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MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

Regulated Electric and Gas Utilities

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Analyst Contacts:

NEW YORK +1.212.553.1653

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

Jim Hempstead +1.212.553.4318
Managing Director – Utilities
ames.hempstead@moodys.com

Walter Winrow +1.212.553.7943
Managing Director - Global Project and Infrastructure Finance
walter.winrow@moodys.com

Jeffrey Cassella +1.212.553.1665
Vice President - Senior Analyst
effrey.cassella@moodys.com

Natividad Martel +1.212.553.4561
Vice President - Senior Analyst
natividad.martel@moodys.com

» contacts continued on the last page

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 We have updated some outdated links and removed certain issuer-specific information.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.

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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.

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

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.

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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	Definitions
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.

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Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

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

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based onlegislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward- looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expectthese 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 forsetting 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.

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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.

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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

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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.

» contacts continued from page 1

Analyst Contacts:

BUENOS AIRES +54.11.5129.260

Daniela Cuan +54.11.5129.261
Vice President - Senior Analyst
daniela.cuan@moodys.com

TORONTO +1.416.214.163

Gavin MacFarlane +1.416.214.386
Vice President - Senior Credit Officer
gavin.macfarlane@moodys.com

LONDON +44.20.7772.545

Douglas Segars +44.20.7772.158
Managing Director - Infrastructure Finance
douglas.segars@moodys.com

Helen Francis +44.20.7772.542
Vice President - Senior Credit Officer
helen.francis@moodys.com

HONG KONG +852.3551.307

Vivian Tsang +852.375.815.3
Associate Managing Director
vivian.tsang@moodys.com

SINGAPORE +65.6398.830

Ray Tay +65.6398.830
Vice President - Senior Credit Officer
ray.tay@moodys.com

TOKYO +81.3.5408.410

Mihoko Manage +81.354.084.033
Associate Managing Director
mihoko.manabe@moodys.com

Mariko Semetko +81.354.084.20
Vice President - Senior Credit Officer
mariko.semetko@moodys.com

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Report Number: 1072530

Author
Michael G. Haggarty

Production Associate
Masaki Shiomi

MOODY'S
INVESTORS SERVICE

STANDARD & POOR'S (S&P) CREDIT METRIC STANDARDS

AS PROVIDED TO THE COMPANY BY S&P

	CCR Standards by S&P (a)			**Northern States Power MN (b)**							
	AA	***A/A- Company Objective***	**BBB**	**2015**	**2016**	**2017**	**2018**	**2019 Forecast**	**2020 Forecast**	**2021 Forecast**	**2022 Forecast**
Debt to Earnings Before Interest, Taxes, Depreciation and Amortization (x)	1.75 – 2.5	***3.5 – 4.5***	4.5 – 5.5	3.9	3.3	3.0	3.3	3.5	3.5	3.5	3.4
Funds from Operations to Total Debt (%)	35 – 50	***13 – 23***	9 – 13	21.0	24.2	26.3	27.4	23.2	24.7	24.7	25.0
Debt to Total Capital (%)	25 – 35	***35 – 50***	50 – 60	51.9	52.6	50.9	50.8	49.7	49.4	49.1	48.9

(a) For a company assigned "medial volatility".
(b) All NSP- MN credit statistics are adjusted by S&P for inclusion of off balance sheet obligations.
The 2015 through 2018 metrics are from S&P. The 2019 through 2022 forecasted metrics are calculated by the Company following S&P's methodology.

NSPM
As of August 2019
Dollars in Millions

	Projected Year End[3] 2019	Projected Year End[3] 2020	Projected Year End[3] 2021	Projected Year End[3] 2022
Adjusted Funds from Operations	$1,459	$1,669	$1,729	$1,816
Interest Expense				
Interest Charges and Financing Costs	$222	$252	$268	$286
AFUDC-Debt	$12	$12	$14	$14
Imputed Interest for Operating Leases(1)	$4	$4	$3	$3
Imputed Interest for PPAs(2)	$13	$13	$11	$10
Imputed Interest for Other Adjustments	$103	$103	$103	$103
Adjusted Interest Expense	$354	$384	$400	$416
EBITDA				
Operating Income	$778	$824	$813	$847
Depreciation & Amortization	$886	$987	$1,066	$1,137
EBITDA	$1,664	$1,811	$1,879	$1,984
Depreciation and Interest Adjustments for Operating Leases(1)	$14	$8	$8	$8
Depreciation and Interest Adjustments for PPAs(2)	$29	$31	$31	$33
Interest Adjustment for Other Adjustments	$103	$103	$103	$103
Adjusted EBITDA	$1,810	$1,953	$2,022	$2,128
Capitalization				
Short-Term Debt	$251	$236	$178	$286
Long-Term Debt (Includes Current Portion)	$5,535	$6,078	$6,429	$6,627
Total Balance Sheet Debt	$5,786	$6,314	$6,606	$6,912
Off-Balance Sheet Debt for Operating Leases (1)	$60	$50	$45	$40
Off-Balance Sheet Debt for PPAs (2)	$187	$171	$153	$132
Off-Balance Sheet Debt for Other Adjustments	$249	$223	$197	$171
Adjusted Total Debt	$6,282	$6,758	$7,002	$7,255
Common Equity from Balance Sheet	$6,346	$6,930	$7,252	$7,588
Adjusted Ratios: S&P Methodology				
FFO/Debt (%)	23.2	24.7	24.7	25.0
FFO/Interest (x)	5.1	5.3	5.3	5.4
Debt/EBITDA (x)	3.5	3.5	3.5	3.4
Total Debt/Total Capitalization (%)	49.7	49.4	49.1	48.9
Total Equity/Total Capitalization (%)	50.3	50.6	50.9	51.1
Unadjusted Ratios				
FFO/Debt (%)	23.0	24.4	24.2	24.4
FFO/Interest	6.7	6.8	6.7	6.6
Debt/EBITDA (x)	3.5	3.5	3.5	3.5
Total Debt/Total Capitalization (%)	47.7	47.7	47.7	47.7
Total Equity/Total Capitalization (%)	52.3	52.3	52.3	52.3

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 2019 - 2022 is from Treasury Forecasting Five-Year Model.

MOODY'S CREDIT METRIC STANDARDS

AS PROVIDED TO THE COMPANY BY MOODY'S

	CCR Standards by Moody's (a)			**Northern States Power MN (b)**							
	Aa	***A Company Objective***	**Baa**	**2015**	**2016**	**2017**	**2018**	**2019 Forecast**	**2020 Forecast**	**2021 Forecast**	**2022 Forecast**
Cash from Operations Pre Working Capital + Interest / Interset (x)	6 – 8	**4.5 – 6**	3.0 - 4.5	6.5	6.7	7.0	6.6	6.4	6.6	6.6	6.6
Cash from Operations Pre Working Capital / Debt (%)	30 – 40	**22 – 30**	13 – 22	23.8	25.5	26.7	25.1	22.1	23.6	23.6	23.9
Cash from Operations Pre Working Capital – Dividends / Debt (%)	25 – 35	**17 – 25**	9 – 17	18.7	18.1	17.4	16.6	16.0	17.3	17.1	17.4
Debt / Book Capitalization (%)	25 +– 35	**35 – 45**	45 – 55	40.3	40.0	44.0	43.0	39.3	39.9	40.4	40.8

(a) For a company assigned the Standard Grid threshold by Moody's based on the level of the issuer's business risk.

(b) All NSP- MN credit statistics are adjusted by Moody's for inclusion of off balance sheet obligations. The 2015 through 2018 metrics are from Moody's. The 2019 through 2022 forecasted metrics are calculated by the Company following Moody's methodology.

NSPM
As of August 2019
Dollars in Millions

	Projected Year End[2] 2019	Projected Year End[2] 2020	Projected Year End[2] 2021	Projected Year End[2] 2022
Adjusted Cash from Operations Pre Working Capital	$1,349	$1,568	$1,636	$1,733
Interest Expense				
Interest Charges and Financing Costs	$222	$252	$268	$286
Imputed Interest for Operating Leases (1)	$3	$3	$3	$3
Imputed Interest for Pension Obligations	$11	$11	$11	$11
Imputed Interest for Other Adjustments	$12	$12	$12	$12
Adjusted Interest Expense	$248	$278	$294	$312
Debt				
Short-Term Debt	$251	$236	$178	$286
Long-Term Debt (Includes Current Portion)	$5,535	$6,078	$6,429	$6,627
Total Balance Sheet Debt	$5,786	$6,314	$6,606	$6,912
Off-Balance Sheet Debt for Operating Leases (1)	$67	$67	$67	$67
Off-Balance Sheet Debt for Pension Obligations	$196	$196	$196	$196
Off-Balance Sheet Debt for Other Adjustments	$63	$63	$63	$63
Adjusted Total Debt	$6,113	$6,640	$6,933	$7,239
Book Capitalization				
Adjusted Total Debt (See Above)	$6,113	$6,640	$6,933	$7,239
Deferred Income Taxes	$3,081	$3,067	$2,988	$2,894
Common Equity from Balance Sheet	$6,346	$6,930	$7,252	$7,588
Adjusted Book Capitalization	$15,539	$16,637	$17,173	$17,722
Dividends	$371	$416	$449	$473
Adjusted Ratios: Moody's Methodology				
CFO pre-WC + Interest / Interest (x)	6.4	6.6	6.6	6.6
CFO pre-WC / Debt (%)	22.1	23.6	23.6	23.9
CFO pre-WC - Dividends / Debt (%)	16.0	17.3	17.1	17.4
Debt / Book Capitalization (%)	39.3	39.9	40.4	40.8
Unadjusted Ratios				
CFO pre-WC + Interest / Interest (x)	6.9	7.0	6.9	6.9
CFO pre-WC / Debt (%)	22.5	24.1	24.1	24.4
CFO pre-WC - Dividends / Debt (%)	16.1	17.5	17.3	17.6
Debt / Book Capitalization (%)	38.0	38.7	39.2	39.7

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 Moody's methodology for operating lease adjustments.

2.) The financial data for the Projected Year End 2019 - 2022 is from Treasury Forecasting Five-Year Model.

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MOODY'S
INVESTORS SERVICE

CREDIT OPINION

31 October 2018

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.

Analyst Contacts

Natividad Martel, CFA — 212-553-4561
VP-Senior Analyst
natividad.martel@moodys.com

Cliff Wang — 212-553-6905
Associate Analyst
cliff.wang@moodys.com

Michael G. Haggarty — 212-553-7172
Associate Managing Director
michael.haggarty@moodys.com

Jim Hempstead — 212-553-4318
MD-Utilities
james.hempstead@moodys.com

Northern States Power Company (Minnesota)

Update to credit analysis

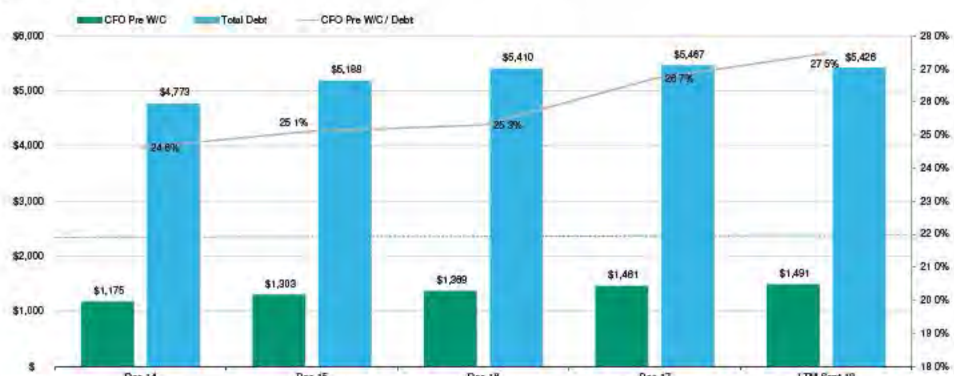
Summary

The credit of Northern States Power Company (Minnesota) (NSP-Minnesota) reflects the fully regulated nature of its electric vertically integrated 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 credit 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, A3 negative) family in terms of rate base (2017: 41%) as well as EBITDA and cash flow contribution (40%-45%). The credit also factors in that NSP-Minnesota's state regulators indirectly restrict dividends that the utility is allowed to upstream to parent Xcel Energy Inc. (Xcel, A3 negative) by requiring NSP-Minnesota to maintain an equity-to-total capitalization ratio ranging between 46.9% to 57.3%.

NSP-Minnesota's credit is tempered by the anticipated deterioration of its financial metrics due to the implementation of the Tax Cuts and Jobs Act (TCJA). However, the credit assumes that the utility will continue to produce a ratio of cash flow from operations pre-working capital (CFO pre-W/C) to debt of at least 22% over the foreseeable future.

Exhibit 1

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



The CFO Pre-W/C downgrade trigger of approximately 22% is shown with the dashed line above
Source: Moody's Financial Metrics

Credit Strengths

» Over $10 billion rate base

» Vertically integrated regulated utility with that operates in overall credit supportive regulatory environments

» A comprehensive multi-year rate plan in Minnesota reduces regulatory fatigue and enhances cash flow visibility

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

Credit Challenges

» Moderate exposure to carbon transition risk

» No regulatory initiative in Minnesota to offset the cash leakage resulting from the implementation of TCJA

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

» Potential separation of North Dakota operations would reduce diversity but impact would be modest

Rating Outlook

NSP-Minnesota's stable outlook is supported by the predictable nature of the utility's operations, and the expectation that, although declining, its key credit metrics will remain adequate for its credit, including CFO pre-W/ C to debt of at least 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 utilitys base case capex.

Factors that Could Lead to an Upgrade

Positive momentum on NSP-Minnesota's ratings is unlikely given our expectation that its weakening credit metrics will result in its credit profile to be commensurate with its current ratings. Longer term, the utility's ratings could experience positive momentum if higher than anticipated regulatory relief and/or cost savings 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 more than currently anticipated; 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-14	Dec-15	Dec-16	Dec-17	LTM Sept-18
CFO Pre-W/C + Interest / Interest	6.6x	7.0x	6.8x	7.0x	7.2x
CFO Pre-W/C / Debt	24.6%	25.1%	25.3%	26.7%	27.5%
CFO Pre-W/C – Dividends / Debt	19.2%	20.1%	18.0%	17.4%	18.0%
Debt / Capitalization	40.4%	40.6%	40.3%	44.0%	43.5%

[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

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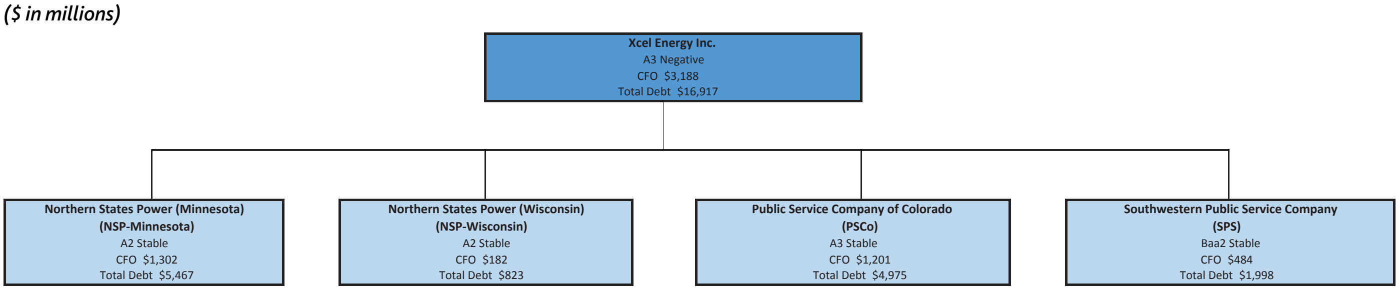
Corporate Profile

Northern States Power Company (Minnesota) (NSP-Minnesota) is a vertically integrated utility that renders 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, A3 negative), 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 largest subsidiary in terms of regulated rate base (2017: $10.2 billion) closely followed by Public Service Company of Colorado (PSCO, A3 stable; 2017 rate base: nearly $9.7 billion). 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
($ 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. Therefore, a possible separation of the utility's operation in North Dakota would have limited impact on the credit. Regulatory proceedings are still ongoing (initiated end of 2016). We understand that a pseudo-separation, which would entail an unchanged corporate structure but with specific jurisdictional cost and benefit allocation, may be the preferred option versus a full legal separation. The estimated costs of the separation (including a one-time $10 million charge and annual expense of up to $3 million p.a. starting in 2020) are modest.

The Federal Energy Regulatory Commission's (FERC) oversight of NSP-Minnesota's wholesale production (2017: around 3.5% of the utility's total electric revenues) and transmission services modestly enhances its regulatory diversity. The FERC's ongoing review of the RoE formula and the reduction in the base RoE that applies to owners of transmission assets in the Midcontinent Independent System Operator (MISO) region (first and second complaints filed in 2013 and 2015, respectively) are credit negatives. However, we estimate the impact on NSP-Minnesota's cash flows will be modest (utility's estimated reduction of transmission revenues of less than $10 million). Our assessment also factors in that FERC's tariffs are set on a forward-looking basis, subject to true-ups and formulaic rate recovery mechanisms, which enhance the utility's cash flow visibility. In October 2018, FERC proposed a new methodology to address the US Court of Appeals for the District of Colombia Circuit's decision (April 2017) to vacate and remand the previous methodology (adopted in June 2014). However, it is unclear whether the new base RoE that results from the application of this methodology (October 2018) will materially differ from the utilities' current base RoE (September 2016 Order: 10.32%). The main change is FERC's proposed reducing of its long-standing reliance on the Discounted cash flow methodology and give equal weight to the results of the other three financial models (risk premium, CAMP, and expected earnings). Refunds related to the first complaint (period: November 2013 to February 2015) were completed last year while the refunds associated with the second complaint (period: February 2015 to May 2016) are pending.

OVERALL CREDIT SUPPORTIVE STATE REGULATORY ENVIRONMENTS

Riders and multi-year plans reduce regulatory fatigue and drive our view of overall above-average ability to recover costs

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 utilities benefit 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. In this state, rates are based on historical test periods which along with a limited number of riders have contributed to the utility's volatile actual RoEs (see Exhibit 4).

Exhibit 4
Summary of key financial parameters including authorized and actual RoEs and applicable regulatory plans

		Authorized Equity Layer / RoE		W/A Earned RoE (actual)			Regulatory Plan
				2015	2016	2017	
NSP-Minnesota	Electric-Mn	52.50%	9.2% (previously 9.72%)	8.93%	9.35%	9.66%	2016-2019 multi-year plan (MYP)
	NG-Mn		10.09%	9.71%	8.12%	9.16%	
	Electric - ND	52.56%	10.25% (previously 10.0%)	8.38%	9.60%	10.91%	2013-2017 MYP
	NG-ND	51.59%	10.75%	8.87%	6%	8.75%	
	Electric - SD	Blackbox		6.21%	8.91%	6.91%	2015-2017 MYP

Source: Xcel Energy, Inc, Regulatory filings

Our opinion also considers that in Minnesota, NSP-Minnesota continues to operate under the four year electric plan (approved in June 2017) that covers the 2016-2019 period. The plan reflects the key terms of a multi-party settlement agreement reached in August 2016. The commission allowed the three-step base rate increase that approximates $180 million, and sales true-ups of $60 million in 2016. We view multi-year rates to be credit positive because they enhance the visibility of the utility's cash flows as well as provide incentives for the utility to implement cost saving initiatives which will be eventually shared with end-users in the next rate case proceeding. This opinion also factors in the authorization to implement true-up mechanisms for property tax (2017-2019) and capex (2016-2019). We also consider the decoupling mechanism (implemented in January 2016), for electric residential end-users, as well as small commercial and industrial (C&I) customers. In addition, revenues from all non-decoupled electric customers are also subject to sales true-ups. For example, in April 2018, NSP-Minnesota started to collect $49 million (12 month period) related to the 2017 sales true-up and revenue decoupling surcharges. Their annual increases are capped at 3% but they help to insulate its cash flows from sales volatility during the rate case stay-out period. We believe that the combination of all these regulatory mechanisms along with the multi-year group's wide cost savings to keep O&M costs overall flat are contributing to the improvement in the utility's electric actual RoEs in Minnesota (see Exhibit 4).

Mixed outcomes of the tax reform regulatory proceedings

In contrast to its sister companies (PSCO and SPS), NSP-Minnesota's proposed regulatory initiatives to offset the impact of tax reform excluded changes in its authorized 52.5% equity ratio (RoE: 9.2%). They rather focused largely on accelerating the amortization and depreciation of certain assets.

NSP-Minnesota's only TCJA-related regulatory proceedings pending regulator's approval are the two settlements entered with the North Dakota Public Service Commission's (NDPSC) staff related to its natural gas (August 2018) and electric (October) operations. If approved, the regulatory treatment would largely resemble the one applied for NSP-Minnesota's electric operations in the Dakotas; that is, a one-time cash refund (totaling in both states: $20 million) in 2018 and the use of the reduced revenue requirements from the application of the lower 21% corporate tax rate to stay out of rate cases in 2019 and 2020. This is overall net credit positive because 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 end of last year. In addition, the utility agreed in ND on an earnings sharing mechanism (October 2018 settlement) if its RoE exceeds 9.85% on a weather normalized basis. In this state, the utility also agreed (August 2018) to offset the financial impact of tax reform on its natural gas cash flows through the amortization of the remediation costs associated with the clean-up of the manufactured gas plant located in Fargo, a credit positive. The estimated costs of $25 million (spent to date: $19 million) were subject to deferred regulatory treatment with the jurisdictional allocation to North Dakota representing 88% of the total.

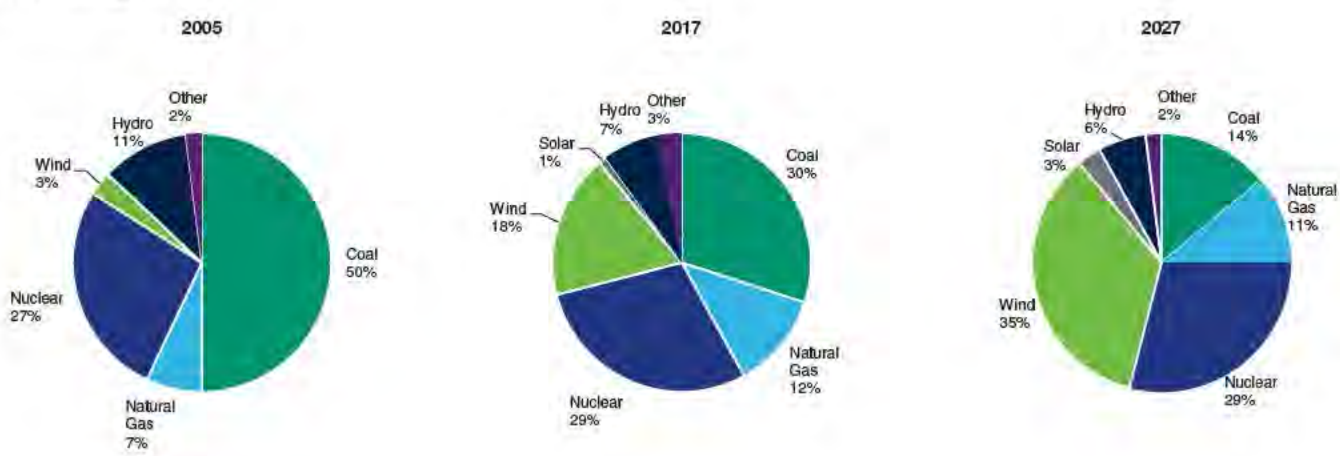
In August 2018, the Minnesota Public Utilities Commission (MPUC) ordered the utility to refund $136 million to its electric and natural gas customers, including $2 million to fund low income program. This refund equates to around 95% of the utility's total estimated impact of the implementation of the TJCA on its 2018 revenue requirements. This decision was less credit supportive than the Minnesota Department of Commerce's (DOC) recommendation earlier this year, that is to refund $90 million but to use additional $53 million to reduce the utility's next natural gas and electric rate cases. The utility had initially requested similar treatment to the DOC's recommendation but also approval to accelerate the depreciation ($22 million) of its 511 MW A.S. King-Bayport coal unit.

MODERATE CARBON TRANSITION RISK EXPOSURE

The future of the King and Sherco 3 coal-fired plants could be considered as part of NSP-Minnesota's next integrated resource plan (IRP; possible filing: 2019). Nevertheless, NSP-Minnesota's gradual reduction of its reliance on coal-fired facilities is credit positive (see Exhibit 5). In 2015, NSP-Minnesota retired the 215 MW Black Dog 3 and 4 Units while the 2016-2030 IRP (approved in January 2017) authorized the retirement of the 682 MW Sherco Unit 2 in 2023 and the 680 MW Unit 1 in 2026. These Sherco units are more than 35 years old, and we assume that its remaining rate base is relatively small, and largely reflects environmental compliance investments. The MPCU approved the utility's recovery of the remaining rate base, which also contributes to our that the utility's exposure to carbon transition risk is moderate, a credit positive.

NSP-Mn's 2016-2030 IRP also foresees the addition of 2,150 MW in renewable assets (including up to 650MW of solar projects) by 2021, through a combination of self-owned and third party projects. To that end, NSP-Minnesota is currently building 1,450 MW of new wind projects at six different locations (completion: 2019-2021), an important component of Xcel's "Steel for Fuel Strategy" to grow the group's renewable rate base. The utility also anticipates that its two nuclear plants (1,647MW) will remain operational at least over the next decade (licenses expiring between 2030-2034).

Exhibit 5
2005-2027 planned development of NSPM's energy mix



Source: Xcel Energy Inc

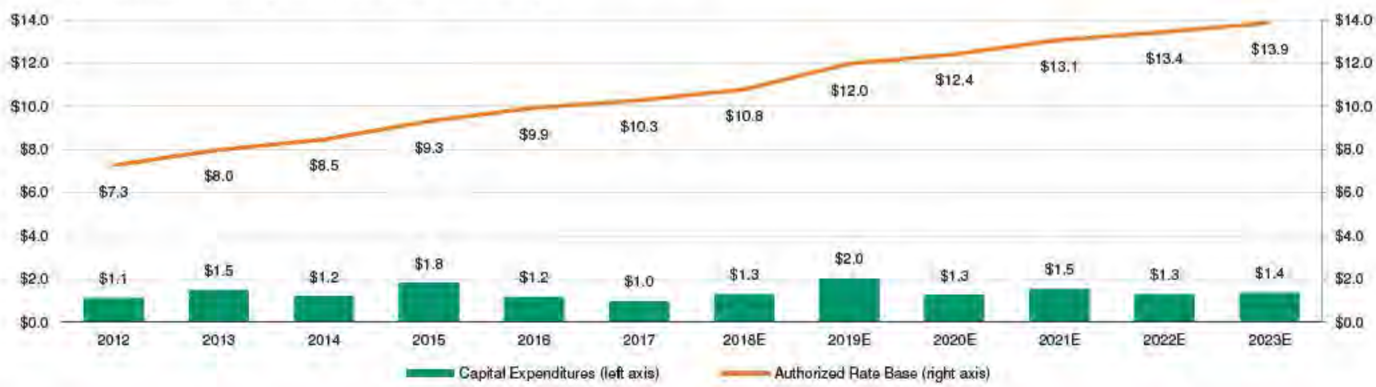
The IRP also incorporates the impact of energy efficiency goals (at least 444 GWh during the planning years) as well as the acquisition of at least 400 MW of additional demand response by 2023, and a study of the technical and economic feasibility of achieving 1,000 MW of demand response by 2025. However, the 2016-2030 IRP estimated that the utility could need 750 MW of intermediate capacity in 2026 which could further increase should the retirement of the King coal-plant be considered in future proceedings. In 2017, a law was passed in Minnesota that gives the utility authority to construct, own, and operate a natural-gas fired facility on the Sherco site. The law exempts NSP-Minnesota from the requirement to obtain a Certificate of Need from the MPUC which initially opposed the plant. However, the MPUC retains authority to approve prudently incurred costs for the plant in a rate case.

We understand that the construction of this new NG-fired facility is not included in NSP-Minnesota's investment plan for the 2019-2023 period that currently approximates $7.6 billion as updated end of October 2018. The bulk of the investments remain earmarked to expand the transmission, distribution and generation regulated footprint. The updated 2019-2023 levels still exceed the company's historical annual capital outlays (around $6.7 billion for the 2013-2017 period). However, we also note that the updated plan includes a reduction in the utility's base case expenditure by around $280 million for the 2019-2022 period while on average, these investments will represent less than 2.0x the utility's depreciation expense during this four year-period (compared to nearly 2.1x in average during the 2014-2017 period). The combination of these factors help to explain some moderation in the utility's rate base growth.

Exhibit 8

NSPM's rate base development and 2012-2022 historical and projected capital expenditure

The utility's investments have grown its rate base significantly



($ in billions)
Source: Xcel Energy Inc., Moody's estimations

NSP-Minnesota and its sister company Northern States Power Wisconsin (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.

Xcel's focus on reducing operation and maintenance costs (reduction in 2017: 1%; 2016: 0.2%) is credit positive because the improvements in the utilities' cost structure mitigate the impact of the increased capex on the end-users' bills amid an environment of overall lower power usage. For example, NSP-Minnesota reported a 0.2% reduction in its electric sales, on a weather-adjusted basis, during the 9month period ended September 2018 (9m-2017: -2.1%). That said, Xcel has disclosed that volatile summer weather conditions in 2018 drove, higher sales across the group, but also a step-up by 2%-3% in consolidated O&M costs to enhance reliability amid unanticipated vegetation growth and some stress in its systems.

NSP-Minnesota expects to complete the majority of its wind projects before year-end 2020 to allow them to quality for 100% of Production Tax Credits (PTCs). NSP-Minnesota's 300 MW Dakota Range project is the exception (COD: 2021) although it is expected to quality for 80% of PTCs. The flow back to customers of the tax benefits, along with the saved fuel costs, help to reduce the electric margin. Additional initiatives to manage the impact on customers' bills of its material investments include NSP-Minnesota's termination this year, after attaining customary regulatory approvals, of the Benson and Laurentian biomass plants Power Purchase Agreements (total: 90MW), and its purchase of the Benson facility. The utility recorded regulatory asset aggregates $212 million, including the Laurentian plant's annual termination payments payable over six years. The utility will be able to recover these costs in rates (6-10 years). However, it anticipates that the termination of these contracts will save its customers over $600 million in the next 10 years. We also understand that the remaining book value of the Sherco Unit 1 and 2 is relatively modest (less than 5% of the rate base) which drives our expectation that the utility will be able to fully recover these assets.

WEAKENING FINANCIAL METRICS

As depicted under Exhibit 2, NSP-Minnesota's credit metrics were well positioned for the credit profile, including CFO pre-W/C to debt that consistently exceeded 25% during the 2015-2017 period. However, we anticipate a deterioration of its financial metrics due to the cash leakage that results from the implementation of the TCJA. For example, the effect of the cash refunds (explained earlier) of the excess deferred income tax liabilities, "unprotected" and "protected" (during the assets' useful life) portions, the PTCs pass-through and the expiration of bonus depreciation last year. 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.

The credit assumes that the anticipated moderation in the utility's base capital expenditure (capex) program will help the utility to record credit metrics that remain adequate, including CFO pre-W/C to debt of at least 22% over the foreseeable future.

Liquidity Analysis

Similar to its sister companies, NSP-Minnesota has its own separate committed credit facility scheduled to mature in June 2021. This back-stops its $500 million CP-program (Prime-1). At the end of September 2018, the utility had $29.3 million of cash on hand and $439 million available under this credit facility (letter of credits outstanding: $37 million). 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%.

NSP-Minnesota also participates in a regulated money pool with its sister companies Public Service Company of Colorado and Southwestern Public Service Company (SPS). As of 30 September 2018 , NSP-Minnesota's $250 million borrowing limit was fully available (year-end 2017: $165 million). 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 FMBs due in August 2020. For the rest of 2018 and 2019, we anticipate that the utility will fund its capital requirements, including investments (2019: $2 billion), largely with internally generated cash flows (LTM September 2018: around $1.4 billion) and a combination of internal and external sources including parent contributions and short and long-term debt financing (planned FMB issuance: up to $700 million, per Xcel's disclosures). In addition, we anticipate that Xcel will continue to manage NSP-Minnesota's dividend policy (LTM September 2018: $460 million) and equity contributions to the utility (LTM September 2018: $71 million) so as to meet its regulatory capital structure (that is a range of equity-to-total capitalization ratio: 46.9%-57.3%; 2017: 52.1%). In January 2018, Xcel contributed $150 million across the four pension plans (NSP-Minnesota's contribution: $63 million; 2017: $61 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 9

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 9/30/2018		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%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.9x	Aa	6x - 6.5x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	26.6%	A	22% - 24%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	18.3%	A	16.5% - 17.5%	A
d) Debt / Capitalization (3 Year Avg)	40.8%	A	38% - 40%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching	0	0	0	0
a) Indicated Rating from Grid		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 9/30/2018(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.
Source: Moody's Financial Metrics

Appendix

Exhibit 10

Cash Flow and Credit Metrics [1]

CF Metrics	Dec-14	Dec-15	Dec-16	Dec-17	LTM Sept-18
As Adjusted					
EBITDA	**1,378**	**1,498**	**1,689**	**1,811**	**1,798**
FFO	**1,106**	**1,283**	**1,395**	**1,482**	**1,475**
- Div	259	259	396	507	515
RCF	**259**	**259**	**396**	**507**	**515**
FFO	1,106	1,283	1,395	1,482	1,475
+/- ΔWC	(35)	19	(42)	(158)	(50)
+/- Other	69	20	(26)	(21)	16
CFO	**1,141**	**1,322**	**1,327**	**1,302**	**1,441**
- Div	259	259	396	507	515
- Capex	1,224	1,830	1,178	984	938
FCF	**(343)**	**(766)**	**(247)**	**(188)**	**(12)**
Debt / EBITDA	3.5x	3.5x	3.2x	3.0x	3.0x
EBITDA / Interest	6.6x	6.9x	7.2x	7.5x	7.5x
FFO / Debt	23.2%	24.7%	25.8%	27.1%	27.2%
RCF / Debt	23.2%	24.7%	25.8%	27.1%	27.2%
Revenue	4,989	4,757	4,900	5,102	5,128
Cost of Goods Sold	2,197	1,909	1,795	1,901	1,959
Interest Expense	210	218	235	242	241
Net Income	417	406	493	523	544
Total Assets	16,108	17,093	17,917	18,005	18,096
Total Liabilities	11,504	12,058	12,691	12,664	12,704
Total Equity	4,603	5,035	5,226	5,341	5,392

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 11

Peer Comparison [1]

	Northern States Power Company (Minnesota)			Northern States Power Company (Wisconsin)			ALLETE, Inc.			Otter Tail Power Company		
	(P)A2 Stable			(P)A2 Stable			A3 Negative			A3 Stable		
	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM
(in US millions)	Dec-16	Dec-17	Sept-18	Dec-16	Dec-17	Sept-18	Dec-16	Dec-17	Jun-18	Dec-16	Dec-17	Jun-18
Revenue	4,900	5,102	5,128	957	1,005	1,015	1,340	1,419	1,403	427	435	439
CFO Pre-W/C	1 369	1,461	1,491	180	192	208	376	445	433	121	137	124
Total Debt	5,410	5,467	5,426	783	823	842	1,823	1,748	1,764	560	603	615
CFO Pre-W/C / Debt	25.3%	26.7%	27.5%	23.0%	23.4%	24.7%	20.6%	25.5%	24.6%	21.5%	22.7%	20.1%
CFO Pre-W/C – Dividends / Debt	18.0%	17.4%	18.0%	16.2%	15.6%	17.9%	15.0%	19.2%	18.2%	14.6%	16.0%	13.5%
Debt / Capitalization	40.3%	44.0%	43.5%	38.9%	42.4%	42.5%	42.8%	43.3%	43.1%	41.9%	48.0%	47.8%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics

Ratings

Exhibit 12

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	Negative
Issuer Rating	A3
Sr Unsec Bank Credit Facility	A3
Senior Unsecured	A3
Subordinate Shelf	(P)Baa1
Pref. Shelf	(P)Baa2
Commercial Paper	P-2

Source: Moody's Investors Service

REPORT NUMBER 1147001

MOODY'S
INVESTORS SERVICE

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

Mnemonic	Description	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2022 Q1	2022 Q2	2022 Q3	2022 Q4
The 3 month eurodollar rates are basis for projected short term debt costs													
RMEUROD3M	**Rate on 3-month eurodollar deposits, percent per annum,**	2.3400	2.3400	2.3900	2.6000	2.6100	2.6100	2.6100	2.6100	2.6200	2.6200	2.6100	2.6100
	Spread to Calculate NSPM's STD Rate	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500
	Total Short Term Debt Interest Rate	2.3900	2.3900	2.4400	2.6500	2.6600	2.6600	2.6600	2.6600	2.6700	2.6700	2.6600	2.6600
	Total Calculated on 365/360 Basis - Multiplied by Average Balance				2.51%				2.69%				2.70%
The 10 and 30-year yields on U.S. Treasuries are the basis for new long term debt													
RMTCM10Y	**Yield on 10-year treasury notes, percent per annum, FRB**	2.4025	2.5314	2.6448	2.7454	2.8330	2.9178	3.0002	3.0771	3.1330	3.1842	3.2271	3.2685
	Credit Spread												
	Total LTD Coupon Interest Rate												
RMTCM25AY	**Yield on 30-year treasury bonds, percent per annum, FRB**	2.8815	2.9968	3.0971	3.1851	3.2623	3.3367	3.4084	3.4746	3.5209	3.5649	3.6018	3.6347
	Credit Spread		0.9032				0.7633				1.0351		
	Total LTD Coupon Interest Rate		3.9000				4.1000				4.6000		

Source: IHS Global Insight, July 2019.

($000's)

2020 FORECASTED LONG TERM DEBT AND COST

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	-	385	314		249,301	17,813	-	78	63		17,954	7.20%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	448	375		149,178	9,750	-	59	49		9,858	6.61%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	243	1,517		248,241	13,125	-	16	101		13,243	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	8,650	742	2,580		405,328	25,000	(546)	47	163		25,756	6.35%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	1,123	2,451		346,426	21,700	-	66	145		21,911	6.32%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(2,065)	367	2,676		294,892	16,050	107	19	139		16,101	5.46%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	473	2,020		247,506	12,125	-	24	101		12,249	4.95%
Series Due August 15, 2022 (FMB)	2.1500	Aug-12	Aug-22	300,000	-	95	643		299,262	6,450	-	46	310		6,806	2.27%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(33,063)	2,811	4,618		459,508	17,000	1,501	128	210		15,837	3.45%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	207	1,282		398,511	10,400	-	73	455		10,928	2.74%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	693	3,037		296,270	12,375	-	29	128		12,532	4.23%
Series Due Aug 15, 2020 (FMB) (2)	2.2000	Aug-15	Aug-20	175,000	-	19	104		174,878	3,850	-	68	383		4,301	2.46%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	4,094	3,259		292,647	12,000	-	164	130		12,294	4.20%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,805	4,663		343,532	12,600	-	70	181		12,851	3.74%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	5,415	7,967	7,581	579,036	22,200	-	200	294	280	22,973	3.97%
Series Due Mar 15, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	-	8,742		591,258	17,400	-	-	295		17,695	2.99%
Series Due Jun 1, 2050 (FMB) (1)	3.9000	Jun-20	Jun-50	495,833	-	-	7,355		488,479	19,338	-	-	249		19,587	4.01%
Other Debt																
Right of Way Notes	var	var	var	9	-	-	-		9	-	-	-	-		-	0.00%
TOTAL DEBT				5,970,843	(26,478)	18,919	53,601	7,581	5,864,263	249,175	1,062	1,086	3,396	280	252,875	4.31%
Unamortized Loss on Reacquired Debt									(6,950)						1,416	
Fees on 5-year Credit Facility (3)									-						380	
GRAND TOTAL and COST OF DEBT									5,857,314						254,671	4.35%

(1) NSPM 2020 issuance of $850M 30 year bond, balance is 7 of 12 months.

(2) NSPM 2015 issuance of $300M 5 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.

($000's)

2021 FORECASTED LONG TERM DEBT AND COST

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	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	-	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		25,754	6.36%
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		16,101	5.45%
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		15,840	3.43%
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 15, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	-	8,447		591,553	17,400	-	-	295		17,695	2.99%
Series Due Jun 1, 2050 (FMB)	3.9000	Jun-20	Jun-50	850,000	-	-	12,272		837,728	33,150	-	-	425		33,575	4.01%
Series Due May 1, 2051 (FMB) (1)	4.1000	May-21	May-51	233,333	-	-	3,456		229,877	9,567	-	-	117		9,684	4.21%
Other Debt																
Right of Way Notes	var	var	var	9	-	-	-		9	-	-	-	-		-	0.00%
TOTAL DEBT				6,383,343	(25,419)	17,885	59,113	7,302	6,273,623	268,704	1,059	1,015	3,298	279	272,238	4.34%
Unamortized Loss on Reacquired Debt									(5,700)						1,217	
Fees on 5-year Credit Facility (2)									-						379	
GRAND TOTAL and COST OF DEBT									6,267,923						273,833	4.37%

(1) NSPM 2021 issuance of $350M 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
Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-Term Debt
($000's)

Docket No. E002/GR-19-564
Exhibit___(SWS-1), Schedule 11
Page 1 of 1

2022 FORECASTED LONG TERM DEBT AND COST

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	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	-	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		25,754	6.36%
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		16,101	5.45%
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		15,840	3.42%
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 15, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	-	8,153		591,847	17,400	-	-	295		17,695	2.99%
Series Due Jun 1, 2050 (FMB)	3.9000	Jun-20	Jun-50	850,000	-	-	11,847		838,153	33,150	-	-	425		33,575	4.01%
Series Due May 1, 2051 (FMB)	4.1000	May-21	May-51	350,000	-	-	5,038		344,962	14,350	-	-	175		14,525	4.21%
Series Due Jun 1, 2052 (FMB) (1)	4.6000	Jun-22	Jun-52	291,667	-	-	4,326		287,340	13,417	-	-	146		13,563	4.72%
Other Debt																
Right of Way Notes	var	var	var	9	-	-	-		9	-	-	-	-		-	0.00%
TOTAL DEBT				6,666,676	(24,360)	16,874	61,868	7,023	6,556,550	284,217	1,059	998	3,385	279	287,819	4.39%
Unamortized Loss on Reacquired Debt									(4,529)						1,020	
Fees on 5-year Credit Facility (3)									-						379	
GRAND TOTAL and COST OF DEBT									6,552,021						289,218	4.41%

(1) NSPM 2022 issuance of $500M 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.

TEST YEAR - 2020 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
2020 Jan	$235,460,046	$243,114,605	$500,343	$42,655	
2020 Feb	$119,925,028	$177,692,537	$342,107	$39,984	
2020 Mar	$81,667,031	$100,796,029	$207,444	$42,655	
2020 Apr	$90,432,124	$86,049,578	$171,382	$41,319	
2020 May	$202,011,399	$146,221,762	$300,933	$42,655	
2020 June	$0	$101,005,700	$201,170	$41,319	
2020 Jul	$0	$0	$0	$42,655	
2020 Aug	$3,596,584	$1,798,292	$3,778	$42,655	
2020 Sep	$90,283,655	$46,940,120	$95,445	$41,319	
2020 Oct	$119,246,715	$104,765,185	$239,068	$42,655	
2020 Nov	$130,184,358	$124,715,537	$275,413	$41,319	
2020 Dec	$235,030,485	$182,607,421	$416,700	$42,655	
Average	$108,986,452	$109,642,230			
Total			$ 2,753,784	$ 503,847	
			2.51%	0.46%	2.97%

(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 Inc 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.)

PLAN YEAR - 2021 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
2021 Jan	$268,108,276	$251,569,380	$576,234	$42,655	
2021 Feb	$200,463,215	$234,285,746	$484,711	$38,648	
2021 Mar	$147,580,500	$174,021,857	$398,607	$42,655	
2021 Apr	$183,674,019	$165,627,259	$367,140	$41,319	
2021 May	$0	$91,837,010	$210,358	$42,655	
2021 June	$125,927,695	$62,963,848	$139,570	$41,319	
2021 Jul	$214,016,604	$169,972,150	$389,331	$42,655	
2021 Aug	$148,687,015	$181,351,810	$415,396	$42,655	
2021 Sep	$93,934,275	$121,310,645	$268,905	$41,319	
2021 Oct	$202,722,003	$148,328,139	$339,754	$42,655	
2021 Nov	$224,031,409	$213,376,706	$472,985	$41,319	
2021 Dec	$174,778,307	$199,404,858	$456,748	$42,655	
Average	$165,326,943	$167,837,451			
Total			$ 4,519,739	$ 502,511	
			2.69%	0.30%	2.99%

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

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

PLAN 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	$248,078,786	$211,428,546	$486,109	$42,655	
2022 Feb	$159,902,562	$203,990,674	$423,621	$38,648	
2022 Mar	$79,798,571	$119,850,566	$275,556	$42,655	
2022 Apr	$127,557,262	$103,677,917	$230,683	$41,319	
2022 May	$267,296,543	$197,426,903	$453,917	$42,655	
2022 June	$0	$133,648,272	$297,367	$41,319	
2022 Jul	$0	$0	$0	$42,655	
2022 Aug	$112,459,550	$56,229,775	$128,797	$42,655	
2022 Sep	$105,150,230	$108,804,890	$241,184	$41,319	
2022 Oct	$204,236,864	$154,693,547	$354,334	$42,655	
2022 Nov	$238,437,553	$221,337,208	$490,631	$41,319	
2022 Dec	$279,113,075	$258,775,314	$592,739	$42,655	
Average	$151,835,916	$147,488,634			
Total			$ 3,974,940	$ 502,511	
			2.70%	0.34%	3.04%

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

(2) Monthly Interest Expense based on weighted average of short term debt outstanding and Interest Rates based on Global Insights Inc 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 2017 Through June 2019

	Borrowings			Investments		
Date	Average Amount Outstanding	Actual Interest Rate	Alternative Interest Rate *	Average Amount Outstanding	Actual Interest Rate	Alternative Interest Rate **
2017						
Jan	$ -	0.9087%	3.7500%			
Feb	$ 464,286	0.9069%	3.7500%	$ 2,857,143	0.9069%	0.5000%
Mar	$ 741,935	0.9481%	4.0000%	$ 4,225,806	0.9481%	0.5000%
Apr	$ 333,333	1.1225%	4.0000%	$ 2,100,000	1.1225%	0.5000%
May	$ -	1.1750%	4.0000%			
Jun	$ 40,833,333	1.2236%	4.2500%			
Jul	$ 54,774,194	1.1000%	4.2500%			
Aug	$ 69,935,484	1.1100%	4.2500%			
Sep	$ 25,800,000	1.1100%	4.2500%			
Oct	$ 27,548,387	1.1200%	4.2500%			
Nov	$ 33,100,000	1.1400%	4.2500%			
Dec	$ 47,129,032	1.1800%	4.5000%			
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%			

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

Northern States Power Company
Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Common Equity
($000's)

Docket No. E002/GR-19-564
Exhibit___(SWS-1), Schedule 16

TEST YEAR - 2020 FORECASTED EQUITY BALANCES

Month	GAAP Common Equity Outstanding	Non-Regulated Subsidiaries (1)	Regulated Common Equity
2019 Dec	$6,346,384	$930	$6,345,454
2020 Jan	$6,459,526	$930	$6,458,596
2020 Feb	$6,518,524	$930	$6,517,594
2020 Mar	$6,473,121	$930	$6,472,191
2020 Apr	$6,488,467	$930	$6,487,537
2020 May	$6,510,895	$930	$6,509,965
2020 Jun	$6,483,361	$930	$6,482,431
2020 Jul	$6,573,992	$930	$6,573,062
2020 Aug	$6,675,891	$930	$6,674,961
2020 Sep	$6,629,755	$930	$6,628,825
2020 Oct	$6,757,834	$930	$6,756,904
2020 Nov	$6,891,853	$930	$6,890,923
2020 Dec	$6,930,433	$930	$6,929,503
13 Month Average	$6,595,388	$930	$6,594,458

(1) United Power and Land.

($000's)

PLAN YEAR - 2021 FORECASTED EQUITY BALANCES

Month	GAAP Common Equity Outstanding	Non-Regulated Subsidiaries (1)	Regulated Common Equity
2020 Dec	$6,930,433	$930	$6,929,503
2021 Jan	$7,023,122	$930	$7,022,192
2021 Feb	$7,061,338	$930	$7,060,408
2021 Mar	$7,003,254	$930	$7,002,324
2021 Apr	$7,040,648	$930	$7,039,718
2021 May	$7,068,999	$930	$7,068,069
2021 June	$7,028,324	$930	$7,027,394
2021 Jul	$7,127,329	$930	$7,126,399
2021 Aug	$7,215,647	$930	$7,214,717
2021 Sep	$7,193,284	$930	$7,192,354
2021 Oct	$7,229,299	$930	$7,228,369
2021 Nov	$7,265,286	$930	$7,264,356
2021 Dec	$7,252,494	$930	$7,251,564
13 Month Average	$7,110,727	$930	$7,109,797

(1) United Power and Land.

($000's)

PLAN YEAR - 2022 FORECASTED EQUITY BALANCES

Month	GAAP Common Equity Outstanding	Non-Regulated Subsidiaries (1)	Regulated Common Equity
2021 Dec	$7,252,494	$930	$7,251,564
2022 Jan	$7,324,051	$930	$7,323,121
2022 Feb	$7,365,868	$930	$7,364,938
2022 Mar	$7,298,450	$930	$7,297,520
2022 Apr	$7,324,665	$930	$7,323,735
2022 May	$7,355,659	$930	$7,354,729
2022 June	$7,327,897	$930	$7,326,967
2022 Jul	$7,429,500	$930	$7,428,570
2022 Aug	$7,518,262	$930	$7,517,332
2022 Sep	$7,459,862	$930	$7,458,932
2022 Oct	$7,527,801	$930	$7,526,871
2022 Nov	$7,563,519	$930	$7,562,589
2022 Dec	$7,588,734	$930	$7,587,804
13 Month Average	$7,410,520	$930	$7,409,590

(1) United Power and Land.

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

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.