
Imputed Interest Expense	$21	$21	$21	$21
Adjusted Interest Expense	$256	$268	$280	$287
Debt				
Short-Term Debt	$177	$127	$258	$192
Long-Term Debt (Includes Current Portion)	$5,917	$6,317	$6,466	$6,810
Total Balance Sheet Debt	$6,094	$6,445	$6,724	$7,003
Imputed Off-Balance Sheet Debt	$276	$276	$276	$276
Adjusted Total Debt	$6,370	$6,721	$7,000	$7,279
Book Capitalization				
Adjusted Total Debt (See Above)	$6,370	$6,721	$7,000	$7,279
Deferred Income Taxes	$3,005	$2,947	$2,894	$2,862
Common Equity from Balance Sheet	$6,699	$7,072	$7,392	$7,689
Adjusted Book Capitalization	$16,074	$16,739	$17,286	$17,830
Dividends	$413	$450	$475	$496

Adjusted Ratios: Moody's Methodology

CFO pre-WC + Interest / Interest (x)	6.7	7.0	7.2	7.2
CFO pre-WC / Debt (%)	22.8	23.8	24.8	24.7
CFO pre-WC - Dividends / Debt (%)	16.3	17.1	18.0	17.8
Debt / Book Capitalization (%)	39.6	40.1	40.5	40.8

1.) The financial data for the Projected Year End 2020 - 2023 is from Treasury Forecasting Model.

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL - BACK UP FOR INTEREST RATES
Cost of Capital

Description	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2023 Q1	2023 Q2	2023 Q3	2023 Q4
The 3 month eurodollar rates are basis for projected short term debt costs (4)												
IHS Global Insight: 3 Month Eurodollar Rate (Libor)	0.3677	0.3672	0.3716	0.3761	0.3863	0.3932	0.4007	0.4044	0.4145	0.4216	0.4282	0.4252
Bloomberg Forward Curve: 3 Month Libor	0.3400	0.3500	0.3800	0.4500	0.6000	0.6500	0.6900	0.7500	N/A	N/A	N/A	N/A
Average 3 Month Libor Rate	0.3538	0.3586	0.3758	0.4131	0.4932	0.5216	0.5453	0.5772	0.4145	0.4216	0.4282	0.4252
Spread to Calculate NSPM's STD Rate	-0.0400	-0.0400	-0.0400	-0.0400	-0.0400	-0.0400	-0.0400	-0.0400	0.1329	0.1328	0.1329	0.1328
Total Forecasted Short Term Debt Interest Rate	0.3138	0.3186	0.3358	0.3731	0.4532	0.4816	0.5053	0.5372	0.5474	0.5544	0.5611	0.5580
The 10 and 30-year yields on U.S. Treasuries are the basis for new long term debt (4)												
IHS Global Insight: Yield on 10-Year Treasury Notes (1)	0.8732	0.9232	0.9789	1.0413	1.0942	1.1610	1.2254	1.2774	1.3382	1.3648	1.4031	1.4447
Credit Spread	0.7500	0.7500	0.7500	0.7500	0.7500	0.7500	0.7500	0.7500	0.7500	0.7500	0.7500	0.7500
Total Forecasted LTD Coupon Interest Rate	1.6232	1.6732	1.7289	1.7913	1.8442	1.9110	1.9754	2.0274	2.0882	2.1148	2.1531	2.1947
Bloomberg Forward Curve: Yield on 10-Year Treasury Notes (2) (3)	0.9600	1.0500	1.1200	1.2300	1.3400	1.4400	1.5400	1.6400	N/A	N/A	N/A	N/A
Credit Spread	0.7500	0.7500	0.7500	0.7500	0.7500	0.7500	0.7500	0.7500	N/A	N/A	N/A	N/A
Total Forecasted LTD Coupon Interest Rate	1.7100	1.8000	1.8700	1.9800	2.0900	2.1900	2.2900	2.3900	N/A	N/A	N/A	N/A
Average: Total Forecasted LTD Coupon Interest Rate on 10-year Treasury Notes	1.7000	1.8000	1.8000	1.9000	2.0000	2.1000	2.2000	2.3000	2.1000	2.2000	2.2000	2.2000
IHS Global Insight: Yield on 30-Year Treasury Notes (1)	1.6886	1.7706	1.8518	1.9335	2.0011	2.0759	2.1447	2.1985	2.2574	2.2800	2.3117	2.3444
Credit Spread	1.0500	1.0500	1.0500	1.0500	1.0500	1.0500	1.0500	1.0500	1.0500	1.0500	1.0500	1.0500
Total Forecasted LTD Coupon Interest Rate	2.7386	2.8206	2.9018	2.9835	3.0511	3.1259	3.1947	3.2485	3.3074	3.3300	3.3617	3.3944
Bloomberg Forward Curve: Yield on 30-Year Treasury Notes (2) (3)	1.6500	1.7300	1.7800	1.8900	1.9900	2.0600	2.1500	2.2500	N/A	N/A	N/A	N/A
Credit Spread	1.0500	1.0500	1.0500	1.0500	1.0500	1.0500	1.0500	1.0500	N/A	N/A	N/A	N/A
Total Forecasted LTD Coupon Interest Rate	2.7000	2.7800	2.8300	2.9400	3.0400	3.1100	3.2000	3.3000	N/A	N/A	N/A	N/A
Average: Total Forecasted LTD Coupon Interest Rate on 30-year Treasury Notes	2.8000	2.9000	2.9000	3.0000	3.1000	3.2000	3.2000	3.3000	3.4000	3.4000	3.4000	3.4000

(1) Source: IHS Global Insight, July 2020.
(2) Source: Bloomberg Forward Curve, August 2020.
(3) Bloomberg forecasts interest rates for only two future years; therefore, 2023 amounts are unavailable.
(4) The 2021-2023 data is based on available interest rate forecast data as of Q3 2020 and are inherently subject to change.

TEST YEAR - 2021 FORECASTED SHORT TERM DEBT AND COST

		Cost of Short Term Debt			
	Month End Balances	Average Of Month End Balances (1)	Monthly Interest Expense (2)	Monthly Fees Expense (3)	Average Short Term Debt Cost
2021 Jan	$184,374,721	$175,093,710	$47,319	$43,467	
2021 Feb	$168,402,468	$176,388,595	$43,056	$39,382	
2021 Mar	$193,457,854	$180,930,161	$48,897	$43,467	
2021 Apr	$247,822,161	$220,640,007	$58,582	$42,106	
2021 May	$0	$123,911,080	$33,996	$43,467	
2021 June	$9,909,031	$4,954,515	$1,315	$42,106	
2021 Jul	$135,844,477	$72,876,754	$21,073	$43,467	
2021 Aug	$74,119,606	$104,982,042	$30,356	$43,467	
2021 Sep	$19,353,155	$46,736,380	$13,078	$42,106	
2021 Oct	$97,366,081	$58,359,618	$18,748	$43,467	
2021 Nov	$57,929,317	$77,647,699	$24,140	$42,106	
2021 Dec	$33,188,058	$45,558,687	$14,636	$43,467	
Average	$101,813,911	$107,339,937			
Total			$ 355,198	$ 512,076	
			0.33%	0.48%	0.81%

(1) January through December Average of Month End Balances.

(2) Monthly Interest Expense is based on the weighted average of short term debt outstanding and Interest Rates are based on the Global Insights and Bloomberg Forecast.

(3) Ongoing fees for NSP-MN's five-year credit facility that was re-syndicated on June 7, 2019. This expense represents the monthly cost of NSP-MN unused portion of the credit facility. Credit facility is used primarily as back up for commercial paper and letters of credit. (Upfront expenses for the five year credit facility are amortized over the life of the facility and are included in the cost of long term debt.)

TEST YEAR - 2022 FORECASTED SHORT TERM DEBT AND COST

		Cost of Short Term Debt			
	Month End Balances	Average Of Month End Balances (1)	Monthly Interest Expense (2)	Monthly Fees Expense (3)	Average Short Term Debt Cost
2022 Jan	$81,612,198	$57,400,128	$22,398	$43,467	
2022 Feb	$0	$40,806,099	$14,382	$39,382	
2022 Mar	$0	$0	$0	$43,467	
2022 Apr	$1,511,833	$755,917	$303	$42,106	
2022 May	$140,650,589	$71,081,211	$29,477	$43,467	
2022 June	$0	$70,325,295	$28,223	$42,106	
2022 Jul	$0	$0	$0	$43,467	
2022 Aug	$4,150,599	$2,075,300	$903	$43,467	
2022 Sep	$0	$2,075,300	$874	$42,106	
2022 Oct	$70,990,737	$35,495,369	$16,419	$43,467	
2022 Nov	$82,054,883	$76,522,810	$34,256	$42,106	
2022 Dec	$135,969,480	$109,012,181	$50,426	$43,467	
Average	$43,078,360	$38,795,801			
Total			$ 197,662	$ 512,076	
			0.51%	1.32%	1.83%

(1) January through December Average of Month End Balances.

(2) Monthly Interest Expense is based on the weighted average of short term debt outstanding and Interest Rates are based on the Global Insights and Bloomberg Forecast.

(3) Ongoing fees for NSP-MN's five-year credit facility that was re-syndicated on June 7, 2019. This expense represents the monthly cost of NSP-MN unused portion of the credit facility. Credit facility is used primarily as back up for commercial paper and letters of credit. (Upfront expenses for the five year credit facility are amortized over the life of the facility and are included in the cost of long term debt.)

TEST YEAR - 2023 FORECASTED SHORT TERM DEBT AND COST

	Month End Balances	Cost of Short Term Debt			
		Average Of Month End Balances (1)	Monthly Interest Expense (2)	Monthly Fees Expense (3)	Average Short Term Debt Cost
2023 Jan	$211,734,878	$173,852,179	$81,943	$43,467	
2023 Feb	$171,525,133	$191,630,005	$81,581	$39,382	
2023 Mar	$168,032,657	$169,778,895	$80,023	$43,467	
2023 Apr	$218,775,323	$193,403,990	$89,356	$42,106	
2023 May	$11,096,193	$114,935,758	$54,872	$43,467	
2023 June	$22,782,034	$16,939,114	$7,826	$42,106	
2023 Jul	$119,848,050	$71,315,042	$34,455	$43,467	
2023 Aug	$29,966,695	$74,907,373	$36,190	$43,467	
2023 Sep	$0	$14,983,348	$7,005	$42,106	
2023 Oct	$108,137,953	$54,068,977	$25,981	$43,467	
2023 Nov	$122,403,503	$115,270,728	$53,603	$42,106	
2023 Dec	$96,580,499	$109,492,001	$52,613	$43,467	
Average	$106,740,243	$108,381,451			
Total			$ 605,448	$ 512,076	
			0.56%	0.47%	1.03%

(1) January through December Average of Month End Balances.

(2) Monthly Interest Expense is based on the weighted average of short term debt outstanding and Interest Rates are based on the Global Insights Forecast.

(3) Ongoing fees for NSP-MN's five-year credit facility that was re-syndicated on June 7, 2019. This expense represents the monthly cost of NSP-MN unused portion of the credit facility. Credit facility is used primarily as back up for commercial paper and letters of credit. (Upfront expenses for the five year credit facility are amortized over the life of the facility and are included in the cost of long term debt.)

NSPM Utility Money Pool Activity
Summary - January 2018 through June 2020

	Borrowings			Investments		
Date	Average Amount Outstanding	Actual Interest Rate	Alternative Interest Rate *	Average Amount Outstanding	Actual Interest Rate	Alternative Interest Rate **
2018						
Jan	$ 37,387,097	1.5900%	4.5000%			
Feb	$ 2,357,143	1.5100%	4.5000%			
Mar	$ -	1.6400%	4.7500%	$ 35,774,194	1.6400%	1.0000%
Apr	$ -	1.8300%	4.7500%	$ 94,500,000	1.8300%	1.0000%
May	$ -	1.8500%	4.7500%	$ 94,580,645	1.8500%	1.2000%
Jun	$ 4,133,333	1.8500%	5.0000%	$ 46,166,667	1.8500%	1.2000%
Jul	$ 96,387,097	1.9700%	5.0000%			
Aug	$ 5,161,290	1.9600%	5.0000%	$ 2,903,226	1.9600%	1.3500%
Sep	$ 466,667	1.9900%	5.2500%	$ 11,433,333	1.9900%	1.5000%
Oct	$ 9,451,613	2.1100%	5.2500%	$ 290,323	2.1100%	1.5000%
Nov	$ 46,066,667	2.2500%	5.2500%			
Dec	$ -	2.3000%	5.5000%	$ 3,419,355	2.3000%	1.5000%
2019						
Jan	$ -	2.5000%	5.5000%			
Feb	$ -	2.4500%	5.5000%			
Mar	$ 2,032,258	2.4400%	5.5000%	$ 3,677,419	2.4400%	1.6500%
Apr	$ -	2.4600%	5.5000%	$ 26,833,333	2.4600%	1.6500%
May	$ 580,645	2.4200%	5.5000%	$ 12,838,710	2.4200%	1.6500%
Jun	$ 6,666,667	2.4100%	5.5000%			
Jul	$ 50,000,000	2.3200%	5.5000%			
Aug	$ 152,516,129	2.2000%	5.2500%			
Sep	$ 70,766,667	2.0300%	5.1250%			
Oct	$ 1,967,742	1.9300%	5.0000%			
Nov	$ 32,200,000	1.7300%	4.7500%			
Dec	$ 66,838,710	1.6300%	4.7500%			
2020						
Jan	$ 29,516,129	1.5800%	4.7500%	$ 1,903,226	1.5800%	1.3500%
Feb	$ -	1.5600%	4.7500%	$ 30,000,000	1.5600%	1.3500%
Mar	$ -	1.1500%	3.7500%	$ 61,032,258	1.1500%	0.7550%
Apr	$ -	1.4200%	3.2500%	$ 24,966,667	1.4200%	0.1600%
May	$ -	0.1900%	3.2500%	$ 21,419,355	0.1900%	0.1600%
Jun	$ -	0.1400%	3.2500%	$ 533,333	0.1400%	0.1600%

* Based on overnight borrowing rate under NSP-MN credit facility.
** Based on investment in a money market account.

RATE OF RETURN COST OF CAPITAL SCHEDULES
Common Equity
($000's)

TEST YEAR - 2021 FORECASTED EQUITY BALANCES

Month	GAAP Common Equity Outstanding	Non-Regulated Subsidiaries (1)	Regulated Common Equity
2020 Dec	$6,666,616	$927	$6,665,689
2021 Jan	$6,841,430	$927	$6,840,503
2021 Feb	$6,873,699	$927	$6,872,772
2021 Mar	$6,816,127	$927	$6,815,200
2021 Apr	$6,839,046	$927	$6,838,119
2021 May	$6,863,188	$927	$6,862,261
2021 Jun	$6,829,118	$927	$6,828,191
2021 Jul	$6,916,576	$927	$6,915,649
2021 Aug	$6,999,064	$927	$6,998,137
2021 Sep	$6,951,011	$927	$6,950,084
2021 Oct	$6,986,017	$927	$6,985,090
2021 Nov	$7,018,711	$927	$7,017,784
2021 Dec	$6,963,897	$927	$6,962,970
13 Month Average	$6,889,577	$927	$6,888,650

(1) United Power and Land.

($000's)

TEST YEAR - 2022 FORECASTED EQUITY BALANCES

Month	GAAP Common Equity Outstanding	Non-Regulated Subsidiaries (1)	Regulated Common Equity
2021 Dec	$6,963,897	$927	$6,962,970
2022 Jan	$7,040,281	$927	$7,039,354
2022 Feb	$7,076,897	$927	$7,075,970
2022 Mar	$7,020,297	$927	$7,019,370
2022 Apr	$7,051,220	$927	$7,050,293
2022 May	$7,079,334	$927	$7,078,407
2022 June	$7,038,999	$927	$7,038,072
2022 Jul	$7,130,430	$927	$7,129,503
2022 Aug	$7,245,797	$927	$7,244,870
2022 Sep	$7,192,350	$927	$7,191,423
2022 Oct	$7,257,941	$927	$7,257,014
2022 Nov	$7,298,104	$927	$7,297,177
2022 Dec	$7,242,262	$927	$7,241,335
13 Month Average	$7,125,985	$927	$7,125,058

(1) United Power and Land.

($000's)

TEST YEAR - 2023 FORECASTED EQUITY BALANCES

Month	GAAP Common Equity Outstanding	Non-Regulated Subsidiaries (1)	Regulated Common Equity
2022 Dec	$7,242,262	$927	$7,241,335
2023 Jan	$7,389,848	$927	$7,388,921
2023 Feb	$7,429,172	$927	$7,428,245
2023 Mar	$7,370,979	$927	$7,370,052
2023 Apr	$7,400,589	$927	$7,399,662
2023 May	$7,446,593	$927	$7,445,666
2023 June	$7,399,522	$927	$7,398,595
2023 Jul	$7,495,956	$927	$7,495,029
2023 Aug	$7,586,730	$927	$7,585,803
2023 Sep	$7,522,586	$927	$7,521,659
2023 Oct	$7,562,736	$927	$7,561,809
2023 Nov	$7,600,599	$927	$7,599,672
2023 Dec	$7,581,105	$927	$7,580,178
13 Month Average	$7,463,744	$927	$7,462,817

(1) United Power and Land.

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Common Equity Flotation Costs

Docket No. E002/GR-20-723
Exhibit___(SWS-1), Schedule 21

Date	Issuing Company	Shares Issued	Market Price	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds	Total Flotation Costs	Gross Equity Issue before Costs	Net Proceeds	Flotation Cost Percentage
11/16/1949	Northern States Power	1,584,238	$10.750	$10.250	$0.124	$0.137	$9.989	$1,205,605	$17,030,559	$15,824,953	7.079%
6/4/1952	Northern States Power	1,108,966	$10.500	$10.500	$0.098	$0.162	$10.240	$288,331	$11,644,143	$11,355,812	2.476%
4/14/1954	Northern States Power	1,219,856	$15.250	$14.000	$0.060	$0.124	$13.816	$1,749,274	$18,602,804	$16,853,530	9.403%
2/29/1956	Northern States Power	670,920	$17.825	$16.750	$0.050	$0.221	$16.479	$903,058	$11,959,149	$11,056,091	7.551%
7/22/1959	Northern States Power	952,033	$23.375	$22.000	$0.069	$0.191	$21.740	$1,556,574	$22,253,771	$20,697,197	6.995%
7/28/1965	Northern States Power	772,008	$35.250	$33.000	$0.092	$0.225	$32.683	$1,981,745	$27,213,282	$25,231,537	7.282%
1/22/1969	Northern States Power	1,080,811	$29.000	$27.000	$0.119	$0.187	$26.694	$2,492,350	$31,343,519	$28,851,169	7.952%
10/21/1970	Northern States Power	1,729,298	$23.125	$21.500	$0.175	$0.149	$21.176	$3,370,402	$39,990,016	$36,619,614	8.428%
7/26/1972	Northern States Power	1,902,228	$25.000	$23.500	$0.129	$0.166	$23.205	$3,414,499	$47,555,700	$44,141,201	7.180%
10/10/1973	Northern States Power	2,092,451	$25.825	$24.500	$0.128	$0.153	$24.219	$3,360,476	$54,037,547	$50,677,071	6.219%
11/20/1974	Northern States Power	2,300,000	$17.625	$17.500	$0.910	$0.069	$16.521	$2,539,200	$40,537,500	$37,998,300	6.264%
8/14/1975	Northern States Power	1,750,000	$23.000	$23.000	$0.740	$0.077	$22.183	$1,429,750	$40,250,000	$38,820,250	3.552%
6/3/1976	Northern States Power	2,000,000	$24.000	$24.000	$0.720	$0.064	$23.216	$1,568,000	$48,000,000	$46,432,000	3.267%
5/31/1993	Northern States Power	3,041,955	$44.125	$43.625	$1.200	$0.048	$42.377	$5,317,337	$134,226,264	$128,908,927	3.961%
9/23/1997	Northern States Power	4,500,000	$49.938	$49.563	$1.230	$0.133	$48.200	$7,821,000	$224,721,000	$216,900,000	3.480%
9/29/1997	Northern States Power	400,000	$50.500	$49.563	$1.230	$0.133	$48.200	$920,000	$20,200,000	$19,280,000	4.554%
2/25/2002	Xcel Energy, Inc.	20,000,000	$22.950	$22.500	$0.730	$0.015	$21.755	$23,900,000	$459,000,000	$435,100,000	5.207%
9/9/2008	Xcel Energy, Inc.	17,250,000	$20.860	$20.200	$0.100	$0.006	$20.094	$13,218,352	$359,835,000	$346,616,648	3.673%
8/3/2010	Xcel Energy, Inc.	21,850,000	$22.100	$21.500	$0.645	$0.013	$20.571	$33,407,927	$482,885,000	$449,477,073	6.918%
March 2013	Xcel Energy, Inc.	7,757,449	$29.057	$29.057	$0.291	$0.052	$28.714	$2,657,558	$225,407,642	$222,750,085	1.179%
June 2014	Xcel Energy, Inc.	5,693,946	$30.663	$30.663	$0.307	$0.030	$30.326	$1,915,210	$174,592,340	$172,677,130	1.097%
September 2018	Xcel Energy, Inc.	4,733,435	$47.885	$47.885	$0.407	$0.073	$47.405	$2,271,040	$226,661,287	$224,390,247	1.002%
8/29/2019	Xcel Energy, Inc.	9,359,103	$48.416	$48.416	$0.173	$0.030	$48.213	$1,901,526	$453,132,797	$451,231,271	0.420%
	Total Public Issuances							$119,189,213	$3,171,079,321	$3,051,890,108	3.759%
	Total Non-Public Issuances							$0	$1,724,487,000	$1,724,487,000	0.000%
NSP/NCE Merger[1]		N/A	N/A	N/A	N/A	N/A	N/A	N/A	$1,944,007,000	N/A	
NRG stock for stock exchange									$1,077,456,000		
Total									$6,192,542,321		

[1] Additional paid in capital for NSP/NCE Merger = $1,944,007,000
Additional paid in capital for NRG = $1,077,456,000
These are balance sheet adjustments to additional paid in capital which did not incur any flotation costs.