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Direct Testimony and Schedules
Patrick L. Cutshall

Before the Minnesota Public Utilities Commission

State of Minnesota

In the Matter of the Application of Minnesota Power
for Authority to Increase Rates for Electric Utility
Service in Minnesota

Docket No. E015/GR-19-442

Exhibit ___________

CAPITAL STRUCTURE, COST OF CAPITAL, RETIREMENT PLAN ACCOUNTING, AND TAX

November 1, 2019

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. I am Patrick L. Cutshall, and my business address is 30 West Superior Street, Duluth, Minnesota 55802.

Q. What is your present position with ALLETE, Inc.?

A. I am the Vice President and Corporate Treasurer of ALLETE, Inc.

Q. Please describe your educational background and work experience with ALLETE, Inc. and Minnesota Power.

A. I have 32 years of experience in finance. I earned a Bachelor's degree in accounting from the University of Minnesota Duluth in 1987 and have the professional designations of a CPA (Certified Public Accountant), which is currently inactive, and a CFA (Chartered Financial Analyst). I began my career at ALLETE in 1989 as an Accounting Analyst and became an Investment Analyst in my first year. I was promoted to the position of Retirement Fund Manager in 2003, to Director of Investments and Tax in 2014, and most recently to Vice President and Corporate Treasurer. Prior to my employment at ALLETE, I worked as a CPA for Ernst & Whinney, a predecessor to Ernst & Young LLP.

Q. What are your present duties as Vice President and Corporate Treasurer of ALLETE?

A. As Vice President and Corporate Treasurer, I am responsible for raising capital, including both debt and equity; banking and bank relationships; credit rating relationships; financial analysis; long-range financial forecasts; cash management; benefit plan investments; rates; and tax.

Q. What is the purpose of the testimony you are presenting on behalf of Minnesota Power?

A. My testimony will address the recommended capital structure and overall rate of return for Minnesota Power ("Minnesota Power" or the "Company"). I also address the

Company's proposals with respect to recovery of test year pension and other post-employment benefit ("OPEB") expense, provide support for the Company's request to include Minnesota Power's accumulated contributions in excess of net periodic benefit cost for the pension in rate base, and provide information regarding tax items.

Q. Please summarize your recommendations to the Minnesota Public Utilities Commission ("Commission") for Minnesota Power's test year capital structure and overall rate of return.

A. My testimony provides support for the Commission to establish an overall rate of return of 7.4737 percent. This is based on a recommended capital structure that consists of 53.8108 percent common equity and a 10.0500 percent return on equity ("ROE") as supported in the Direct Testimony of Company witness Ms. Ann E. Bulkley. The recommended capital structure and rate of return are needed to support and maintain adequate investment-grade corporate credit ratings and financial integrity necessary for Minnesota Power to continue to provide quality electric service. My recommendations are summarized below in Table 1.

Table 1. Recommended 2020 Test Year Capital Structure and Rate of Return

	Percentage	Cost	Weighted Cost
Long-Term Debt	46.1892 %	4.4723 %	2.0657 %
Short-Term Debt	0.0000 %		0.0000 %
Common Equity	53.8108 %	10.0500 %	5.4080 %
Total	**100.0000 %**		**7.4737 %**

I also support Minnesota Power's forecasted 2020 test year pension and OPEB expense, totaling $7,060,000 ALLETE ($4,958,254 Minnesota Power regulated ("MP regulated"); $4,435,113 Minnesota jurisdictional ("MN")) and $3,670,000 ALLETE

($2,885,794 MP regulated; $2,581,317 MN), respectively.[1] I explain why the Company believes it is reasonable to establish pension and OPEB expense based on our best estimate of current costs for the pension and OPEB plans.

I also support the inclusion in rate base of our pension's accumulated contributions in excess of net periodic benefit cost on the grounds that this outcome is consistent with standard ratemaking treatment for other rate base items, provides fairness for the use of investor capital, supports critical credit ratings, and the Company's levels of contributions are mandated.

I conclude with a tax discussion that includes support for the proposed proration of accumulated deferred income taxes ("ADIT"), the treatment of excess ADIT, and Federal Production Tax Credits ("PTCs").

Q. Please summarize the basis for your recommendations for the Company's capital structure and overall rate of return.

A. Minnesota Power requires an appropriate capital structure, cost of debt, and ROE to support ALLETE's credit rating and to attract investor capital, especially considering: 1) the size and risk (concentrated industrial load) of Minnesota Power; 2) the need to attract capital to continue Minnesota Power's efforts toward 50 percent carbon free renewable generation by 2021 and continuing state leadership in renewable generation as a percentage of total generation; 3) the need for annual financing to fulfill Minnesota Power's future capital requirements and to address maturing debt; and 4) Minnesota Power's ongoing obligation to deliver safe, reliable and affordable electric power.

My recommended capital structure is the same as Minnesota Power received in its last rate case. The overall rate of return is based upon ALLETE's embedded cost of debt plus one estimated debt financing for the middle of the 2020 test year to replace

[1] A summary of allocation factors used across the Company for purposes of calculating the Minnesota Jurisdictional totals is provided with the Direct Testimony of Company witness Mr. Stewart J. Shimmin at MP Exhibit ___ (Shimmin), Direct Schedule 1 – Guide to Minnesota Power's CCOSS, at Table 4.

maturing debt, and an appropriate ROE that is slightly higher than the nation's average utilities' ROE, due to Minnesota Power's unique factors described above.

Q. Please summarize the basis for your recommendations regarding the Company's retirement plan accounting.

A. Minnesota Power needs an appropriate authorized capital structure and supportive overall rate of return on its invested capital to further advance the quality and effectiveness of services the Company provides to its customers. This includes retirement plan expenses and investor's capital invested in the retirement plans. The retirement plan expenses are estimated with current assumptions by the Company's actuaries, which has been shown to be the most consistent predictor of the future year's retirement expense. Shareholder investments in the pension plan, which are easily determinable, and are the accumulated contributions in excess of net periodic pension cost, need to be included in rate base (or in another recovery mechanism) to compensate shareholders for their contributed capital. Both in Minnesota and nationally, there is a precedent for recovery of such shareholder investments.

Q. Please summarize the bases for your recommendations regarding tax issues.

A. The bases for my recommendations regarding all tax issues I discuss are current tax law, prior rate making precedent, and common understanding based on prior Commission decisions on how to treat certain newer items related to the Tax Cuts and Jobs Act ("TCJA").

Q. Please explain the organization of the remainder of your testimony.

A. The remainder of my testimony is organized as follows:

- In Section II, I describe ALLETE's corporate structure.
- In Section III, I describe Minnesota Power's financial position. This section will explain the credit ratings, risks facing Minnesota Power, and recent actions taken by the rating agencies.
- In Section IV, I discuss the recommended test year capital structure.
- In Section V, I discuss pension and OPEB accounting and contributions.

- In Section VI, I discuss tax matters.
- In Section VII, I provide my overall conclusions and recommendations.

Q. What schedules are you sponsoring in this proceeding?

A. I am sponsoring the following schedules, which immediately follow my testimony and are identified as:

- MP Exhibit ___ (Cutshall), Direct Schedule 1: Moody's Investor Services ("Moody's") Rating Methodology Regulated Electric and Gas Utilities. (Jun. 23, 2017);
- MP Exhibit ___ (Cutshall), Direct Schedule 2: Moody's Credit Report on ALLETE, Inc. (Feb. 22, 2018) (Trade Secret);
- MP Exhibit ___ (Cutshall), Direct Schedule 3: Moody's Credit Report on ALLETE, Inc. (Apr. 3, 2019) (Trade Secret);
- MP Exhibit ___ (Cutshall), Direct Schedule 4: Standard & Poor's ("S&P") Corporation Key Credit Factors for the Regulated Utilities Industry (Nov. 19, 2013);
- MP Exhibit ___ (Cutshall), Direct Schedule 5: S&P's Credit Report on ALLETE, Inc. (Feb. 6, 2018) (Trade Secret);
- MP Exhibit ___ (Cutshall), Direct Schedule 6: S&P's Credit Report on ALLETE, Inc. (May 13, 2019) (Trade Secret);
- MP Exhibit ___ (Cutshall), Direct Schedule 7: Prepaid Pension Roll Forward;
- MP Exhibit ___ (Cutshall), Direct Schedule 8: Mercer (US) Inc. ("Mercer") Pension Portfolio Asset Allocation;
- MP Exhibit ___ (Cutshall), Direct Schedule 9: EEI Member Companies, Per Company's 2018 Annual Reports, Expected Return on Plan Assets;
- MP Exhibit ___ (Cutshall), Direct Schedule 10: EEI Pension and OPEB Survey 2018-2019 (Trade Secret);
- MP Exhibit ___ (Cutshall), Direct Schedule 11: Prepaid Pension Asset Working Capital Requirements;

- MP Exhibit ___ (Cutshall), Direct Schedule 12: Customer Benefits from Prepaid Pension Assets;
- MP Exhibit ___ (Cutshall), Direct Schedule 13: 2018 Mercer Actuarial Valuation Report;
- MP Exhibit ___ (Cutshall), Direct Schedule 14: Mercer Letter – Investment Earnings Impact on Pension Expense;
- MP Exhibit ___ (Cutshall), Direct Schedule 15: Mercer OPEB Portfolio Asset Allocation; and
- MP Exhibit ___ (Cutshall), Direct Schedule 16: 2018 Form 10-K Independent Auditor Report.

Q. Are there other schedules in the rate filing that support your testimony?

A. Yes. For General Rates, my testimony is supported by the rate of return and cost of capital exhibits in Volume 3, including:

- Direct Schedule D-1 – Rate of Return Cost of Capital Summary Schedule;
- Direct Schedule D-2 – Embedded Cost of Long-Term Debt; and
- Direct Schedule D-3 – Average Short-Term Securities.

Direct Schedule D-1, Rate of Return Cost of Capital Summary Schedule, shows the cost of each capital element, including rate of return on equity capital; capitalization amounts and ratios; weighted cost of each capital element; and overall rate of return. The actual cost is provided for the 2018 calendar year, and projected costs are provided for 2019 and the 2020 test year. Direct Schedule D-2, Embedded Cost of Long-Term Debt, shows the actual weighted cost of capital for all issuances of long-term debt for 2018, and as projected for 2019 and the 2020 test year. Direct Schedule D-3, Average Short-Term Securities, explains that Minnesota Power does not have any short-term debt in its capital structure.

For Interim Rates, my testimony is supported by the rate of return and cost of capital exhibits in Volume 1, including:

- Direct Schedule C-6 (IR) – Capital Structure and Rate of Return Calculations Comparison to Most Recent General Rate Case;
- Direct Schedule C-7 (IR) – Description of Changes to Capital Structure and Rate of Return Calculations Comparison to Most Recent General Rate Case;
- Direct Schedule D-6 (IR) – Capital Structure and Rate of Return Calculations Comparison to Most Recent (Actual) Fiscal Year; and
- Direct Schedule D-7 (IR) – Description of Changes to Capital Structure and Rate of Return Calculations Comparison to Most Recent (Actual) Fiscal Year.

In addition, my testimony is supported by the capital structure calculations in Volume 4, including:

- Workpaper COC-1 – Minnesota Power Capital Structure Determination.

II. ALLETE CORPORATE STRUCTURE

Q. Please explain the significance of Minnesota Power to ALLETE.

A. Minnesota Power is an operating division of ALLETE, and is ALLETE's dominant business by a significant margin, representing approximately 70 percent of ALLETE's capital.

Q. What are ALLETE's other investments, in addition to Minnesota Power?

A. ALLETE's other investments are organized into two types of energy businesses: (1) other regulated utility businesses; and (2) energy infrastructure and related services. ALLETE's regulated utility investments in addition to Minnesota Power are: (1) American Transmission Company ("ATC") (approximately 8 percent ownership), an independent transmission company in Wisconsin; and (2) Superior Water, Light & Power ("SWLP"), an electric, water, and gas utility in Wisconsin. ALLETE's energy infrastructure and related services investments are: (1) ALLETE Clean Energy ("ACE"), a company that develops, acquires, and manages clean and renewable energy projects; and (2) BNI Energy ("BNI"), whose primary business is a lignite coal mining operation in North Dakota that serves the Milton R. Young generating plant located at the mine site. ALLETE also has additional non-regulated investments, including

ALLETE South Wind, an investment in the Nobles 2 wind project which is expected to commence operation in late 2020; ALLETE Properties, a legacy Florida real estate investment; and South Shore Energy, an investment in the Nemadji Trail Energy Center, expected to be in operations in 2025.

ALLETE historically had an additional investment: it owned U.S. Water Services. However, ALLETE divested this business in March 2019.

Q. How does Minnesota Power's capital structure relate to that of ALLETE?

A. As an operating division of ALLETE, Minnesota Power has a capital structure that is derived from ALLETE's consolidated capital structure.[2] The ALLETE consolidated capital structure includes common equity and debt that finance all of ALLETE's business activities, including those of its subsidiary operations. The Minnesota Power capital structure, which is the capital structure used for ratemaking purposes, is calculated by starting with ALLETE's capital structure and then extracting the debt located at ALLETE's subsidiaries and ALLETE's equity and debt investments in those subsidiaries. Capital structure calculations are included in Volume 4, Workpaper COC-1 – Minnesota Power Capital Structure Determination.

Q. You note that Minnesota Power is an operating division of ALLETE. Has ALLETE considered forming a holding company?

A. Yes. As noted by Company witness Mr. David J. McMillan in the Company's 2016 rate filing in Docket No. E015/GR-16-664 ("2016 Rate Case"), ALLETE has considered this structure in the past. No decision was made at that time. The Company is currently still evaluating the potential implications of forming a holding company. Any such filing would be made outside of a rate proceeding.

[2] ALLETE's capital structure is reflected in its 2018 Form 10-K filed with the U.S. Securities and Exchange Commission and included in this filing as Direct Schedule F-1 in Volume 3.

Q. Is Minnesota Power proposing any changes to the methodology that was used to establish its capital structure in the Company's 2016 rate case filing?

A. No, the proposed 2020 test year capital structure is consistent with the methodology that was approved in the Company's 2016 Rate Case.

In addition, the Company requests that the capital structure in the current filing remain unchanged from the last approved amounts in the 2016 Rate Case. While the capital structure has been maintained near the allowed capital structure, there are slight fluctuations in the ratios due to specific timing of debt and equity issuances and capital expenditures. For the test year, the Company is projected to carry an equity ratio that is slightly higher than what was approved in the last rate case, but requests that the capital structure remain unchanged.

Q. Does the sale of U.S. Water Services by ALLETE impact Minnesota Power's capital structure?

A. No. In March 2019, ALLETE closed on the sale of U.S. Water Services. While the cash proceeds of this non-regulated transaction reduced the need for external equity financing at ALLETE, Minnesota Power's capital structure request is unchanged: Minnesota Power still needs to appropriately capitalize its business commensurate with its risk profile in order to meet rating agency expectations.

III. MINNESOTA POWER'S FINANCIAL POSITION

A. <u>The Company's Current Financial Position</u>

Q. What is the purpose of this section of your testimony?

A. Since the 2016 Rate Case, Minnesota Power had a reduction in its credit rating and cash flow metrics due to the results of the 2016 Rate Case and, to a lesser extent, the reduction of rates and refunding of deferred taxes due to the TCJA. This downgrade occurred in spite of Minnesota Power's effort to support its credit ratings and cash flow metrics by maintaining an appropriate capital structure and by reducing operations and maintenance ("O&M") expense in the 2019 Minnesota Power forecast by approximately $45 million (Minnesota Power regulated) compared to its 2017 budget used to develop the 2017 test year in the 2016 Rate Case. In this section of my testimony, I discuss the Company's financial position since the 2016 Rate Case, as well as the view of the market with respect to the Company's access to capital. I outline the challenges facing Minnesota Power despite a strong financial marketplace and relatively stable recent taconite sales, and how the Company has successfully managed through this time within the parameters set forth in the 2016 Rate Case.

Q. Please summarize Minnesota Power's present authorized capital structure and rate of return.

A. In Minnesota Power's 2016 Rate Case, the Commission found that an equity ratio of 53.81 percent and a 9.25 percent ROE were appropriate, resulting in an overall rate of return of 7.06 percent.

Q. Please describe Minnesota Power's debt financing since the 2016 Rate Case.

A. Compared to the 2016 Rate Case, Minnesota Power's long-term debt portion of the capital structure has increased by $53.2 million, while the cost of long-term debt has decreased by 4 basis points due to the favorable pricing of long-term debt in recent years and the projected test year. The recent low interest rate environment has been instrumental in the ability to raise low-cost debt at Minnesota Power. A positive regulatory framework and supportive credit rating will be needed moving forward to continue accessing low-cost capital for the benefit of customers.

Q. Has Minnesota Power maintained its approved equity ratio following its last rate proceeding?

A. Yes. Since the 2016 Rate Case, Minnesota Power's capital structure has been prudently managed in support of its credit ratings: the 2017 approved capital structure (equity to capital ratio of 53.81 percent) was maintained within a reasonable corridor of 52.79 percent to 54.46 percent. Table 2 below displays Minnesota Power's actual capital structure for 2017 and 2018 as well as the projected amounts for 2019 and 2020.

Table 2. Minnesota Power Capital Structure 2017-2020

	2017 Actual	2018 Actual	2019 Projected	2020 Projected	2020 Requested
Common Equity	$1,402,976	$1,358,634	$1,459,671	$1,532,832	
Short-term Debt	-	-	-	-	
Long-term Debt	1,207,237	1,214,784	1,256,125	1,281,771	
Total Capitalization	$2,610,213	$2,573,418	$2,715,796	$2,814,603	
Equity Ratio	*53.75%*	*52.79%*	*53.75 %*	*54.46 %*	*53.8108%*
Debt Ratio	*46.25 %*	*47.21%*	*46.25 %*	*45.54 %*	*46.1892%*

Q. Has Minnesota Power earned its allowed rate of return since its 2016 Rate Case?

A. No. Minnesota Power's 2018 unadjusted MN Jurisdictional rate of return was 6.50 percent. The Company's 2018 rate of return was materially below its authorized level due to incurred costs that were not included in rates, as well as a loss of load compared to the sales forecast approved in the last rate case. The Company's projected 2019 unadjusted MN Jurisdictional rate of return (6.84 percent) is expected to be closer to its authorized level due to additional cost reductions and relatively stable revenues during the course of the year. However, the Company's current cost levels are not sustainable in the long term, and revenues are expected to be materially lower in 2020 due to the loss of high margin off-system sales.[3] Without rate relief, the Company's 2020 test year MN Jurisdictional rate of return is projected to be only 5.21 percent.

Q. At what level have Moody's and S&P set the Company's credit ratings and outlook since the 2016 Rate Case?

A. As discussed in the next section of my testimony, Moody's placed ALLETE on negative outlook in February 2018, and then subsequently downgraded it in March 2019. ALLETE was placed on negative outlook by S&P in February 2018 and continues to remain on negative outlook. These changes were attributed to several factors, including

[3] *See* Volume 3, Direct Schedule A-1.

the enactment of the TCJA, the outcome of the 2016 Rate Case, and Minnesota Power's ongoing financial and business risk associated primarily with its unique load (both the dominance of large power customers and the types of industries those customers serve). Additionally, these risks are not offset by access to the Midcontinent Independent System Operator ("MISO") market as they have been in the past, due to significantly reduced market prices. I discuss the impacts of these changes for the present and the future in the following section of my testimony.

Q. Why is Minnesota Power's financial position since the 2016 Rate Case relevant to this proceeding?

A. Minnesota Power's financial position is relevant to this proceeding because it speaks to the challenging conditions currently facing the Company. Without reasonable rate relief, the Company's financial metrics and overall financial integrity will continue to be challenged. Additionally, a supportive regulatory framework is instrumental to avoid a further decline to the Company's credit rating. Moody's stated that if credit supportiveness from the Minnesota regulatory framework continues to decline, ALLETE could be downgraded further (see MP Exhibit ___ (Cutshall), Direct Schedule 3). Minnesota Power seeks to work with its state regulators to avoid such an outcome.

B. Importance of Credit Ratings

Q. Why are adequate investment grade credit ratings important?

A. Credit ratings by major credit rating agencies are the primary measure used by investors to evaluate the creditworthiness of companies. The credit ratings assigned by rating agencies indicate their opinions of a company's ability to meet its financial obligations. Rating agency opinions are considered valuable by potential investors because they represent independent, third-party opinions that are based upon a consistent approach to the evaluation of company risk over time. Ratings affect the number of potential investors and the cost of a company's debt, and offer important insight into a company's investment risk in the past and future.

Because Minnesota Power is an operating division of ALLETE, ALLETE's credit ratings and access to low-cost capital on behalf of Minnesota Power directly impact the cost of capital incurred by Minnesota Power customers. The stronger the Company's credit ratings, the greater the number of investors willing to consider investing in the Company's debt and the less the Company will need to pay in fees and interest in order to issue debt. Investment-grade credit ratings are crucial because the cost of debt increases very rapidly — and the number of potential buyers decreases substantially — for those companies rated near the bottom of or below investment grade. Because the income available to common equity holders is subordinate to debt obligations, the weakening of a company's creditworthiness also increases the cost of equity.

Q. Do Minnesota Power customers benefit if ALLETE has higher credit ratings?

A. Yes, the higher the credit rating, the lower the debt cost to the Company's customers. The contrary is also true — the lower the credit rating, the higher the cost to our customers. ALLETE's credit rating is also important to customers because it allows for the availability of capital to support utility projects, especially during economically challenging times. For example, because of ALLETE's strong credit rating at the time, the Company was able to price $160 million of first mortgage bonds in the middle of the 2008-2009 financial crisis, while non-investment grade companies struggled to issue debt. More recently, however, ALLETE was unable to issue first mortgage bond debt with a one-year delayed funding feature due to various reasons including (1) the downgrade by Moody's in 2019, (2) continued negative outlook by S&P, and (3) multiple investors not willing to invest in ALLETE's 30-year and 10-year bonds with reasonable pricing (due to Minnesota Power's customer profile and mix), combined with a one-year delay funding feature. The delayed funding would have locked in favorable interest rates for the 2020 test year, but the deal was cancelled due to a lack of investor interest and appetite. ALLETE will look to reprice first mortgage bonds in 2020 when there is either no delay, or a shorter delay feature.

Q. How do economic conditions affect the Company in terms of credit ratings?

A. Credit ratings take on greater importance when economic conditions worsen and credit becomes more difficult to obtain. As credit availability tightens, investors become increasingly selective with respect to the companies in which they will invest. Therefore, lower credit ratings reduce access to capital markets, or increase the expense of obtaining capital.

Minnesota Power is heavily impacted by downturns in the taconite and paper industries, which can have an impact on its credit ratings because those industries represent such a large portion of Minnesota Power's revenue. In fact, revenue from industrial customers was approximately 63 percent of Minnesota Power total retail revenue in 2018.[4] The way such downturns can affect Minnesota Power was demonstrated in 2015, when the Company underwent significant impacts as a result of an economic downturn. Taconite customer power nomination levels dropped to 80 percent of capacity in September 2015. In the second quarter of 2015, U.S. Steel Corporation temporarily idled its Minnesota ore operations at its Keetac plant in Keewatin, and a portion of its Minnesota ore operations at its Minntac plant in Mountain Iron. In August 2015, Cliffs Natural Resources, Inc. temporarily idled its United Taconite plant in Eveleth, Minnesota. Magnetation, another Minnesota Power customer, idled its facilities in 2016, resulting in a 20 MW load reduction. The Company's contracts with Magnetation were rejected in bankruptcy court, our services to them were disconnected, and we have no indication of any intent to restart the former Magnetation facilities. Aside from these taconite reductions in 2015 and 2016, Blandin Paper announced in October 2017 that it would permanently shut down its Paper Machine #5 in Grand Rapids. Paper Machine #5 ceased operations on December 23, 2017, which was approximately a 25 MW reduction in load for Minnesota Power. These changes underscore the ongoing business risks facing the Company, which are reflected in our credit ratings.

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[4] Based on Form FERC Form 1 for ALLETE, Inc. (2018).

Q. Why are strong credit ratings important for the 2020 test year and beyond?

A. Attracting capital is important for Minnesota Power in 2020 and moving forward. Debtholders are selective in regards to determining in which companies they will invest their capital. Favorable credit ratings and a sound regulatory environment will allow ALLETE to finance utility infrastructure and renewable projects with favorable terms and low-cost capital for customers. ALLETE will also need to refinance its existing maturing debt in 2020 and beyond. In addition, the Company anticipates continuing to invest in incremental carbon-free renewable generation to meet Minnesota energy policy and societal goals and customer expectations, which will require financing. Finally, a strong credit rating for the 2020 test year would make the potential for a significant downgrade in the event of a future economic downturn less likely. This will allow the Company to be in a position to finance needed capital additions in order to continue providing clean (50 percent carbon-free renewable), safe, reliable, and affordable energy (the most affordable in the state and one of the most affordable in the country) to its customers.

C. <u>Determination of Credit Ratings and Risk</u>

Q. How does Minnesota Power's capital structure impact ALLETE's credit rating?

A. As mentioned, Minnesota Power's capital represents a majority of the ALLETE capital structure. Both Moody's and S&P focus on the quantitative and qualitative areas of a company which make up the financial and business risks. For financial risks, the rating agency ratios focus on cash flow, debt payback, and interest coverage, which are directly impacted by the amount of debt carried in the capital structure. A higher level of equity in the capital structure reduces the Company's risk and improves credit metrics. Consequently, Minnesota Power's capital structure and financial performance substantially dictate ALLETE's credit ratings and financial integrity.

Q. How is ALLETE's creditworthiness rated?

A. ALLETE is rated by both Moody's and S&P. Moody's and S&P divide issuer ratings into categories, ranging from Aaa/AAA reflecting the strongest credit quality, to "/" or "D", reflecting the lowest credit quality. The ratings are modified with a number (1, 2 or 3) or a symbol (+ or -) to describe the relative position in the credit rating category. For example, Moody's Baa category (comprised of Baa1, Baa2, Baa3, ranked highest to lowest) aligns with S&P's BBB category (comprised of BBB+, BBB, BBB-, ranked highest to lowest). A credit rating of Baa3/BBB- is the lowest rating to be considered investment grade; debt rated below Baa3/BBB- is considered non-investment grade, or speculative grade. In determining ratings, credit rating agencies consider (i) business risk (including regulatory support, customer concentration and size); (ii) financial risk; (iii) credit metrics; and (iv) other factors. I discuss each of these in turn, below.

1. <u>Business Risk</u>

Q. What is "business risk" in the context of credit ratings?

A. Business risk refers to the qualitative assessment used by the rating agencies, which include general risks such as country and industry risk. The rating agencies will then identify specific risks with a company. Specifically, Minnesota Power's customer concentration is its biggest, and most unique, business risk factor identified by Moody's and S&P. The applicable regulatory framework, Minnesota Power's small size and service territory, and reduced price offsets in the MISO market each further contribute to Minnesota Power's riskier business profile.

Q. When establishing a credit rating, what factors do the rating agencies consider from a business risk perspective?

A. According to Moody's June 23, 2017 rating methodology titled *Regulated Electric and Gas Utilities* (see MP Exhibit ___ (Cutshall), Direct Schedule 1), nearly 80 percent of the business risk is within the regulatory environment. Because utility rates are set in a regulatory process rather than a competitive process, in this report, Moody's highlights regulatory framework as a key determinant to the success of a company in the utility industry. In addition, Moody's examines the ability of a utility to recover its costs and earn an appropriate return because the regulatory environment impacts the utility's ability to generate cash flow and repay its debt over time.

S&P explains, in its November 19, 2013 rating methodology titled *Key Credit Factors for the Regulated Utilities Industry*, that its business risk evaluation for utility companies considers country risks, industry risk, and a company's advantages and disadvantages within its markets or its competitive position (see MP Exhibit ___ (Cutshall), Direct Schedule 4). Within its evaluation of competitive position, S&P places 60 percent of its weighting on competitive advantage, measured by the utility's regulatory advantage, or "regulatory framework."

Q. How does the "regulatory framework" affect perceptions of Minnesota Power's creditworthiness?

A. The regulatory framework is very important to perceptions of Minnesota Power's creditworthiness, as it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance. The regulatory environment is critical to protect the Company's credit quality, its ability to recover its costs, and to earn a fair and reasonable return. The rating agencies place a high value on stability, predictability, consistency, and transparency in regulation. Moody's noted in its 2019 credit report that the 2016 Rate Case outcome was a credit negative for ALLETE and placed downward pressure on the company's debt coverage ratios.

Q. Does ALLETE's business risk profile reflect unique characteristics of Minnesota Power's business operations?

A. Yes. According to Moody's 2019 credit report (MP Exhibit ___ (Cutshall), Direct Schedule 3), ALLETE's material industrial customer exposure adds volatility to the company's business risk profile. Moody's stated that ALLETE's exposure to industrial customers, representing roughly 50 percent of annual sales in most years, is the highest within Moody's U.S. regulated utility universe. In addition, Moody's stated that the cyclicality of ALLETE's industrial customers' demand "is a credit negative since these are the company's largest customers which account for 45 percent of consolidated revenues."

Q. Can you provide more detail on the risks associated with Minnesota Power's customer concentration?

A. Yes. Minnesota Power's significant industrial customer concentration makes it unique compared to other utilities. Minnesota Power's revenue from industrial customers was approximately 63 percent and 65 percent of retail revenue in 2018 and 2017, respectively[5]. This compares to an industry average of 16 percent in 2018, making Minnesota Power's revenue as a percentage of industrial sales the highest amongst investor-owned utilities in the United States.[6]

In addition, Minnesota Power's retail customer mix is unique in that energy sales to large industrial customers make up approximately 74 percent of the Company's total retail energy sales.[7]

This industrial concentration is a factor that subjects Minnesota Power to substantial earnings volatility risk relative to its peers. Minnesota Power operates in a natural resource-based service territory with economic prospects closely linked to the economic success of a few large customers that operate in highly competitive and cyclical industries: taconite processing, paper and wood products manufacturing, and oil pipelines. This is unlike the typical utility with a stable base comprised mostly of residential and commercial customers.

Q. Can you provide direct evidence of the kind of risk that Minnesota Power's unique customer mix represents, independent of other risk considerations?

A. Yes. Minnesota Power's customer mix is heavily weighted towards resource-based industry, and trends in sales are largely driven by demand for iron, steel, and paper. Demand for iron and steel is highly cyclical, and downturns in iron/steel demand will result in a sudden loss of energy sales to Minnesota Power's taconite mining customers. For example, energy sales decreased by nearly 900,000 MWh from 2014 to 2015 due to

[5] Based on Form FERC Form 1 for ALLETE, Inc. (2017 and 2018).
[6] Based on Form EIA-861 Annual Electric Power Industry Report (2018).
[7] Based on Form FERC Form 1 for ALLETE, Inc. (2018).

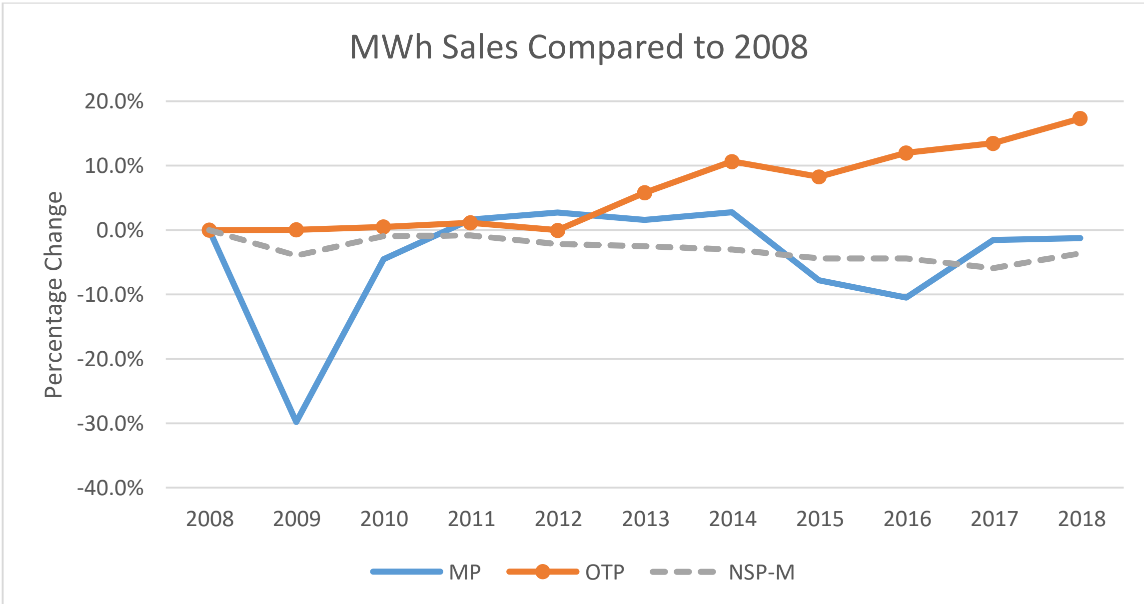
the 2015-2016 downturn due to the temporary idling of production at U.S. Steel's Keetac and Minntac facilities, and Cleveland-Cliffs' United Taconite plants. The 2015-2016 downturn also resulted in the permanent closure of several iron concentrate facilities and a Direct Reduced Iron nugget facility that, at full load, would have amounted to around 360,000 MWh in annual sales.

Minnesota Power's sales to the paper sector also represent a notable risk. The Company's annual sales to Paper and Pulp customers have declined by about 500,000 MWh (34.1 percent) in the last four years due to the longer-term, secular decline in the market for printing and writing papers. As previously noted, most recently Blandin Paper announced the permanent shut down of Paper Machine #5 in October 2017. This reduction is reflected in the 2020 test year energy sales forecast discussed in the testimony of Company witness Mr. Benjamin S. Levine.

Q. Can you provide direct evidence of the uniqueness of the risk that Minnesota Power's customer concentration presents?

A. Yes. To illustrate the unique level of risk that Minnesota Power's load profile presents, we have compared Minnesota Power to two neighboring Minnesota electric utilities: Northern States Power Company–Minnesota and Otter Tail Power Company. These utilities face comparable levels of competition, operate in the same Minnesota regulatory environment, and are allowed the same cost recovery riders. Their load profile, however, is much different because they are not so heavily reliant on sales to a small number of large industrial customers who operate in the highly cyclical taconite and paper industries. Figure 1 below illustrates the level of volatility of Minnesota Power's MWh sales to ultimate customers, comparing it to the relative stability of Otter Tail Power Company's and Northern States Power Company–Minnesota's MWh sales on a percentage of 2008 sales.

Figure 1.



Q. Does this customer concentration specifically distinguish Minnesota Power from other Minnesota investor-owned electric utilities?

A. Yes. Minnesota Power's industrial customer concentration is significantly higher than other Minnesota investor-owned electric utilities. As mentioned above, Minnesota Power's percentage of retail revenue from its industrial customers was 63 percent in 2018. Otter Tail Power Company and Northern States Power Company–Minnesota's percentages of retail revenue from its industrial customers were 31 percent and 19 percent, respectively, in 2018.[8]

Q. Has the Commission previously recognized Minnesota Power's unique customer concentration and the associated variability in the Company's sales?

A. Yes. In the Company's 2009 rate case, the Administrative Law Judge stated:

> Minnesota Power's retail customer profile is unique among Minnesota's investor-owned utilities, in that its industrial customers use approximately two-thirds of the retail energy it

[8] Based on Form FERC Form 1 for Northern States Power–Minnesota and Otter Tail Power Company (2018).

> supplies. It has twelve large power customers (taconite plants, paper mills, and pipelines) that account for 64% of the Company's retail revenues.[9]

Likewise, in the Company's 2009 rate case, the Commission recognized that:

> The Company's sales forecasts are volatile because its sales are volatile – over 60% of its retail generation serves Large Power customers such as taconite plants and paper mills, whose usage fluctuates with the global economy. This heavy concentration of customers marked by high usage and volatility ensures that the Company's sales forecasting process will be both complex and critical to rate-setting. The Commission will continue to monitor the Company's sales forecasting and will require its ongoing cooperation with the OES to refine its forecasting, but forecasting issues are likely to persist, even as the process improves.[10]

Finally, in the Company's 2016 Rate Case, the Commission noted the importance of setting just and reasonable rates in light of Minnesota Power's "unique risk profile."[11]

Q. Do the rating agencies also recognize Minnesota Power's customer concentration as a risk?

A. Yes. Moody's and S&P include customer concentration as a major risk in their credit reports. Moody's explains that because of Minnesota Power's elevated exposure to industrial customers, the Company could be downgraded if there is a substantial deterioration in economic conditions that results in a material drop in retail electricity

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[9] *In the Matter of the Application of Minn. Power for Auth. To Increase Rates for Elec. Serv. in Minn.*, Docket No. E-015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS, AND RECOMMENDATION at 2-3 (Aug. 17, 2010).

[10] *In the Matter of the Application of Minn. Power for Auth. To Increase Rates for Elec. Serv. in Minn.*, Docket No. E-015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 11 (Nov. 2, 2010).

[11] *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 61 (Mar. 12, 2018).

volumes that are not offset by off-system sales or other means (see MP Exhibit ___ (Cutshall), Direct Schedule 3).

Q. Do the large industrial customer contracts provide protection to the Company during a business cycle downturn?

A. Minnesota Power's eight Large Power customers have long-term Electric Service Agreements with two- to four-year cancellation notice provisions. These contracts, however, also contain operating flexibility provisions that allow the customers to reduce their demand commitments significantly with minimal notice. If all Large Power customers were to nominate their Minimum Service Requirement, as stated in their Electric Service Agreements, Minnesota Power's Large Power firm demand revenues could decline substantially – by approximately 72 percent, which equates to $140 million annually. If select Large Power customers were to shut down, and after proper notification is given, in two years the impact would increase to approximately a 98 percent revenue reduction, or $191 million annually.

Q. Does the MISO wholesale market offset the losses the Company has experienced – and will experience – when its industrial customers' sales decline?

A. Only partially.

Q. Please explain.

A. While the MISO market gives the Company a market into which power can be sold, the margins in this market are based on what can be achieved in the day-ahead or spot prices and not the Company's cost of service. MISO prices have continued to remain lower than historical levels and Minnesota Power expects to recover only 4 percent of lost retail margin today compared to about 57 percent of the lost large industrial customer retail margins in 2015, as explained in the Direct Testimony of Company witness Ms. Julie I. Pierce.

Q. How is this different from the risks facing any other utility operating in the MISO footprint?

A. Minnesota Power is heavily reliant on sales to a small number of large industrial customers who operate in cyclical taconite and paper industries. As a result, Minnesota Power's exposure to recover lost large industrial retail margins is significantly greater than other utilities in the MISO footprint. There are no other investor-owned utilities in the nation that have a customer load profile directly comparable to Minnesota Power's.

Q. Do the rating agencies also factor in the Company's size, service territory, and access to the MISO market when they evaluate the Company?

A. Yes. Both Moody's and S&P evaluate the Company's size, service territory, and access to wholesale markets when determining ALLETE's credit rating. Moody's specifically notes in its 2017 methodology *Regulated Electric and Gas Utilities* that it looks at the population, size, and breadth of the service territory. Moody's further explains that an issuer with a small service territory that is highly dependent on one or two sectors, especially highly cyclical industries, will score lower on diversification (see MP Exhibit ___ (Cutshall), Direct Schedule 1).

S&P considers the size of Minnesota Power's customer base as detrimental to its credit evaluation. In its May 2019 Credit Report, S&P notes incremental business risk to the Company because of its utility operations, heavily concentrated industrial customer base, small residential customer base, and lower wholesale power prices in the MISO region (see MP Exhibit ___ (Cutshall), Direct Schedule 6).

Q. Overall, how do business risk factors translate into impacts to the Company's financial metrics and cost of or access to capital?

A. As a result of the business risk factors unique to Minnesota Power, credit rating agencies require the Company to have higher debt coverage ratios to support its credit rating. If Minnesota Power's ratios fall below its thresholds, the Company's credit rating will be downgraded. As a result, the weaker credit rating would ultimately increase costs for customers.

Q. How do you recommend that the Commission factor these risks into its determinations in this proceeding?

A. Minnesota Power needs to have the ability to earn its authorized return on equity and produce sufficient cash flow to support its credit rating. The recommended capital structure consisting of 53.81 percent common equity and a return on equity supported by the testimony of Company witness Ms. Bulkley is the first step in allowing ALLETE to sustain its investment grade corporate credit rating and financial integrity to provide its customers with quality, safe, and reliable service.

2. <u>Financial Risk</u>

Q. What does the financial risk profile address?

A. Financial risk addresses the ability of a company to make scheduled payments of principal and interest on its financial obligations. To assess a company's ability to make these payments, the credit agencies evaluate certain financial ratios to determine whether the company will have sufficient levels of cash flow to cover its interest expense and repay the principal amount of its debt. Because it impacts the financial ratios, the credit rating agencies also evaluate the relative amounts of debt and equity in the company's capital structure to determine whether the company is appropriately capitalized given its business risk.

Q. What key financial metrics does Moody's consider in establishing a company's financial risk profile?

A. Moody's evaluates four key financial metrics in order to consider the company's financial risk profile. The four key ratios are listed below. S&P uses similar requirements and metrics to establish its financial risk profile.

(1) Cash Flow from Operations Before Changes in Working Capital (CFO Pre-Working Capital) to Debt;

(2) CFO Pre-Working Capital Plus Interest Expense to Debt;

(3) CFO Pre-Working Capital Minus Dividends to Debt; and

(4) Debt to Capitalization.

CFO Pre-Working Capital to Debt is the most heavily weighted sub-factor in Moody's assessment of the financial metrics. Based upon Moody's April 3, 2019, credit report, Moody's expects ALLETE's CFO Pre-Working Capital to Debt to decrease from 22 percent, but remain at or close to 20 percent. A downgrade could result if further weakening financial ratios of CFO Pre-Working Capital to Debt is below 19 percent (see MP Exhibit ___ (Cutshall), Direct Schedule 3).

3. Company Credit Ratings

Q. Where do ALLETE's current credit ratings rank among investment grade credit ratings?

A. Table 3 below depicts the investment grade credit rating scales used by Moody's and S&P. ALLETE, with its downgrade by Moody's on March 26, 2019, is currently rated Baa1 (outlook stable) by Moody's and BBB+ (outlook negative) by S&P. These ratings are only two notches above the lowest investment grade rating by each respective agency.

Table 3.

	Investment Grade Credit Ratings ALLETE's ratings are circled in red	
	Moody's	**S&P**
Higher	Aaa	AAA
	Aa1 / Aa2 / Aa3	AA+ / AA / AA-
	A1 / A2 / *A3*	A+ /A / A-
Lower	***Baa1*** / Baa2 / Baa3	***BBB+*** / BBB / BBB-
	Anything below these ratings is considered non-investment grade	

Q. Why is it important for ALLETE to maintain an adequate credit rating and not be downgraded further?

A. The closer ALLETE is to non-investment grade, the higher its cost of debt will be when it looks to issue debt for future regulated projects or to refinance maturing first mortgage bond debt. The cost of debt increases dramatically during times of financial distress. Minnesota Power wants to be strategically aligned and positioned to take advantage of low-cost financing by maintaining its existing credit rating and being taken off of outlook negative by S&P.

Q. Do ALLETE's subsidiaries (other than Minnesota Power as an operating division) impact its credit metrics?

A. Yes. ALLETE's subsidiaries help positively offset Minnesota Power's credit metrics. SWLP is rated A3 by Moody's (one notch above ALLETE). ATC (an investment by a subsidiary of ALLETE) is rated A2 by Moody's (two notches above ALLETE) and A+ by S&P (three notches above ALLETE). In addition, ALLETE's credit rating is determined by ALLETE's financial risk, business risk, and other factors (i.e., corporate governance, liquidity and capital structure) for Moody's and S&P. Aside from SWLP and the ATC investment, Moody's and S&P do not assess a credit rating for individual subsidiaries under ALLETE because Minnesota Power is ALLETE's dominant business, representing approximately 70 percent of ALLETE's capital. ALLETE appropriately capitalizes its subsidiaries, and in 2018 other ALLETE subsidiaries in aggregate had a CFO Pre-Working Capital to Debt ratio of 36.1 percent, enhancing Minnesota Power's CFO Pre-Working Capital to Debt of 19.4 percent for an overall CFO Pre-Working Capital to Debt of 22.7 percent for ALLETE, as shown in Table 4. Therefore, ALLETE's other subsidiaries enhanced ALLETE's credit metrics in 2018 and are expected to continue to enhance ALLETE's credit metrics in the 2020 test year.

Table 4. Moody's CFO Pre-Working Capital to Debt Financial Metric - 2018

Metric	Minnesota Power	ALLETE
CFO Pre-Working Capital/Debt	19.4%	22.7%

Q. Was SWLP, ALLETE's other regulated utility, also downgraded in 2018 or 2019?

A. SWLP was not downgraded by Moody's, despite ALLETE's downgrade from A3 to Baa1. The affirmation of SWLP's credit rating was due to the strong financial ratios SWLP produces, including Pre-Working Capital to Debt above 30 percent in recent years. SWLP's Wisconsin regulators recently approved a rate increase on December 20, 2018, with a 10.4 percent ROE and a 55 percent equity ratio.

4. Other Factors

Q. In your experience, does ALLETE compete with other companies for investor dollars?

A. Yes. A regulated utility must have the opportunity to earn a return that is competitive and will satisfy investor expectations. From an investor's perspective, the operating and credit risk associated with Minnesota Power's large amount of customer concentration is significant and requires a higher return.

Q. Why does this matter?

A. Investors are critical to the Company. ALLETE will have to refinance maturing first mortgage bonds and continue to invest in infrastructure to address reliability in its service territory. In addition, the Company will rely on investors for capital investments, a critical component in order to address future renewable energy and carbon reduction standards.

Q. Do Moody's and S&P make adjustments for other items in determining credit ratings?

A. Yes. A company's balance sheet by itself does not provide the information necessary to determine the appropriateness of a company's capital structure. It is important to understand that credit ratings do not reflect unadjusted balance sheet capital structure ratios, but rather financial ratios that include off-balance sheet debt obligations. Consequently, ALLETE's balance sheet ratios are adjusted to reflect debt equivalents for off-balance sheet debt obligations.

Q. What are "debt equivalents" and "off-balance sheet debt obligations"?

A. In the determination of a company's credit rating, rating agencies consider the amount of debt and debt-like instruments (debt equivalents) that a company utilizes relative to the total capital employed by the company. These debt equivalents are either on- or off-balance sheet obligations the rating agencies treat as debt. All else equal, a company's financial risk profile will increase — and its credit rating will face downward pressure — as a company increases the amount of leverage (debt and debt equivalents) used in its capitalization.

Q. Should debt equivalents be considered in determining the reasonableness of Minnesota Power's test year capital structure for ratemaking purposes?

A. Yes. Since credit ratings are driven by financial ratios that include debt equivalents for off-balance sheet obligations, the Company must consider these obligations in its capital structure decisions. Due to the debt equivalents associated with Minnesota Power's operations, in order to maintain its credit metrics and investment grade credit ratings, the Company is required to carry a higher level of common equity in its capital structure.
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D. <u>Recent Credit Actions</u>

1. <u>Basis for Credit Actions Toward ALLETE</u>

Q. Earlier you noted that the Company's credit ratings have changed since the 2016 Rate Case. Did the credit rating agencies explain why these changes occurred?

A. Yes. As previously noted, Moody's placed ALLETE on negative outlook in February 2018 and then subsequently downgraded it in March 2019. S&P placed ALLETE on negative outlook in February 2018 and it continues to remain on negative outlook. Moody's and S&P both provided explanations of their reasoning for these changes.

Q. Please explain why ALLETE was downgraded by Moody's.

A. Moody's explained its rationale in its Credit Opinion dated April 3, 2019, which is attached to my testimony as MP Exhibit ___ (Cutshall), Direct Schedule 3. Moody's reasoning was twofold. First, Moody's noted the adverse outcome of the 2016 Rate Case as the primary reason for the downgrade. The lower revenues from that ratemaking outcome, including a low return on equity given the risks associated with Minnesota Power's profile, combined with the disallowance of multiple core cost recovery items such as lost transmission revenues, distribution and generation O&M, and $3 million of prepaid pension expenses, placed pressure on ALLETE's credit rating and ultimately led to a downgrade. Second, Moody's identified weaker debt coverage ratios in the future due to impacts from tax reform (the TCJA) and necessary continued capital investment in utility infrastructure going forward.

Q. How did the TCJA impact Minnesota Power's cash flow and debt coverage ratios?

A. The passage of the TCJA had negative cash flow impact to the Company. The impact of the TCJA's lower tax rates is unique to the utility sector, compared to other corporate sectors. Although in other industries the benefit of lower tax rates can be used to bolster growth and capital spend, for the utility industry in general, including Minnesota Power, the lower federal tax is not utilized or kept by the utility, but is instead typically returned to the customers. In addition, the ADIT that was built up over time must now be returned to Minnesota Power's customers, which constrains cash flows at the Company even more. The changes as a result of the TCJA were detrimental to Minnesota Power's revenue requirement and operating cash flow and thus put further constraints on its credit metrics, but were not the sole cause for the Moody's downgrade.

Q. Please explain why S&P placed ALLETE on negative outlook?

A. ALLETE was placed on negative outlook in February 2018 following the Commission's decision in its 2016 Rate Case, which S&P stated it viewed as a credit negative. This negative assessment of the regulatory risk, and the revised federal tax code which led to weaker cash flows for ALLETE, triggered S&P's negative outlook (see MP Exhibit ___ (Cutshall), Direct Schedule 5). S&P affirmed its negative outlook in its credit report on ALLETE in May 2019 (see MP Exhibit ___ (Cutshall), Direct Schedule 6).

Q. Did either Moody's or S&P comment on the detrimental cash flow impacts to ALLETE from the TCJA?

A. Yes, both Moody's and S&P provided comments in their credit reports on the negative impact that the TCJA had on ALLETE's financial metrics. Moody's noted in its February 2018 report that the negative rate case outcome, reduced tax collection in customer rates, and deferred tax liability refunds would place downward pressure on ALLETE's financial ratios (see MP Exhibit ___ (Cutshall), Direct Schedule 2). S&P also placed ALLETE on negative outlook and explained in its 2018 credit report that the TCJA would strain the Company's cash flow metrics (see Cutshall Direct Schedule 5). In addition, Moody's comments in its 2019 credit report that ALLETE's CFO Pre-Working Capital to Debt is expected to decline to roughly 20 percent as a result of a less credit supportive rate case outcome in 2018 and the passage of the TCJA in late 2017 (see MP Exhibit ___ (Cutshall), Direct Schedule 3). The TCJA alone did not cause the decrease in the credit rating or outlook. This is evident because before the order in the 2016 Rate Case was released, Moody's published a list of utilities where the rating outlook changed to negative from stable as a result of the TCJA. ALLETE was not on this list. It was only after the order in the 2016 Rate Case was announced that ALLETE was put on outlook negative from both rating agencies.

Q. Is it easy to get upgraded after a downgrade occurs?

A. No, it is not an easy process to get upgraded after a downgrade occurs. Given the recent regulatory impacts, the Company will have to achieve stronger financial ratios on a sustained basis before it can be considered for an upgrade.

2. <u>Impacts on Access to and Cost of Capital</u>

Q. What is the estimated impact of the downgrade on the Company's access to and cost of capital?

A. The first impact is to the Company's access to capital markets, overall. In August 2018, ALLETE entered into a private placement offering of $100 million of first mortgage bonds that were to be issued in March of 2019. In October 2018, after the pricing of the first mortgage bonds, U.S. Bancorp Investments and Wells Fargo Securities, LLC issued a Private Placement Transaction Review summarizing the strategy and results of the issuance. The marketing analysis included in this summary stated that while "many of the participating investors mentioned that the Moody's A1 first mortgage bond rating was helpful…the negative outlook caused some investors to look at A2 rated utilities as comps." They also noted that one of the top reasons that investors passed on the deal was because "investors viewed the recent rate case as lacking support from the regulatory and legislative bodies."[12]

This occurred in a strong financial market. These conditions would be exacerbated if the market was distressed, as that can cause the cost to issue debt to increase substantially. In a financially distressed environment, investors will more stringently evaluate the Company's ability to meet its fixed obligations and to provide an acceptable return before committing their capital to the Company.

The second impact is the actual cost impact of obtaining capital when it is made available. Although the cost of debt will not be impacted immediately, the impacts will be felt over time. Based on Bloomberg data, the additional cost in terms of added credit spread paid by BBB- credit companies compared to BBB+ rated companies averaged 0.52 percent for the period December 2006 through December 2018. Credit spreads between BBB- and BBB+ rated companies were as high as 1.75 percent at one point during the 2008-2009 financial crisis. Ultimately, then, a downgrade will also result in a higher cost of debt for Minnesota Power's customers, which will compound over time, and will likely be magnified in financial distressed markets.

Finally, there is the uncertainty associated with the reduced attractiveness of ALLETE as an investment. As Minnesota Power looks to refinance its debt and issue new debt, the cost of debt will likely be higher than it would have been otherwise. That uncertainty grows if and when the market becomes less stable, the Company's revenues shift with its large power customers, and other economic conditions change significantly.

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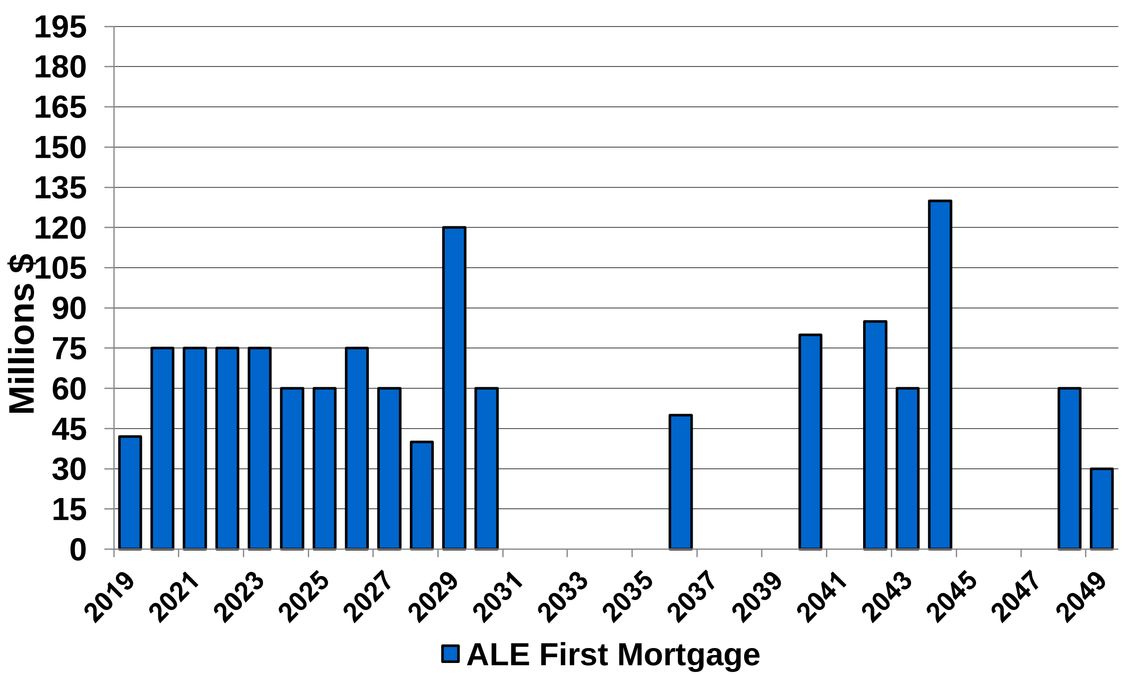
[12] U.S. Bancorp Investments and Wells Fargo Securities, LLC, Private Placement Transaction Review (Oct. 4, 2018).

Q. How do these factor into future ALLETE debt or equity offerings?

A. ALLETE has a significant amount of first mortgage bond maturities in the next ten years (see Figure 2, below), making access to low-cost capital particularly important. First mortgage bonds are the main debt financing and support for Minnesota Power utility assets. As displayed in Figure 2 below, ALLETE will have to refinance first mortgage bonds every year through 2030. Because Minnesota Power's operations will not generate sufficient cash flow to fund these requirements, the Company will need to secure additional capital from external sources. It is imperative that Minnesota Power receive a constructive rate case outcome and maintain its credit rating in order to be well positioned to refinance the maturing first mortgage bonds.

Figure 2. Minnesota Power First Mortgage Bond Maturities



Q. Will the Company need external financing beyond refinancing its maturing debt?

A. Yes. Minnesota Power's capital investment plan includes investments to meet safety, environmental, regulatory, and system reliability objectives. Additional investments are planned for Minnesota Power's existing facilities to maintain and expand its system to address reliability as well as renewable and carbon reduction efforts. The Company also plans to invest in transmission opportunities that strengthen or enhance the transmission grid or take advantage of its geographical location between sources of renewable energy and end users. These include the Great Northern Transmission Line investments to enhance the Company's own transmission facilities, and investments in other transmission assets (individually or in combination with others).

Q. Will the Company have to finance incremental renewable projects that are unknown in the future?

A. Although specifics are not known at this time, the Company expects future investments will be needed to keep up with changing renewable energy and carbon reduction standards at the state and federal levels. As technology advances and renewable pricing continues to become more competitive, the Company will evaluate its portfolio mix and customer costs. It is important the Company remains in good financial standing in order to be able to finance renewable and reliability investments now and in the future.

Q. Did the rating agencies indicate any positives related to ratings?

A. Yes. Moody's rating methodology gives a small weighting to generation and fuel diversity. Due to Minnesota Power's investment in a more diverse generation and renewable mix, Moody's increased our generation and fuel diversity score in their April 2019 report and the Company expects this to continue to increase as it becomes 50 percent renewable by 2021 (see MP Exhibit ___ (Cutshall), Direct Schedule 3). The positive trend is a result of Minnesota Power's phasing out over 600 MW of coal-fired generation and its commitment to obtain more renewable resources, as discussed in the Rate Case Overview testimony of Company witness Mr. Frank L. Frederickson. We also know both rating agencies are considering placing even more weighting on environmental, governance, and social issues, which should be credit rating positive for Minnesota Power since the Company has gone faster and further than most integrated electric utilities in this regard.

3. Looking Forward

Q. What is Minnesota Power hoping to achieve in this rate proceeding with respect to its financial metrics and credit ratings?

A. At a minimum, Minnesota Power needs to maintain its current credit rating. As discussed above, in order to achieve this, Minnesota Power must earn an appropriate ROE as supported in the testimony of Company witness Ms. Bulkley. In addition, Minnesota Power needs approval of its recommended 53.81 percent equity ratio, the ability to recover reasonable expenses, and approval of its recommended cost of capital.

Q. What regulatory support is needed in Minnesota for the Company to maintain its current credit rating?

A. Regulatory support is heavily weighted by Moody's when determining business risk profile. Moody's 2017 rating methodology *Regulated Electric and Gas Utilities* explains two factors that are instrumental in determining the credit rating of a company (see MP Exhibit ___ (Cutshall), Direct Schedule 1). The two factors include:

- Regulatory Framework
- Ability to Recover Costs and Earn Returns

Moody's states "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."

S&P also states in its 2013 report, *Key Credit Factors for the Regulated Utilities Industry* (see MP Exhibit ___ (Cutshall), Direct Schedule 4): "We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency or tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return."

These reports, and discussions with both Moody's and S&P, confirm that regulatory support is critical for ALLETE. ALLETE has already been downgraded. Regulatory decisions that are perceived as unfavorable can increase the Company's business risk and put downward pressure on credit ratings. The regulatory framework is a critical factor in determining the credit risk of a utility because of the environment in which the utility operates and its influence on financial performance. If regulatory support is further jeopardized, Minnesota Power may be perceived as a weakened company and Minnesota Power customers will ultimately pay for this perception through higher rates.

In the next section of my Direct Testimony, I address how these considerations should factor into the Company's overall 2020 test year capital structure.

IV. RECOMMENDED TEST YEAR CAPITAL STRUCTURE

Q. Please describe the components of Minnesota Power's capital structure.

A. Minnesota Power recommends a capital structure consisting of 53.81 percent common equity and 46.19 percent long-term debt. Minnesota Power's capital structures for 2018, the 2019 projected year, and the 2020 test year are shown in Direct Schedule D-1 in Volume 3. For 2018, Minnesota Power's 13-month average capital structure consisted of 52.79 percent common equity and 47.21 percent long-term debt. For the 2019 projected year, the average capital structure is expected to consist of 53.75 percent common equity and 46.25 percent long-term debt. These ratios do not reflect any off-balance sheet obligations that, for credit rating purposes, are viewed as the equivalent of debt.

Table 5 below summarizes Minnesota Power's capital structure, ROE, and overall rate of return for 2017 as authorized in the Company's 2016 Rate Case, 2018 actuals, 2019 projected year, and as requested for the 2020 test year.

Table 5. Minnesota Power Rate of Return

($000)	Authorized 2017 Retail Rate Case Test Year (E015/GR-16-664)	Actual 2018	2019 Projected Year	2020 Test Year
Long-Term Debt	$1,228,550	$1,214,784	$1,256,125	$1,281,771
Common Equity	1,431,272	1,358,634	1,459,671	1,532,832
Total Capital	$2,659,822	$2,573,418	$2,715,796	$2,814,603
Return on Equity	9.2500%	8.2206%	8.8715%	10.0500%
Overall Rate of Return	7.0639%	6.5034%	6.8422%	7.4737 %

Q. Why is this capital structure reasonable?

A. The Company's objective is to maintain adequate investment credit ratings in order to access needed capital at reasonable costs. This means, at a minimum, maintaining its credit ratings of Baa1 by Moody's and BBB+ by S&P: maintaining these ratings is critical for efficiently accessing capital markets and allowing us to provide low capital costs to our customers. The Company's proposed capital structure is reasonable because it supports the Company's ability to achieve these important objectives in order to keep overall customer costs at reasonable levels.

A. <u>Debt</u>

Q. Please describe the composition of Minnesota Power's debt.

A. Debt attributable to Minnesota Power consists of first mortgage bonds and a floating rate tax-exempt bond that was used to finance pollution control equipment at Boswell Energy Center, which is maturing in 2020. Minnesota Power does not carry any short-term debt.

Q. Why does Minnesota Power not carry short-term debt?

A. Due to Minnesota Power's risk as determined by rating agencies, using long-term, low-cost, fixed-rate debt better matches Minnesota Power's assets and liabilities. Not having short-term debt is prudent when considering that Minnesota Power's demand has a low seasonality effect compared to other utilities and the cyclical nature of the Company's large industrial customers. This is especially true during economic downturns when access to capital markets is restricted and the Company's financial metrics are challenged, thus putting pressure on credit ratings. Additionally, short-term debt adds repricing risk and subjects the company to interest rate volatility. It also reduces the rating agencies' liquidity calculations for the Company because short-term debt matures every year, requiring additional financing. By issuing long-term debt, the Company has been able to lock in the current extremely low rates for many years, similar to homeowners locking in fixed mortgages rather than subjecting themselves to fluctuations in interest rates in the market. This has been especially prudent in the current low interest rate environment of the last several years.

Q. Does ALLETE have other debt outstanding?

A. Yes, but all other debt held at ALLETE is allocated to or held directly at the subsidiary level. This debt is all unsecured.

Q. What determines which debt supports Minnesota Power and which debt supports the subsidiaries?

A. As described above, debt attributable to Minnesota Power consists of only first mortgage bonds and a floating rate tax-exempt bond that was used to finance pollution control equipment at Boswell Energy Center. The first mortgage bonds are secured by all of Minnesota Power's utility assets, which keeps rates lower, all else being equal. The floating rate tax-exempt bond was issued by the City of Cohasset, but Minnesota Power is obligated to make the payments on the bond. The Cohasset bond is supported by a letter of credit issued by J.P. Morgan and matures in 2020.

The ALLETE debt that supports subsidiaries consists of unsecured notes, a floating rate term loan, and a floating rate tax-exempt bond issued by Collier County, Florida (supported by a letter of credit issued by Wells Fargo), which was originally issued for

ALLETE's previously-owned Florida Water subsidiary. Minnesota Power assets do not secure any of the ALLETE debt used by the subsidiaries.

Q. Is it beneficial for Minnesota Power to issue first mortgage bonds?

A. Yes, first mortgage bonds are rated two notches above the unsecured credit rating for Moody's. The two notch upgrade provides the first mortgage bonds with a lower interest rate which directly reduces the Company's cost of debt.

Q. What are the Company's objectives when issuing long-term debt?

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

Q. What new debt is expected to be issued in 2020 for Minnesota Power?

A. Minnesota Power expects to add $100 million in first mortgage bonds in 2020. Minnesota Power's projected long-term debt balance at the end of the 2020 test year is detailed in Direct Schedule D-2 and is expected to be $1,287.7 million, or 44.96 percent of total ending capitalization. When calculated from a 13-month average, however, the balance is $1,281.8 million, or 45.54 percent of total average capitalization. As discussed above, the Company is requesting that the capital structure remain unchanged from the 2016 Rate Case, with a debt to capital ratio of 46.19 percent. This amount is shown in Direct Schedule D-1 and is used to calculate Minnesota Power's overall cost of capital. The weighted average cost of debt projected in the 2020 test year capital structure is 4.47 percent.

The precise size, timing, and tenor of debt issuances will depend on prevailing financial market conditions and trends, as well as the timing of Minnesota Power's cash receipts and disbursements.

Q. Does ALLETE expect to issue any other debt in 2020?

A. Yes. In addition to the first mortgage bonds for Minnesota Power, ALLETE may issue unsecured debt in support of its subsidiary operations. The specific size, timing, and tenor of the unsecured debt issuances will be dependent on the needs of the subsidiaries. Since this debt is being issued for subsidiary use, it must not be included in calculations of Minnesota Power's cost of debt or as part of Minnesota Power's capital structure.

Q. Please summarize the embedded cost of the Company's long-term debt.

A. The cost of long-term debt shown in Direct Schedule D-2, calculated from a 13-month average balance, is 4.58 percent for 2018, 4.48 percent projected for 2019, and 4.47 percent for the 2020 test year. These amounts are shown in Direct Schedule D-1 and are used to calculate the overall returns. The cost of the first mortgage bonds issued in 2020 is projected to be 4.00 percent, and the cost of Minnesota Power's floating rate tax-exempt bond is projected to be 1.75 percent. Please see Table 6 below for a comparison of the long-term debt costs for Minnesota electric utilities as authorized and agreed upon between parties in their most recent rate cases.

Table 6. MN Electric Utility Debt Costs

Utility	Cost of Debt	Year
Minnesota Power	4.47%	2020
Minnesota Power[13]	4.52%	2017
Northern States Power[14]	4.75%	2019
Otter Tail Power[15]	5.62%	2016

[13] *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E-015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 61 (Mar. 12, 2018).

[14] *See In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (June 12, 2017)

[15] *See In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (May 1, 2017).

Q. Has the cost of debt changed since the last rate filing?

A. Yes. Minnesota Power's projected debt cost has decreased since the last rate filing. The previously approved cost of debt was 4.52 percent and is expected to be 4.47 percent for the 2020 test year. Minnesota Power has continued to lock in long-term debt at attractable rates which will benefit customers for years to come.

B. <u>Common Equity</u>

Q. Please summarize the level of common equity in the Minnesota Power capital structure.

A. The projected common equity balance in Minnesota Power's capital structure at the end of the 2020 test year is expected to be $1,576.3 million, or 55.04 percent of total ending capitalization. When calculated from a 13-month average, however, the balance is $1,532.8 million, or 54.46 percent of average capitalization. As discussed above, the Company is requesting that the capital structure remain unchanged from the 2016 Rate Case, with an equity to capital ratio of 53.81 percent. This amount is used to calculate the overall rate of return Minnesota Power is proposing in this case.[16]

Q. To determine Minnesota Power's capital structure, what amount of common equity in ALLETE's capital structure reflects investments in ALLETE subsidiaries?

A. In the 2020 test year, ALLETE's average equity investment balance in subsidiary activities is expected to be $784.2 million. The $784.2 million of equity is removed from the ALLETE capital structure to determine Minnesota Power's test year capital structure.

Q. Does the determination of Minnesota Power's common equity include any other adjustments to ALLETE's balance sheet?

A. Yes. Equity in Minnesota Power's capital structure includes an accounting entry recorded in ALLETE's "Accumulated Other Comprehensive Income" for certain

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[16] *See* Volume 3, Direct Schedule D-1.

amounts associated with non-regulated operations' post-employment plans as required by the statements of financial accounting standards ("SFAS") 158 (Employers' Accounting for Defined Benefit Pension and Other Post-Employment Plans).

Q. Are these adjustments consistent with the adjustments made in previous rate filings?

A. Yes, the SFAS 158 adjustment is consistent with the capital structure approved in the Company's most recent rate order.

Q. Please explain the SFAS 158 post-employment plan balance sheet entry.

A. In September 2006, the Financial Accounting Standards Board issued SFAS 158. SFAS 158 requires employers to recognize certain costs associated with their defined benefit pension and other post-employment plans on their balance sheets. While SFAS 158 amounts for regulated operations are reflected as a long-term regulatory asset, amounts relating to non-regulated operations are recorded in "Accumulated Other Comprehensive Income" in the Equity section of the balance sheet.

Q. Please explain why ALLETE's SFAS 158 post-employment plan entry is reversed in Minnesota Power's capital structure.

A. The SFAS 158 amounts recorded in ALLETE's "Accumulated Other Comprehensive Income" are removed from Minnesota Power's capital structure because they relate only to non-regulated operations. For the 2020 test year, the projected non-regulated post-employment plan amount is $26.7 million.

Q. How much equity does ALLETE carry in its capitalization?

A. Minnesota Power is by far ALLETE's dominant business. Consequently, ALLETE's equity ratios are driven by Minnesota Power's capital structure. For the test year, ALLETE is expected to be capitalized with a projected equity ratio of 58.91 percent and Minnesota Power with a projected equity ratio of 54.46 percent.

Q. Does ALLETE expect to issue common stock in 2020?

A. Yes. As previously indicated, Minnesota Power has a need for additional external financing. To maintain a capital structure that will support adequate investment grade credit ratings and allow the Company to access needed capital at reasonable costs, ALLETE expects to issue both debt and equity capital.

Q. Please explain why the recommended capital structure for Minnesota Power for the 2020 test year is reasonable and appropriate.

A. The Company's objective is to maintain adequate investment-grade credit ratings in order to continue to access the capital it needs at reasonable terms and maintain its financial integrity. The ongoing capital expenditure requirements and debt maturities facing Minnesota Power make this objective both more difficult and more important. The Company's recommended test year capital structure produces an adjusted CFO Pre-Working Capital to Debt ratio within the expected range for ALLETE's current Moody's credit rating.

Q. Do you support the analysis and the rate of return on common equity of 10.05 percent presented by Company witness Ms. Bulkley?

A. Yes. Company witness Ms. Bulkley's conclusion of 10.05 percent is reasonable in today's economic environment, including the risks that are unique to Minnesota Power, and is representative of the range of equity investors' required rate of return for investment in integrated electric utilities in today's capital markets. The significance of the ROE increases in volatile markets because the level of earnings authorized by the Commission directly impacts the Company's ability to fund capital investment with internally generated funds.

Ms. Bulkley's recommended ROE considers the Company's unique risk profile, including its customer concentration, capital expenditure program, and debt maturities. With the Company required to access debt and equity markets for a substantial amount of capital, our ability to attract capital at reasonable returns to ensure continued safe and reliable electric service while maintaining the Company's financial integrity is crucial.

Potential investors will evaluate the Company's ability to meet its fixed obligations and provide an acceptable return before committing their capital to the Company.

V. RETIREMENT PLAN ACCOUNTING

Q. What is the purpose of this section of your Direct Testimony?

A. In this section of my testimony, I explain how the Company's pension and OPEB expense amounts for the 2020 test year were derived. I note Company witness Ms. Laura E. Krollman's Direct Testimony provides background information on overall compensation, including how retirement plans fit into the Company's overall compensation management strategy. Therefore, this section focuses on pension and OPEB expense accounting and the resulting accumulated contributions in excess of net periodic benefit cost.

A. <u>Pension Accounting</u>

Q. How many qualified pension plans does ALLETE have?

A. Company witness Ms. Krollman discusses the Company's qualified pension plans and plan components in her Direct Testimony. In summary, for purposes of my testimony, ALLETE has two qualified pension plans: Plans B and C, collectively referred to as ALLETE's pension or pension plan, with the former Plan A rolled into Plan C in late 2018:

- Plan A – "non-bargaining plan": As a cost-savings measure, all benefits in Plan A were frozen effective November 30, 2018 and Plan A was merged into Plan C on December 31, 2018.
- Plan B – "bargaining plan" for active bargaining unit employees as of January 31, 2011.
- Plan C – "inactive plan," for non-bargaining participants with a deferred vested benefit; retired participants, including surviving spouses; and bargaining unit participants or retirees, including surviving spouses, who were no longer represented by the union contract as of December 31, 2015.

Q. How are the pension benefits paid to Minnesota Power employees funded?

A. They are funded in one of three primary ways:

- Market returns on contributions to the pension fund are used solely to reduce annual pension expense on a dollar-for-dollar basis.
- Annual pension expense, which consists of benefits earned by participants each year (less market returns as described in the first bullet point), is funded through rates, at least to the extent the Company's authorized recovery of pension expense matches its actual annual expense.
- Company contributions to the pension fund are determined separate and apart from the annual expense. When these cumulative contributions exceed cumulative expense, the Company has a prepaid asset, or accumulated contributions in excess of net periodic benefit cost. When the cumulative expense exceeds cumulative contributions, the result is a liability.

Q. How are ALLETE's pension plan contribution and expense levels determined?

A. The amounts of the Company's (1) contributions to its pension plan and (2) its annual pension expense are different because they are governed by two different authorities. Contributions to the pension plan are made to comply with the funding requirements of the Employee Retirement Income Security Act of 1974 ("ERISA") and the Internal Revenue Code ("IRC"), including the provisions of the Pension Protection Act of 2006.

The pension expense is determined by Generally Accepted Accounting Principles ("GAAP") determined by the Financial Accounting Standards Board ("FASB") and accepted by the U.S. Securities and Exchange Commission ("SEC"). Minnesota Power's actuary, Mercer (US) Inc. ("Mercer"), calculates the Company's pension expense using actuarial analyses, which are performed in accordance with Financial Accounting Standards Codification ("ASC") 715-30 Defined Benefit Plans – Pension.

ASC 715-30 requires the pension expense for a given year to be determined on an annual basis, which is calculated by Mercer. In addition, the Company's independent auditor, PricewaterhouseCoopers, LLP ("PwC"), audits the actuarial assumptions used to ensure compliance with GAAP. PwC has always found the actuarial assumptions applied to be in accordance with GAAP.

Q. What are SFAS and ASC, and why are they important?

A. SFAS is the acronym for "statements of financial accounting standards." It is usually used with a number after it, which is the pronouncement number. These pronouncements were created by the FASB, which is the "independent, private-sector, not-for-profit organization…that establishes financial accounting and reporting standards for public and private companies and not-for-profit organizations that follow [GAAP]. The FASB is recognized by the [SEC] as the designated accounting standard setter for public companies."[17]

In September 2006, the FASB issued SFAS 158, which required employers to recognize on a prospective basis the funded status of their defined benefit pension and other postretirement plans on their consolidated balance sheet and recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but that are not recognized as components of net periodic benefit cost. The pronouncement also required additional disclosures in the notes to financial statements.[18] SFAS 158 was effective for fiscal years ending after December 15, 2006.

In 2009, the FASB moved from a SFAS structure to the current ASC structure. This change did not fundamentally alter GAAP, but did provide a new topical structure that was designed to make GAAP requirements easier to locate. SFAS 158 was re-codified as ASC 715 (Compensation—Retirement Benefits).

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[17] *About the FASB*, FIN. ACCOUNTING STANDARDS BD., https://www.fasb.org/jsp/%20FASB/Page/SectionPage&cid=1176154526495 (last visited Aug. 14, 2019).

[18] *Summary of Statement No. 158*, FIN. ACCOUNTING STANDARDS BD., available at https://www.fasb.org/summary/stsum158.shtml.

Q. How is the Minnesota Jurisdictional portion of pension expense and contributions derived from the ALLETE totals?

A. As described in more detail below, Minnesota Power's actuary, Mercer, calculates ALLETE's, as well as SWLP's, pension expense, contributions, accumulated contributions in excess of net periodic benefit cost, etc. using actuarial analyses. To determine the Minnesota jurisdictional amounts, we first start with the ALLETE total and subtract out subsidiaries (SWLP and ALLETE Clean Energy) to get to Minnesota Power's allocation. We then apply a regulated allocator to remove (1) the non-regulated Minnesota Power portion and (2) the capitalized numbers in order to arrive at MP regulated (also called Total Company) pension expense/contributions. We then apply the Minnesota jurisdictional allocator to get to the amount we are requesting in this general rate case. The calculation for the 2020 test year is provided below in Table 7.

Table 7. Allocation – Test Year 2020

	Expense	**Contribution**
ALLETE	$7,060,000	$12,600,000
Less: Subsidiaries	1,220,990	1,145,200
Minnesota Power	$5,839,010	$11,454,800
x Regulated Allocator	84.916%	84.916%
MP Regulated	$4,958,254	$9,726,958
MN Jurisdictional Allocator	89.4491%	89.4491%
MN Jurisdictional	**$4,435,113**	**$8,700,676**

Q. Conversely, how are the subsidiary amounts determined for pension expense and contributions?

A. As mentioned above, Mercer calculates SWLP's pension expense, contributions, accumulated contributions in excess of net periodic benefit cost, etc. using actuarial analyses. Due to its small size, ALLETE's other subsidiary, ALLETE Clean Energy, is allocated expense based on its proportion of pension-eligible salaries to ALLETE's total pension eligible salaries. ALLETE Clean Energy makes contributions to the plan equal to its expense; therefore, ALLETE Clean Energy does not have an accumulated contributions in excess of net periodic benefit cost balance.

1. Pension Expense

Q. What amount of pension expense is included in Minnesota Power's 2020 test year budget?

A. The 2020 pension expense is projected to be $7,060,000 for ALLETE ($4,958,254 MP regulated), which equates to $4,435,113 (MN) pension expense in the 2020 test year. This is a reduction of $794,235 from the Minnesota jurisdictional amount included in the Company's last approved 2017 test year.

Q. How was the Company's 2017 test year pension expense established in Minnesota Power's prior rate case?

A. In the 2016 Rate Case, the Department of Commerce, Division of Energy Resources ("Department"), recommended using Minnesota Power's actual 2017 pension expense based on a December 31, 2016 measurement date. The Commission agreed. After updating for the jurisdictional allocator changes in the proceeding, the actual pension expense amount included in rates was $5,229,348 (MN).

Q. Can you provide more information about the Company's historical pension expense?

A. Yes. In MP Exhibit ___ (Cutshall), Direct Schedule 7 I have compiled a 33-year historical schedule of pertinent pension information, such as contributions, expense, and rate case recovery starting in 1987. Because the historical information available from our accounting and other systems is somewhat limited going back so far, the main source of this data is actuarial calculations. I believe this presents a reasonable and accurate view of the available information.

Q. Has the Company taken any steps in recent years to reduce its pension expense?

A. Yes. Below is a summary of these steps Minnesota Power has taken to reduce its pension expense. Company witness Ms. Krollman also discusses some of these changes in her Direct Testimony.

- Closed Plan A to new entrants – October 1, 2006
- Closed Plan B to new entrants – February 1, 2011
- Determined discount rate using Mercer Bond Model to support a higher discount rate, lowering liabilities and overall expense – 2014
- Created Plan C – Effective January 1, 2016. The purpose of creating Plan C was to restructure Plan A and Plan B into a third plan (Plan C) for inactive participants, in order to deliver benefits in a more cost-effective method. Plan C was established to place all participants not accruing benefits into one plan with the assets and liabilities associated with those accrued benefits. The benefits from creating Plan C were: (1) to create a plan that could, if so desired, be more easily annuitized when the opportunity arises, thus reducing risk to the company; (2) to take advantage of accounting rules that allow a longer amortization period for unrealized losses within the pension calculation for plans covering only inactive participants; and (3) as to some participants who received benefits under both Plan A and Plan B, placing them into Plan C meant they were paid out of only one plan, reducing the Company's Pension Benefit Guarantee Corporation premiums. Accordingly, certain assets and liabilities were transferred from Plans A and B to Plan C with this change. Because no new Minnesota Power employees are eligible for pension benefits, this was just a shifting of participants from one plan to another plan. The 2020 estimated expense savings of this restructuring for ALLETE is $5.0 million ($3.5 million MP regulated; $3.1 million MN).
- As part of the Company's cost control efforts following the 2016 Rate Case, ALLETE froze the final average earnings for all non-union pension plan participants effective November 30, 2018. This resulted in an estimated expense savings for ALLETE of approximately $1.8 million ($1.3 million MP regulated; $1.1 million MN) per year for at least the next 5 to 10 years. Since there were

no more benefits accruing in Plan A, Plan A was merged into Plan C on December 31, 2018, which created an additional expense savings per year for at least the next 5 to 10 years (due to Plan C having a longer amortization period than Plan A) of approximately $0.7 million for ALLETE ($0.5 million MP regulated; $0.4 million MN).

Q. Generally speaking, what are the components of ALLETE's pension expense calculation?

A. ALLETE's pension expense is determined by calculating and aggregating five components:

1. Service Cost – The present value (using the discount rate as described below) of the projected retirement benefits earned by each employee in the current year.
2. Interest Cost – The amount that the present value (using the discount rate as described below) of future benefit payments is expected to increase during the year due to interest accrual over a one-year period. In other words, this is the expense incurred because employees are one year closer to receiving benefits.
3. Expected Return on Plan Assets – The amount expected to be earned on the plan's assets. It is estimated by multiplying the Expected Return on Assets ("EROA") to the five-year smoothed pension asset balance.
4. Amortization of Prior Service Cost – The cost of increased/(decreased) benefits, amortized over the remaining service life of the affected participants.
5. Amortization of Net Gain or Loss – Gains or losses accumulated when the annual change in the benefit obligation or the plan assets deviate from expectations, i.e., the difference between the prior years' actual return on plan assets versus the prior years' Expected Return on Plan Assets. If these accumulated gains or losses exceed 10 percent of the greater of the benefit obligation or plan assets, the excess is amortized over a period of time based on participant demographics.

Q. What information did Mercer use to calculate the annual pension expense for the 2020 test year?

A. The primary pension assumptions used by Mercer to estimate the Company's 2020 pension expense are listed below:

- Discount rate of 3.25 percent: The discount rate is computed using the Mercer Bond Model, which creates a hypothetical portfolio of AA or better rated corporate bonds such that bond yields and principal payments would fully match the projected benefit payments from the pension plan. The discount rate is set equal to the yield on this hypothetical portfolio. This methodology is the most precise and yields the highest discount rate (lowest expense) allowed by the SEC.
- 2020 contributions of $12.6 million ALLETE ($9.7 million MP regulated; $8.7 million MN).
- EROA of 6.75 percent: The 6.75 percent rate is Mercer's highest supportable return (lowest expense) using Mercer's passive investment projections for ALLETE's pension asset allocation, which has an approximate fixed-asset allocation of 60 percent. Mercer's net of fee mid- or 50th percentile projection for ALLETE's portfolio is 5.83 percent, but Mercer can support using returns that are in the 35th percentile (return of 4.91 percent) to 65th percentile (return 6.75 percent) range. (See MP Exhibit ___ (Cutshall), Direct Schedule 8).

Q. How do these assumptions compare to the 2017 test year that was the focus of the 2016 Rate Case?

A. The discount rate, 2020 contributions, and the EROA are all lower than in the 2017 test year. The discount rate is lower due to overall lower interest rates since the 2017 test year; contributions are lower but still almost twice as much as expense, similar to 2017; and the EROA is lower because the pension's asset allocation to fixed income is almost double what it was in 2017 due to the plan's investment policy of reducing risk as the plan becomes more fully funded (this is known as "Liability Driven Investing").

Q. Can you explain further why the Company's EROA is lower in the current rate case?

A. Yes. Per the investment policy's dynamic asset allocation glide path, as the plan becomes more fully funded, the Company prudently reduces risk by investing more in fixed income assets, which increasingly reduces investment risk (generally, fixed income investments are less risky than equity investments) and hedges a greater portion of the plan's interest rate risk that is inherent in a pension plan's liability (because pension liabilities change in value similar to long-duration high-quality corporate bonds); however, as the Company allocates more to the less risky fixed income assets, the plan's EROA also needs to be reduced.

Q. Besides Mercer's return projection, was there other supportable evidence for the EROA for the plan?

A. Yes. As stated above, 6.75 percent is the highest supportable return using Mercer's passive investment projection for ALLETE's approximate 60 percent asset allocation to fixed income. In addition, the Company retrieved pension data from all investor-owned electric utilities in the Edison Electric Institute ("EEI") through their 2018 annual reports (SEC required Form 10-K reports). We then created a schedule showing the electric utility companies' names, pension investment allocations to fixed income, and the EROA (see MP Exhibit ___ (Cutshall), Direct Schedule 9). The average pension return of 6.95 percent on Schedule 9 materially agrees with the average pension return of 7.0 percent reported in the most recent EEI 2018-19 Pension and Other Post-Employment Benefits Survey (see MP Exhibit ___ (Cutshall), Direct Schedule 10). As expected, both schedules show that pensions with higher investment allocations to fixed income as a whole have a lower EROA. This is because fixed income investments are typically less risky; therefore, they have a lower expected return than equity investments.

In addition, Figure 3 below is a scatter graph showing ALLETE's and the EEI utilities' pension plans' fixed income allocations compared to each company's plans' expected returns. The scatter graph includes a best fit trend line (using Microsoft Excel's TREND function) which visually shows the same relationship.

This function uses the "least squares" method to calculate a straight line that best fits the data. The equation for the line is:

y = mx + b

Where:

y = trend line return for a fixed asset allocation = 6.44 percent

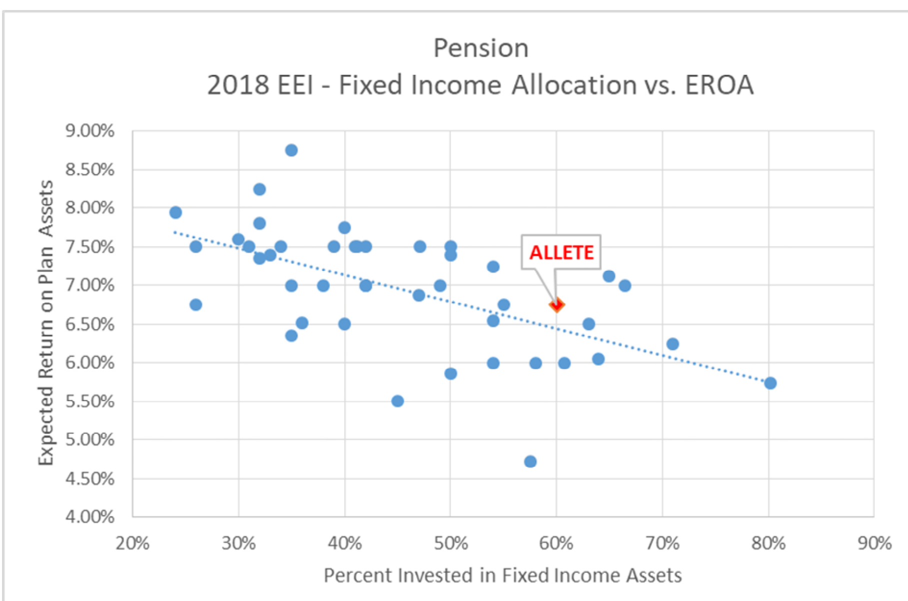
m = the slope determined by Excel SLOPE function = -3.48 percent

x = percent a portfolio is allocated to fixed income = ALLETE portfolio ~ 60 percent

b = intercept determined by Excel INTERCEPT function = 8.53 percent

This scatter graph demonstrates ALLETE's EROA is higher (therefore, expense is lower) than what would be expected using the trend line or expected return for the average utility with the same allocation to fixed income.

Figure 3.



Q. What would you expect ALLETE's EROA would be using the trend line?

A. Using the trend line, the projected EROA for a plan with a fixed income asset allocation of 60 percent (ALLETE's approximate asset allocation) would be 6.44 percent, versus ALLETE's EROA of 6.75 percent. This analysis supports the statement that ALLETE uses a higher EROA than average taking into consideration ALLETE's 60 percent fixed income allocation. The higher EROA of 6.75 percent also creates a lower pension expense than the pension expense that would have been created had ALLETE used a 6.44 percent EROA as supported by the trend line.

Q. Why does the Company's plan have an approximate 60 percent allocation to fixed income?

A. Many people understand from their personal financial advisors for personal 401(k) investment allocations that one should reduce risk as retirement approaches by gradually switching to less risky, fixed-income-type investments from more risky equity-type investments. Aging investors nearing retirement have less opportunity or time to recover from a loss.

This scenario is no different for pension plans that "age." A pension plan that is open – meaning that new employees get pension benefits and participants accrue benefits – doesn't "age" significantly from year to year. However, once pension plans freeze benefits, as is the case for ALLETE's plan, such plans have similar risk aging characteristics. Taking the increasing maturity of the plan into consideration, ALLETE has made a commitment to lowering the risk of the investment by gradually increasing allocation to fixed income. With the help of Mercer, ALLETE adopted an investment policy in November 2013 that reduces risk over time as the plan becomes more funded. It does this by allocating a higher percentage of the portfolio's assets to fixed income assets as the plan achieves higher funded trigger levels. This dynamic asset allocation over time is commonly referred to as an investment "glide path." Thus, ALLETE's plan's 60 percent allocation to fixed income is a result of ALLETE prudently adopting and following the plan's investment policy glide path.

Q. Did ALLETE's plan recently reach any trigger points?

A. Yes. Due to contributions, robust equity markets, and an increase in interest rates, the plan attained two trigger points in the first quarter of 2018. The first trigger point was at the 85 percent funded level on January 9, 2018; therefore, following the investment policy glide path, the plan's fixed income asset allocation was increased to approximately 45 percent. The second trigger point was initiated at the 90 percent funded level on March 9, 2018, increasing the plan's fixed income asset allocation to approximately 56 percent. Since then, the pension fund's fixed income allocation increased to approximately 60 percent due to asset performance consistent with the above policy ranges.

Q. Are there other benefits of a pension owning fixed income investments?

A. Yes. Pension expenses and liabilities are directly and directionally sensitive to interest rate changes; however, fixed income asset prices are inversely sensitive to interest rate movements (e.g. interest rates go down causing fixed income asset prices to increase). Therefore, a pension that invests in more fixed income assets, all other things being equal, will hedge more of the interest rate risk inherent in a pension plan's liability, which provides an additional risk reducing benefit. As mentioned above, this characteristic of matching a pension's assets to its liabilities is called Liability Driven Investing, which is what ALLETE's pension policy is accomplishing over time. As the plan becomes more fully funded, the Company is transitioning its assets from return seeking to liability hedging.

Q. What is the benefit of Liability Driven Investing to investors?

A. Liability Driven Investing means the assets of a plan mimic the liabilities of the plan. It is impossible for a pension to have perfect Liability Driven Investing, because all the future variables of the assets and liabilities, such as participants' life spans, cannot be predicted perfectly. However, for the five main pension expense components,[19] explained previously, fixed income investments when appropriately stratified by

[19] 1) Service Cost, 2) Interest Cost, 3) Expected Return on Plan Assets, 4) Amortization of Prior Service Cost, 5) Amortization of Net Gain or Loss.

maturity, or in technical terms duration, are the best investments to mimic the liabilities. This is because all five of the pension expense components are driven by interest rates, return on assets, or both which are the same drivers of fixed income returns. Because of this, adjusting fixed income assets through Liability Driven Investing reduces expense volatility through matching interest cost and EROA while also mitigating risk of additional loss amortizations.

Q. What is the benefit of the EROA to customers?

A. When the Company makes contributions to the pension fund, those funds earn the EROA, which is then incorporated into the revenue requirement to reduce the funds needed to cover annual pension expense. This is a direct benefit to customers, who cover the annual pension expense in rates. It is not a benefit to Company investors, as they do not receive the benefits of the EROA and related Expected Return on Plan Assets and (presently) are not compensated for their cumulative contributions to the pension fund that exceed cumulative expense.

Q. Please provide an example of how the EROA and the related investment earnings reduce pension expense.

A. The earnings on the investments, referred to as the Expected Return on Plan Assets (created by the EROA) significantly reduce ALLETE's pension expense. For example, Table 8 below shows the components used to calculate ALLETE's 2018 pension expense (the last full year with audited numbers). As Table 8 demonstrates, the investment return or EROA reduces the 2018 pension expense by $44.4 million, or approximately 90 percent of the plan's expense. If there was no reduction for the Expected Return on Plan Assets, 2018 pension expense would be $50.0 million rather than $5.6 million.

Table 8. Pension Expense Example ($'s in millions)

	2018 ALLETE Actual	2020 ALLETE Test Year	2020 MP Regulated Test Year	2020 MN Jurisdictional Test Year
Service cost	$ 10.6	$ 11.2	$ 7.8	$ 7.0
Interest cost	28.8	26.4	18.5	16.5
Amortization of loss	10.7	12.5	8.8	7.8
Amortization of prior service cost	(0.1)	(0.2)	(0.1)	(0.1)
Expected Return on Plan Assets	(44.4)	(42.8)	(30.0)	(26.8)
Pension Expense	**$ 5.6**	**$ 7.1**	**$ 5.0**	**$ 4.4**

Q. Earlier you mentioned the EROA is multiplied by a five-year smoothed pension asset balance. Why does the Company take this step to determine pension expense?

A. GAAP allows the use of certain smoothing techniques to "normalize" pension expense. Using a five-year smoothed pension asset balance reduces the volatility, or normalizes the pension expense, so that customers do not see such wide ranges of pension expense from year to year as they otherwise would. This is a benefit to customers.

Q. Does ALLETE take other steps to reduce pension expense volatility?

A. Yes. For purposes of calculating pension expense, the Company utilizes all smoothing methods allowed under pension accounting rules (ASC 715-30). Under these methods:

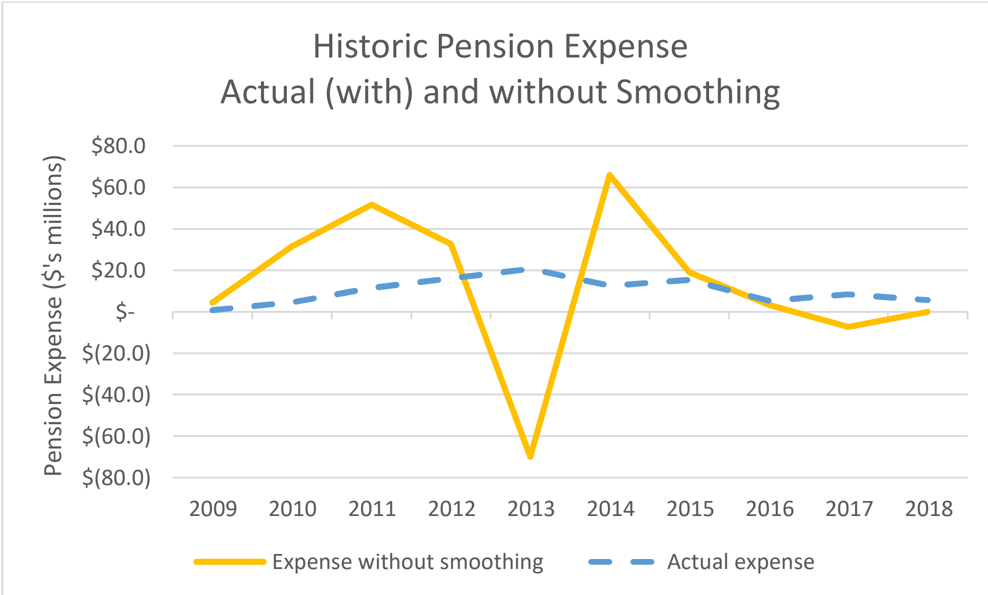
- ALLETE uses a market-related value of assets in calculating expense. The market-related value of assets phases in gains or losses over a five-year period, which reduces volatility by using a more stable asset value to determine the Expected Return on Plan Assets component of expense. The market-related value of assets also reduces volatility in the amortization of gains and losses, described below, because recent gains and losses are excluded from the amortization calculation to the extent they are not phased in.

- ALLETE amortizes accumulated gains and losses, excluding gains and losses not yet phased into the market-related value of assets, in the pension expense.
    - ALLETE uses a corridor to determine if gains and losses will be amortized in expense. The corridor is the greater of 10 percent of the plan's obligation or 10 percent of the plan's market-related value of assets.
        - If accumulated gains and losses fall within the corridor, no gains and losses are amortized in expense.
        - If accumulated gains and losses exceed the corridor, the excess is amortized over the average working lifetime of active participants, or the average lifetime of all plan participants if there are no active participants accruing benefits in the plan.
- Increases or decreases in plan liabilities resulting from plan amendments are amortized over the average working lifetime of the active participants affected by the plan amendment.

Q. What are the effects of the smoothing?

A. Appropriate smoothing has the benefit of reducing volatility and increasing predictability of the pension expense. The actual benefits of smoothing on ALLETE's pension expense over the last 10 years are shown vividly in Figure 4, where the actual expense (smoothed), or blue dashed line, is relatively flat compared to the pension expense without smoothing (the orange solid line). This comparison demonstrates that over the last 10 years, ALLETE's actual pension expense (smoothed) range was less than $20 million ($0.8 million to $20.7 million); however, the range of pension expense without smoothing was almost seven times greater, with an approximate range of $136 million (negative $69.9 million to $66.0 million).

Figure 4.



Q. Does Minnesota Power support using the actuarially determined pension expense for ratemaking purposes in this case?

A. Yes. As in past cases, Minnesota Power has consistently recommended using Mercer's actuarially determined pension expense to set rates, because it is consistent and measurably accurate and represents a specific test year cost of providing utility service. Conversely, if pension expenses are not determined consistently, "cherry picking" of other methodologies could occur, which could artificially increase or reduce the Company's pension expense recovery.

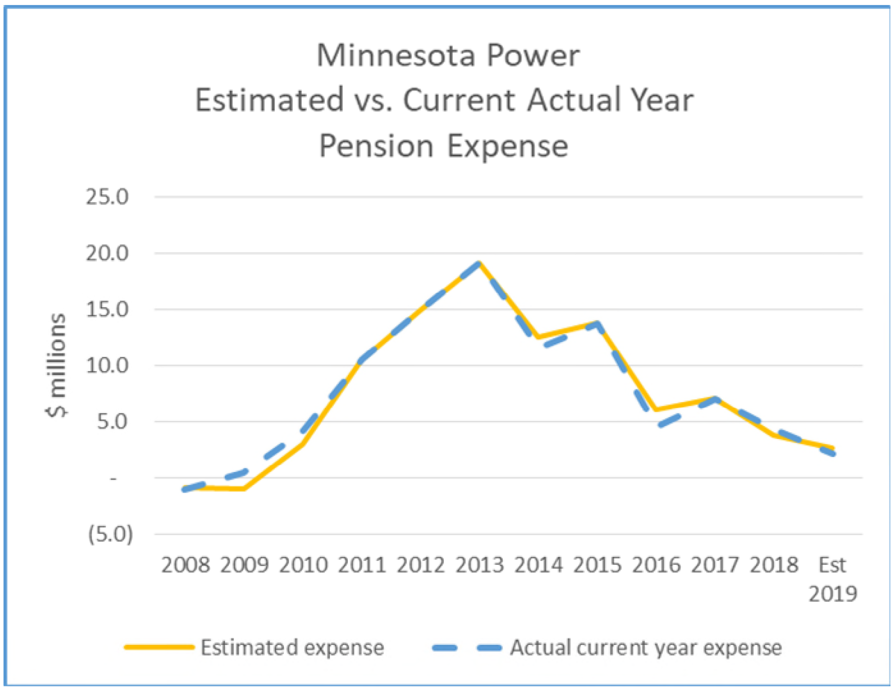
Q. Why do you believe using the actuarially determined estimated pension expense is the most accurate?

A. Because the actuarially-determined method relies on third-party specific expertise in this area, and incorporates all of the most recent known and relevant information.

Q. Is there evidence that the actuarially-determined pension expense is also the most accurate measure of actual Company expense?

A. Yes. We have statistically measured the actuarially determined pension expense estimate's correlation, or r-squared, to the next year's actual pension expense. The correlation is very high at 0.96, close to being almost statistically perfectly correlated. An r-squared value is a statistical measurement that measures how the proportion of the variance of one number is attributable to another number. An r-squared value of 1 is perfectly correlated (or explains all of the variability), 0 is uncorrelated, and -1 is perfectly negatively correlated. The high correlation we measured is illustrated in Figure 5 below, where the two lines (blue being the estimated pension expense and orange being the actual pension expense) are essentially on top of each other — indicating the actuarial estimate is an excellent predictor of actual expense over the last decade.

Figure 5.



Q. Is there an alternative way to recover pension expense that is more accurate?

A. Yes. An alternative approach would be to institute a mechanism that adjusts rates annually for pension expense and the associated contributions. An annual true-up would be consistent with the Commission's past approval of true-ups related to other volatile costs, such as property taxes. Such an approach would represent the most accurate, timely, and direct recovery mechanism supporting the true cost of service. The

Company would be amenable to such a mechanism to ensure there is neither under- nor over-recovery of pension expense in any given year.

Q. What do you conclude regarding the Company's pension expense included in Minnesota Power's 2020 test year?

A. Minnesota Power supports recovery of the Company's forecasted 2020 pension expense as determined by Mercer or an annual adjustment mechanism as set forth above. Over the years, the Company has consistently recommended and supported the determination of pension expense based on the Company's GAAP pension expense as determined by our actuary, including the current year's assumptions, which are presented herein. Using another method to calculate pension expense, or switching methods from rate case to rate case, has the strong potential to distort the forecasting methodology mandated by the SEC and GAAP to measure the cost of the plan, thereby precluding the Company from recovering its costs of providing retirement benefits to Company employees.

2. <u>Pension – Accumulated Contributions in Excess of Net Periodic Benefit Cost</u>

Q. What is the Company requesting with regard to its accumulated contributions in excess of net periodic benefit cost.

A. The Company requests that the thirteen-month average of its test year pension plan accumulated contributions in excess of net periodic benefit cost of $78,515,202 (MN) (see MP Exhibit ___ (Cutshall), Direct Schedule 11) be included in the working capital section of rate base. This would result in a net increase to rate base of $49,068,112 (MN) for accumulated contributions, net of ADIT. The ADIT applied to the accumulated contributions in excess of net period benefit cost equals $29,447,090 (MN) and consists of $22,566,839 computed at the statutory tax rate of 28.742 percent, plus excess deferred tax of $6,880,251. The excess deferred tax is a result of the corporate income tax rate change in the TCJA. The net increase, or $49,068,112 (MN), is the amount on which the Company seeks to earn a return. In other words, Minnesota Power asks to treat these accumulated contributions in the same manner as any other working capital item, all of which similarly fluctuate.

Q. Has the Company used other naming conventions for accumulated contributions in excess of net periodic benefit cost?

A. Yes. Historically, GAAP has used the terms "prepaid pension cost," "prepaid pension expense," and "prepaid pension asset" to signify cumulative contributions to a pension plan in excess of its cumulative expense. These terms mean the same thing, and many GAAP-compliant audited companies and financial statements still use the term "prepaid pension." Here, the Company will use the more current terminology; however, the Company would note that prior Commission orders used the term "prepaid pension," and many surveys, articles, companies, and audited GAAP financial statements reviewed by the SEC still use that term.

Q. Has the Company requested recovery of these prepaid contributions to the pension fund before this case?

A. Yes. Minnesota Power recognizes that the Commission concluded in the Company's 2016 Rate Case that the Company did not justify rate-base treatment of prepaid pension funds. The Commission directed the Company to remove the prepaid pension asset, along with the associated tax savings, from the test-year rate base.[20]

Q. Why is Minnesota Power seeking to include this asset in rate base and earn a return on it in this proceeding?

A. Although the Commission has not approved rate-base treatment and associated recovery for several utilities, including for Minnesota Power (but has permitted rate base treatment for another Minnesota utility over the course of several rate cases), the Company feels compelled under its current circumstances to renew its request for authorization to include in rate base this important utility investment made on behalf of the Company's workers and to the benefit of its customers.

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[20] *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 16 (Mar. 12, 2018).

In the 2016 Rate Case Order, the Commission adopted the rationale for excluding the prepaid pension asset from rate base that was originally articulated in the 2013 and 2015 rate cases for Minnesota Energy Resources Corporation ("MERC").[21] The Commission noted that the circumstances that originally warranted denying a return on the asset in those earlier MERC cases were likewise present in Minnesota Power's 2016 Rate Case.[22] While the Company respectfully disagrees with the Commission's assessment in the 2016 Rate Case, and believes that Minnesota Power is justified on the merits and the reasonableness of including the prepaid pension asset in rate base, the Company addresses the concerns expressed by the Commission in the 2016 Rate Case, provides additional information, and explains and bolsters the facts supporting recovery in this proceeding.

Q. How is your discussion of this issue organized in your Direct Testimony?

A. First, I explain what the accumulated contributions in excess of net periodic benefit cost are, and how they benefit Minnesota Power employees while also *directly* reducing customer rates. I also provide a specific, simplified example of how this works — shareholder contributions to the pension fund in excess of expense earn market returns, which directly reduces the annual expense included in customer rates, and, under the current non-recovery of its capital costs, reduces the Company's earnings. Next, I explain how the Company's accumulated contributions in excess of net periodic benefit cost appear on the ALLETE financial statements and are stated in accordance with GAAP. Finally, I walk through the Commission's reasons for denying a return on this asset in the 2016 Rate Case, and identify how the Company has rectified any concerns the Commission had.

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[21] In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn., Docket No. E-015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 16 n.22 (March 12, 2018) ("2016 Rate Case Order") (citing In the Matter of the Application of Minn. Energy Resources Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn., Docket No. G-011/GR-15-736, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at 8-11 (October 31, 2016); In the Matter of a Petition by Minn. Energy Resources Corp. for Auth. to Increase Natural Gas Rates in Minn., Docket No. G011/GR-13-617, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at 22-24 (Oct. 28, 2014)).

[22] 2016 Rate Case Order at 16.

a. Accumulated Contributions in Excess of Net Periodic Benefit Cost

Q. Can you describe in more detail what Minnesota Power's pension's accumulated contributions in excess of net periodic benefit cost are?

A. Yes. Minnesota Power's accumulated contributions in excess of net periodic benefit cost arose from the fact the Company has contributed more to its employee pension plan (cumulatively) than it has expensed since 1952, the inception year of the plan.

Q. What is the current balance of the plan's accumulated contributions in excess of net periodic benefit cost?

A. As of December 31, 2018, the ALLETE plan's accumulated contributions in excess of net periodic benefit cost balance was an asset balance of $95,697,238, and the Company estimates the ALLETE plan's December 31, 2019 and 2020 balances to be $103,303,312 and $108,843,312, respectively. Additional historical information is included in MP Exhibit ___ (Cutshall), Direct Schedule 7.

Q. Is there a tax benefit for making contributions to the pension plan?

A. Yes. The Company's contribution to the pension plan is tax-deductible up to the limit set by the Internal Revenue Service ("IRS"). When pension contributions exceed the expense in any given year, it creates a corresponding deferred income tax liability. This will lower the taxes Minnesota Power pays relative to its GAAP expense. Since the pension plan's inception, the accumulation of these annual deferred tax liabilities has created a related ADIT balance. If the Minnesota-jurisdictional portion of the accumulated contributions in excess of net periodic pension cost is included in rate base, then the resulting ADIT will also be included and reduce rate base.

Q. Are there other current components in rate base that are treated the same way as pension contributions for tax purposes?

A. Yes. When Minnesota Power makes a contribution to the pension plan, that contribution is tax deductible when paid. Therefore, the payment is treated exactly the same as prepaid insurance, another item in working capital that is included in rate base. In contrast, other components in rate base, such as fixed assets, are depreciated, but differently, for GAAP accounting and IRS purposes.

Q. Can you calculate the ADIT related to the pension's accumulated contributions in excess of net periodic pension costs?

A. Yes. The calculation for the tax treatment of the pension contributions that created the accumulated contributions in excess of net periodic pension cost is as follows: multiply the accumulated contributions in excess of net periodic pension cost by ALLETE's combined federal and state tax rate of 28.742 percent, which equals the ADIT, then add back the excess deferred tax. The total impact to the full Minnesota jurisdictional amount in rate base will be reduced by the corresponding ADIT.

Q. What, then, is the total amount the Company is proposing to include in rate base?

A. The Company requests that the thirteen-month average of its 2020 test year pension plan accumulated contributions in excess of net periodic benefit cost of $78,515,202 (MN), less the related ADIT of $29,447,090 (MN), for a net amount of $49,068,112 (MN) be included in rate base.

b. Ratemaking Support for Asset

Q. Please summarize why Minnesota Power's accumulated contributions in excess of net periodic pension costs should be included in rate base and earn a return like other prepaid assets.

A. As discussed in detail below, recognition of Minnesota Power's funding of the accumulated contributions in excess of net periodic pension costs should be included in the working capital section of its rate base for several reasons: (1) these costs are a necessary cost of providing electric service; (2) a certain level of pension contribution is required by law to fund pension plans, and thus these costs are not discretionary; (3) contributions in excess of pension expense to the pension plan are made by the Company's shareholders and benefit customers (as demonstrated previously in Table 8); (4) there is precedent in Minnesota and nationwide for including accumulated contributions in excess of net periodic pension costs in rate base, and many other states have also recognized that this is necessary to compensate shareholders for pension funds contributed in excess of amounts included in rates; and (5) it is consistent with standard ratemaking treatment when contributions and expenses differ significantly for any cost of providing utility service. Given that the Company is entitled to a fair return on costs it incurs as necessary to provide utility service, these costs should be included in rate base.

Q. Is including accumulated contributions in excess of net periodic benefit cost in rate base consistent with standard ratemaking treatment?

A. Yes. Including the accumulated contributions in excess of net periodic benefit cost in rate base is consistent with standard ratemaking treatment. For an expenditure, when cash payments (or other forms of payments) and expenses differ significantly, the Company must include this difference in rate base. Examples include deferred tax assets, deferred tax liabilities, and working capital items such as accounts receivable, accounts payable, inventory, and prepaid expenses. All of these items involve shareholders providing or receiving funds greater or lesser than expenses. It should be no different for the timing difference between contributions and expenses for a pension plan.

Q. Is there precedent for including accumulated contributions in excess of net periodic benefit cost in rate base?

A. Yes, both in Minnesota and in other states. Northern States Power–Minnesota includes accumulated contributions in excess of net periodic benefit cost in its rate base per a May 8, 2015 rate order that stated:[23]

> "For rate-base purposes, the pension asset is to reflect the cumulative difference between actual cash deposits made by the Company reduced by the recognized qualified pension cost…"

[23] *In the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E-002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 20 (May 8, 2015).

In addition, multiple other state commissions have also specifically found that it is important to the regulatory compact to allow a utility making cumulative contributions to its pension fund in excess of cumulative expense to earn a return on those assets; otherwise, the utility's additional contributions are being used to reduce customer expense without any compensation to the shareholders who made the contribution. I discuss other states' analysis and conclusions later in my testimony.

(1) Legal Requirements for Contributions

Q. Why doesn't the Company just make contributions to the plan equal to its pension expense, so that it would not have accumulated contributions in excess of net periodic benefit cost balance?

A. Because by law, it cannot. As I discussed earlier, the pension expense and contributions represent different aspects of the pension plan and are governed by two different authorities. The *pension expense* represents the Company's annual pension plan costs on the income statement, which is determined by GAAP as set forth by the FASB and accepted by the SEC, and which is recovered from Minnesota Power customers. *Contributions* to the pension plan, on the other hand, are made by the Company (via its shareholders) to satisfy the funding requirements of ERISA, the IRC, and the provisions of the Pension Protection Act of 2006 ("PPA"). The PPA established certain minimum funding requirements for plan years beginning in 2008 and continuing through the present. Prior to enactment of the PPA, pension contributions and pension expense were either largely equal or in balance.

Q. How do these requirements result in an asset or liability?

A. Because of these different requirements, when an employer contributes more cash to the pension plan (per ERISA, the IRC, and the PPA) than it has recorded expense for over the same period (per GAAP), the result is the recognition of accumulated contributions in excess of net periodic benefit cost, or using earlier terminology, a "prepaid pension asset." Conversely, contributing less than the expense recognized will result in additional liability, or a "prepaid pension liability."

Q. How does the enactment of the PPA relate to the fact that the Company did not seek to include the asset in rate base until the previous rate case?

A. There are several reasons the Company did not request prepaid pension assets\liabilities to be included in rate base prior to the enactment of the PPA: (1) contributions and expense were largely the same, as illustrated in MP Exhibit ___ (Cutshall), Direct Schedule 7 and as a result this issue did not have a material impact on either customers or the Company; (2) the prepaid pension balance was both an asset and liability, and neither favored customers nor the Company over long periods of time; and (3) prior to enactment of the PPA, there was more flexibility in determining the timing and amount of contributions.

The enactment of the PPA resulted in significant increases in contributions in 2008 and projected future years. This had noticeable detrimental impacts on the then-current and future cash financial ratios. In fact, these projected contributions had such a large impact on any company offering pension plans that the U.S. Congress subsequently enacted laws multiple times reducing some of the PPA-required contributions. Upon understanding these impacts, the Company requested deferred accounting and the recognition of the prepaid asset in its Petition for Approval of Deferred Accounting Related to Pension Plan (Docket No. E015/M-11-1264) filed on December 22, 2011. The Company's request was denied in part because the cost was not considered "unusual, unforeseeable, and large enough to have a significant impact on the utility's financial condition," which are the traditional Commission criteria for deferred accounting.[24] The Company was directed to take up the issue in a future rate case if the Company so chose.

[24] *In the Matter of Minn. Power's Petition for Approval of Deferred Accounting Related to Pension Plan Contributions and Expenses*, Docket No. E-015/M-11-1264, ORDER DENYING PETITION at 2 (Mar. 11, 2013).

Q. Is the Company only seeking to include the accumulated contributions in excess of net periodic cost in rate base to the extent it is an asset?

A. No. The Company believes it is appropriate to include accumulated contributions in excess of net periodic cost in rate base, whether it is an asset or a liability, for the duration of the plan.

(2) Harm of Excluding Asset from Rate Base

Q. Does <u>not</u> allowing accumulated contributions in excess of net periodic benefit cost in rate base have financial and credit implications?

A. Yes, in at least two ways — by denying shareholders the time value of their money contributed to the pension fund in excess of recovered expense, and by reducing the Company's cash flows such that its credit metrics and resulting credit ratings are impacted.

Q. Please explain how excluding the accumulated contributions in excess of net periodic benefit cost from rate base denies shareholders the time value of their money.

A. The PPA required substantial increases in contributions to the Company's pension fund beginning in 2008 and going forward. In many of the years since 2008, annual contributions have been significantly greater than the pension expense (shown in MP Exhibit ___ (Cutshall), Direct Schedule 7 and in Figure 6 later in my testimony). These increased contributions also have reduced, and will continue to reduce, pension expense more than would have been expected pre-PPA, since ASC 715-30-35[25] requires all earnings on pension fund investments be used to reduce pension expense. Because the Company's cash contributions since 2008 have been significantly higher than the pension expense funded by customers, creating the accumulated contributions in excess of net periodic benefit cost asset, the shareholders should be compensated for the use of their funds that reduce pension expense. If shareholders are not compensated for the use of their money, customers receive benefits (in the form of reductions to pension

[25] ASC 715-30-35-3 and 4.

expense) without compensating shareholders for utilizing their dollars. Meanwhile, shareholders receive no value for contributions while they are tied up in the pension funds. Customers thus receive the benefit of the return on the shareholder investments until such time there is no longer any accumulated contributions in excess of net periodic benefit cost.

Q. Please explain how excluding the accumulated contributions in excess of net periodic benefit cost from rate base could harm the Company's cash flows and credit metrics?

A. Denying Minnesota Power the ability to include and earn a return on the accumulated contributions in excess of net periodic benefit cost decreases Minnesota Power's cash flow. In turn, decreased cash flow negatively impacts the Company's credit metrics (because many credit rating agency metrics are based on cash flow). Moreover, such exclusion raises fairness concerns and would call into question whether a utility has the needed credit support from its regulators. In fact, Moody's downgraded ALLETE from an A3 to Baa1 in its April 3, 2019, report, citing,

> "…various expense disallowances including a decision to disallow the recovery of about $3 million of prepaid pension expenses."[26]

(3) Benefit of Accumulated Contributions to Customers

Q. Earlier you referenced that accumulated contributions in excess of net periodic benefit cost provide a direct benefit to customers. Please explain how that works.

A. Pension contributions in excess of expense are made by the Company, rather than by customers. However, these contributions have benefited customers as the earnings on these funds have significantly reduced the Company's annual pension expense under ASC 715-30, yet the Company has not earned a return on these funds. Customers benefit as a result of lower pension expense being included in base electric rates. More

[26] *See* MP Exhibit ___ (Cutshall), Direct Schedule 3.

specifically, the recognition of accumulated contributions in excess of net periodic pension costs can provide benefits to the customer in at least three ways:

1. Customers benefit from a reduction in the balance of the pension obligation because the risk of being required to fund more in future years is also reduced.
2. The earnings resulting from the balance reduce the current year pension expense through applying the EROA on the balance and ASC 715-30.
3. Customers benefit from applying the EROA to the accumulated earnings on the prepaid pension asset (the compounding of earnings).

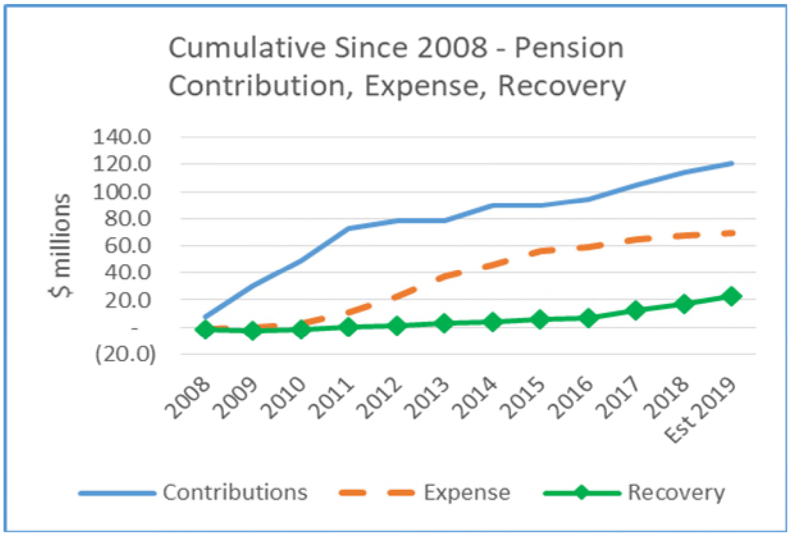
It is a long-standing ratemaking principle that utilities are entitled to an opportunity to earn a reasonable return on investments made for the benefit of customers.[27] Without including the Company's contributions (the accumulated contributions in excess of net periodic benefit cost) in rate base, the customer is essentially borrowing funds from the Company at no cost and, through application of the EROA, the *customer* is earning a return on these assets through the resulting pension expense reduction. Here, customers benefit from the federally-mandated contributions made to fund pension benefits available to utility employees.

Q. What is the level of Minnesota Power's pension contributions, expense, and recovery since the PPA took effect?

A. As illustrated in MP Exhibit ___ (Cutshall), Direct Schedule 7 and in Figure 6 below, ALLETE's pension contributions from 2008 through 2019 have totaled $177.8 million ($139.5 million MP regulated; $121.2 million MN). In addition, ALLETE has incurred pension expense totaling $103.0 million ($80.3 million MP regulated; $69.4 million MN), of which it has collected only $22.7 million (MN) through rates since 2008.

[27] *See Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692 (1923) (stating that a "public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public.").

Figure 6. MN Jurisdictional Historical Pension Contributions, Expense, and Recovery



Q. Why doesn't recovery of pension expense adequately compensate the Company for its pension investments?

A. As illustrated in the actual recovery amounts identified in Figure 6, by recovering only the pension expense, the Company is not recovering the cost of capital for its obligatory pension contributions made in excess of the recovered pension expense. If the prepaid asset were included in the working capital section of rate base, such amount would be easily calculated by multiplying the weighted average cost of capital ("WACC") by the Company's accumulated contributions in excess of net periodic benefit cost. The WACC is the true cost to investors, who must fund the pension plan in excess of what the Company recovers from customers.

Q. Can you identify the specific amount by which Minnesota Power's accumulated contributions in excess of net periodic benefit cost are reducing customer rates in the 2020 test year?

A. Yes. As shown in MP Exhibit ___ (Cutshall), Direct Schedule 12, the 2020 ALLETE accumulated contributions in excess of net periodic benefit cost will reduce the 2020 test year pension expense by $7,159,949 ($5,664,319 MP regulated; $5,066,683 MN). Note this calculation does not reflect the savings that would have been generated in prior years if the EROA percentage had been applied to the accumulated earnings on the accumulated contributions in excess of net periodic benefit cost in those years.

Q. How can the current situation — the Company providing contributions that reduce customer rates while not being compensated for the value of those contributions — be remedied?

A. The Company should be able to recover its cost of the capital that it uses to finance its contributions to the plan, or the $3.7 million (MN) net of ADIT in the Company's test year using the 2020 estimated 13-month average. Recovering the cost of capital will make the Company's net income and cash flow neutral to the size and timing of its pension contributions. In particular, the Company would include its accumulated contributions in excess of net periodic benefit cost into the working capital section of rate base, thus allowing Minnesota Power to recover the cost of financing these contributions, just as for any other working capital prepayments.

c. Financial and Audit Support for Asset

Q. Is the accumulated contributions in excess of net periodic benefit cost balance reported in your GAAP financial statements?

A. Yes. This balance, which is a net debit balance (asset), is included in ALLETE's audited GAAP financial statements. The balance is reported in ALLETE's most recent Form 10-K, in Note 15 — PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (page 117 of the 2018 Form 10-K; included in Other Supplemental Information, Direct Schedule F-1 in Volume 3). An excerpt of this portion of the footnote is shown in Figure 7 below.

Figure 7.

Reconciliation of Net Pension Amounts Recognized in Consolidated Balance Sheet

As of December 31	2018	2017
Millions		
Net Loss	$(230.5)	$(236.2)
Prior Service Cost	1.4	—
Accumulated Contributions in Excess of Net Periodic Benefit Cost (Prepaid Pension Asset)	80.1	71.2
Total Net Pension Amounts Recognized in Consolidated Balance Sheet	$(149.0)	$(165.0)

Q. Can you reconcile what is reported in the ALLETE's 2018 Form 10-K Note 15 for accumulated contributions in excess of net periodic benefit cost balance with the ALLETE plan's balance?

A. Yes. The footnote in the 2018 Form 10-K also includes other plans. To reconcile ALLETE's reported Form 10-K balance, two other benefit plans, Supplemental Executive Retirement Plan ("SERP") and Executive Investment Plan ("EIP"), must be included with ALLETE's pension plan's accumulated contributions in excess of net periodic benefit cost debit or asset balance. Table 9 below illustrates the reconciliation:

Table 9. Reconciliation of ALLETE's plan balance to ALLETE's Form 10-K for the year ended 2018

ALLETE plan asset balance	$95,697,238
SERP and EIP liability balances	($15,548,005)
Form 10-K reported balance	**$80,149,233**

Q. Following GAAP, does ALLETE have a net asset or liability balance when reporting its balance?

A. It has an asset balance. Table 10 below illustrates how the plan balance is recorded in the Company's financial records.

Table 10. Plan Balance as Recorded in Company Financial Records ($'s in millions)

FERC Account Number	Name	Type	2020 MP Balance Test Year	2020 MP Regulated Test Year	2020 MN Juris. Balance Test Year
18230-6015	Pension	Asset	$183.5	$155.8	$139.4
22830-2008	Pension Plan A	Liability	–	–	–
22830-2009	Pension Plan B&C	Liability	(114.3)	(97.0)	(86.8)
21900-0003	AOCI Pension		32.4	27.5	24.6
Total Plan Balance			**$101.6**	**$86.3**	**$77.2**

Q. How does this $77.2 million total correspond to the amount the Company is requesting to include in rates?

A. The 2020 expected ending balance for Minnesota Power of $101.6 million ($86.3 million MP regulated; $77.2 million MN) as reflected in Table 10 above, corresponds to the amount of Minnesota Power's estimated 2020 test year 13-month average, which is $103.7 million ($87.8 million MP regulated; $78.5 million MN) as reflected in MP Exhibit ___ (Cutshall), Direct Schedule 11.

Q. Does Minnesota Power follow GAAP in all regards to its accounting and financial statements?

A. Yes, of course. ALLETE (doing business as Minnesota Power) is a publicly-traded entity that is required to have an annual audit of its consolidated financial statements. As part of this annual audit, ALLETE's independent registered public accounting firm, PwC, opines that ALLETE's consolidated financial statements, which are supported by the books and records that also form the basis for this general rate case, are presented fairly, in all material respects, and are "in conformity with accounting principles generally accepted in the United States of America."[28] This opinion would not be possible if Minnesota Power did not follow GAAP with respect to a net asset as significant as its accumulated contributions in excess of net periodic benefit cost. In addition, other governmental authorities also review ALLETE's audited financial statements; for example the SEC periodically reviews ALLETE's Form 10-K and has had no comments on the Company's accounting for its benefit plans.

d. Prior Commission Decisions

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I address the Commission's past decisions that the Company did not meet its burden to justify including the prepaid pension asset in rate base. I provide additional information and explanation, and further identify the relevant circumstances that have changed since the 2016 Rate Case.

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[28] *See* MP Exhibit ___ (Cutshall), Direct Schedule 16.

Q. At the outset, have circumstances changed since the 2016 Rate Case that warrant rate base treatment for the Company's accumulated contributions in excess of net periodic benefit cost?

A. Yes. Several facts have changed since the Company last addressed this issue. Most notably, one of the Department's grounds for objecting to inclusion of the asset in rate base in the 2016 Rate Case was the Company's alleged failure to account for pension contributions in accordance with GAAP. While Minnesota Power found this characterization to be unwarranted, as well as based on an apparent misunderstanding of and inconsistent with independently-audited financial statements, the Company's financial statements now use the Department's preferred terminology and explicitly show Minnesota Power's existing accumulated contributions in excess of net periodic benefit cost. Both are accurate statements of GAAP, as noted earlier in my testimony.

Second, the Company's credit rating decisions make it particularly important to recover its significant costs of service. The Company's credit rating agencies have identified the decision not to include Minnesota Power's pension prepayments in rate base as contributing to their concern about the regulatory framework and about the Company's financial position. As discussed previously, Moody's most recent Credit Opinion stated that one of the reasons for ALLETE's credit downgraded from A3 to Baa1 was the "negative general rate case outcome" and further stated that one of the negatives was the disallowance of the Company recovering the cost of the prepaid pension expense even though the state's largest utility is allowed to recover its prepaid pension expense.[29] Minnesota Power seeks to remedy that issue in this proceeding.

Q. What is the first rationale for the Commission's decision in the 2016 Rate Case to exclude the prepaid pension asset from rate base?

A. The Commission held that Minnesota Power "recovers its allowable pension expense from ratepayers and is not denied recovery of this operating cost."[30]

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[29] *See* MP Exhibit ___ (Cutshall), Direct Schedule 3.
[30] 2016 Rate Case Order at 16.

Q. How does this finding bear on recovery of a return on the prepaid pension asset?

A. While the Company does not disagree that it is permitted to recover an authorized level of pension expense in its rate cases, the Company respectfully submits that such recovery of expense is separate from the issue of allowance for recovery of its contributions. As I discussed earlier, pension expense and the accumulated contributions in excess of net periodic benefit cost each represent different aspects of the Company's pension plan and are governed by two different authorities. Excluding the latter (contributions) on the basis of the Company's ability to recover the former (pension expense) overlooks that the accumulated contributions represent a shareholder-paid asset that is distinct from the customer-funded pension expense, and that those shareholders are entitled to have the opportunity to earn a reasonable return on the value of their money dedicated to this asset.

Q. How did the Commission distinguish the prepaid pension asset from other assets that are typically included in rate base in the 2016 rate case?

A. The Commission found that the prepaid pension asset differs from other rate base assets because it "already earns a return in the form of investment returns, it fluctuates in value, and is misleading in that it does not account for the funding status of the entire pension plan."[31]

Q. What information in this rate case filing addresses these concerns?

A. My testimony addresses these three concerns in turn. First, although the pension plan indeed earns a return in the form of investment returns, as I discussed earlier, those investment returns are — by law — used solely to reduce the amount of pension expense recoverable from customers and to benefit retirees. In other words, the benefit of those investment returns remain internal to the pension fund itself. Importantly, those returns can *never* be used to compensate shareholders for the value of the federally-mandated contributions into the pension plan — money that shareholders would otherwise not be

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[31] 2016 Rate Case Order at 16.

able to use. Rather, as I demonstrated earlier in my testimony, the market returns reduce customer expense.

Q. Can the Company prove that the market returns on shareholder contributions are not being returned to shareholders as a return on their investment, but rather are applied to reduce expense?

A. Yes. The Company only recovers, or said another way, the customer only pays, the pension expense, as was shown previously. Accounting for pension expense under GAAP (ACS 715) requires reducing the actuarially calculated pension expense by the actuarially determined return on assets. In respect to cash payments, all of the contributions and benefit payments are made to/from the pension trust and the corresponding assets and income generated from these assets are retained by the pension trust. Therefore the customer receives all the benefit of the income generated by the assets in the pension.

This was shown previously in Table 8 where the Expected Return on Plan Assets reduced pension expense by approximately 90 percent. This pension expense, which is net of expected return on plan assets, or net of future expected earnings on plan assets, then is recorded in FERC general ledger account 92608.

Further evidence that shareholders do not earn a return on their contributions is shown in the Company's latest actuarial statements on page A-3, section F: "Components of net periodic benefit cost," line 3, which is included as MP Exhibit ___ (Cutshall), Direct Schedule 13. Furthermore, MP Exhibit ___ (Cutshall), Direct Schedule 14 is a letter from Mercer explaining how investment earnings on pension plan assets affect pension expense. Shareholders do not benefit in any way from investment returns on the pension plan assets.

Q. Second, how is the fluctuation in value of the asset relevant to the determination whether to include the asset in rate base?

A. While the Commission noted that the amount of any prepayment can fluctuate, this does not change the fact that Company shareholders lose the value of their money when they are prepaying benefits. Minnesota Power's investment in its pension fund on behalf of employees is too large and important to permanently forego a return on prepayments made by shareholders.

Q. Third, how do you address the Commission's concern that the status of the prepaid pension asset is misleading in that it does not represent the funded status of the pension plan?

A. This is irrelevant because they are two different financial measurements. The total liabilities of the pension less the pension trust assets are considered the funded status of a plan. But the liabilities are actuarial estimates of amounts that may be paid to employees in the future; they are not like a debt because payment (in the form of annual pension expense) is not yet due. In addition, the amount to be paid may change. When pension payments to employees are actually due, they are paid through annual pension expense. In contrast, the asset exists when known and measureable cash or stock contributions to a fund exceed actual cumulative pension expense – meaning there is a measurable net amount of contributions that reflects cash actual investments in the retirement fund and which generates earnings that are being used to pay down expense. Thus the difference between the asset and liabilities – i.e., the funded status – does not change that there is an existing asset in the form of known contributions to the pension fund.

For example, think of an escrow account on a home mortgage. Lenders estimate the amount of taxes and insurance due each year, then collect money to fund the escrow account that is then used to pay the taxes and insurance when due. The tax and insurance liabilities (similar to a pension's liability) is unknown because it is not known if the taxes and insurance will increase or decrease. However, when those liabilities come due, there may be a shortage or an overage in the escrow account. If there is a shortage, the mortgage lender will bill the homeowner for the excess needed to fund those payments, or increase monthly payments to cover the shortage; in contrast, if there is an overage in the escrow account, the mortgage lender will refund the homeowner for the difference. In essence, an escrow account is a prepaid asset that will be used to partially or fully payoff the future liability when it occurs, just like a pension plan. The fact that the actual amount owed when taxes or insurance are due may be higher or lower than anticipated (the funding level) does not change that the homeowner has contributed real dollars in the form of prepayments to the escrow fund. Nor should the mortgage lender be able to keep overage amounts without providing a value to the homeowner for them. This is similar to what is currently happening with accumulated contributions to the pension fund in excess of net periodic cost.

Q. Is denying a return on the asset helpful to encourage a utility to fund pension benefits?

A. No, it creates the opposite incentive. If the Commission wants the pension plan to be fully funded, this requires additional contributions to the pension fund. Denying a return on prepaid pension assets discourages funding, because shareholders have no incentive to maximize investments in a fund that earns no returns for the shareholder.

Q. How else does the Commission support its prior decisions to deny rate base treatment to prepaid pension assets?

A. The Commission has found that such balances in the prepaid pension asset "fluctuate up and down, depending on funding or market conditions," and are "temporary."[32]

Q. Are these factors any different than other prepayments that are entitled to earn a return?

A. No, this is true of all prepayments. As I explained earlier, the purpose of a prepayment is to accumulate funds to pay for a future expense, based on the theory that eventually the prepayment amount will cover the expense obligation and therefore no longer exist.

[32] 2016 Rate Case Order at 17.

But this does not change the fact that during the prepayment period, shareholders lose the use of their pension fund investments – in other words, without a return, the time value of money and market returns are both utilized solely to benefit customers, while shareholder lose the use of their money during this period and get no return.

Q. Does the Commission cite any more reasons for its prepaid pension asset decision in the 2016 Rate Case Order?

A. Yes. The Commission concurred with the Department that "it would be impractical, if not impossible, to equitably separate the prepaid amount attributable solely to Minnesota Power's contributions from that attributable to ratepayer contributions and market returns."[33]

Q. Is it difficult to determine whether customers or investors made the contribution?

A. No. In every rate case since the Pension Protection Act was enacted, Minnesota Power's revenue recovery for the pension fund has been established based on the expected pension expense. For example, in Minnesota Power's most recent rate case (test year 2017) the only amount included in rates associated with the pension plan was the Company's actual 2017 pension expense totaling $5,229,348 (MN). Contributions to the pension for 2017 totaled $15,165,725 ALLETE ($11,733,946 MP regulated; $10,210,047 MN). The difference of $4,980,699 MN ($10,210,047 MN minus $5,229,348 MN)[34] is paid by the Company shareholders, which is also the contribution in excess of net periodic cost for 2017.

The accumulated contribution in excess of net periodic cost is equal to the summation of all contributions in excess of net periodic cost year over year. As mentioned earlier, by using actuarial reports, the Company was able to compile a 33-year history of expense, contributions, and accumulated contributions in excess of net periodic benefit cost, rolled forward year by year, beginning with 1987, when the accumulated

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[33] 2016 Rate Case Order at 17.

[34] *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E-015/GR-16-664, COMPLIANCE FILING – FINAL GENERAL RATES, SCHEDULE 15 at p. 45 of 46 (Jun. 28, 2018).

contributions in excess of net periodic benefit cost essentially began, up until the present time. This cumulative effect can be seen in MP Exhibit ___ (Cutshall), Direct Schedule 7.

Q. Is there precedent in Minnesota for including accumulated contributions in excess of net periodic benefit cost in rate base?

A. Yes. Northern States Power–Minnesota includes accumulated contributions in excess of net periodic benefit cost in rate base. The Commission authorized rate-base treatment in May 2015 by requiring that "the pension asset reflect the cumulative difference between actual cash deposits made by the Company reduced by the recognized qualified pension cost…."[35]

Q. Do other state jurisdictions allow utilities to recover their accumulated contributions in excess of net periodic benefit cost?

A. Yes. Several jurisdictions allow recovery for accumulated contributions in excess of net periodic benefit cost in one form or another.[36] This was also addressed in the most recent EEI 2018-19 Pension and Other Post-Employment Benefits Survey; where the majority of respondents also stated they were allowed to recover excess contributions.[37]

Moreover, Minnesota Power has identified a recent appellate court precedent in New Mexico that upheld the decision of the New Mexico Public Regulation Commission to allow rate base treatment for the "prepaid pension asset" of Southwestern Public Service

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[35] *In the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E-002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 20 (May 8, 2015).

[36] *See e.g., N.M. Atty. Gen. v. N.M. Pub. Regulation Comm'n*, 359 P.3d 133, 138-40 (N.M. 2015) (authorizing inclusion of prepayments for pension expenses in rate base with a return because the utility is "out-of-pocket for such costs" until they are recovered from customers); *Ind. Office of Util. Consumer Counselor*, 7 N.E.3d 1025, 2014 WL 934350, at *12 (Ind. Ct. App. 2014) (unpublished) (upholding inclusion of prepaid pension asset in rate base with a return because the "asset amounted to working capital that benefited the ratepayers by reducing the total pension costs needed in [the utility's] revenue requirement"); *R.I. Consumers' Council v. Smith*, 322 A.2d 17 (R.I. 1974) (authorizing inclusion in rate base of insurance premium prepayments, which reduce the cost of premiums for ratepayers); *In re Rocky Mountain Power*, 2014 WL 7526282, at *14, *36 (Wyo. P.S.C. 2014) (agreeing utility should recover financing costs of its prepaid pension asset by including the asset in the rate base and earning a return on it); *In re Potomac Elec. Power Co.*, 263 P.U.R.4th 1, ¶ 113 (D.C. P.S.C. Jan. 30, 2008) (finding investor-supplied cash contributions created a prepaid pension asset that should earn a return); *In re Ky.-Am. Water Co.*, No. 97-034, 1997 WL 34863470 (Ky. P.S.C. Sept. 30, 1997).

[37] *See* MP Exhibit ___ (Cutshall), Direct Schedule 10.

Company. The Company recognizes these other states' appellate decisions and commission decisions are not binding on the Minnesota Commission, but they do clearly identify the issue, correctly state federal law, and their straightforward and accurate reasoning for recognizing these assets should serve as persuasive guidance to the Commission.

Specifically, the New Mexico Supreme Court noted that a utility should be compensated for prepayments for both physical property and other investments on behalf of customers and employees:

> A utility can include prepayments for pension expenses in its rate base because the utility is out-of-pocket for such costs until they are recovered from ratepayers and is therefore entitled to recover its cost of financing such prepaid expenses. For example, in the context of prepaid pension assets, income earned on the pension fund is reported under [GAAP] as a reduction to the utility's pension expense. If that reduction in pension expense is used in determining a utility's rates, there will be a corresponding reduction in the amounts collected from ratepayers. Under these circumstances, the utility must finance the reduction because it cannot use the income from the pension trust to pay other current obligations; as a result, the utility is allowed to recover the costs of financing the reduction by including the pension income in the rate base.
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> […]
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> Basically, when a utility supplies working capital to fund contributions in excess of pension expenses to create an income-producing prepaid pension asset, the utility finances the entire cost of the prepaid pension asset.[38]

[38] *N.M. Atty. Gen. v. N.M. Pub. Regulation Comm'n*, 359 P.3d 133, 137-38 (N.M. 2015) (citing *S. Co. Servs., Inc.*, 122 FERC ¶ 61,218, at 62,235 (2008)) (order on tariff filing) (finding it generally appropriate to include pension

Q. Based on all of this information, please summarize the Company's request with respect to the accumulated contributions in excess of net periodic benefit cost.

A. Minnesota Power requests that the 13-month average balance for the 2020 test year of the accumulated contributions in excess of net periodic benefit cost, which is $78,515,202 (MN), be included in the working capital section of rate base. The total rate base increase, net of the associated ADIT asset of $29,447,090 (MN), would be $49,068,112 (MN), and the Company requests that it be allowed the opportunity to earn a WACC return on this net asset, the same as it does on any other working capital prepayments and the same as other Minnesota and U.S. utilities are allowed to do.

Because the accumulated contributions in excess of net periodic benefit cost represent contributions in excess of pension expense (recovered from customers), investor capital is required to fund those contributions; as such, investors should be permitted to a return on their capital.

Lastly, the Company reiterates that it is required by federal law to fund the pension plan and that customers benefit from these pension plan shareholder contributions because earnings on these contributions directly reduce pension expense. Accordingly, it is necessary to include the accumulated contributions in excess of net periodic benefit cost in rate base to fully reimburse the Company (shareholders) for its reasonable and necessary utility costs to comply with federal law, which provides benefits to customers.

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prepayments in rate base because "utility is out-of-pocket for such costs until they are recovered from ratepayers and is therefore entitled to recover its cost of financing such prepaid expenses"), *order clarified by* 128 FERC ¶ 61,276 (2009); *In re Rocky Mountain Power*, 2014 WL 7526282, at *14, *36 (a "prepaid pension asset represents [a utility's] contributions to its pension ... plans in excess of what is expensed to that time" and the utility "finances the asset with a combination of debt and equity financing").

B. Other Post-Employment Benefit Expense

1. OPEB Expense

Q. What Post-Employment Benefit Expenses are included in the OPEB?

A. ALLETE's OPEB expense reflects employees' post-employment (retirement) medical, dental, and life benefits. Please see Company witness Ms. Krollman's testimony for more details regarding these benefits for employees.

Q. How many OPEB plans does the Company have and why?

A. ALLETE has two main types of OPEB plans, because collectively bargained plans and non-bargained plans have different IRS rules for contributions and taxability:

- "Bargaining, union plan, or non-taxable plan" — Company contributions to bargained plans are fully deductible for tax purposes. In addition, similar to a pension plan, earnings are generally not taxed.
- "Non-bargained plan or taxable plan" — Company contributions to non-bargained plans have deductibility limitations. In addition, the plans pay tax on their investment income.

Q. What amount of OPEB expense is included in Minnesota Power's 2020 test year?

A. ALLETE's 2020 test year OPEB expense is $3,670,000 ($2,885,794 MP regulated; $2,581,317 MN).

Q. How did the Commission establish the Company's 2017 test year OPEB expense?

A. OPEB costs allowed by the Commission for the 2017 test year were based on the Company's forecasted 2017 expense.

Q. What has the historical OPEB expense been?

A. ALLETE's OPEB was an expense from its inception in 1996 to 2012. Then, primarily due to benefit reductions, and $145 million of largely customer-funded contributions through 2013 and the related earnings, the OPEB expense turned to a benefit in 2013; it remained a negative expense, but in a declining amount, through 2019. Below in Table 11 is the last five years of OPEB expense.

Table 11. Historical OPEB Expense/(Benefit) in $ millions

Year	ALLETE	MP Regulated	MN Jurisdictional
2015	($2.5)	($2.0)	($1.7)
2016	($3.1)	($2.4)	($2.0)
2017	($1.0)	($0.7)	($0.6)
2018	($1.2)	($0.9)	($0.8)
2019 Est.	($1.0)	($0.7)	($0.6)

Q. Can you explain in more detail why the OPEB expense has been negative for the last few years?

A. Yes. A main reason the OPEB benefit has persisted so long is because Minnesota Power has funded its OPEB plans at the expense level. This has created significant investment income that has, along with benefit reduction measures, more than offset the other components of OPEB expense, which I will address later in my testimony. Minnesota Power's customers have benefitted from negative OPEB expenses for the last 7 years, when it has served to both reduce the Company's revenue requirement and provide well-earned benefits to retirees. However, this negative expense situation is very unusual.

Q. Is OPEB expense likely to be negative in the 2020 test year?

A. No, for several reasons, including: changes in projected investment returns, discount rate changes, and eligible employees reaching 45 years of age. When eligible employees reach 45 years of age, the result is additional expense because GAAP only requires Minnesota Power to accrue expenses for eligible employees that are 45 years of age or older, due to Minnesota Power's OPEB plan design. Although the Company has mostly closed its OPEB plans to new employees (as explained in Ms. Krollman's testimony), some of the Company's current eligible employees are younger than 45 years of age. Therefore, when they attain this age, the Company begins to accrue for their benefits and this increases OPEB expenses over time.

Q. How do utilities fund OPEB plans and calculate OPEB expense?

A. There is no legal mandate to fund OPEB plans as there is for pension plans; however, utilities have typically funded their OPEB plans as mandated or agreed upon by their governing commissions. ALLETE's OPEB funding policy is to fund, at a minimum, its OPEB expense. The OPEB expense is determined by GAAP mandated by FASB and accepted by the SEC, which is similar to pension expense.

Q. Why does the Company have the policy to fund OPEB expense?

A. On September 22, 1992, the Commission issued an Order adopting "SFAS 106 accrual accounting for Minnesota utility recordkeeping and ratemaking purposes."[39] That Order stated, "SFAS 106 does not require funding for OPEB obligations."[40] The Department, however, "recommended that external funding be required, in order to provide assurance of future payment of these obligations."[41] In 1992, "the Commission required Xcel to establish an external funding mechanism by its next general rate case for FAS 106."[42] Later, Minnesota Power filed its 1994 rate case, in which Company witness Bruce E. Gagnon testified, based largely on the Northern States Power Company d/b/a Xcel Energy precedent, that "[t]he Company intends to fund the SFAS 106 liabilities as the funds are collected."[43] Since then, Minnesota Power has not only funded its expense, it has funded more than its expense.

On June 27, 2012, the Company requested the ability to determine on an annual basis whether to fund its post-employment benefit trust obligations; [44] however, the

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[39] *In the Matter of the Accounting and Ratemaking Effects of the Statement of Fin. Accounting Standards*, Docket U-999/CI-92-96, ORDER ADOPTING ACCOUNTING STANDARD AND ALLOWING DEFERRED ACCOUNTING at 7 (Sept. 22, 1992).

[40] *Id.* at 4.

[41] *Id.*

[42] *In the Matter of Xcel's Petition for Approval to Discontinue Funding of Tax Advantaged Extern Fund (VEBA Fund) for Retiree Medical Costs and the Withdrawal of the Accumulated VEBA Fund Balance over a Five-Year Period*, Docket No. E,G-002/M-02-2188, ORDER APPROVING PETITION WITH MODIFICATION AND REQUIRING COMPLIANCE FILING at 1 (Oct. 17, 2003) (citing the Commission's Order in Docket No. U-999/CI-92-96).

[43] *In the Matter of the Application of Minn. Power for Auth. to Change its Schedule of Rates for Retail Elec. Serv. in the State of Minn.*, Docket No. E-015/GR-94-001, DIRECT TESTIMONY OF BRUCE E. GAGNON at 8 (Jan. 3, 1994).

[44] *In the Matter of Minn. Power's Petition for Approval of Deferred Accounting Related to Pension Plan Contributions and Expenses*, Docket No. E-015/M-11-1264, REPLY COMMENTS (Jun. 27, 2012).

Commission denied this request.[45] One of the reasons for the denial was that the "request would appear to defeat the trust account's purpose, which is to ensure that funds are available to pay benefits when they are due."[46]

Q. What is the benefit of contributions to fund the OPEB plan?

A. As with pension funding, by making contributions to the OPEB fund, investors are providing an assurance of future payments of these obligations and reducing annual expense amounts. For test year 2020, Mercer projected that the earnings on these funds will reduce ALLETE's OPEB expense by $9.7 million ($7.6 million MP regulated; $6.8 million MN).

Q. Can you provide more detail explaining how the Company's annual OPEB expense is derived?

A. Yes. Minnesota Power had the OPEB expense calculated by Mercer using actuarial analyses, which are performed in accordance with ASC 715-60 Defined Benefit Plans — Other Post-Employment ("ASC 715-60"). ASC 715-60 sets forth the methodologies and assumptions used to calculate OPEB expense.

ASC 715-60 requires the OPEB expense for a given year to be determined annually, which is calculated by Mercer. In addition, the Company's independent auditor, PwC, audits the actuarial assumptions used to ensure compliance with GAAP.

Q. Has the Company taken steps to reduce/control OPEB costs in recent years?

A. Yes. The Company has made several recent major changes, which are also addressed in Ms. Krollman's Direct Testimony:

1. Beginning on February 1, 2011, new employees were no longer eligible for OPEB health benefits;

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[45] *In the Matter of Minn. Power's Petition for Approval of Deferred Accounting Related to Pension Plan Contributions and Expenses*, Docket No. E-015/M-11-1264, ORDER DENYING PETITION (Mar. 11, 2013).
[46] *Id.* at 2.

2. Effective January 1, 2012, the age requirement for retiree health eligibility was increased to age 55, up from age 50;
3. In 2013, health cost sharing for post-65 retirees was changed from 75 percent Company/25 percent retiree to 70 percent Company/30 percent retiree;
4. Post-employment life insurance for non-bargaining unit participants was eliminated unless the employee retired prior to January 1, 2016;
5. Minnesota Power added a high-deductible consumer-directed health plan option in 2014, and a second high-deductible consumer-directed health plan option in 2017;
6. Effective January 1, 2018, the pre-65 Preferred Provider Organization ("PPO") retiree health plan is no longer available to new retirees. Retiree medical-eligible participants retiring after January 1, 2018 must choose one of the pre-65 consumer directed health plan options. Any retiree that elected the pre-65 PPO retiree health plan prior to January 1, 2018, is eligible to keep PPO coverage for a maximum period of five years, i.e., through age 65 or December 31, 2022 if earlier, at which time any pre-65 retirees with PPO coverage will be transitioned to a consumer-directed health plan; and
7. Effective April 1, 2018, post-employment life insurance for bargaining unit participants retiring after April 1, 2018, was changed to a $20,000 death benefit for Minnesota Power employees. The death benefit for bargaining unit employees that retired prior to April 1, 2018, was equal to 50 percent of a participant's final salary before retirement.
8. Effective January 1, 2020, for the post-65 group the Company is offering a Medicare Advantage Plan rather than a Medicare Supplement Plan. The Medicare Advantage Plan design shifts more first dollar-coverage responsibility to the participants.

Q. What are the components of the 2020 OPEB calculation?

A. ALLETE's OPEB expense is determined in largely the same manner as pension expense — that is, by calculating and aggregating five components:

1. Service Cost – The present value (using the discount rate as described below) of the projected post-employment benefits earned by each employee in the current year.
2. Interest Cost – The amount the present value (using the discount rate as described below) of future benefit payments is expected to increase during the year due to one year's interest accrual. In other words, this is the expense incurred because the employees are one year closer to receiving their benefits.
3. Expected Return on Plan Assets – The amount expected to be earned on the plan's assets. It is estimated by multiplying the EROA by the five-year smoothed OPEB asset balance.
4. Amortization of Prior Service Cost – The amortization of the cost of increased/ decreased benefits, amortized over the remaining service life of the affected participants.
5. Amortization of Net Gain or Loss – Gains or losses accumulate when the annual change in the benefit obligation or the plan assets deviate from expectations, i.e., the difference between the prior years' actual return on plan assets vs. the prior years' Expected Return on Plan Assets. If these accumulated gains or losses exceed 10 percent of the greater of the benefit obligation or plan assets, the excess is amortized over a period of time based on participant demographics.

Q. What information did the actuary utilize to calculate the annual 2020 OPEB expense?

A. The primary OPEB assumptions used to estimate the Company's 2020 OPEB expense are listed below:

- Discount rate of 3.25 percent: The discount rate is computed using the Mercer Bond Model, which creates a hypothetical portfolio of AA or better rated corporate bonds such that bond yields and principal payments would fully match the projected benefit payments from the pension plan. The discount rate is set equal to the yield on this hypothetical portfolio. This methodology is the most precise and yields the highest discount rate (lowest expense) which we are allowed to use per the SEC.

- EROA of 6.75 percent for non-taxable plans. This 6.75 percent rate is (1) equal to ALLETE's pension plan (as we have always done since the inception of the plan); (2) above Mercer's 6.49 percent (or 0.26 percent higher) net of fee mid- or 50 percentile projection, for the plan (see MP Exhibit ___ (Cutshall), Direct Schedule 15); and (3) higher than the average OPEB EROA rates of 6.49 percent as determined in ALLETE's survey of EEI member companies 2018 annual reports (see MP Exhibit ___ (Cutshall), Direct Schedule 9). ALLETE's taxable plan's EROA is 5.4 percent, or 80 percent of the non-taxable plan's EROA, because it assumes a 20 percent tax rate.
- Health care trend rates: initial trend rate of 6.46 percent with ultimate trend rate of 4.50 percent. This is very comparable to the EEI Pension and OPEB Survey 2018-2019 average initial trend rate of 6.41 percent and average ultimate trend rate of 4.74 percent (see MP Exhibit ___ (Cutshall), Direct Schedule 10).

Q. Please provide an example how the EROA and the related investment earnings reduce OPEB expense?

A. As illustrated by Table 12, the EROA and related Expected Return on Plan Assets are the main OPEB expense reducer, at a negative $10.9 million for 2018. However, the amortization of prior service cost of a negative $2.0 million also reduces the cost of the OPEB plans and shows how the reduction of OPEB benefits has helped to reduce the Company's OPEB expense.

Table 12. OPEB Expense Example Utilizing 2018 Actual and 2020 Expected Information
($'s in millions)

	2018 ALLETE Actual	2020 ALLETE Test Year	2020 MP Regulated Test Year	2020 MN Jurisdictional Test Year
Service cost	$ 4.2	$ 4.7	$ 3.7	$ 3.3
Interest cost	6.8	6.4	5.0	4.5
Amortization of loss	0.7	3.5	2.7	2.4
Amortization of prior service cost	(2.0)	(1.2)	(0.9)	(0.8)
Expected Return on Plan Assets	(10.9)	(9.7)	(7.6)	(6.8)
OPEB Expense	**$ (1.2)**	**$ 3.7**	**$ 2.9**	**$ 2.6**

Q. Does the OPEB expense calculation, like the pension expense calculation, incorporate a smoothing mechanism?

A. Yes, the OPEB expense calculation incorporates the same smoothing mechanisms as the pension expense, including use of the market-related value of assets, amortizations of prior service costs/(credits), amortizations of (gains)/losses, and the application of the corridor, described below, for determining if (gains)/losses need to be amortized.

For purposes of calculating OPEB expense, the Company utilizes all smoothing methods allowed under OPEB accounting rules (ASC 715-60) that are designed to reduce OPEB expense volatility. Under these-methods:

- ALLETE uses a market-related value of assets in calculating expense. The market-related value of assets phases in gains or losses over a five-year period. This reduces volatility by using a more stable asset value to determine the Expected Return on Plan Assets component of expense. The market-related value of assets also reduces volatility in the amortization of gains and losses, described below, because recent gains and losses are excluded from the amortization calculation to the extent they are not phased in.

- ALLETE amortizes accumulated gains and losses, excluding gains and losses not yet phased into the market-related value of assets, in the OPEB expense.
    - ALLETE uses a corridor to determine if gains and losses will be amortized in expense. The corridor is the greater of 10 percent of the plan's obligation or 10 percent of the plan's market-related value of assets.
        - If accumulated gains and losses fall within the corridor, no gains and losses are amortized in expense.
        - If accumulated gains and losses exceed the corridor, the excess is amortized over the average working lifetime of active participants, or the average lifetime of inactive participants if there are no active participants in the plan.
- Increases or decreases in plan liabilities resulting from plan amendments are amortized over the average working lifetime of the active participants affected by the plan amendment.

Q. Is there an alternative way to recover OPEB expense?

A. Yes, as with the pension expense discussed previously, the Company could institute a mechanism that adjusts rates annually for OPEB expense, and the associated contributions. This would be the most accurate and direct recovery mechanism, and Minnesota Power would be open to this approach to ensure neither over- nor under-recovery of OPEB expense.

Q. What do you recommend with respect to including OPEB costs in Minnesota Power's 2020 test year?

A. Similar to the pension expense, Minnesota Power supports recovery of the Company's forecasted 2020 OPEB expense as determined by the actuaries, including the current year's assumptions, or through an annual adjustment mechanism. Recovery of the forecasted 2020 OPEB expense is a reasonably accurate and consistent method for determining OPEB expense, and was approved in the 2016 Rate Case. Using another method, such as an historic average, has the strong potential to distort the forecasting methodology required by the SEC and GAAP to measure the cost of the plan, thereby precluding the Company from recovering its actual costs of providing these benefits to utility employees. Further, historic averages do not incorporate changes in the economic environment, or plan and assumption changes implemented by the Company, to help control the cost of the OPEB plans.

2. <u>OPEB – Accumulated Contributions in Excess of Net Periodic Benefit Cost</u>

Q. What is ALLETE proposing with respect to its OPEB's accumulated contributions in excess of net periodic benefit cost balance?

A. Minnesota Power is only providing information regarding its accumulated contributions in excess of net periodic benefit cost OPEB balance. We are not asking to include the accumulated contributions in excess of net periodic benefit cost in rate base at this time, as I explain later in my testimony.

Q. Are there other naming conventions for accumulated contributions in excess of net periodic benefit cost as it relates to OPEB plans?

A. Yes. Historically, when a Company contributed more to its OPEB plan than expensed, this has been called a "prepaid OPEB expense" or a "prepaid OPEB asset." More recently this has been called "accumulated contributions in excess of net periodic benefit cost," analogous to the accumulated contributions in excess of net periodic benefit cost for the Company's pension.

Q. Why does the Company have an accumulated contributions in excess of net periodic benefit cost OPEB asset?

A. The accumulated contributions in excess of net periodic benefit cost OPEB asset arises from the fact the Company has contributed more to the OPEB plans than it has expensed since the inception of the plans.

Q. What is the amount of ALLETE's OPEB's accumulated contributions in excess of net periodic benefit cost?

A. The amount of ALLETE's estimated 2020 test year OPEB accumulated contributions in excess of net periodic benefit cost — the OPEB asset — is $2,289,005 ALLETE ($2,208,867 MP regulated; $1,975,812 MN).

Q. Can the Company withdraw assets from the OPEB plans other than to pay benefits or plan expenses?

A. Doing so is technically possible, but ill-advised, because the funds are held in a Voluntary Employees Beneficiary Association ("VEBA") trust. The Company would pay a federal excise tax of 50 percent in addition to the Company's statutory tax rate on the withdrawn amount. Consequently, Minnesota Power cannot realistically use these funds for any purpose but covering employee benefits.

Q. If the Company has generally matched OPEB funding to the level of expense, why is there an accumulated contributions in excess of net periodic benefit cost OPEB asset?

A. Accumulated contributions in excess of net periodic benefit cost assets are created when cumulative contributions exceed expense. Due to the Company's policy of funding OPEB expenses, and the changes in OPEB benefits as discussed previously and in Ms. Krollman's testimony, the Company's OPEB expenses have been negative for years 2013 through 2019. If the Company funds expense and expense is negative, the Company would need to withdraw funds from the OPEB or VEBA trust to avoid an accumulated contributions in excess of net periodic benefit cost asset;[47] however, as described above, it would be arguably foolish for the Company to withdraw funds due to tax penalties. Consequently, the Company will continue to have an accumulated contributions in excess of net periodic benefit cost OPEB asset. The earnings on this accumulated contribution in excess of net periodic benefit cost will benefit customers by decreasing the OPEB expense; however, it will continue to be small.

Q. Why isn't the Company asking to include its accumulated contributions in excess of net periodic benefit cost OPEB asset in rate base?

A. Because there is no legal mandate to fund the OPEB, as there is for the pension, the accumulated contributions in excess of net periodic benefit cost OPEB asset should not grow significantly over time or become a liability, and will likely shrink. In addition, since the Company has a long-standing policy and agreement with the Commission to fund, at a minimum, the Company's OPEB expense, Minnesota Power will not have an unfunded accrued benefit liability as other utilities have. Therefore, the Company is not seeking to include the accumulated contributions in excess of net periodic benefit cost (OPEB assets) in rate base, as we have for the accumulated contributions in excess of net periodic benefit cost pension asset.

Q. Would including the OPEB asset in rate base increase or decrease the Company's revenue requirement?

A. Including the OPEB asset in rate base would increase the Company's revenue requirement. As stated before, however, the Company is not requesting to include the prepaid OPEB asset in rate base because that asset is relatively small and because, due to the funding policy, it will neither become large nor become a liability.

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[47] A prepaid asset is created when contributions exceed expense. The math holds true when a prepaid asset is created even when expense is negative. For example, if the contribution is 0 and the expense is negative, the prepaid amount will increase because the contribution is greater than the expense.

Q. Please summarize the Company's requests with respect to its retirement plan accounting.

A. Minnesota Power's pension and OPEB benefits are an integral part of its eligible current and retired employees' earned retirement compensation for providing services for safe, affordable, and reliable power to customers. Over 1,750 retired employees (and their families), and 775 eligible employees[48] rely on these well-funded and well-managed plans for their retirement.

As with all benefits, the pension and OPEB plans cost money. However, these types of compensation are unusual as compared to other forms of compensation that are paid when earned. Pension and OPEB benefits are paid in future years, after they are earned. In fact, these benefits may be paid 50 or more years in the future. Due to the nature of these long-term commitments and promises, Minnesota Power is required to contribute, invest, and manage these funds, ensuring the earned benefits are paid when they are due.

Minnesota Power continues to support recovery of its test year pension and OPEB expense amounts as they are determined by actuarial accounting and GAAP; otherwise the Company will not recover these legitimate and important costs of providing utility service.

In addition, the Company's legally mandated contributions to the pension plan in excess of its GAAP expense described above creates the accumulated contributions in excess of net periodic benefit cost asset balance (also known as prepaid pension asset). This balance must be included in the working capital section of rate base, like other prepaid assets, to compensate shareholders and to recognize that customers benefit by receiving all of the earnings on these funds through the reduction of pension expense. Denying compensation to shareholders for this use of their money negatively impacts Minnesota Power's financial ratios, and was identified by the credit rating agencies as a contributor to Minnesota Power's negative outlook. Additionally, denial of a return on this asset

[48] Non-eligible employees have different retirement compensation as outlined in Company witness Ms. Krollman's testimony.

precludes the Company from a reasonable opportunity to recover its cost of service and earn its authorized rate of return. If this issue is not resolved appropriately, in future years the resulting negative credit impacts will continue to grow and have increasingly detrimental impacts to the Company and send the wrong message about the need to support this important employee benefit.

VI. TAX

Q. What is the purpose of this portion of your testimony?

A. In this section of my testimony, I discuss several tax issues relevant to this rate proceeding. The main tax issue is how Minnesota Power incorporated the impacts of the TCJA. In addition I provide information on two other issues: the federal PTCs and proration of ADIT with interim rates.

A. <u>Tax Cuts and Jobs Act</u>

Q. Please describe the TCJA.

A. On December 22, 2017, Public Law 115-97 (known as the Tax Cuts and Jobs Act, or TCJA) took effect, reducing the federal income tax rate for corporations from a maximum of 35 percent to a flat 21 percent, starting January 1, 2018.

Q. Please describe the excess accumulated deferred income taxes resulting from the TCJA.

A. The reduction in the federal tax rate from the TCJA resulted in excess (accumulated) deferred income taxes ("EDIT"). The EDIT has been recorded as a regulatory asset or liability, with the net amount passed back to Minnesota Power's customers over time. The EDIT is also still included in the ADIT utilized to reduce rate base, as it has not yet been returned to customers.

Q. Has the Commission addressed the impacts of the TCJA for Minnesota Power in a prior proceeding?

A. Yes. Minnesota Power was working with the Commission to conclude its 2016 Rate Case when the TCJA was passed and the Commission began reviewing the impacts of the TCJA on utilities in Docket No. E,G999/CI-17-895 (the "Tax Reform Docket"). The Commission decided that Minnesota Power should incorporate the lower federal tax rate to reduce current period annual tax expense in the 2016 Rate Case, but did not incorporate the excess deferred tax issue in the final rates decided in that case due to timing.[49] In the Tax Reform Docket, Minnesota Power proposed to return the EDIT to customers through a rate reduction rider that would be implemented at the same time as final rates, with a separate one-time refund for the period from January 1, 2018 to the implementation of the rate reduction rider. The Commission agreed with this proposal and issued an Order Responding to Changes in Federal Tax Law on December 5, 2018[50]. As part of the order, Minnesota Power was directed to amortize its protected EDIT as early as IRS provisions allow, and amortize its unprotected EDIT over ten years.

Q. Has Minnesota Power complied with this order?

A. Yes. Minnesota Power implemented the rate reduction rider effective January 1, 2019, and has completed the one-time refund of $10.0 million (MN) for EDIT for 2018. In addition, on February 14, 2019, Minnesota Power submitted a letter confirming that it will make compliance filings by March 1 of each year, and that the Company intends to incorporate the benefit of the EDIT in base rates in the next rate case and will request at that time to suspend future compliance requirements in the Tax Reform Docket.

Q. Is Minnesota Power proposing to incorporate the benefit of the EDIT in base rates in this rate proceeding?

A. Yes. Minnesota Power has included the updated benefit of the EDIT amortization in this rate proceeding in the current period annual deferred tax expense. This proposal is consistent with the Commission's December 5, 2018 Order authorizing Northern States

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[49] *See In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-16-664, ORDER GRANTING RECONSIDERATION IN PART, REVISING MARCH 12, 2018 ORDER, AND OTHERWISE DENYING RECONSIDERATION PETITIONS (May 29, 2018).

[50] *See In the Matter of a Commission Investigation into the Effects on Electric and Natural Gas Utility Rates and Services of the 2017 Federal Tax Act,* Docket No. E, G-999/CI-17-895, ORDER RESPONDING TO CHANGES IN FEDERAL TAX LAW (Dec. 5, 2018).

Power Company–Minnesota to include the amortization of EDIT in base rates.[51] Under IRS normalization rules, the Company is utilizing the Average Rate Assumption Method ("ARAM") for amortizing the EDIT for plant items. This amortization amount changes slightly from year to year as the excess deferred taxes related to specific assets will not begin reversing and thus benefiting customers until the book depreciation on those assets is greater than the tax depreciation.

Q. What are the 2020 amortization amounts related to including the EDIT in base rates?

A. The 2020 tax rate amortization included in this filing is a tax benefit of $10,711,413 for MP regulated ($9,325,249 MN). This consists of $10,016,120 for MP regulated ($8,719,934 MN) for protected EDIT, and $695,293 for MP regulated ($605,315 MN) for unprotected EDIT.

Q. How does Minnesota Power propose to flow back all of the benefits of the excess deferred taxes to customers?

A. Minnesota Power proposes to include the above amount of excess deferred taxes in base rates until such time that the Company files a subsequent rate case. At that time the amount of excess deferred taxes incorporated in current period annual deferred tax expense will be updated. As with the prior federal and state corporate tax rate reductions, this methodology of incorporating the updated benefit of the excess deferred tax amortization in base rates with each subsequent rate case filing has been utilized to return the excess deferred taxes to customers. Accordingly, the Company believes annual future compliance filings will not be necessary.

Q. What is Minnesota Power requesting with respect to future EDIT-related compliance filings?

A. Minnesota Power recommends discontinuation of the compliance filing requirement, as

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[51] *See In the Matter of a Commission Investigation into the Effects on Electric and Natural Gas Utility Rates and Services of the 2017 Federal Tax Act,* Docket No. E, G-999/CI-17-895. ORDER RESPONDING TO CHANGES IN FEDERAL TAX LAW (Dec. 5, 2018).

of the conclusion of this rate case.

B. <u>Federal Production Tax Credits</u>

Q. What are Production Tax Credits?

A. Federal Production Tax Credits (PTCs) are tax credits that are earned from the generation of electricity using renewable resources. They are intended to act as a financial incentive to support the development of renewable energy facilities, and are provided for the first ten years of a renewable energy facility's operation. Minnesota Power currently generates PTCs for its Bison Wind Energy Center.

Q. How were PTCs addressed in the 2016 Rate Case?

A. Prior to the 2016 Rate Case, as PTCs were generated they were included in the Renewable Resource Rider ("RRR") and used to reduce revenue requirements in the RRR. In the last rate case, the annual benefit of the tax credits was moved from the RRR and incorporated in base rates. Along with the incorporation of the PTC benefit in base rates, Minnesota Power proposed to continue to utilize the RRR for an annual true-up of PTCs. An annual true-up of the PTCs is appropriate due to the difficulty of predicting annual wind generation, because of expected future increases in the tax benefit from the PTCs for IRS-determined inflation, and to account for the loss of PTCs at the end of the respective ten-year credit period. The Commission agreed with this proposal, and the RRR has been utilized to true up the difference between PTCs in base rates and actual PTCs generated since the prior rate case.

Q. What is the Company's proposal for PTCs in this rate case?

A. The Company believes the current methodology — including estimated PTCs in base rates and annually trueing up the actual PTCs generated in the RRR — is working as designed and should be continued.

Q. What is the amount of PTCs Minnesota Power proposes to include in base rates for the 2020 test year?

A. Minnesota Power's PTC tax benefit for the 2020 test year is $39.6 million MP regulated ($34.5 million MN). Because Minnesota Power has an unutilized balance of PTCs, the rate base includes a carryover deferred tax asset of $269.0 million MP regulated ($238.3 million MN).

Q. How did Minnesota Power determine this proposed amount is reasonable?

A. The tax credit computation is based on the IRS published rates multiplied by wind production operation estimates used in this rate case. For the 2020 test year, this amount is $0.025 x 1,582,068,975 kWh = $39,551,724, or $39.6 million.

C. <u>Proration of Accumulated Deferred Income Taxes</u>

Q. Please describe the proration of accumulated deferred income taxes.

A. When a utility is utilizing a forecasted test year for determining revenue requirements, the IRS has a normalization requirement that governs the calculation of the ADIT balance used to reduce rate base. The application of this normalization requirement was clarified as it applies to the Minnesota retail rate process with the issuance of a Private Letter Ruling ("PLR") to Otter Tail Power Company in 2017. In Minnesota Power's 2016 Rate Case, the Company agreed that although Otter Tail Power Company's PLR is expressly applicable only to them, Minnesota Power is subject to the same requirements in its Minnesota retail rate proceedings; therefore, Minnesota Power would follow the guidance in Otter Tail's PLR.

Q. How does Minnesota Power intend to incorporate the proration requirements of a forecast test year in this rate proceeding?

A. Minnesota Power utilized a proration calculation method in the computation of accumulated deferred taxes in its 2016 Rate Case. Minnesota Power intends to utilize the same proration calculation method to apply proration in this proceeding for the interim rate calculation of the ADIT balance used to reduce rate base. The effects of proration on interim rates will not be reversed or offset in a subsequent phase or with any interim rate refund for the period of the test year. Consistent with the PLR received by Otter Tail Power Company, Minnesota Power will remove the proration calculation from the ADIT balances for rate base for the final test year revenue requirement calculation.[52]

Q. Do you believe the Company's position is reasonable?

A. Yes. Utilizing Otter Tail Power Company's PLR to ensure Minnesota Power is complying with IRS normalization requirements is a cost-effective solution for customers. If the Company did not follow IRS normalization requirements, a normalization violation would occur where the IRS would disallow all accelerated depreciation, thereby increasing the Company's tax liability by the amount not normalized, which would increase rates for customers. Therefore, Minnesota Power recommends continuing to utilize this methodology for Minnesota retail rate proceedings.

D. <u>Tax Conclusion</u>

Q. Please summarize your tax testimony.

A. For the TCJA, Minnesota Power has updated the calculation of the excess deferred tax amortization and included the tax benefit in base rates in this rate proceeding, and is requesting the discontinuation of the rate reduction rider effective with the implementation of final rates.

As to PTCs, Minnesota Power has updated the amount of PTCs to be included in base rates to reflect current generation estimates and the published PTC credit amount. Minnesota Power will continue to use the annual RRR filings to true up the estimated PTCs included in base rates to the actual PTCs generated.

[52] This is consistent with the Commission's Order in Docket No. E-015/GR-16-664, which provided "Minnesota Power shall reduce its revenue requirement to remove proration from accumulated deferred income taxes (ADIT). Proration of ADIT is required for interim rates." 2016 Rate Case Order at 111.

Minnesota Power has properly incorporated the pro rata deferred tax computation in the calculation of interim rates, and excluded the computation for final rates.

VII. CONCLUSION

Q. What are your overall recommendations for the 2020 test year?

A. Minnesota Power recommends a capital structure consisting of 53.81 percent common equity and 46.19 percent long-term debt; as well as a 4.47 percent cost of debt for the 2020 test year. I also support a rate of return on common equity of 10.05 percent as presented by Company witness Ms. Bulkley.

In regards to pension and OPEB expense, Minnesota Power supports recovery of the Company's forecasted 2020 pension and OPEB expense of $4,435,113 (MN) and $2,581,317 (MN), respectively, as determined by Mercer, or an annual adjustment mechanism. Minnesota Power also requests that the 13-month average balance for the 2020 test year of the pension's accumulated contributions in excess of net periodic benefit cost of $78,515,202 (MN) be included in the working capital section of rate base.

In regards to tax, for the TCJA, Minnesota Power has updated the calculation of the excess deferred tax amortization and included the tax benefit in base rates in this rate proceeding, and is requesting discontinuation of the rate reduction rider effective with the implementation of final rates. As to PTCs, Minnesota Power has updated the amount of PTCs to be included in base rates to reflect current generation estimates and the published PTC credit amount. Minnesota Power will continue to use the annual RRR filings to true up the estimated PTCs included in base rates to the actual PTCs generated.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

JUNE 23, 2017

INFRASTRUCTURE

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RATING METHODOLOGY

Regulated Electric and Gas Utilities

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

Table of Contents:

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Summary

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

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

THIS METHODOLOGY WAS UPDATED ON THE DATES LISTED AS NOTED: ON FEBRUARY 22, 2019, WE AMENDED A REFERENCE TO A METHODOLOGY IN APPENDIX E AND REMOVED OUTDATED TEXT; ON AUGUST 2, 2018, WE MADE MINOR FORMATTING ADJUSTMENTS THROUGHOUT THE METHODOLOGY; ON FEBRUARY 15, 2018, WE CORRECTED THE FORMATTING OF THE FACTOR 4: FINANCIAL STRENGTH TABLE ON PAGE 34; AND ON SEPTEMBER 27, 2017, WE REMOVED A DUPLICATE FOOTNOTE THAT WAS PLACED IN THE MIDDLE OF THE TEXT ON PAGE 7.

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

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

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

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

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

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

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

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

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

About the Rated Universe

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

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

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

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

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

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

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

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

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

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

About this Rating Methodology

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

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

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

Factor / Sub-Factor Weighting - Regulated Utilities

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

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

2. Measurement or Estimation of Factors in the Grid

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

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

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

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in the rating grid. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of several years or more, or for individual twelve month periods.

3. Mapping Factors to the Rating Categories

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

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

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

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

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

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

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

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	$x < 1.5$
Aa1	$1.5 \le x < 2.5$
Aa2	$2.5 \le x < 3.5$
Aa3	$3.5 \le x < 4.5$
A1	$4.5 \le x < 5.5$
A2	$5.5 \le x < 6.5$
A3	$6.5 \le x < 7.5$
Baa1	$7.5 \le x < 8.5$
Baa2	$8.5 \le x < 9.5$
Baa3	$9.5 \le x < 10.5$

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

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

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

6. Appendices

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

Discussion of the Grid Factors

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

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

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

Factor 1: Regulatory Framework (25%)

Why It Matters

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

How We Assess Consistency and Predictability of Regulation for the Grid

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

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

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

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

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

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

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

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

Why It Matters

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

How We Assess Ability to Recover Costs and Earn Returns

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

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

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

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

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

How We Assess Sufficiency of Rates and Returns for the Grid

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

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

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

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

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

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

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

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

Factor 3: Diversification (10%)

Why It Matters

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

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

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

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

How We Assess Market Position for the Grid

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

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

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

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

How We Assess Generation and Fuel Diversity for the Grid

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

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

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

Factor 3: Diversification (10%)

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

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

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

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

Factor 4: Financial Strength (40%)

Why It Matters

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

How We Assess It for the Grid

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

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

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

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

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

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

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

CFO Pre-Working Capital / Debt

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

CFO Pre-Working Capital Minus Dividends / Debt

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

Debt/Capitalization

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

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

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

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

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

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

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

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

Factor 4: Financial Strength

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

Notching for Structural Subordination of Holding Companies

Why It Matters

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

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

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

How We Assess It

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

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

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

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[14]

» Significant dividend limitations or potential limitations at an important OpCo

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

Strained liquidity at the HoldCo level

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

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

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

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

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

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

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

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

Rating Methodology Assumptions, Limitations, and Other Rating Considerations

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

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

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

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

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries.

Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible precisely to express these in the rating methodology grid without making the grid excessively complex and significantly less transparent.

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

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

Other Rating Considerations

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

Liquidity and Access to Capital Markets

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

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

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality and Financial Policy

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

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

Size – Natural Disasters, Customer Concentration and Construction Risks

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

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

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

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

Diversified Operations at the Utility

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

Event Risk

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

Corporate Governance

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

Investment and Acquisition Strategy

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

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

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

Financial Controls

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

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

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Factor 3: Diversification (10%)

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

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

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

Factor 4: Financial Strength

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

Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

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

General Approach to a Utility Family

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

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

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

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

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

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

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

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

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

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

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

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

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

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

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

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

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

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

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

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

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

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

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Appendix D: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

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

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

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

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

Economic and Financial Market Conditions

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

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

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

Fuel Price Volatility and the Global Impact of Shale Gas

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

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

Distributed Generation Versus the Central Station Paradigm

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

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

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

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

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. 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 decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

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 on notching corporate instrument ratings based on differences in security and priority of claim, 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.
18 A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report,

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Additional considerations for PPAs

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

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

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

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

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

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

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

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

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

Methods for estimating a liability amount for PPAs

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

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

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

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

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

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

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

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

Moody's Related Research

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

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

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

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TRADE SECRET DATA
EXCISED IN ITS ENTIRETY

Moody's Credit Report (Apr 3 2019)

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Key Credit Factors For The Regulated Utilities Industry

November 19, 2013

*(**Editor's Note:** On July 25, 2019, we republished this criteria article to make nonmaterial changes. See the "Revisions And Updates" section for details.)*

1. This article presents S&P Global Ratings' methodology and assumptions for Regulated Utilities. This article relates to "Corporate Methodology" and "Principles Of Credit Ratings."

2. This paragraph has been deleted.

SCOPE OF THE CRITERIA

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

SUMMARY OF THE CRITERIA

4. This article presents S&P Global Ratings criteria for analyzing regulated utilities, applying its corporate criteria. The criteria for evaluating the competitive position of regulated utilities amend and partially supersede the "Competitive Position" section of the corporate criteria when evaluating these entities. The criteria for determining the cash flow leverage assessment partially supersede the "Cash Flow/Leverage" section of the corporate criteria for the purpose of evaluating regulated utilities, specifically, the conditions to apply low, medial, and standard volatility tables. The section on liquidity for regulated utilities partially amends existing criteria. All

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other sections of the corporate criteria apply to the analysis of regulated utilities.

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METHODOLOGY

Part I--Business Risk Analysis

Industry risk

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

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

Cyclicality

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

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

Competitive risk and growth

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

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

Effectiveness of barriers to entry--low risk

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

Level and trend of industry profit margins--low risk

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

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

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

Risk in industry growth trends--low risk

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

B. Country risk

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

C. Competitive position

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

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

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

- Profitability.

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

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

Assessing regulatory advantage

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

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

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

24. Regulatory stability:

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

25. Tariff-setting procedures and design:

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

26. Financial stability:

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

of heavy investments

27. Regulatory independence and insulation:

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

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

Table 1

Preliminary Regulatory Advantage Assessment

Qualifier	What it means	Guidance
Strong	The utility has a major regulatory advantage due to one or a combination of factors that support cost recovery and a return on capital combined with lower than average volatility of earnings and cash flows.	The utility operates in a regulatory climate that is transparent, predictable, and consistent from a credit perspective.
	There are strong prospects that the utility can sustain this advantage over the long term.	The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base).
	This should enable the utility to withstand economic downturns and political risks better than other utilities.	The tariff set may include a pass-through mechanism for major expenses such as commodity costs, or a higher return on new assets, effectively shielding the utility from volume and input cost risks.
		Any incentives in the regulatory scheme are contained and symmetrical.
		The tariff set includes mechanisms allowing for a tariff adjustment for the timely recovery of volatile or unexpected operating and capital costs.
		There is a track record of earning a stable, compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.
		There is support of cash flows during construction of large projects, and pre-approval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs.
		The utility operates under a regulatory system that is sufficiently insulated from political intervention to efficiently protect the utility's credit risk profile even during stressful events.
Adequate	The utility has some regulatory advantages and protection, but not to the extent that it leads to a superior business model or durable benefit.	It operates in a regulatory environment that is less transparent, less predictable, and less consistent from a credit perspective.

Table 1

Preliminary Regulatory Advantage Assessment (cont.)

Qualifier	What it means	Guidance
	The utility has some but not all drivers of well-managed regulatory risk. Certain regulatory factors support the business's long-term stability and viability but could result in periods of below-average levels of profitability and greater profit volatility. However, overall these regulatory drivers are partially offset by the utility's disadvantages or lack of sustainability of other factors.	The utility is exposed to delays or is not, with sufficient certainty, able to recover all of its fixed and variable operating costs, investments. and capital costs (depreciation and a reasonable return on the asset base) within a reasonable time.
		Incentive ratemaking practices are asymmetrical and material, and could detract from credit quality.
		The utility is exposed to the risk that it doesn't recover unexpected or volatile costs in a full or less than timely manner due to lack of flexible reopeners or annual revenue adjustments.
		There is an uneven track record of earning a compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.
		There is little or no support of cash flows during construction, and investment decisions on large projects (and therefore the risk of subsequent disallowances of capital costs) rest mostly with the utility.
		The utility operates under a regulatory system that is not sufficiently insulated from political intervention and is sometimes subject to overt political influence.
Weak	The utility suffers from a complete breakdown of regulatory protection that places the utility at a significant disadvantage.	The utility operates in an opaque regulatory climate that lacks transparency, predictability, and consistency.
	The utility's regulatory risk is such that the long-term cost recovery and investment return is highly uncertain and materially delayed, leading to volatile or weak cash flows. There is the potential for material stranded assets with no prospect of recovery.	The utility cannot fully and/or timely recover its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base).
		There is a track record of earning minimal or negative rates of return in cash through various economic and political cycles and a projected inability to improve that record sustainably.
		The utility must make significant capital commitments with no solid legal basis for the full recovery of capital costs.
		Ratemaking practices actively harm credit quality.
		The utility is regularly subject to overt political influence.

29. After determining the preliminary regulatory advantage assessment, we then assess the utility's business strategy. Most importantly, this factor addresses the effectiveness of a utility's

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

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

Table 2

Determining The Final Regulatory Advantage Assessment

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

Scale, scope, and diversity

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

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

- A large and diverse customer base with no meaningful customer concentration risk, where residential and small to medium commercial customers typically provide most operating income.

- The utility's range of service territories and regulatory jurisdictions is better than others in the sector.
- Exposure to multiple regulatory authorities where we assess preliminary regulatory advantage to be at least Adequate. In the case of exposure to a single regulatory regime, the regulatory advantage assessment is either Strong or Strong/Adequate.
- No meaningful exposure to a single or few assets or suppliers that could hurt operations or could not easily be replaced.

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

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

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

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

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

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

Operating efficiency

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

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

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

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

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

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

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

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

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

- High safety performance;
- Service reliability is satisfactory with a track record of mostly meeting operating performance

requirements of stakeholders, including those of regulators. We have confidence that a favorable performance against targets can be mostly sustained;

- Where applicable, the utility may be challenged to comply with current and future environmental standards that could increase in the medium term;
- Management maintains adequate cost control. Utilities that we assess as having adequate operating efficiency mostly manage their fixed and variable costs in line with regulatory expectations (including labor and working capital management being mostly in line with regulator's allowed collection cycles); or
- There is a history of adequate project management skills in capital spending programs within regulatory allowances for timing and budget.

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

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

Profitability

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

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

Level of profitability

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

- EBITDA margin,

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

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

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

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

Volatility of profitability

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

53. We use actual returns to calculate the standard error of regression for regulated utility issuers (only if there are at least seven years of historical annual data to ensure meaningful results). If we believe recurring mergers and acquisitions or currency fluctuations affect the results, we may make adjustments.

Part II--Financial Risk Analysis

D. Accounting

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

Accounting characteristics

55. Some important accounting practices for utilities include:

- For integrated electric utilities that meet native load obligations in part with third-party power contracts, we use our purchased power methodology to adjust measures for the debt-like obligation such contracts represent.
- Due to distortions in leverage measures from the substantial seasonal working-capital requirements of natural gas distribution utilities, we adjust inventory and debt balances by netting the value of inventory against outstanding short-term borrowings. This adjustment provides an accurate view of the company's balance sheet by reducing seasonal debt balances when we see a very high certainty of near-term cost recovery.
- We deconsolidate securitized debt (and associated revenues and expenses) that has been accorded specialized recovery provisions.

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

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E. Cash flow/leverage analysis

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

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

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

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

- A vast majority of operating cash flows come from regulated operations that are predominantly at the low end of the utility risk spectrum (e.g., a "network," or distribution/transmission business unexposed to commodity risk and with very low operating risk);
- A "strong" regulatory advantage assessment;
- An established track record of normally stable credit measures that is expected to continue;
- A demonstrated long-term track record of low funding costs (credit spread) for long-term debt that is expected to continue; and
- Non-utility activities that are in a separate part of the group (as defined in our group rating methodology) that we consider to have "nonstrategic" group status and are not deemed high risk and/or volatile.

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

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

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

- About one-third or less of its operating cash flow comes from regulated utility activities, regardless of its regulatory advantage assessment; or

- A regulatory advantage assessment of "adequate/weak" or "weak."

Part III--Rating Modifiers

F. Diversification/portfolio effect

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

G. Capital structure

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

H. Liquidity

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

84. The relative certainty of financial performance by utilities operating under relatively predictable regulatory monopoly frameworks make these utilities attractive to investors even in times of economic stress and market turbulence compared to conventional industrials. Also, recognizing the cash flow stability of regulated utilities we allow more discretion when calculating covenant headroom. For this reason, when determining if utilities with business risk profiles of at least "satisfactory" meet our definition of "adequate" liquidity, we use slightly lower thresholds:

- A ratio of sources to uses higher than 1.1x, compared with the standard 1.2x;
- Positive sources over uses even if forecast EBITDA declines by 10% (compared with a 15% decline for corporate issuers); and
- No covenant breach even if forecast EBITDA declines by 10% (compared with a 15% decline for corporate issuers).

I. Financial policy

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

J. Management and governance

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

K. Comparable ratings analysis

87. In assessing the comparable ratings analysis on a regulated utility, our analysis uses the same

methodology as with other corporate issuers (see "Corporate Methodology").

APPENDIX--Frequently Asked Questions

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

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

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

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

What is your definition of regulatory jurisdiction?

90. A regulatory jurisdiction is defined as the area over which the regulator has oversight and could include single or multiple subsectors (water, gas, and power). A geographic region may have several regulatory jurisdictions. For example, the Office of Gas and Electricity Markets and the Water Services Regulation Authority in the U.K. are considered separate regulatory jurisdictions. In Ontario, Canada, the Ontario Energy Board represents a single jurisdiction with regulatory

oversight for power and gas. Also, in Australia, the Australian Energy Regulator would be considered a single jurisdiction given that it is responsible for both electricity and gas transmission and distribution networks in the entire country, with the exception of Western Australia.

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

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

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

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

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

93. No. The table is guidance as to what we would typically expect from a regulatory framework that we would assess as "strong." We would expect some frameworks with no capital support during

construction to receive a "strong" regulatory advantage assessment if in aggregate the other factors we analyze support that conclusion.

REVISIONS AND UPDATES

This article was originally published on Nov. 19, 2013. These criteria became effective on Nov. 19, 2013.

Changes introduced after original publication:

- Following our periodic review completed on June 17, 2016, we updated the contact information and criteria references and deleted paragraphs 2, 5, and 6, which were related to the initial publication of our criteria and no longer relevant.
- Following our periodic review completed on June 6, 2017, we updated the contact information and criteria references and clarified paragraphs 4 and 84.
- Following our periodic review completed on June 5, 2018, we updated the contact information and criteria references and renamed the "Revision History" section to "Revisions And Updates."
- On April 1, 2019, we republished this criteria article to make nonmaterial changes. We deleted paragraphs 57-74 because they were superseded by "Corporate Methodology: Ratios And Adjustments," published April 1, 2019 (Ratios and Adjustments). The sector-specific accounting and analytical adjustments previously included in those paragraphs are now included in the Guidance supporting the Ratios and Adjustments criteria. We also updated the contacts list.
- On July 25, 2019, we republished this criteria article to make nonmaterial changes. We updated the contact information and updated several references to other criteria articles throughout the body of this article by removing the dates of publication. These dates are provided in the "Related Criteria" section.

RELATED PUBLICATIONS

Superseded Criteria

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

Related Criteria

- Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016
- Methodology: Jurisdiction Ranking Assessments, Jan. 21, 2016

- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Corporate Methodology, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, Nov. 19, 2013
- Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities and Insurers, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011
- Securitizing Stranded Costs, Jan. 18, 2001

Related Guidance

- Guidance: Corporate Methodology: Ratios And Adjustments, April 1, 2019

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

PUBLIC DOCUMENT
TRADE SECRET DATA
EXCISED IN ITS ENTIRETY

S&P Credit Report (Feb 6 2019)

PUBLIC DOCUMENT
TRADE SECRET DATA
EXCISED IN ITS ENTIRETY

S&P Credit Report (May 13, 2019)

Total Pension Rollforward

A	B	C	D	E	F	G
				(B+C-D)		
	ALLETE				Less Subsidiary	
Year	Beginning Prepaid	Contributions	Expense	Ending Prepaid	Contributions	Expense
1987	3,908	4,054,160	4,053,454	4,614	559,999	457,574
1988	4,614	2,673,674	2,678,288	0	149,635	204,411
1989	0	2,466,133	2,466,133	0	102,421	169,626
1990	0	3,022,676	2,796,953	225,723	164,956	120,722
1991	225,723	5,724,650	2,321,988	3,628,385	258,884	67,754
1992	3,628,385	4,033,434	2,026,297	5,635,522	169,750	38,131
1993	5,635,522	4,008,886	1,904,872	7,739,536	62,510	105,189
1994	7,739,536	1,787,709	801,925	8,725,320	27,909	(113,184)
1995	8,725,320	3,621	2,323,762	6,405,179	-	13,352
1996	6,405,179	-	5,195,829	1,209,350	-	113,051
1997	1,209,350	-	4,596,632	(3,387,282)	-	109,340
1998	(3,387,282)	-	(459,478)	(2,927,804)	-	(171,476)
1999	(2,927,804)	-	(3,922,267)	994,463	-	(284,191)
2000	994,463	-	(8,497,214)	9,491,677	-	(411,904)
2001	9,491,677	-	(9,567,909)	19,059,586	-	(725,066)
2002	19,059,586	-	(6,975,895)	26,035,481	-	(379,100)
2003	26,035,481	-	(2,628,334)	28,663,815	-	(52,538)
2004	28,663,815	7,862,565	3,097,015	33,429,365	390,044	425,527
2005	33,429,365	-	4,951,308	28,478,057	-	547,212
2006	28,478,057	8,257,827	7,305,480	29,430,404	873,279	722,553
2007	29,430,404	187,819	1,096,191	28,522,032	-	389,871
2008	28,522,032	10,898,460	(577,913)	39,998,405	1,111,644	492,799
2009	39,998,405	32,900,000	764,042	72,134,363	3,355,820	306,228
2010	72,134,363	26,500,000	4,603,064	94,031,299	2,081,415	514,800
2011	94,031,299	33,819,786	11,486,072	116,365,013	2,289,883	991,698
2012	116,365,013	7,292,000	16,174,087	107,482,926	673,856	1,245,657
2013	107,482,926	-	20,670,516	86,812,410	-	1,529,187
2014	86,812,410	19,499,040	12,522,446	93,789,004	3,780,934	935,383
2015	93,789,004	-	15,304,684	78,484,320	-	1,562,991
2016	78,484,320	6,300,180	5,285,744	79,498,756	582,518	788,160
2017	79,498,756	15,165,725	8,376,836	86,287,645	1,385,239	1,348,589
2018	86,287,645	15,000,000	5,590,407	95,697,238	1,675,888	1,333,926
2019 est	95,697,238	10,430,000	2,823,926	103,303,312	682,042	693,322
2020 est	103,303,312	12,600,000	7,060,000	108,843,312	1,145,200	1,220,990

H	I	J	K	L	M
		(C-F)	(D-G)	(I+J-K)	
		Minnesota Power			
Year	Beginning Prepaid	Contributions	Expense	Ending Prepaid	MN Power to MP Regulated Allocator
1987	3,908	3,494,161	3,595,880	(97,811)	76.70%
1988	(97,811)	2,524,039	2,473,877	(47,649)	76.70%
1989	(47,649)	2,363,712	2,296,507	19,556	76.70%
1990	19,556	2,857,720	2,676,231	201,045	76.70%
1991	201,045	5,465,766	2,254,234	3,412,577	76.700%
1992	3,412,577	3,863,684	1,988,166	5,288,095	76.700%
1993	5,288,095	3,946,376	1,799,683	7,434,788	76.700%
1994	7,434,788	1,759,800	915,109	8,279,479	76.700%
1995	8,279,479	3,621	2,310,410	5,972,690	76.700%
1996	5,972,690	-	5,082,778	889,912	76.700%
1997	889,912	-	4,487,292	(3,597,380)	76.700%
1998	(3,597,380)	-	(288,002)	(3,309,378)	76.700%
1999	(3,309,378)	-	(3,638,076)	328,698	76.700%
2000	328,698	-	(8,085,310)	8,414,008	76.700%
2001	8,414,008	-	(8,842,843)	17,256,851	76.700%
2002	17,256,851	-	(6,596,795)	23,853,646	76.700%
2003	23,853,646	-	(2,575,796)	26,429,442	76.700%
2004	26,429,442	7,472,521	2,671,488	31,230,475	76.700%
2005	31,230,475	-	4,404,096	26,826,379	77.120%
2006	26,826,379	7,384,548	6,582,927	27,628,000	82.956%
2007	27,628,000	187,819	706,320	27,109,499	83.657%
2008	27,109,499	9,786,816	(1,070,712)	37,967,027	85.936%
2009	37,967,027	29,544,180	457,814	67,053,394	87.422%
2010	67,053,394	24,418,585	4,088,264	87,383,715	89.220%
2011	87,383,715	31,529,903	10,494,374	108,419,244	88.827%
2012	108,419,244	6,618,144	14,928,430	100,108,958	89.600%
2013	100,108,958	-	19,141,329	80,967,629	89.693%
2014	80,967,629	15,718,106	11,587,063	85,098,672	88.661%
2015	85,098,672	-	13,741,693	71,356,979	87.124%
2016	71,356,979	5,717,662	4,497,584	72,577,057	85.021%
2017	72,577,057	13,780,486	7,028,247	79,329,296	85.149%
2018	79,329,296	13,324,112	4,256,481	88,396,927	82.681%
2019 est	88,396,927	9,747,958	2,130,604	96,014,281	81.907%
2020 est	96,014,281	11,454,800	5,839,010	101,630,071	84.916%

N	O	P	Q	R	S
		(J* M)	(K*M)	(O+P-Q)	
		Minnesota Power Regulated			
Year	Beginning Prepaid	Contributions	Expense	Ending Prepaid	Jurisdictional Allocator
1987	3,908	2,680,021	2,758,040	(74,110)	92.1000%
1988	(74,110)	1,935,938	1,897,464	(35,636)	92.1000%
1989	(35,636)	1,812,967	1,761,421	15,910	92.1000%
1990	15,910	2,191,871	2,052,669	155,112	92.1000%
1991	155,112	4,192,243	1,728,997	2,618,357	92.1000%
1992	2,618,357	2,963,446	1,524,923	4,056,880	92.1000%
1993	4,056,880	3,026,870	1,380,357	5,703,393	92.1000%
1994	5,703,393	1,349,767	701,889	6,351,271	92.1000%
1995	6,351,271	2,777	1,772,084	4,581,964	92.1000%
1996	4,581,964	-	3,898,491	683,473	91.9200%
1997	683,473	-	3,441,753	(2,758,280)	91.9200%
1998	(2,758,280)	-	(220,898)	(2,537,382)	91.9200%
1999	(2,537,382)	-	(2,790,404)	253,022	91.9200%
2000	253,022	-	(6,201,433)	6,454,455	91.9200%
2001	6,454,455	-	(6,782,461)	13,236,916	91.9200%
2002	13,236,916	-	(5,059,742)	18,296,657	91.9200%
2003	18,296,657	-	(1,975,636)	20,272,293	91.9200%
2004	20,272,293	5,731,424	2,049,031	23,954,685	91.9200%
2005	23,954,685	-	3,396,439	20,558,246	89.4600%
2006	20,558,246	6,125,926	5,460,933	21,223,239	89.4600%
2007	21,223,239	157,124	590,886	20,789,477	87.4900%
2008	20,789,477	8,410,399	(920,127)	30,120,002	87.6767%
2009	30,120,002	25,828,113	400,230	55,547,885	87.6767%
2010	55,547,885	21,786,262	3,647,549	73,686,598	86.1672%
2011	73,686,598	28,007,067	9,321,838	92,371,828	86.1672%
2012	92,371,828	5,929,857	13,375,873	84,925,811	86.1672%
2013	84,925,811	-	17,168,432	67,757,379	86.1672%
2014	67,757,379	13,935,830	10,273,206	71,420,003	86.1672%
2015	71,420,003	-	11,972,313	59,447,691	86.5161%
2016	59,447,691	4,861,213	3,823,891	60,485,013	86.0536%
2017	60,485,013	11,733,946	5,984,482	66,234,477	87.0129%
2018	66,234,477	11,016,509	3,519,301	73,731,685	87.5035%
2019 est	73,731,685	7,984,260	1,745,114	79,970,831	88.9693%
2020 est	79,970,831	9,726,958	4,958,254	84,739,535	89.4491%

T	U	V	W	X	Y	Z
		(P * S)	(Q * S)	(U+V-W)		
		MN Jurisdictional				
Year	Beginning Prepaid	Contributions	Expense	Ending Prepaid	Year	TOTAL Recovery
1987	3,908	2,468,300	2,540,155	(67,947)	1987	n/a
1988	(67,947)	1,782,999	1,747,564	(32,512)	1988	n/a
1989	(32,512)	1,669,743	1,622,269	14,962	1989	n/a
1990	14,962	2,018,713	1,890,508	143,167	1990	n/a
1991	143,167	3,861,055	1,592,407	2,411,816	1991	n/a
1992	2,411,816	2,729,333	1,404,454	3,736,695	1992	n/a
1993	3,736,695	2,787,748	1,271,309	5,253,134	1993	n/a
1994	5,253,134	1,243,135	646,439	5,849,830	1994	368,504 [1]
1995	5,849,830	2,558	1,632,090	4,220,298	1995	368,504
1996	4,220,298	-	3,583,493	636,805	1996	368,504
1997	636,805	-	3,163,659	(2,526,854)	1997	368,504
1998	(2,526,854)	-	(203,049)	(2,323,805)	1998	368,504
1999	(2,323,805)	-	(2,564,940)	241,134	1999	368,504
2000	241,134	-	(5,700,357)	5,941,491	2000	368,504
2001	5,941,491	-	(6,234,438)	12,175,929	2001	368,504
2002	12,175,929	-	(4,650,915)	16,826,844	2002	368,504
2003	16,826,844	-	(1,816,004)	18,642,848	2003	368,504
2004	18,642,848	5,268,325	1,883,470	22,027,703	2004	368,504
2005	22,027,703	-	3,038,454	18,989,249	2005	368,504
2006	18,989,249	5,480,253	4,885,351	19,584,151	2006	368,504
2007	19,584,151	137,468	516,966	19,204,653	2007	368,504
2008	19,204,653	7,373,960	(806,737)	27,385,349	2008	(1,566,373) [2]
2009	27,385,349	22,645,237	350,909	49,679,678	2009	(1,566,373)
2010	49,679,678	18,772,612	3,142,991	65,309,299	2010	1,452,891 [3]
2011	65,309,299	24,132,906	8,032,366	81,409,838	2011	1,452,891
2012	81,409,838	5,109,592	11,525,615	74,993,814	2012	1,452,891
2013	74,993,814	-	14,793,557	60,200,257	2013	1,452,891
2014	60,200,257	12,008,114	8,852,134	63,356,238	2014	1,452,891
2015	63,356,238	-	10,357,978	52,998,260	2015	1,452,891
2016	52,998,260	4,183,249	3,290,596	53,890,913	2016	1,452,891
2017	53,890,913	10,210,047	5,207,271	58,893,688	2017	5,229,348 [4,5]
2018	58,893,688	9,639,831	3,079,512	65,454,008	2018	5,229,348
2019 est	65,454,008	7,103,540	1,552,616	71,004,932	2019 est	5,229,348
2020 est	71,004,932	8,700,676	4,435,113	75,270,495	2020 est	5,229,348
						33,113,939

[1] Docket Number E015/GR-94-001.

[2] Per Information Request 184, Date July 31, 2008, Docket Number E015/GR-08-415.

[3] In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota at p. 26, Findings of Fact, Conclusions, and Order, Docket No. E-015/GR-09-1151 (Nov. 2, 2010) ("Docket 09-1151 Order").

[4] In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota Rebuttal Testimony and Schedules of Patrick Cutshall, Docket No. E-015/GR-16-664 (June 29, 2017) at p. 6 and p.7, and Schedule 12 p.4.

[5] The MN Jurisdicational Allocation factor of 87.0129% was used to calculate the amount of pension expense recovered in the 2016 rate case (Docket No. E-015/GR-16-664, "Compliance Filing - Final General Rates", Schedule 16, pg. 45). The calculation of the pension expense was calculated as follows:

	Per Cutshall Rebuttal Testimony	Per Compliance Filing - Final Rates
Total Company	$ 6,009,854	$ 6,009,854
MN Jurisdictional Allocation	86.5278%	87.0129%
MN Power Jurisdictional (MN)	$ 5,200,194	$ 5,229,348

Mercer Standard Percentile Approach

Asset Allocation of Portfolio

Specified By Consultant

Name of Client: ALLETE
Analyst: SS

	Percentage Allocation
Domestic Equity	
Domestic Equity-All Cap	0.0%
Domestic Equity-Large Cap	9.9%
Domestic Equity-Mid Cap	4.7%
Domestic Equity-Small Cap	4.6%
Domestic Equity-Micro Cap	0.0%
Company Stock-Large	0.0%
Company Stock-Small	0.0%
Defensive Equity	0.0%
International Equity	
International Equity-Unhedged	0.0%
International Equity-Hedged	0.0%
International Eq-Emerging Mkts	6.5%
International Eq-Small Cap	0.0%
Global Equity x-U.S. - All Cap	6.2%
Global Equity x-U.S. - Large Cap	0.0%
Global Equity	0.0%
Global Small Cap	0.0%
Global Defensive Equity - Unhedged	0.0%
Fixed Income	
Fixed Income-Aggregate	0.0%
Fixed Income-Gov/Credit	0.0%
Fixed Income-Gov/Credit (Downgrade Tolerant)	0.0%
Fixed Income-Short Gov/Corp	0.0%
Fixed Income-Intermediate Gov/Corp	0.0%
Fixed Income-Long Gov/Corp	0.0%
Fixed Income-Long Gov/Corp (Downgrade Tolerant)	0.0%
Fixed Income-Intermediate Government	0.0%
Fixed Income-Government	0.0%
Fixed Income-Long Gov	0.0%
Fixed Income-Very Long Gov	30.0%
Fixed Income-Intermediate Credit	0.0%
Fixed Income-Credit	0.0%
Fixed Income-Credit (Downgrade Tolerant)	0.0%
Fixed Income-Long Credit	0.0%
Fixed Income-Long Credit (Downgrade Tolerant)	29.1%
Fixed Income-Mortgages	0.0%
Fixed Income-High Yield	0.0%
Fixed Income-Muni Bonds	0.0%
Inflation-Indexed Bonds	0.0%
Cash	1.1%
Convertibles	0.0%
GICs	0.0%
Private Debt	0.0%
Multi-Asset Credit	0.0%
International FixInc-Unhedged	0.0%
International FixInc-Hedged	0.0%
Broad International-Unhedged	0.0%
Emerging Market Debt	0.0%
Alternatives	
Real Estate - Core	0.0%
Real Estate - REITS	3.3%
Private Equity	4.6%
Hedge Funds - Conservative (Mkt Neutral prior to 7/1/2006)	0.0%
Hedge Funds - Moderate	0.0%
Hedge Funds - Mod/Aggressive (Aggressive prior to 7/1/2006)	0.0%
Idosyncratic Multi-Asset	0.0%
Commodities	0.0%
TOTAL	100.0%

Mercer Standard Percentile Approach

Asset Class Return Assumptions

Project File:	C:\...\2019 PRC - MINPOW Passive Approach.mpc
Name of Client:	ALLETE
Source of Return Data:	Mercer Investment Consulting
Date of Return Data:	January 2019
Annual Expense:	0.08%
Analyst:	SS

	Compound Annual Returns	Annual Arithmetic Returns	Standard Deviation of Annual Returns
Domestic Equity			
Domestic Equity-All Cap	6.45%	7.99%	18.4%
Domestic Equity-Large Cap	6.40%	7.88%	18.0%
Domestic Equity-Mid Cap	6.71%	8.45%	19.6%
Domestic Equity-Small Cap	6.84%	9.02%	22.2%
Domestic Equity-Micro Cap	7.00%	9.50%	23.8%
Company Stock-Large	4.56%	7.88%	27.4%
Company Stock-Small	2.44%	9.02%	39.7%
Defensive Equity	6.43%	7.30%	13.7%
International Equity			
International Equity-Unhedged	7.37%	9.22%	20.4%
International Equity-Hedged	7.62%	9.14%	18.4%
International Eq-Emerging Mkts	8.86%	11.88%	26.5%
International Eq-Small Cap	7.72%	9.94%	22.4%
Global Equity x-U.S. - All Cap	7.76%	9.68%	20.8%
Global Equity x-U.S. - Large Cap	7.69%	9.58%	20.6%
Global Equity	7.33%	8.87%	18.5%
Global Small Cap	7.67%	9.63%	21.0%
Global Defensive Equity - Unhedged	6.89%	7.70%	13.2%
Fixed Income			
Fixed Income-Aggregate	3.76%	3.89%	5.3%
Fixed Income-Gov/Credit	3.63%	3.77%	5.4%
Fixed Income-Gov/Credit (Downgrade Tolerant)	3.72%	3.86%	5.4%
Fixed Income-Short Gov/Corp	3.59%	3.69%	4.5%
Fixed Income-Intermediate Gov/Corp	3.66%	3.78%	5.0%
Fixed Income-Long Gov/Corp	3.54%	3.98%	9.6%
Fixed Income-Long Gov/Corp (Downgrade Tolerant)	3.75%	4.20%	9.7%
Fixed Income-Intermediate Government	3.35%	3.45%	4.5%
Fixed Income-Government	3.29%	3.42%	5.2%
Fixed Income-Long Gov	3.01%	3.80%	12.9%
Fixed Income-Very Long Gov	2.53%	4.07%	18.1%
Fixed Income-Intermediate Credit	4.25%	4.42%	6.0%
Fixed Income-Credit	4.18%	4.40%	6.9%
Fixed Income-Credit (Downgrade Tolerant)	4.41%	4.63%	6.8%
Fixed Income-Long Credit	4.01%	4.49%	10.1%
Fixed Income-Long Credit (Downgrade Tolerant)	4.37%	4.84%	9.9%
Fixed Income-Mortgages	3.67%	3.82%	5.6%
Fixed Income-High Yield	5.79%	6.26%	10.0%
Fixed Income-Muni Bonds	3.61%	3.80%	6.3%
Inflation-Indexed Bonds	3.43%	3.58%	5.6%
Cash	2.88%	2.90%	2.0%
Convertibles	5.54%	5.96%	9.5%
GICs	3.67%	3.74%	3.5%
Private Debt	6.57%	7.07%	10.3%
Multi-Asset Credit	5.74%	5.99%	7.3%
International FixInc-Unhedged	2.05%	2.55%	10.2%
International FixInc-Hedged	2.66%	2.89%	6.9%
Broad International-Unhedged	2.29%	2.75%	9.8%
Emerging Market Debt	5.74%	6.37%	11.6%
Alternatives			
Real Estate - Core	6.86%	7.98%	15.7%
Real Estate - REITS	6.16%	8.20%	21.3%
Private Equity	9.38%	11.95%	24.4%
Hedge Funds - Conservative (Mkt Neutral prior to 7/1/2006)	5.54%	5.71%	6.0%
Hedge Funds - Moderate	6.23%	6.54%	8.2%
Hedge Funds - Mod/Aggressive (Aggressive prior to 7/1/2006)	6.91%	7.44%	10.7%
Idosyncratic Multi-Asset	5.77%	6.10%	8.3%
Commodities	3.20%	4.60%	17.3%
Inflation	2.19%	2.20%	1.7%
PORTFOLIO - Gross	5.91%	6.45%	10.7%
PORTFOLIO - Net of Expense	5.83%	6.36%	10.7%

Note: Compound Returns reflect expected volatility and are, therefore, less than simple Arithmetic Average Returns.

Example: If Year 1 Return = 5% and Year 2 Return = 15%, then Annual Arithmetic Return = 10.00% and Compound Annual Return = 9.88%

Mercer Standard Percentile Approach

Range of Net Portfolio Returns

Annual Returns are Net of Expenses

Project File:	C:\...\2019 PRC - MINPOW Passive Approach.mpc
Name of Client:	ALLETE
Source of Return Data:	Mercer Investment Consulting
Date of Return Data:	January 2019
Annual Expense:	0.08%
Analyst:	SS

Percentiles	**Projection Horizon (years)** 20
5%	1.90%
10%	2.77%
15%	3.35%
20%	3.82%
25%	**4.22%**
30%	**4.58%**
35%	**4.91%**
40%	**5.23%**
45%	**5.53%**
50%	**5.83%**
55%	**6.13%**
60%	**6.44%**
65%	**6.75%**
70%	**7.08%**
75%	**7.44%**
80%	7.84%
85%	8.31%
90%	8.89%
95%	9.76%

EEI Member Companies
Per Company's 2018 Annual Report
Expected Return on Plan Assets and Fixed Income Allocation

	Pension	
Company[1]	Fixed income Asset Allocation	Expected Return on Assets EROA
Southern Company	24%	7.95%
IDACORP	26%	7.50%
Tennessee Valley Authority	26%	6.75%
Alliant Energy	30%	7.60%
Hawaiian Electric Industries	31%	7.50%
Eversource Energy	32%	8.25%
NextEra Energy	32%	7.35%
Public Service Enterprise Group	32%	7.80%
MGE Energy	33%	7.40%
First Energy	34%	7.50%
Berkshire Hathaway Energy - MidAmerican Energy	35%	6.36%
Dominion Energy	35%	8.75%
Portland General Electric	35%	7.00%
Evergy	36%	6.52%
Exelon Corporation	38%	7.00%
Consolidated Edison	39%	7.50%
Edison International	40%	6.50%
Unitil Corporation	40%	7.75%
Entergy Corporation	41%	7.50%
El Paso Electric	41%	7.50%
Ameren Corporation	42%	7.00%
CMS Energy	42%	7.00%
DTE Energy	42%	7.50%
Avista Corporation	45%	5.50%
Xcel Energy	47%	6.87%
Otter Tail Corporation	47%	7.50%
Sempra Energy	49%	7.00%
Avangrid	50%	7.40%
Cleco Corporate Holdings	50%	5.86%
OGE Energy Corp	50%	7.50%
CenterPoint Energy	54%	6.00%
PNM Resources	54%	6.54%
PPL Corporation	54%	7.25%
MDU Resources Group	55%	6.75%
NorthWestern Energy	58%	4.72%
PG&E Corporation	58%	6.00%
American Electric Power	61%	6.00%
Duke Energy	63%	6.50%
Pinnacle West Capital Corporation	64%	6.05%
WEC Energy Group	65%	7.12%
NiSource	67%	7.00%
Black Hills Corporation	71%	6.25%
AES Corporation	80%	5.73%
Average		6.95%

	OPEB	
Company[1]	Fixed income Asset Allocation	Expected Return on Assets EROA
Exelon Corporation	28%	6.60%
Edison International	29%	5.30%
Southern Company	30%	6.83%
Hawaiian Electric Industries	30%	7.50%
CMS Energy	31%	7.00%
Public Service Enterprise Group	32%	7.80%
El Paso Electric	34%	6.12%
Berkshire Hathaway Energy - MidAmerican Energy	35%	6.44%
Evergy	35%	6.00%
Ameren Corporation	38%	7.00%
Duke Energy	40%	6.50%
American Electric Power	41%	6.00%
NorthWestern Energy	41%	4.82%
Portland General Electric	42%	6.20%
Sempra Energy	44%	6.49%
Unitil Corporation	47%	7.75%
Consolidated Edison	48%	7.50%
Avangrid	50%	6.13%
NiSource	53%	5.80%
First Energy	55%	7.50%
Entergy Corporation	56%	6.50%
PPL Corporation	56%	6.46%
PG&E Corporation	58%	5.20%
WEC Energy Group	61%	7.25%
Pinnacle West Capital Corporation	69%	5.40%
Xcel Energy	70%	5.30%
MDU Resources Group	73%	5.75%
Alliant Energy	73%	5.44%
CenterPoint Energy	74%	4.55%
Average		6.31%

[1] - Companies are sorted in ascending order of Fixed Income Allocation percentages.

PUBLIC DOCUMENT
TRADE SECRET DATA
EXCISED IN ITS ENTIRETY

EEI 2018-2019 Pension and OPEB Survey and Select Results

Minnesota Power
Working Capital Requirements
Prepaid Pension Asset
2020 Projected Budget Unadjusted

Projected

	A	B	C	D	E	F	G	H	I	J
Month	Pension 18230-6015	Pension Plan A 22830-2008	Pension Plan B 22830-2009	Pension Plan C 22830-2011	AOCI Pension 21900-0003	Total (A+B+C+D+E)	MP Regulated Allocator	Prepaid Pension Asset MP Regulated F x G	MN Jurisdictional Allocator	Prepaid Pension Asset - MN Jurisdictional H x I
December-19	$ 183,476,845	-	$ (81,918,263)	$ (37,922,570)	$ 32,378,269	$ 96,014,281	81.91%	$ 78,642,417	88.9693%	$ 69,967,608
January-20	183,476,845	-	(71,414,476)	(37,458,142)	32,378,269	106,982,496	84.92%	90,845,256	89.4491%	81,260,264
February-20	183,476,845	-	(72,365,489)	(36,993,714)	32,378,269	106,495,911	84.92%	90,432,068	89.4491%	80,890,671
March-20	183,476,845	-	(73,316,502)	(36,529,286)	32,378,269	106,009,326	84.92%	90,018,879	89.4491%	80,521,077
April-20	183,476,845	-	(74,267,515)	(36,064,858)	32,378,269	105,522,741	84.92%	89,605,691	89.4491%	80,151,484
May-20	183,476,845	-	(75,218,528)	(35,600,430)	32,378,269	105,036,156	84.92%	89,192,502	89.4491%	79,781,891
June-20	183,476,845	-	(76,169,541)	(35,136,002)	32,378,269	104,549,571	84.92%	88,779,314	89.4491%	79,412,297
July-20	183,476,845	-	(77,120,554)	(34,671,574)	32,378,269	104,062,986	84.92%	88,366,125	89.4491%	79,042,704
August-20	183,476,845	-	(78,071,567)	(34,207,146)	32,378,269	103,576,401	84.92%	87,952,937	89.4491%	78,673,110
September-20	183,476,845	-	(79,022,580)	(33,742,718)	32,378,269	103,089,816	84.92%	87,539,748	89.4491%	78,303,517
October-20	183,476,845	-	(79,973,593)	(33,278,290)	32,378,269	102,603,231	84.92%	87,126,560	89.4491%	77,933,923
November-20	183,476,845	-	(80,924,606)	(32,813,862)	32,378,269	102,116,646	84.92%	86,713,371	89.4491%	77,564,330
December-20	$ 183,476,845	-	$ (81,875,613)	$ (32,349,430)	$ 32,378,269	$ 101,630,071	84.92%	$ 86,300,191	89.4491%	$ 77,194,744
								$ 1,141,515,059 [1]		$ 1,020,697,620 [1]
					13 month Average	**$ 103,668,433**		**$ 87,808,851** [2]		**$ 78,515,202** [2]

Reconciliation of how 13-month average number and year end 2020 numbers tie to each other.

Total Minnesota Power 2020 year end balance	$ 101,630,071
Minnesota Power regulated allocator	84.92%
Total Minnesota Power regulated	86,300,191
MN Jurisdictional allocator	89.449%
MN Jurisdictional 2020 year end balance	$ 77,194,744

[1] Total 13 months - Dec 19 to Dec 20
[2] Total 13 months in [1] divided 13 months

Prepaid Pension Balance Components and Earnings

ALLETE

	A	B	C	D	E	F	G	H
Year	Beginning Prepaid	Contributions	Expense	Ending Prepaid (A+B-C)	Pension Return[1]	Current Year Return on Prepaid (E*(D+A)/2)	Compounded Return (E*Prior yr H)	Cumulative Return (Prior yr H+F+G)
1987	3,908	4,054,160	4,053,454	4,614	8.00%	162,166		162,166
1988	4,614	2,673,674	2,678,288	0	8.00%	185	12,973	175,324
1989	0	2,466,133	2,466,133	0	8.50%	0	14,903	190,227
1990	0	3,022,676	2,796,953	225,723	8.50%	9,593	16,169	215,989
1991	225,723	5,724,650	2,321,988	3,628,385	8.50%	163,800	18,359	398,148
1992	3,628,385	4,033,434	2,026,297	5,635,522	8.20%	379,820	32,648	810,617
1993	5,635,522	4,008,886	1,904,872	7,739,536	14.20%	949,629	115,108	1,875,353
1994	7,739,536	1,787,709	801,925	8,725,320	-1.30%	(107,022)	(24,380)	1,743,952
1995	8,725,320	3,621	2,323,762	6,405,179	24.08%	1,821,712	419,944	3,985,608
1996	6,405,179	-	5,195,829	1,209,350	7.99%	304,200	318,450	4,608,259
1997	1,209,350	-	4,596,632	(3,387,282)	18.82%	(204,943)	867,274	5,270,590
1998	(3,387,282)	-	(459,478)	(2,927,804)	7.94%	(250,709)	418,485	5,438,366
1999	(2,927,804)	-	(3,922,267)	994,463	18.14%	(175,354)	986,520	6,249,531
2000	994,463	-	(8,497,214)	9,491,677	4.48%	234,890	279,979	6,764,400
2001	9,491,677	-	(9,567,909)	19,059,586	-0.58%	(82,799)	(39,234)	6,642,367
2002	19,059,586	-	(6,975,895)	26,035,481	-7.36%	(1,659,499)	(488,878)	4,493,991
2003	26,035,481	-	(2,628,334)	28,663,815	23.46%	6,416,228	1,054,290	11,964,508
2004	28,663,815	7,862,565	3,097,015	33,429,365	9.81%	3,045,671	1,173,718	16,183,897
2005	33,429,365	-	4,951,308	28,478,057	8.37%	2,590,826	1,354,592	20,129,315
2006	28,478,057	8,257,827	7,305,480	29,430,404	15.60%	4,516,860	3,140,173	27,786,348
2007	29,430,404	187,819	1,096,191	28,522,032	9.00%	2,607,860	2,500,771	32,894,979
2008	28,522,032	10,898,460	(577,913)	39,998,405	-28.71%	(9,836,109)	(9,444,149)	13,614,722
2009	39,998,405	32,900,000	764,042	72,134,363	12.22%	6,851,312	1,663,719	22,129,753
2010	72,134,363	26,500,000	4,603,064	94,031,299	14.95%	12,420,883	3,308,398	37,859,034
2011	94,031,299	33,819,786	11,486,072	116,365,013	9.47%	9,962,265	3,585,251	51,406,550
2012	116,365,013	7,292,000	16,174,087	107,482,926	10.00%	11,192,397	5,140,655	67,739,602
2013	107,482,926	-	20,670,516	86,812,410	13.30%	12,920,640	9,009,367	89,669,610
2014	86,812,410	19,499,040	12,522,446	93,789,004	7.70%	6,953,154	6,904,560	103,527,324
2015	93,789,004	-	15,304,684	78,484,320	-1.50%	(1,292,050)	(1,552,910)	100,682,364
2016	78,484,320	6,300,180	5,285,744	79,498,756	10.70%	8,452,095	10,773,013	119,907,472
2017	79,498,756	15,165,725	8,376,836	86,287,645	16.70%	13,843,165	20,024,548	153,775,184
2018	86,287,645	15,000,000	5,590,407	95,697,238	-4.00%	(3,639,698)	(6,151,007)	143,984,479
Est 2019	95,697,238	10,430,000	2,823,926	103,303,312	7.25%	7,213,770	10,438,875	161,637,124
Est 2020	103,303,312	12,600,000	7,060,000	108,843,312	6.75%	7,159,949	10,910,506	179,707,578

Minnesota Power

	I	J	K	L	M	N	O	P
Year	Beginning Prepaid	Contributions	Expense	Ending Prepaid (I+J-K)	Pension Return[1]	Current Year Return on Prepaid (M*(L+I)/2)	Compounded Return (M*Prior yr P)	Cumulative Return (Prior yr P+N+O)
1987	3,908	3,494,161	3,595,880	(97,811)	8.00%	(3,756)		(3,756)
1988	(97,811)	2,524,039	2,473,877	(47,649)	8.00%	(5,818)	(300)	(9,875)
1989	(47,649)	2,363,712	2,296,507	19,556	8.50%	(1,194)	(839)	(11,908)
1990	19,556	2,857,720	2,676,231	201,045	8.50%	9,376	(1,012)	(3,545)
1991	201,045	5,465,766	2,254,234	3,412,577	8.50%	153,579	(301)	149,733
1992	3,412,577	3,863,684	1,988,166	5,288,095	8.20%	356,728	12,278	518,738
1993	5,288,095	3,946,376	1,799,683	7,434,788	14.20%	903,325	73,661	1,495,724
1994	7,434,788	1,759,800	915,109	8,279,479	-1.30%	(102,143)	(19,444)	1,374,137
1995	8,279,479	3,621	2,310,410	5,972,690	24.08%	1,715,961	330,892	3,420,990
1996	5,972,690	-	5,082,778	889,912	7.99%	274,161	273,337	3,968,488
1997	889,912	-	4,487,292	(3,597,380)	18.82%	(254,773)	746,870	4,460,585
1998	(3,597,380)	-	(288,002)	(3,309,378)	7.94%	(274,198)	354,170	4,540,557
1999	(3,309,378)	-	(3,638,076)	328,698	18.14%	(270,348)	823,657	5,093,867
2000	328,698	-	(8,085,310)	8,414,008	4.48%	195,837	228,205	5,517,909
2001	8,414,008	-	(8,842,843)	17,256,851	-0.58%	(74,445)	(32,004)	5,411,459
2002	17,256,851	-	(6,596,795)	23,853,646	-7.36%	(1,512,866)	(398,283)	3,500,310
2003	23,853,646	-	(2,575,796)	26,429,442	23.46%	5,898,206	821,173	10,219,689
2004	26,429,442	7,472,521	2,671,488	31,230,475	9.81%	2,828,219	1,002,551	14,050,459
2005	31,230,475	-	4,404,096	26,826,379	8.37%	2,429,679	1,176,023	17,656,162
2006	26,826,379	7,384,548	6,582,927	27,628,000	15.60%	4,247,442	2,754,361	24,657,965
2007	27,628,000	187,819	706,320	27,109,499	9.00%	2,463,187	2,219,217	29,340,369
2008	27,109,499	9,786,816	(1,070,712)	37,967,027	-28.71%	(9,341,735)	(8,423,620)	11,575,014
2009	37,967,027	29,544,180	457,814	67,053,394	12.22%	6,416,748	1,414,467	19,406,228
2010	67,053,394	24,418,585	4,088,264	87,383,715	14.95%	11,544,174	2,901,231	33,851,633
2011	87,383,715	31,529,903	10,494,374	108,419,244	9.47%	9,271,270	3,205,750	46,328,653
2012	108,419,244	6,618,144	14,928,430	100,108,958	10.00%	10,426,410	4,632,865	61,387,928
2013	100,108,958	-	19,141,329	80,967,629	13.30%	12,041,593	8,164,594	81,594,116
2014	80,967,629	15,718,106	11,587,063	85,098,672	7.70%	6,393,553	6,282,747	94,270,415
2015	85,098,672	-	13,741,693	71,356,979	-1.50%	(1,173,417)	(1,414,056)	91,682,941
2016	71,356,979	5,717,662	4,497,584	72,577,057	10.70%	7,700,471	9,810,075	109,193,487
2017	72,577,057	13,780,486	7,028,247	79,329,296	16.70%	12,684,181	18,235,312	140,112,980
2018	79,329,296	13,324,112	4,256,481	88,396,927	-4.00%	(3,354,524)	(5,604,519)	131,153,936
Est 2019	88,396,927	9,747,958	2,130,604	96,014,281	7.25%	6,684,906	9,508,660	147,347,503
Est 2020	96,014,281	11,454,800	5,839,010	101,630,071	6.75%	6,670,497	9,945,956	163,963,956

Minnesota Jurisdictional Allocation

	Current Year Return on Prepaid	Compounded Return	Total
1 2020 Minnesota Power prepaid from above	6,670,497	9,945,956	16,616,453
2 MN Power to MP Regulated Allocator	84.9160%	84.9160%	84.9160%
3 MN Power Regulated (1)*(2)	5,664,319	8,445,708	14,110,028
4 MN Jurisdictional Allocator	89.4491%	89.4491%	89.4491%
5 **MN Jurisdictional (3)*(4)**	**$ 5,066,683**	**$ 7,554,610**	**$ 12,621,293**

[1] Assumed rate of return used for years 1987 to 1995, actual rate of return used afterwards, assumed rate of return for 2019 and 2020.

MERCER
MAKE TOMORROW, TODAY

ASC 715 (US GAAP)
ACTUARIAL VALUATION REPORT
AS OF DECEMBER 31, 2018 - REVISED

ALLETE AND AFFILIATED COMPANIES
QUALIFIED RETIREMENT PLANS

10 OCTOBER 2019

MARSH & McLENNAN
COMPANIES

CONTENTS

1

Report Highlights

Mercer has prepared this report for ALLETE, Inc. and Affiliated Companies (ALLETE) to (i) present actuarial estimates of liabilities as of December 31, 2018 for the ALLETE and Affiliated Companies Retirement Plan A (Plan A), ALLETE and Affiliated Companies Retirement Plan B (Plan B) and ALLETE and Affiliated Companies Retirement Plan C (Plan C) to be incorporated, as ALLETE deems appropriate, in the financial statements prepared under US accounting standards, and to (ii) provide an actuarial estimate of the net periodic benefit cost for the fiscal year ending December 31, 2019 for Plan B and Plan C.

All figures in this report are expressed in US Dollars, unless otherwise stated.

This re-issued report updates the prior version, dated January 30, 2019, which included an incorrect market-related value of assets. Correcting the market-related value of assets impacts the expected return on assets and loss amortization components of the 2019 expense. As a result, the 2019 Plan B expense increased from $8,703,804 to $8,811,793, and the 2019 Plan C expense increased from ($6,301,723) to ($5,987,867). No other numbers were effected.

Please see Section 3 of this report for further explanation as to the purposes and limitations of this report.

Summary of Results

Below are highlights of the results as of December 31, 2018 compared to the corresponding figures as of December 31, 2017.

	December 31, 2018				**December 31, 2017**			
	Plan A	Plan B	Plan C	Total	Plan A	Plan B	Plan C	Total
Net periodic benefit cost	639,248	11,662,673	(6,711,514)	5,590,407	1,692,411	11,593,705	(4,909,280)	8,376,836
Benefit obligation	N/A	189,765,693	535,081,187	724,846,880	65,846,323	189,762,325	514,521,217	770,129,865
Fair value of plan assets	N/A	110,294,608	487,711,208	598,005,816	39,459,637	97,962,227	490,765,851	628,187,715
Funded status	N/A	(79,471,085)	(47,369,979)	(126,841,064)	(26,386,686)	(91,800,098)	(23,755,366)	(141,942,150)
Discount rate at year-end	N/A	4.53%	4.39%		3.86%	3.96%	3.81%	

Plan A merged into Plan C effective December 31, 2018. Values shown as of December 31, 2018 reflect the combination of Plans A and C.

The net periodic benefit cost for Plan A for the fiscal year ending December 31, 2018 was remeasured for the second half of 2018, reflecting the July board resolution to hard-freeze the plan effective November 30, 2018, and to eliminate the SIB death benefit on that same date. The hard-freeze reduced the benefit obligation $6,877,541, which reduced unrecognized losses. The elimination of the death benefit reduced the benefit obligation $1,475,277, resulting in a prior service credit amortized in equal instalments of $149,018 over the average future working lifetime of active participants in the plan, 9.9 years, as confirmed by PwC. The 2018 net periodic benefit cost for Plan A changed from $1,448,810 to $639,248. Full details can be found in Appendix D.

	December 31, 2019		
	Plan B	Plan C	Total
Estimated net periodic benefit cost	8,811,793	(5,987,867)	2,823,926

Please note that the actual net periodic benefit cost for the fiscal year ending December 31, 2019 may be substantially different from the estimate and may be revised if assets and/or liabilities are remeasured during the year due to a significant event and/or cash flows are updated.

Review of Results

The total unfunded obligation decreased (i.e. improved) $15,101,086 between December 31, 2017 and December 31, 2018. Accumulated other comprehensive income changed from -$228,229,795 at December 31, 2017 to -$222,538,302 at December 31, 2018.

Contributing factors to these changes include:

- The unfunded obligation was expected to decrease $5,005,448 due to the expected return on plan assets exceeding the sum of benefit and interest accruals in 2018.
- Company contributions during 2018 reduced the unfunded obligation by $15,000,000.
- The discount rate increased from 3.86% to 4.39% for Plan A, 3.96% to 4.53% for Plan B and 3.81% to 4.39% for Plan C. This decreased the benefit obligation by $48,533,486.
- The mortality improvement projection scale was updated from MMP-2016 to MMP-2018. This decreased the benefit obligation by $3,141,893.
- Benefit accruals in Plan A were frozen effective November 30, 2018. This decreased the benefit obligation by $6,877,541.
- The SIB benefit was eliminated effective November 30, 2018. This decreased the benefit obligation by $1,475,277.
- The plan's assets earned a return of -$21,202,485, which generated an asset loss and increased the unfunded obligation by $65,613,392.
- Finally, we incorporated new census data in our valuation. This decreased the benefit obligation by $680,833.

Details of the disclosure information are shown in Appendix A. The estimated net periodic benefit cost information is shown in Appendix B. The development of the market-related value of assets is shown in Appendix C. The remeasurement of the 2018 net periodic benefit cost for Plan A is shown in Appendix D.

Please refer to the remainder of the report for more information about these summary numbers.

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Data, assumptions, methods and provisions

This report is based on the participant data, assumptions, methods and provisions summarized in the reports titled *Retirement Plan Data, Assumptions, Methods and Provisions as of January 1, 2018*, dated September 2018 for Plans A, B and C (DAMP reports) and incorporated herein by reference, except as follows:

- Assumptions:
  - The discount rate was updated from 3.86% for Plan A, 3.96% for Plan B and 3.81% for Plan C as of December 31, 2017 to 4.39% for Plan A and Plan C and 4.53% for Plan B as of December 31, 2018.
  - The mortality improvement projection scale was updated from scale MMP-2016 to scale MMP-2018. The MMP-2018 projection scale is based on the same historical data as the SOA's MP-2018 projection scale but uses an alternative forecasting methodology.
- Provisions:
  - Final average earnings were frozen effective November 30, 2018, resulting in a complete hard-freeze of benefits in Plan A.
  - The SIB death benefit was eliminated from Plan A prospectively effective November 30, 2018. Beginning December 1, 2018, the Qualified Preretirement Spouse's Annuity will be paid to spouses of active participants that pass away before retirement
  - Plan A and Plan C merged effective December 31, 2018.

Authorized users of this report should contact Mercer to request a copy of the above reports, if they do not already have the reports, in order to understand all aspects of the calculations that are incorporated by reference.

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Important notices

Mercer has prepared this report exclusively for ALLETE, Inc. and Affiliated Companies (ALLETE); subject to this limitation, ALLETE may direct that this report be provided to its auditors in connection with the audit of its financial statements. Mercer is not responsible for use of this report by any other party.

The only purposes of this report are to present actuarial estimates of liabilities as of December 31, 2018 for Plan A, Plan B and Plan C for ALLETE to incorporate, as ALLETE deems appropriate, in its financial statements under US accounting standards, to provide details of the remeasurement of Plan A's net periodic benefit cost for fiscal year ending December 31, 2018, and to provide an actuarial estimate of the net periodic benefit cost for the fiscal year ending December 31, 2019 for Plan A, Plan B and Plan C.

This report may not be used for any other purpose. Mercer is not responsible for the consequences of any unauthorized use. Its content may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission.

This report was prepared in accordance with generally accepted actuarial principles and procedures. The actuarial assumptions were selected by ALLETE. Based on the information provided to us, we believe that the actuarial assumptions are reasonable for the purposes described in this report.

All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents; no part may be taken out of context, used or relied upon without reference to the report as a whole.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security and/or benefit-related issues should not be made solely on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic and societal factors, including financial scenarios that assume future sustained investment losses.

ALLETE is ultimately responsible for selecting the plan's accounting policies, methods and assumptions. This information is referenced or described in Section 2 of this report. ALLETE is solely responsible for communicating to Mercer any changes required to those policies, methods and assumptions.

ALLETE is solely responsible for selecting the plan's investment policies, asset allocations and individual investments. The Mercer actuaries who prepared this report have not provided any investment advice to the ALLETE.

This report is based on our understanding of applicable law and regulations as of the valuation date. Mercer is not an accountant or auditor and is not responsible for the interpretation of, or compliance with, accounting standards; citations to, and descriptions of accounting standards provided in this report are for reference purposes only. As you know, Mercer is not a law firm, and this analysis is not intended to be a legal opinion. You should consider securing the advice of legal counsel with respect to any legal matters related to this document and any attachments.

ALLETE should notify Mercer promptly after receipt of this valuation report if ALLETE disagrees with anything contained herein or is aware of any information that would affect the results of this report that has not been communicated to Mercer or incorporated therein. The valuation report will be deemed final and acceptable to ALLETE unless ALLETE promptly provides such notice to Mercer.

Professional Qualifications

I am available to answer any questions on the material contained in this report, or to provide explanations or further details as may be appropriate. I meet the Qualification Standards of the American Academy of Actuaries to render the actuarial opinion contained in this report. I am not aware of any direct or material indirect financial interest or relationship, including investments or other services that could create a conflict of interest that would impair the objectivity of this work.

Scott Striegel

October 10, 2019

Scott Striegel, FSA, EA, MAAA **Date**

Mercer
333 South 7th Street, Suite 1400
Minneapolis, MN 55402-2427

Phone: 612 642 8600

APPENDIX A

Disclosure Information

Plan Name	Plan A		Plan B		Plan C		All Plans	
Fiscal year ending on	Dec 31, 2018	Dec 31, 2017	Dec 31, 2018	Dec 31, 2017	Dec 31, 2018	Dec 31, 2017	Dec 31, 2018	Dec 31, 2017
A. Change in benefit obligation								
1. Benefit obligation at beginning of year	$ 65,846,323	$ 51,654,626	$ 189,762,325	$ 155,614,525	$ 514,521,217	$ 514,609,190	$ 770,129,865	$ 721,878,341
2. Service cost	400,000	400,000	9,032,322	8,480,719	1,200,000	1,000,000	10,632,322	9,880,719
3. Interest cost	2,560,692	2,326,894	7,443,939	7,008,185	18,768,506	22,296,333	28,773,137	31,631,412
4. Employee contributions	-	-	-	-	-	-	-	-
5. Plan amendments	(1,475,277)	-	-	-	-	-	(1,475,277)	-
6. Plan curtailments	(6,877,541)	-	-	-	-	-	(6,877,541)	-
7. Plan settlements	-	-	-	-	-	-	-	-
8. Special termination benefits	-	-	-	-	-	-	-	-
9. a. Benefits paid from the plan	(2,711,319)	(1,190,552)	(4,427,384)	(2,882,762)	(40,885,462)	(45,414,566)	(48,024,165)	(49,487,880)
b. Direct benefit payments	-	-	-	-	-	-	-	-
10. Medicare subsidies received	-	-	-	-	-	-	-	-
11. Expenses paid	-	-	-	-	-	-	-	-
12. Taxes paid	-	-	-	-	-	-	-	-
13. Premiums paid	-	-	-	-	-	-	-	-
14. RSOP rollovers	16,637,370	7,061,380	7,207,108	5,960,500	200,273	349,575	24,044,751	13,371,455
15. Plan combinations	(69,687,205)	-	-	-	69,687,205	-	-	-
16. Actuarial loss (gain)	(4,693,043)	5,593,975	(19,252,617)	15,581,158	(28,410,552)	21,680,685	(52,356,212)	42,855,818
17. Exchange rate changes	-	-	-	-	-	-	-	-
18. Benefit obligation at end of year	$ -	$ 65,846,323	$ 189,765,693	$ 189,762,325	$ 535,081,187	$ 514,521,217	$ 724,846,880	$ 770,129,865

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ALLETE, INC.

Plan Name	**Plan A**		**Plan B**		**Plan C**		**All Plans**	
Fiscal year ending on	**Dec 31, 2018**	**Dec 31, 2017**	**Dec 31, 2018**	**Dec 31, 2017**	**Dec 31, 2018**	**Dec 31, 2017**	**Dec 31, 2018**	**Dec 31, 2017**
B. Change in plan assets								
1. Fair value of plan assets at beginning of year	$ 39,459,637	$ 24,386,137	$ 97,962,227	$ 70,168,895	$ 490,765,851	$ 462,984,300	$ 628,187,715	$ 557,539,332
2. Actual return on plan assets	(1,751,146)	4,822,072	(3,947,343)	13,930,469	(15,503,996)	72,846,542	(21,202,485)	91,599,083
3. a. Employer contributions to plan	1,500,000	4,380,600	13,500,000	10,785,125	-	-	15,000,000	15,165,725
b. Employer direct benefit payments	-	-	-	-	-	-	-	-
4. Employee contributions	-	-	-	-	-	-	-	-
5. Plan settlements	-	-	-	-	-	-	-	-
6. a. Benefits paid from the plan	(2,711,319)	(1,190,552)	(4,427,384)	(2,882,762)	(40,885,462)	(45,414,566)	(48,024,165)	(49,487,880)
b. Direct benefit payments	-	-	-	-	-	-	-	-
7. Medicare subsidies received	-	-	-	-	-	-	-	-
8. Expenses paid	-	-	-	-	-	-	-	-
9. Taxes paid	-	-	-	-	-	-	-	-
10. Premiums paid	-	-	-	-	-	-	-	-
11. RSOP rollovers	16,637,370	7,061,380	7,207,108	5,960,500	200,273	349,575	24,044,751	13,371,455
12. Plan combinations	(53,134,542)	-	-	-	53,134,542	-	-	-
13. Adjustments	-	-	-	-	-	-	-	-
14. Exchange rate changes	-	-	-	-	-	-	-	-
15. Fair value of plan assets at end of year	$ -	$ 39,459,637	$ 110,294,608	$ 97,962,227	$ 487,711,208	$ 490,765,851	$ 598,005,816	$ 628,187,715
C. Reconciliation of funded status								
1. Fair value of plan assets	$ -	$ 39,459,637	$ 110,294,608	$ 97,962,227	$ 487,711,208	$ 490,765,851	$ 598,005,816	$ 628,187,715
2. Benefit obligations	-	65,846,323	189,765,693	189,762,325	535,081,187	514,521,217	724,846,880	770,129,865
3. Funded status (plan assets less benefit obligations)	$ -	$ (26,386,686)	$ (79,471,085)	$ (91,800,098)	$ (47,369,979)	$ (23,755,366)	$ (126,841,064)	$ (141,942,150)
4. Contributions and distributions made by company from measurement date to fiscal year end	-	-	-	-	-	-	-	-
5. Net amount [asset (obligation)] recognized in statement of financial position	$ -	$ (26,386,686)	$ (79,471,085)	$ (91,800,098)	$ (47,369,979)	$ (23,755,366)	$ (126,841,064)	$ (141,942,150)
D. Amounts recognized on the consolidated balance sheet position consists of								
1. Noncurrent assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2. Current liabilities	-	-	-	-	-	-	-	-
3. Noncurrent liabilities	-	(26,386,686)	(79,471,085)	(91,800,098)	(47,369,979)	(23,755,366)	(126,841,064)	(141,942,150)
4. Net amount [asset (obligation)] recognized in statement of financial position	$ -	$ (26,386,686)	$ (79,471,085)	$ (91,800,098)	$ (47,369,979)	$ (23,755,366)	$ (126,841,064)	$ (141,942,150)

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ALLETE, INC.

Plan Name	Plan A		Plan B		Plan C		All Plans	
Fiscal year ending on	Dec 31, 2018	Dec 31, 2017	Dec 31, 2018	Dec 31, 2017	Dec 31, 2018	Dec 31, 2017	Dec 31, 2018	Dec 31, 2017
E. Reconciliation of amounts recognized in statement of financial position								
1. Initial net asset(obligation)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2. Prior service credit (cost)	-	-	-	-	1,400,768	-	1,400,768	-
3. Net gain (loss)	-	(18,054,832)	(40,519,341)	(51,011,027)	(183,419,729)	(159,163,936)	(223,939,070)	(228,229,795)
4. Accumulated other comprehensive income (loss)	$ -	$ (18,054,832)	$ (40,519,341)	$ (51,011,027)	$ (182,018,961)	$ (159,163,936)	$ (222,538,302)	$ (228,229,795)
5. Accumulated contributions in excess of net periodic benefit cost	-	(8,331,854)	(38,951,744)	(40,789,071)	134,648,982	135,408,570	95,697,238	86,287,645
6. Net amount [surplus (deficit)] recognized in statement of financial position	$ -	$ (26,386,686)	$ (79,471,085)	$ (91,800,098)	$ (47,369,979)	$ (23,755,366)	$ (126,841,064)	$ (141,942,150)
F. Components of net periodic benefit cost								
1. Service cost	$ 400,000	$ 400,000	$ 9,032,322	$ 8,480,719	$ 1,200,000	$ 1,000,000	$ 10,632,322	$ 9,880,719
2. Interest cost	2,560,692	2,326,894	7,443,939	7,008,185	18,768,506	22,296,333	28,773,137	31,631,412
3. Expected return on plan assets	(3,056,193)	(2,089,999)	(7,796,785)	(6,121,915)	(33,557,929)	(34,191,933)	(44,410,907)	(42,403,847)
4. Amortization of initial net obligation (asset)	-	-	-	-	-	-	-	-
5. Amortization of prior service cost	(74,509)	-	-	-	-	-	(74,509)	-
6. Amortization of net (gain) loss	809,258	1,055,516	2,983,197	2,226,716	6,877,909	5,986,320	10,670,364	9,268,552
7. Curtailment (gain) / loss recognized	-	-	-	-	-	-	-	-
8. Settlement (gain) / loss recognized	-	-	-	-	-	-	-	-
9. Special termination benefit recognized	-	-	-	-	-	-	-	-
10. Net periodic benefit cost	$ 639,248	$ 1,692,411	$ 11,662,673	$ 11,593,705	$ (6,711,514)	$ (4,909,280)	$ 5,590,407	$ 8,376,836

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ALLETE, INC.

Plan Name	**Plan A**		**Plan B**		**Plan C**		**All Plans**	
Fiscal year ending on	**Dec 31, 2018**	**Dec 31, 2017**	**Dec 31, 2018**	**Dec 31, 2017**	**Dec 31, 2018**	**Dec 31, 2017**	**Dec 31, 2018**	**Dec 31, 2017**
G. Changes recognized in other comprehensive income								
Changes in plan assets and benefit obligations recognized in other comprehensive income								
1. New prior service cost	$ (1,475,277)	$ -	$ -	$ -	$ -	$ -	$ (1,475,277)	$ -
2. Net loss (gain) arising during the year (includes curtailment gains not recognized as a component of net period cost)	(6,763,245)	2,861,902	(7,508,489)	7,772,604	20,651,373	(16,973,924)	6,379,639	(6,339,418)
3. Effect of exchange rates on amounts included in AOCI	-	-	-	-	-	-	-	-
Amounts recognized as a component of net periodic benefit cost								
4. Amortization, settlement or curtailment recognition of net transition asset (obligation)	-	-	-	-	-	-	-	-
5. Amortization or curtailment recognition of prior service credit (cost)	74,509	-	-	-	-	-	74,509	-
6. Amortization or settlement recognition of net gain (loss)	(809,258)	(1,055,516)	(2,983,197)	(2,226,716)	(6,877,909)	(5,986,320)	(10,670,364)	(9,268,552)
7. Total recognized in other comprehensive loss (income)	$ (8,973,271)	$ 1,806,386	$ (10,491,686)	$ 5,545,888	$ 13,773,464	$ (22,960,244)	$ (5,691,493)	$ (15,607,970)
8. Total recognized in net periodic benefit and other comprehensive loss (income)	$ (8,334,023)	$ 3,498,797	$ 1,170,987	$ 17,139,593	$ 7,061,950	$ (27,869,524)	$ (101,086)	$ (7,231,134)
Estimated amounts that will be amortized from accumulated other comprehensive income over the next fiscal year								
9. Initial net asset (obligation)	$ -		$ -		$ -		$ -	
10. Prior service credit (cost)	-		-		149,018		149,018	
11. Net gain (loss)	-		(1,276,971)		(5,367,458)		(6,644,429)	
12. Total estimated to be amortized from AOCI over the next fiscal year	$ -		$ (1,276,971)		$ (5,218,440)		$ (6,495,411)	

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ALLETE, INC.

Plan Name	**Plan A**		**Plan B**		**Plan C**		**All Plans**	
Fiscal year ending on	**Dec 31, 2018**	**Dec 31, 2017**	**Dec 31, 2018**	**Dec 31, 2017**	**Dec 31, 2018**	**Dec 31, 2017**	**Dec 31, 2018**	**Dec 31, 2017**
H. Weighted-average assumptions to determine benefit obligations								
1. Discount rate	4.39%	3.86%	4.53%	3.96%	4.39%	3.81%	4.43%	3.85%
2. Rate of compensation increase	3.70%	3.70%	4.10%	4.10%	Not applicable	Not applicable	4.10%	4.00%
3. Measurement date	31-Dec-2018	31-Dec-2017	31-Dec-2018	31-Dec-2017	31-Dec-2018	31-Dec-2017	31-Dec-2018	31-Dec-2017
I. Assumptions to determine net cost								
1. Discount rate	3.86%	4.53%	3.96%	4.53%	3.81%	4.53%	3.85%	4.53%
2. Expected return on assets	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
3. Rate of compensation increase	3.70%	3.70%	4.10%	4.30%	Not applicable	Not applicable	4.00%	4.15%
J. Additional year-end information								
Required information for all defined benefit plans								
1. Accumulated benefit obligation	$ -	$ 56,844,199	$ 158,721,348	$ 153,147,699	$ 535,081,187	$ 514,521,217	$ 693,802,535	$ 724,513,115
K. Additional year-end information for plans with accumulated benefit obligations in excess of plan assets								
1. Projected benefit obligation	$ -	$ 65,846,323	$ 189,765,693	$ 189,762,325	$ 535,081,187	$ 514,521,217	$ 724,846,880	$ 770,129,865
2. Accumulated benefit obligation	-	56,844,199	158,721,348	153,147,699	535,081,187	514,521,217	693,802,535	724,513,115
3. Fair value of plan assets	-	39,459,637	110,294,608	97,962,227	487,711,208	490,765,851	598,005,816	628,187,715
L. Additional year-end information for plans with projected benefit obligations in excess of plan assets								
1. Projected benefit obligation	$ -	$ 65,846,323	$ 189,765,693	$ 189,762,325	$ 535,081,187	$ 514,521,217	$ 724,846,880	$ 770,129,865
2. Fair value of plan assets	-	39,459,637	110,294,608	97,962,227	487,711,208	490,765,851	598,005,816	628,187,715
M. Cash flows								
1. Projected company contributions for following fiscal year	$ -		$ 7,820,000		$ 2,610,000		$ 10,430,000	
2. Expected benefit payments for FYE								
31-Dec-2019 :	-		4,793,270		41,604,579		46,397,849	
31-Dec-2020 :	-		5,396,548		40,419,964		45,816,512	
31-Dec-2021 :	-		6,027,446		39,602,611		45,630,057	
31-Dec-2022 :	-		6,580,328		38,905,716		45,486,044	
31-Dec-2023 :	-		7,278,927		38,174,129		45,453,056	
Next five years	-		45,562,682		178,485,455		224,048,137	

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ALLETE, INC.

Plan Name	Plan A		Plan B		Plan C		All Plans	
Fiscal year ending on	**Dec 31, 2018**	**Dec 31, 2017**	**Dec 31, 2018**	**Dec 31, 2017**	**Dec 31, 2018**	**Dec 31, 2017**	**Dec 31, 2018**	**Dec 31, 2017**
N. Accumulated contributions in excess of net periodic benefit cost								
1. Amount as of beginning of year	$ (8,331,854)	$ (11,020,043)	$ (40,789,071)	$ (39,980,491)	$ 135,408,570	$ 130,499,290	$ 86,287,645	$ 79,498,756
2. Net periodic pension (cost) income for fiscal year	(639,248)	(1,692,411)	(11,662,673)	(11,593,705)	6,711,514	4,909,280	(5,590,407)	(8,376,836)
3. Employer contributions made in fiscal year (excludes contributions made between measurement year end and fiscal year end)	1,500,000	4,380,600	13,500,000	10,785,125	-	-	15,000,000	15,165,725
4. Benefits paid directly by company in the fiscal year (excludes contributions made between measurement year end and fiscal year end)	-	-	-	-	-	-	-	-
5. FAS 88 (expense) income	-	-	-	-	-	-	-	-
6. Other gain / (loss) recognized	-	-	-	-	-	-	-	-
7. Plan combinations	7,471,102	-	-	-	(7,471,102)	-	-	-
8. Adjustment to match local books	-	-	-	-	-	-	-	-
9. Exchange rate adjustment	-	-	-	-	-	-	-	-
10. Preliminary amount as of end of year	-	(8,331,854)	(38,951,744)	(40,789,071)	134,648,982	135,408,570	95,697,238	86,287,645
11. Contributions and direct benefit payments made between measurement date and fiscal year end	-	-	-	-	-	-	-	-
12. Amount as of end of year	$ -	$ (8,331,854)	$ (38,951,744)	$ (40,789,071)	$ 134,648,982	$ 135,408,570	$ 95,697,238	$ 86,287,645

APPENDIX B

Estimated Net Periodic Benefit Cost Information

Plan Name	Plan A	Plan B	Plan C	All Plans
Fiscal year ending on	**Dec 31, 2019**	**Dec 31, 2019**	**Dec 31, 2019**	**Dec 31, 2019**
A. Net Periodic Benefit Cost				
1. Service cost	$ -	$ 7,714,149	$ 1,600,000	$ 9,314,149
2. Interest cost	-	8,478,771	22,500,742	30,979,513
3. Expected return on plan assets	-	(8,715,846)	(35,437,077)	(44,152,923)
4. Amortization of initial net obligation (asset)	-	-	-	-
5. Amortization of prior service cost	-	-	(149,018)	(149,018)
6. Amortization of net (gain) loss	-	1,334,719	5,497,486	6,832,205
7. Curtailment (gain) / loss recognized	-	-	-	-
8. Settlement (gain) / loss recognized	-	-	-	-
9. Special termination benefit recognized	-	-	-	-
10. Net periodic benefit cost	$ -	$ 8,811,793	$ (5,987,867)	$ 2,823,926

ASC715 (US GAAP)
ACTUARIAL VALUATION REPORT AS OF DECEMBER 31, 2018

ALLETE, INC.

Plan Name	Plan A	Plan B	Plan C	All Plans
Fiscal year ending on	Dec 31, 2019	Dec 31, 2019	Dec 31, 2019	Dec 31, 2019
B. Additional Items For Net Periodic Benefit Cost Calculations				
1. Fair Value of Assets	$ -	$ 110,294,608	$ 487,711,208	$ 598,005,816
2. Market-related value of assets	-	115,820,758	510,421,833	626,242,591
3. a. Expected expenses, taxes and insurance premiums	-	500,000	1,600,000	2,100,000
b. Weighted for timing	-	500,000	1,600,000	2,100,000
4. a. Expected benefits paid from plan assets	-	4,793,270	41,604,576	46,397,846
b. Weighted for timing	-	2,596,355	22,535,812	25,132,167
5. a. Expected benefits paid by company	-	-	-	-
b. Weighted for timing	-	-	-	-
6. a. Expected employer contributions to plan assets	-	7,820,000	2,610,000	10,430,000
b. Weighted for timing	-	7,494,166	2,501,250	9,995,416
7. a. Expected employee contributions	-	-	-	-
b. Weighted for timing	-	-	-	-
8. Average future years of service	-	12.0	19.5	Not applicable

ASC715 (US GAAP)
ACTUARIAL VALUATION REPORT AS OF DECEMBER 31, 2018

ALLETE, INC.

Plan Name	**Plan A**	**Plan B**	**Plan C**	**All Plans**
Fiscal year ending on	**Dec 31, 2019**	**Dec 31, 2019**	**Dec 31, 2019**	**Dec 31, 2019**
C. Benefit Obligations and assets				
Funded Status				
1. Projected benefit obligation (PBO)	$ -	$ (189,765,693)	$ (535,081,187)	$ (724,846,880)
2. Fair value of plan assets	-	110,294,608	487,711,208	598,005,816
3. Funded status (1. + 2.)	$ -	$ (79,471,085)	$ (47,369,979)	$ (126,841,064)
Amounts to be reflected in future periods				
1. Transition obligation (asset)	$ -	$ -	$ -	$ -
2. Prior service cost (credit)	-	-	(1,400,768)	(1,400,768)
3. Net loss (gain)	-	40,519,341	183,419,729	223,939,070
4. Total not yet recognized in net periodic benefit cost (1. + 2. + 3.)	$ -	$ 40,519,341	$ 182,018,961	$ 222,538,302
Cumulative employer contributions in excess of net periodic benefit cost	$ -	$ (38,951,744)	$ 134,648,982	$ 95,697,238

ASC715 (US GAAP)
ACTUARIAL VALUATION REPORT AS OF DECEMBER 31, 2018

ALLETE, INC.

Plan Name	**Plan A**	**Plan B**	**Plan C**	**All Plans**
Fiscal year ending on	**Dec 31, 2019**	**Dec 31, 2019**	**Dec 31, 2019**	**Dec 31, 2019**
D. Amortization amounts				
1. Transition obligation (asset)				
a. Net amount as of beginning of fiscal year	$ -	$ -	$ -	$ -
b. Years remaining	-	-	-	-
c. Annual amortization	$ -	$ -	$ -	$ -
2. Prior service cost (credit) - unrecognized base amounts shown as of beginning of fiscal year				
a. (i) Total unrecognized prior service cost	$ -	$ -	$ (1,400,768)	$ (1,400,768)
(ii) Total amortization of prior service cost	-	-	(149,018)	(149,018)
3. (Gain) loss				
a. Net amount as of beginning of fiscal year	$ -	$ 40,519,341	$ 183,419,729	$ 223,939,070
b. Excess of fair value over market-related value	-	(5,526,150)	(22,710,625)	(28,236,775)
c. Net (gain) loss potentially subject to amortization (a. + b.)	-	34,993,191	160,709,104	195,702,295
d. Corridor	-	18,976,569	53,508,119	72,484,688
e. Amount subject to amortization (c. - d.)	-	16,016,622	107,200,985	123,217,607
f. Amortization period	-	12.0	19.5	Not applicable
g. Annual amortization	$ -	$ 1,334,719	$ 5,497,486	$ 6,832,205
E. Assumptions to determine net cost				
1. Discount rate to determine benefit obligation	N/A	4.53%	4.39%	4.43%
2. Expected return on assets	N/A	7.25%	7.25%	7.25%
3. Salary scale	N/A	4.10%	Not applicable	4.10%

ASC715 (US GAAP)
ACTUARIAL VALUATION REPORT AS OF DECEMBER 31, 2018

ALLETE, INC.

APPENDIX C

Development of market-related value of assets

Plan Name	**Plan A**	**Plan B**	**Plan C**	**All Plans**
Fiscal year ending on	**Dec 31, 2018**	**Dec 31, 2018**	**Dec 31, 2018**	**Dec 31, 2018**
A. Development of Market-Related Value of Assets				
1. Fair value of assets at beginning of previous fiscal year	$ 39,459,637	$ 97,962,227	$ 490,765,851	$ 628,187,715
2. Contributions during previous fiscal year	1,500,000	13,500,000	-	15,000,000
3. Distributions during previous fiscal year	(2,711,319)	(4,427,384)	(40,885,462)	(48,024,165)
4. RSOP rollovers during previous fiscal year	16,637,370	7,207,108	200,273	24,044,751
5. Administrative expenses during previous fiscal year	(291,084)	(417,454)	(1,236,363)	(1,944,901)
6. Expected return on assets at 7.50%	3,570,124	8,392,229	35,107,614	47,069,967
7. Expected market value as of Dec 31, 2018 (1. + 2. + 3. + 4. + 5. + 6.)	$ 58,164,728	$ 122,216,726	$ 483,951,913	$ 664,333,367
8. Market value of assets as of Dec 31, 2018	53,134,542	110,294,608	434,576,666	598,005,816
9. Prior year fair value gain/(loss) *(8. – 7.)*	$ (5,030,186)	$ (11,922,118)	$ (49,375,247)	$ (66,327,551)
10. Phase in of gains/(losses)				
a. Prior fiscal year gain/(loss) * 4/5	(4,024,149)	(9,537,694)	(39,500,198)	(53,062,041)
b. 2 years ago gain/(loss) * 3/5	1,685,937	4,943,936	24,732,289	31,362,162
c. 3 years ago gain/(loss) * 2/5	425,161	158,165	3,261,517	3,844,843
d. 4 years ago gain/(loss) * 1/5	(337,813)	(1,090,557)	(8,953,369)	(10,381,739)
11. Market-related value of assets at end of fiscal year (8. – 10a. – 10b. – 10c. – 10d.)	$ 55,385,406	$ 115,820,758	$ 455,036,427	$ 626,242,591
12. Plan A and Plan C Merger effective 1/1/2019	(55,385,406)	N/A	55,385,406	N/A
13. Market-related value of assets at beginning of next fiscal year (11. + 12.)	$ -	$ 115,820,758	510,421,833	626,242,591

APPENDIX D

Remeasurement of 2018 Net Periodic Benefit Cost for Plan A

Plan Name		(a) Plan A - Original Budget		(b) Plan A - Remeasured July 1, 2018		[.5 x (a) + .5 x (b)] Plan A - Final FYE 2018 Expense
Fiscal year ending on		**Dec 31, 2018**		**Jun 30, 2019**		**Dec 31, 2018**
A. Net Periodic Benefit Cost						
1. Service cost	$	400,000	$	400,000	$	400,000
2. Interest cost		2,518,701		2,602,683		2,560,692
3. Expected return on plan assets		(2,825,814)		(3,286,572)		(3,056,193)
4. Amortization of initial net obligation (asset)		-		-		-
5. Amortization of prior service cost		-		(149,018)		(74,509)
6. Amortization of net (gain) loss		1,355,923		262,593		809,258
7. Curtailment (gain) / loss recognized		-		-		-
8. Settlement (gain) / loss recognized		-		-		-
9. Special termination benefit recognized		-		-		-
10. Net periodic benefit cost	$	1,448,810	$	(170,314)	$	639,248
B. Benefit Obligations and assets						
Funded Status						
1. Projected benefit obligation (PBO)	$	(65,846,323)	$	(59,342,715)		
2. Fair value of plan assets		39,459,637		45,704,326		
3. Funded status (1. + 2.)	$	(26,386,686)	$	(13,638,389)		
Amounts to be reflected in future periods						
1. Transition obligation (asset)	$	-	$	-		
2. Prior service cost (credit)		-		(1,475,277)		
3. Net loss (gain)		18,054,832		7,557,407		
4. Total not yet recognized in net periodic benefit cost (1. + 2. + 3.)	$	18,054,832	$	6,082,130		
Cumulative employer contributions in excess of net periodic benefit cost	$	(8,331,854)	$	(7,556,259)		

ASC715 (US GAAP)
ACTUARIAL VALUATION REPORT AS OF DECEMBER 31, 2018

ALLETE, INC.

	(a)	(b)	[.5 x (a) + .5 x (b)]
Plan Name	**Plan A - Original Budget**	**Plan A - Remeasured July 1, 2018**	**Plan A - Final FYE 2018 Expense**
Fiscal year ending on	**Dec 31, 2018**	**Jun 30, 2019**	**Dec 31, 2018**
C. Remeasured Obligations and assets			
Obligations			
1. Projected benefit obligation (PBO) remeasured 7/1/2018 before changes	N/A	67,695,533	
2. Projected benefit obligation (PBO) remeasured 7/1/2018 after pay freeze	N/A	60,817,992	
3. Projected benefit obligation (PBO) remeasured 7/1/2018 after eliminating SIB benefit	N/A	59,342,715	
Assets			
1. Fair value of plan assets	39,459,637	45,704,326	
2. Market-related value of assets	37,235,010	45,338,102	
Other information			
1. Discount rate to determine benefit obligation	3.86%	4.47%	
2. Expected return on assets	7.50%	7.50%	
3. Average future working lifetime	10.1	9.9	

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Mr. Pat Cutshall
Treasurer
ALLETE
30 West Superior Street
Duluth, MN 55802-2093

October 10, 2019

Subject: Investment Returns on Pension Assets and their Impact on Pension Expense

Dear Pat,

You asked that we describe how investment earnings on pension plan assets affect pension expense. The short answer is that the investment returns reduce future years' pension expense.

The following example using ALLETE's 2020 budgeted expense for Plan B may help illustrate how excess investment returns affect pension expense. Scenario 1 shows the projected 2020 expense as detailed in Mercer's letter dated October 10, 2019. Scenario 2 shows the projected 2020 expense assuming Plan B assets return an additional $5 million in 2019.

FISCAL YEAR 2020 EXPENSE				
	SCENARIO 1		SCENARIO 2	
Service Cost	$	9,570,000	$	9,570,000
Interest Cost		8,180,000		8,180,000
Expected Return on Assets		(9,390,000)		(9,457,500)
Amortization of Prior Service Cost		-		-
Amortization of (Gain)/Loss		4,720,000		4,640,000
Total Pension Expense	$	13,080,000	$	12,932,500

The exhibit shows that the additional actual return in 2019 ($5 million) decreases the amortization of loss component of expense by $80,000 in 2020. In addition, this exhibit shows that because of the extra earnings, the asset base – on which the expected return on assets component of expense is calculated – increases, resulting in another annual credit to the expense calculation of $67,500 in 2020. As such, the total reduction in 2020 expense as a result of $5 million of excess returns is $147,500.

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A somewhat similar phenomenon occurs when a company makes extra contributions. The following exhibit repeats the information above for Scenario 1, but now adds Scenario 3 in which investment returns are the same as Scenario 1, but ALLETE makes an extra $10 million contribution to the plan on 12/31/2019.

FISCAL YEAR 2020 EXPENSE				
	SCENARIO 1		SCENARIO 2	
Service Cost	$	9,570,000	$	9,570,000
Interest Cost		8,180,000		8,180,000
Expected Return on Assets		(9,390,000)		(10,065,000)
Amortization of Prior Service Cost		-		-
Amortization of (Gain)/Loss		4,720,000		4,720,000
Total Pension Expense	$	13,080,000	$	12,405,000

This exhibit shows that by making the extra contribution, the 2020 expense drops by $675,000. Of course by making this contribution, ALLETE loses the opportunity to invest the money elsewhere. If ALLETE were to invest the money outside the pension plan and earn 6.75% (the same as the expected return in the plan), ALLETE would recognize $675,000 in other investment income rather than a $675,000 reduction in pension expense.

Pat, I hope this is helpful. Please give me a call if you have questions.

Regards,

Scott Striegel

Scott Striegel, FSA, EA, MAAA
Principal

Copy:
Tara Anderson – ALLETE

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Principal

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Mr. Pat Cutshall
Treasurer
ALLETE
30 West Superior Street
Duluth, MN 55802-2093

October 10, 2019

Subject: 2020 Expense Estimates –August 2019 Economic Update

Dear Pat:

We have calculated the estimated 2020 expense for ALLETE's Qualified Pension Plans (Plans B and C) and ALLETE's OPEB plans. A summary of the 2020 expense by plan is shown in the chart below:

	Qualified Pension Plans		
($millions)	**Plan B**	**Plan C**	**Total**
Service Cost	9.57	1.60	11.17
Interest Cost	8.18	18.25	26.43
Expected Return on Assets	(9.39)	(33.45)	(42.84)
Annual Amortization Amounts			
Transition Obligation	-	-	-
Prior Service Cost	-	(0.15)	(0.15)
(Gain)/Loss	4.72	7.73	12.45
Estimated 2020 Expense	**13.08**	**(6.02)**	**7.06**

	OPEB Plans						
	Non-Union			**Union**			
($ millions)	**Medical**	**Dental**	**Life**	**Medical**	**Dental**	**Life**	**Total**
Service Cost	1.92	0.19	-	2.31	0.21	0.11	4.74
Interest Cost	2.77	0.32	0.42	2.30	0.25	0.34	6.40
Expected Return on Assets	(3.69)	(0.39)	(0.34)	(4.29)	(0.50)	(0.51)	(9.72)
Annual Amortization Amounts							
Transition Obligation	-	-	-	-	-	-	-
Prior Service Cost	(0.14)	-	(0.42)	(0.24)	-	(0.40)	(1.20)
(Gain)/Loss	1.21	-	0.35	1.46	0.03	0.40	3.45
Estimated 2020 Expense	**2.07**	**0.12**	**0.01**	**1.54**	**(0.01)**	**(0.06)**	**3.67**

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Aside from the exceptions noted in this letter, the data, assumptions, methods and plan provisions used to estimate the 2020 expense are summarized in the following reports ("2018 disclosure reports"):

- *ALLETE and Affiliated Companies Qualified Retirement Plans ASC 715 (US GAAP) Actuarial Valuation Report as of December 31, 2018 - Revised* dated October 10, 2019
- *ALLETE, Inc. and Affiliated Companies Postretirement Welfare Plans ASC 715 (US GAAP) Actuarial Valuation Report as of December 31, 2018* – dated January 30, 2019

Updated census data was updated for the following plans:

- Data was updated for Retirement Plan B as of January 1, 2019, as detailed in the report titled *ALLETE, and Affiliated Companies Retirement Plan B Data, Assumptions, Methods, and Provisions as of January 1, 2019*, dated March 29, 2019.

Results were rolled forward to December 31, 2019 in order to estimate the 2020 expense. Our estimates of the 2020 expense also include the following assumptions:

- Discount rate of 3.25%, based on the Mercer Yield Curve as of August 27, 2019, plus a spread for a sample mature plan to reflect the higher yield that would have been produced by the Mercer Bond Model, had it been used.
- Asset values as of July 31, 2019 were projected to December 31, 2019 using the 2019 long-term rate of return assumption of 7.25%, prorated for five months.
- The long-term rate of return used to determine the 2019 expense is 6.75%.
- Administrative expenses for the qualified pension plans are assumed to be $2.1 million in 2019, allocated $0.5 million to Plan B and $1.6 million to Plan C. The administrative expense assumption is equal to historical non-PBGC administrative expenses, plus the expected PBGC premiums payable in 2020.
- Contributions made during 2019 and 2020 can significantly impact the 2020 expense. We have assumed no additional contributions will be made in 2019, and a contribution of $12.6 million will be made to Plan B in mid-January 2020. No contributions are expected to be made to Plan C or the OPEB plans 2020.

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Important notices

Mercer has prepared this letter exclusively for ALLETE. Mercer is not responsible for use of this letter by any other party.

Mercer has prepared this letter to provide an actuarial estimate of the net periodic benefit cost for the qualified pension plans and OPEB plans for the fiscal year ending December 31, 2020. This letter may not be used for any other purpose. Mercer is not responsible for the consequences of any unauthorized use. Its content may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission.

All parts of this letter, including any documents incorporated by reference, are integral to understanding and explaining its contents, no part may be taken out of context, used or relied upon without reference to the letter as a whole. Unless noted otherwise, this report is based on the participant data, assumptions, methods and provisions summarized in the 2018 disclosure reports listed above. These documents are incorporated herein by reference.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security and/or benefit-related issues should not be made on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic and societal factors, including financial scenarios that assume future sustained investment losses.

The plan sponsor is ultimately responsible for selecting the plan's accounting policies, methods and assumptions. The policies, methods, and assumptions used in this valuation are detailed in the 2018 disclosure reports, referenced above. The plan sponsor is solely responsible for communicating to Mercer any changes required to those policies, methods and assumptions.

This letter was prepared in accordance with generally accepted actuarial principles and procedures. The results reported herein are based on the assumptions and methods detailed in the 2018 disclosure reports referenced above, with exceptions noted in this letter. The actuarial assumptions were selected by the company. Based on the information provided to us, we believe that the actuarial assumptions are reasonable for the purposes described in this letter.

This letter is based on our understanding of applicable law and regulations as of the valuation date. Mercer is not an accountant or auditor and is not responsible for the interpretation of, or compliance with, accounting standards; citations to, and descriptions of accounting standards provided in this letter are for reference purposes only. As you know, Mercer is not a law firm, and

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this analysis is not intended to be a legal opinion. You should consider securing the advice of legal counsel with respect to any legal matters related to this document and any attachments.

ALLETE is solely responsible for selecting the plan's investment policies, asset allocations and individual investments. The Mercer actuaries who prepared this report have not provided any investment advice to ALLETE.

We used financial data submitted by the trustees as of December 31, 2018 and July 31, 2019 without further audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and general reasonableness.

ALLETE should notify Mercer promptly after receipt of this letter ALLETE disagrees with anything contained in the letter or is aware of any information that would affect the results shown in this letter that has not been communicated to Mercer or incorporated herein.

Professional qualifications

I am available to answer any questions on the material contained in the letter, or to provide explanations or further details as may be appropriate. I meet the Qualification Standards of the American Academy of Actuaries to render the actuarial opinion contained in this letter. I am not aware of any direct or material indirect financial interest or relationship, including investments or other services that could create a conflict of interest, that would impair the objectivity of this work.

Sincerely,

Scott Striegel

Scott Striegel, FSA, EA, MAAA
Principal

Copy:
Steve Morris, Tara Anderson – ALLETE
Emily Shakked – Mercer

Mercer Standard Percentile Approach

Asset Allocation of Portfolio

Specified By Consultant

Name of Client: ALLETE - OPEB

Analyst: SS

Domestic Equity	Percentage Allocation
Domestic Equity-All Cap	0.0%
Domestic Equity-Large Cap	18.0%
Domestic Equity-Mid Cap	14.0%
Domestic Equity-Small Cap	7.0%
Domestic Equity-Micro Cap	0.0%
Company Stock-Large	0.0%
Company Stock-Small	0.0%
Defensive Equity	0.0%
International Equity	
International Equity-Unhedged	0.0%
International Equity-Hedged	0.0%
International Eq-Emerging Mkts	10.0%
International Eq-Small Cap	0.0%
Global Equity x-U.S. - All Cap	13.0%
Global Equity x-U.S. - Large Cap	0.0%
Global Equity	0.0%
Global Small Cap	0.0%
Global Defensive Equity - Unhedged	0.0%
Fixed Income	
Fixed Income-Aggregate	0.0%
Fixed Income-Gov/Credit	0.0%
Fixed Income-Gov/Credit (Downgrade Tolerant)	0.0%
Fixed Income-Short Gov/Corp	0.0%
Fixed Income-Intermediate Gov/Corp	35.0%
Fixed Income-Long Gov/Corp	0.0%
Fixed Income-Long Gov/Corp (Downgrade Tolerant)	0.0%
Fixed Income-Intermediate Government	0.0%
Fixed Income-Government	0.0%
Fixed Income-Long Gov	0.0%
Fixed Income-Very Long Gov	0.0%
Fixed Income-Intermediate Credit	0.0%
Fixed Income-Credit	0.0%
Fixed Income-Credit (Downgrade Tolerant)	0.0%
Fixed Income-Long Credit	0.0%
Fixed Income-Long Credit (Downgrade Tolerant)	0.0%
Fixed Income-Mortgages	0.0%
Fixed Income-High Yield	0.0%
Fixed Income-Muni Bonds	0.0%
Inflation-Indexed Bonds	0.0%
Cash	0.0%
Convertibles	0.0%
GICs	0.0%
Private Debt	0.0%
Multi-Asset Credit	0.0%
International FixInc-Unhedged	0.0%
International FixInc-Hedged	0.0%
Broad International-Unhedged	0.0%
Emerging Market Debt	0.0%
Alternatives	
Real Estate - Core	0.0%
Real Estate - REITS	0.0%
Private Equity	3.0%
Hedge Funds - Conservative (Mkt Neutral prior to 7/1/2006)	0.0%
Hedge Funds - Moderate	0.0%
Hedge Funds - Mod/Aggressive (Aggressive prior to 7/1/2006)	0.0%
Idosyncratic Multi-Asset	0.0%
Commodities	0.0%
TOTAL	100.0%

Mercer Standard Percentile Approach

Asset Class Return Assumptions

Project File: C:\Users\...\2019 PRC - MINPOW OPEB.mpc
Name of Client: ALLETE - OPEB
Source of Return Data: Mercer Investment Consulting
Date of Return Data: January 2019
Annual Expense: 0.11%
Analyst: SS

	Compound Annual Returns	Annual Arithmetic Returns	Standard Deviation of Annual Returns
Domestic Equity			
Domestic Equity-All Cap	6.45%	7.99%	18.4%
Domestic Equity-Large Cap	6.40%	7.88%	18.0%
Domestic Equity-Mid Cap	6.71%	8.45%	19.6%
Domestic Equity-Small Cap	6.84%	9.02%	22.2%
Domestic Equity-Micro Cap	7.00%	9.50%	23.8%
Company Stock-Large	4.56%	7.88%	27.4%
Company Stock-Small	2.44%	9.02%	39.7%
Defensive Equity	6.43%	7.30%	13.7%
International Equity			
International Equity-Unhedged	7.37%	9.22%	20.4%
International Equity-Hedged	7.62%	9.14%	18.4%
International Eq-Emerging Mkts	8.86%	11.88%	26.5%
International Eq-Small Cap	7.72%	9.94%	22.4%
Global Equity x-U.S. - All Cap	7.76%	9.68%	20.8%
Global Equity x-U.S. - Large Cap	7.69%	9.58%	20.6%
Global Equity	7.33%	8.87%	18.5%
Global Small Cap	7.67%	9.63%	21.0%
Global Defensive Equity - Unhedged	6.89%	7.70%	13.2%
Fixed Income			
Fixed Income-Aggregate	3.76%	3.89%	5.3%
Fixed Income-Gov/Credit	3.63%	3.77%	5.4%
Fixed Income-Gov/Credit (Downgrade Tolerant)	3.72%	3.86%	5.4%
Fixed Income-Short Gov/Corp	3.59%	3.69%	4.5%
Fixed Income-Intermediate Gov/Corp	3.66%	3.78%	5.0%
Fixed Income-Long Gov/Corp	3.54%	3.98%	9.6%
Fixed Income-Long Gov/Corp (Downgrade Tolerant)	3.75%	4.20%	9.7%
Fixed Income-Intermediate Government	3.35%	3.45%	4.5%
Fixed Income-Government	3.29%	3.42%	5.2%
Fixed Income-Long Gov	3.01%	3.80%	12.9%
Fixed Income-Very Long Gov	2.53%	4.07%	18.1%
Fixed Income-Intermediate Credit	4.25%	4.42%	6.0%
Fixed Income-Credit	4.18%	4.40%	6.9%
Fixed Income-Credit (Downgrade Tolerant)	4.41%	4.63%	6.8%
Fixed Income-Long Credit	4.01%	4.49%	10.1%
Fixed Income-Long Credit (Downgrade Tolerant)	4.37%	4.84%	9.9%
Fixed Income-Mortgages	3.67%	3.82%	5.6%
Fixed Income-High Yield	5.79%	6.26%	10.0%
Fixed Income-Muni Bonds	3.61%	3.80%	6.3%
Inflation-Indexed Bonds	3.43%	3.58%	5.6%
Cash	2.88%	2.90%	2.0%
Convertibles	5.54%	5.96%	9.5%
GICs	3.67%	3.74%	3.5%
Private Debt	6.57%	7.07%	10.3%
Multi-Asset Credit	5.74%	5.99%	7.3%
International FixInc-Unhedged	2.05%	2.55%	10.2%
International FixInc-Hedged	2.66%	2.89%	6.9%
Broad International-Unhedged	2.29%	2.75%	9.8%
Emerging Market Debt	5.74%	6.37%	11.6%
Alternatives			
Real Estate - Core	6.86%	7.98%	15.7%
Real Estate - REITS	6.16%	8.20%	21.3%
Private Equity	9.38%	11.95%	24.4%
Hedge Funds - Conservative (Mkt Neutral prior to 7/1/2006)	5.54%	5.71%	6.0%
Hedge Funds - Moderate	6.23%	6.54%	8.2%
Hedge Funds - Mod/Aggressive (Aggressive prior to 7/1/2006)	6.91%	7.44%	10.7%
Idosyncratic Multi-Asset	5.77%	6.10%	8.3%
Commodities	3.20%	4.60%	17.3%
Inflation	2.19%	2.20%	1.7%
PORTFOLIO - Gross	6.60%	7.36%	12.8%
PORTFOLIO - Net of Expense	6.49%	7.25%	12.8%

Note: Compound Returns reflect expected volatility and are, therefore, less than simple Arithmetic Average Returns.

Example: If Year 1 Return = 5% and Year 2 Return = 15%, then Annual Arithmetic Return = 10.00% and Compound Annual Return = 9.88%

Mercer Standard Percentile Approach

Range of Net Portfolio Returns

Annual Returns are Net of Expenses

Project File: C:\Users\...\2019 PRC - MINPOW OPEB.mpc
Name of Client: ALLETE - OPEB
Source of Return Data: Mercer Investment Consulting
Date of Return Data: January 2019
Annual Expense: 0.11%
Analyst: SS

Percentiles	Projection Horizon (years): 20
5%	1.77%
10%	2.81%
15%	3.51%
20%	4.07%
25%	**4.55%**
30%	**4.98%**
35%	**5.38%**
40%	**5.76%**
45%	**6.13%**
50%	**6.49%**
55%	**6.85%**
60%	**7.22%**
65%	**7.60%**
70%	**8.00%**
75%	**8.43%**
80%	8.91%
85%	9.47%
90%	10.17%
95%	11.21%

pwc

February 14, 2019

ALLETE, Inc.
30 West Superior Street
Duluth, MN 55802

Enclosed is our manually signed report dated February 14, 2019 for use in the Annual Report on Form 10-K relating to the financial statements, financial statement schedule, and the effectiveness of internal control over financial reporting of ALLETE, Inc. (the "Company"). Also enclosed is our manually signed consent relating to the incorporation by reference in the Registration Statements on Form S-3 and S-8 of our report.

Our manually signed report and consent serves to authorize the use of our name on our report and consent in the electronic filing of the Company's Annual Report on Form 10-K with the SEC.

Very truly yours,

PricewaterhouseCoopers LLP

pwc

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of ALLETE, Inc.:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of ALLETE, Inc. and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of income, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2018, including the related notes and schedule of valuation and qualifying accounts and reserves for each of the three years in the period ended December 31, 2018 appearing under Item 15(a)(2) (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
February 14, 2019

We have served as the Company's auditor since 1963.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-212794, 333-211075) and Form S-8 (Nos. 333-162890, 333-183051, 333-190336, 333-207846, 333-228120) of ALLETE, Inc. of our report dated February 14, 2019, relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
February 14, 2019