

Direct Testimony and Schedules
Brian J. Van Abel

Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. E002/GR-15-826
Exhibit____(BVA-1)

**Capital Structure, Overall Rate of Return
And Investor Relations**

November 2, 2015

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Brian J. Van Abel. I am Vice President and Treasurer of Xcel Energy Inc. (Xcel or XEI) as well as Northern States Power Company-Minnesota (NSPM or the Company).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have five years of experience in corporate finance. In my current role I am responsible for recommending and implementing the financing required to achieve target capital structure objectives at each of the regulated utility operating companies and at the holding company. I am also responsible for corporate cash management, pension plan management, hazard risk insurance, and treasury forecasting. Exhibit____(BVA-1), Schedule 1 summarizes my qualifications.

Q. PLEASE STATE THE PURPOSE OF YOUR TESTIMONY.

A. In my testimony, I will:

- Demonstrate the reasonableness of the Company's capital structure and costs of Long-Term debt (LTD), Short-Term debt (STD) and the overall Rate of Return (ROR) for 2016, 2017, and 2018 in the context of Commission standards and the current environment.
- Discuss how constructive regulatory policy, including an overall return on equity (ROE) that will allow the Company to achieve reasonable earnings levels and regulatory stability and predictability, is important for the Company to attract capital at competitive rates, and to provide customers with service at a fair and reasonable cost.

- Discuss how NSPM's current credit ratings and resulting access to debt capital markets at low cost provide long-term benefits to customers and support the Company's capital investment plan.
- Explain the financial impacts of the Company's significant infrastructure investment plan in this rate case and how the Company's multi-year rate plan request can reduce the frequency of rate case filings, while still supporting these substantial investments.
- Provide updated responses to information requests from the Company's last rate case.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present my testimony in the following sections:

- Section II provides a Summary and Overview of NSPM's proposed Capital Structure, Cost of Debt, and ROR, and the Company's investor relations costs for the time period covered by this rate case.
- Section III identifies the Commission's standards for review of capital structure and explains the purpose of, and how the Company determines, the capital structure.
- Section IV describes the Company's historic and planned financing and investment activities, explains the importance of the regulatory environment to the credit rating agencies' and investors' perceptions of the regulatory risk and to the Company's ability to carry out its capital expenditure plans. This section also includes a discussion of the credit rating agencies' criteria and NSPM's current credit ratings and financial metrics.
- Section V provides a detailed description of the components of NSPM's capital structure and costs of LTD and STD for 2016, 2017

1 and 2018.

- 2 • Section VI provides certain compliance information.
- 3 • Section VII includes a Summary and Recommendations.

4
5 Q. DO YOU PROVIDE ANY ADDITIONAL INFORMATION RELATED TO CAPITAL
6 STRUCTURE AND COMPANY DEBT BEYOND THAT PROVIDED IN YOUR
7 TESTIMONY AND SCHEDULES?

8 A. Yes. To prepare testimony for this case, I reviewed the discovery that the
9 Company provided in the most recent rate case. I incorporated some of this
10 discovery into my testimony through expanded discussion and schedules.
11 Appendix A provides a list of relevant information requests from the 12-961
12 and 13-868 rate cases that I have already responded to in this case (with new
13 time frames as appropriate to reflect the November 2, 2015 filing date of this
14 case), indicating where the responsive information is included in my testimony
15 or schedules, or if it is provided in Appendix A.

16 17 II. SUMMARY AND OVERVIEW

18
19 Q. WHAT DO YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY?

20 A. In this section I provide an overview of the Company's recommended capital
21 structure for 2016, 2017 and 2018. I summarize the importance of NSPM's
22 financial strength and the resulting long-term benefits that strength provides
23 to ratepayers. Finally, I discuss the importance of decisions by the
24 Commission to investors' perceptions of NSPM's regulatory risk and to its
25 cost of capital and cost of service.

1 Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED CAPITAL STRUCTURE, COSTS
2 OF DEBT AND EQUITY, AND ROR FOR 2016, 2017 AND 2018.

3 A. The Company's proposed capital structure for the 2016 test year, including
4 costs of STD, LTD, Common Equity are included on Exhibit____(BVA-1),
5 Schedule 2, Page 1 of 3, and can be summarized as follows:

6
7 **Table 1**
8 **2016 Test Year**
9 **Recommended Capital Structure Ratios and Costs (NSPM)**

	Percent of Total Capital	Cost	Weighted Cost
Short-Term Debt	1.26%	1.84%	0.02%
Long-Term Debt	46.24%	4.81%	2.22%
Common Equity	52.50%	10.00%	5.25%
Total Capital	100.00%		7.49%

14
15 As shown in Table 1 above, the Company's capital structure and associated
16 costs of capital result in an overall ROR of 7.49 percent for the 2016 test year.

17
18 The Company's proposed capital structure for the 2017 plan year is included
19 In Exhibit____(BVA-1), Schedule 2, Page 2 of 3, and can be summarized as
20 follows:

21 **Table 2**
22 **2017**
23 **Recommended Capital Structure Ratios and Costs (NSPM)**

	Percent of Total Capital	Cost	Weighted Cost
Short-Term Debt	1.46%	3.57%	0.05%
Long-Term Debt	46.04%	4.81%	2.21%
Common Equity	52.50%	10.00%	5.25%
Total Capital	100.00%		7.51%

1 The Company's proposed capital structure for the 2018 plan year is included
2 on Exhibit___(BVA-1), Schedule 2, Page 3 of 3, and can be summarized as
3 follows:

4
5 **Table 3**
6 **2018**
7 **Recommended Capital Structure Ratios and Costs (NSPM)**

	Percent of Total Capital	Cost	Weighted Cost
Short-Term Debt	1.09%	4.45%	0.05%
Long-Term Debt	46.41%	4.77%	2.21%
Common Equity	52.50%	10.00%	5.25%
Total Capital	100.00%		7.51%

12
13 Q. HOW DO THE RECOMMENDED RORS OF 7.49 PERCENT IN 2016 AND 7.51
14 PERCENT IN 2017 AND 2018 COMPARE TO THE LAST AUTHORIZED RETURN?

15 A. The Company's recommended RORs are similar to the most recent
16 authorized ROR in Docket No. E002/GR-13-868 of 7.34 percent. As I
17 discuss below, and as Company witness Mr. James M. Coyne discusses
18 regarding the cost of common equity, the Company's recommended RORs
19 for 2016, 2017 and 2018 are reasonable. The cost of long-term debt has
20 declined from 4.90 percent to our recommended 4.81 percent in 2016 and
21 2017, and 4.77 percent in 2018. The recommended ROE of 10.0 percent as
22 supported in the Direct Testimony of Mr. Coyne provides a reasonable return
23 and supports NSPM's financial integrity.

24
25 Q. HOW DOES THE RECOMMENDED CAPITAL STRUCTURE OF 52.50 PERCENT
26 EQUITY COMPARE TO THE LAST AUTHORIZED CAPITAL STRUCTURE?

27 A. The Company's recommended capital structure of 52.50 percent equity for the

1 2016 test year and for the 2017 and 2018 plan years is in line with the 52.50
2 percent equity ratio authorized by the Commission in the last rate case
3 (Docket No. E002/GR-13-868), in the Commission's May 8, 2015 Order in
4 that case. Moreover, the Company's authorized equity ratio has ranged
5 between 52.47 percent and 52.56 percent over the last four electric general
6 rate case proceedings dating back to 2009. In each of those contested cases,
7 the Commission has agreed with the reasonableness of the Company's
8 proposed capital structure. The Company has been consistent and transparent
9 in managing its capital structure to ensure the Company's financial health, and
10 is following those same principles in this proceeding.

11
12 Q. DO CUSTOMERS BENEFIT FROM NSPM'S FINANCIAL HEALTH?

13 A. Yes. The Company's financial health delivers benefits to our customers in
14 several ways:

- 15 • It enables the Company to maintain its credit ratings, which results in
16 lower borrowing costs that are directly passed on to customers.
- 17 • It enables the Company to support the significant investments in utility
18 infrastructure discussed by other witnesses. As I will explain further in
19 my Direct Testimony, from 2005 through 2014 the Company invested
20 approximately \$10.1 billion. We expect to continue making significant
21 investments in Minnesota, with additional capital expenditures
22 averaging approximately \$1.2 billion per year from 2015 through 2019,
23 with the largest amount occurring in 2015. These capital expenditures
24 are needed to meet reliability standards and other compliance
25 requirements, invest in renewable energy resources and to further
26 develop the infrastructure necessary to serve the Company's customers.
27 Additionally, our early action to achieve renewable energy goals, as

described in our Integrated Resource Plan, would increase expenditures in the coming five years above our current plan.

Q. WHY ARE THE COMMISSION'S DECISIONS REGARDING NSPM'S COST OF DEBT, CAPITAL STRUCTURE, AND ROE IMPORTANT TO INVESTORS' PERCEPTIONS?

A. As I will discuss in Section IV of my Direct Testimony, both debt and equity investors know that: (i) Minnesota is NSPM's primary regulatory jurisdiction; (ii) NSPM's electric business is predominant; and (iii) NSPM continues to be engaged in a necessary and substantial capital expenditure program. Since regulatory climate is one of the principle investment risk factors for a regulated utility, the Commission's rate case decisions are of particular importance to the debt and equity investors. Investors and credit rating agencies look for stability and predictability in a regulatory environment – unpredictability and instability drive additional risk into a company and can lead to higher costs of capital for both debt and equity.

Q. CAN YOU PLEASE ALSO DISCUSS THE COMPANY'S INVESTOR RELATIONS EFFORTS AND THE EXPENSES YOU EXPECT TO INCUR IN THE 2016 TEST YEAR?

A. We expect to incur investor relations expenses in 2016 keeping the credit rating agencies fully informed regarding NSPM's business and financing plans and creating strong investor demand for NSPM's LTD securities. These efforts will enable NSPM to issue LTD securities at favorable costs, as evidenced by NSPM's very low cost of LTD. Additionally, the investor relations group will continue to support the Company's equity program, and customers receive the benefit of improved proceeds as a result of obtaining favorable prices from the issuance of stock.

1 Q. ARE THESE DISCRETIONARY EXPENSES?

2 A. No. A company with publicly-traded equity must engage in investor relations
3 activities, including but not limited to: (i) the listing of shares of XEI on the
4 New York Stock Exchange; (ii) stock transfer agent services associated with
5 the issuance of new common shares to investors, providing shareholders
6 online access to accounts, and maintaining the list of registered shareholders;
7 and (iii) an annual shareholders meeting.

8
9 Q. IS IT APPROPRIATE TO INCLUDE THESE EXPENSES AS PART OF THE COMPANY'S
10 COST OF PROVIDING ELECTRIC SERVICE TO MINNESOTA RATEPAYERS?

11 A. Yes. These are unavoidable, just and reasonable expenses that should be
12 included in the Company's cost of service for ratemaking purposes.

13
14 Q. BUT ISN'T THE COMPANY ONLY REQUESTING RECOVERY OF HALF OF THESE
15 EXPENSES?

16 A. Yes. Company witness Ms. Anne Heuer's testimony, and the Company's rate
17 request, reflects recovery of only 50 percent of these expenses in this case.
18 We have removed 50 percent of these expenses, given past Commission
19 decisions on this topic and due to our desire to minimize controversy in this
20 proceeding. However, we continue to view these as just, reasonable and
21 necessary expenses.

22
23 **III. STANDARDS AND FUNDAMENTAL CONSIDERATIONS**
24 **FOR THE NSPM CAPITAL STRUCTURE**

25
26 Q. PLEASE SUMMARIZE THE MOST SIGNIFICANT POINTS YOU DISCUSS IN THIS
27 SECTION OF YOUR DIRECT TESTIMONY.

1 A. The most significant points I discuss in this section are as follows:

- 2 • A utility's capital structure should support credit ratings that enable cost
3 efficient access to capital in all market conditions.
- 4 • The Commission's basic standard for reviewing a utility's capital
5 structure is one of reasonableness. The Commission considers whether
6 the capital structure is comparable to other utilities, whether it is an
7 actual structure based on market forces or is only an accounting
8 structure, whether it supports the utility's financing requirements, and
9 whether there are benefits to customers.
- 10 • NSPM's capital structure meets these Commission criteria, and
11 provides long-term customer benefits, including financing for capital
12 expenditures that serve customer needs and reduced LTD costs.
- 13 • The Company's management of its capital structure is based on long-
14 term considerations, including credit ratings, future financing plans to
- 15 • Fund NSPM's capital expenditures, the relative capital structures of
16 other utilities, and overall financial market conditions.

17
18 Q. WHY IS THE CAPITAL STRUCTURE IMPORTANT TO CREDIT RATINGS AND ACCESS
19 TO CAPITAL?

20 A. A utility's capital structure provides the long-term structural foundation for
21 the financing required to support its operations and capital investment plans.
22 It is particularly important that a utility's capital structure support its ability to
23 raise needed financing at favorable costs when a utility must access the capital
24 markets to finance the capital expenditures necessary to provide safe and
25 reliable service to its customers.

1 Q. WHAT GENERAL STANDARD DOES THE COMMISSION USE TO EVALUATE
2 CAPITAL STRUCTURES FOR SETTING UTILITY RATES?

3 A. The Commission typically uses the standard of reasonableness in making
4 capital structure decisions. To determine whether a company's actual capital
5 structure is reasonable, the Commission considers:

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

15
16 Q. DOES NSPM'S PROPOSED CAPITAL STRUCTURE MEET THE COMMISSION'S
17 STANDARDS AND CRITERIA FOR REASONABLENESS?

18 A. Yes. NSPM's proposed capital structure meets the Commission's standards
19 and criteria and has provided a stable structure for financing NSPM's
20 operations and capital investment plans at a reasonable cost of capital.
21 NSPM's capital structure is within a reasonable range of equity ratios for
22 similarly situated utilities, as Mr. Coyne's analysis shows. NSPM's proposed
23 capital structure is also an actual, market-based capital structure. This capital
24 structure has provided long-term benefits to customers in the form of low
25 costs of capital over time and sufficient access to capital markets during a
26 period of elevated investment. In addition, the Commission has found the
27 Company's recommended capital structure to be reasonable, as the requested

1 equity ratio in this case is consistent with the most recently approved equity
2 ratio in Docket No. E002/GR-13-868, and is in line with the approved equity
3 ratio in the three cases prior to the last general proceeding (Docket Nos.
4 E002/GR-12-961, E002/GR-10-971, and E002/GR-08-1065).

5
6 Q. HOW DOES THE COMPANY'S 52.50 PERCENT EQUITY RATIO COMPARE WITH
7 THE EQUITY RATIOS OF COMPANIES IN MR. COYNE'S PROXY GROUP?

8 A. The Company's 52.50 equity ratio is well within the ranges of the operating
9 utilities in Mr. Coyne's proxy group, as Mr. Coyne explains. Based on the 12
10 months ending June 30, 2015, the average equity ratio of his proxy group is
11 54.48 percent, which is nearly 200 basis points higher than our
12 recommendation, with 8 of the 13 proxy group companies having higher
13 equity ratios than NSPM. See Exhibit___(JMC-1), Schedule 11.

14
15 Q. WHEN YOU DESCRIBE NSPM'S CAPITAL STRUCTURE AS AN ACTUAL AND
16 MARKET-BASED CAPITAL STRUCTURE, WHAT DOES THAT MEAN?

17 A. NSPM is a separate legal Minnesota corporation that is a subsidiary of XEI.
18 NSPM has its own separate capital structure and issues its own debt securities.
19 The Company currently has approximately \$4.6 billion of outstanding publicly
20 traded LTD in the form of First Mortgage Bonds (FMB) with senior secured
21 credit ratings of A, Aa3 and A+ from Standard & Poor's (S&P), Moody's, and
22 Fitch, respectively. NSPM reports its capital structure in separate Securities
23 and Exchange Commission (SEC) filings, including annual Form 10-K filings
24 and quarterly Form 10-Q filings. Each of the credit rating agencies assigns
25 credit ratings to NSPM as a corporate entity and to each of its individual
26 bonds as they are issued.

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

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

- 4 • Credit rating evaluations that reflect rating agency assessments of
5 NSPM's business and financial risk;
- 6 • NSPM's position in relation to its long-term construction cycle and the
7 scale of its capital investments relative to earnings;
- 8 • Capital structures of other utilities;
- 9 • The long-term stability of the capital structure in relation to the long
10 life of the Company's asset investments;
- 11 • The current macroeconomic outlook and associated risk factors
12 affecting the utility sector and the capital markets generally; and
- 13 • The need to manage the maturities of long-term debt to avoid excessive
14 refinancing risk exposure in any given year.

15
16 Q. DO YOU HAVE A TARGET FOR MANAGING NSPM'S EQUITY RATIO?

17 A. Yes. As I discuss later in my testimony, NSPM continues to target a regulated
18 capital structure having an equity ratio of 52.50 percent, which the Company
19 considers appropriate to support NSPM's current credit ratings and projected
20 cost of LTD and STD.

21
22 Q. WHY IS THAT TARGET EQUITY RATIO APPROPRIATE?

23 A. NSPM's target equity ratio supports its current S&P A- corporate credit rating
24 and is consistent with the Company's plan to maintain its credit rating, which
25 provides access to low cost financing while the Company is making significant
26 capital investments in our utility. The target regulated equity ratio of 52.50
27 percent is also consistent with other utility capital structures, albeit on the

1 lower end of the range of the equity ratios of the utilities in the proxy group.

2
3 Q. HAS NSPM'S EQUITY RATIO CHANGED OVER TIME?

4 A. Since 2009, NSPM has maintained its equity ratio at approximately 52.50
5 percent. This equity ratio has contributed to the improved credit ratings of
6 the Company and helps the Company maintain its current credit ratings in
7 light of its extensive, multi-year infrastructure investment plan and increased
8 level of purchased power agreement obligations. In the interest of
9 streamlining contested issues, we note that the Commission has consistently
10 reviewed and approved this reasonable ratio in each of the past four electric
11 rate cases. See Docket Nos. E002/GR-13-868, E002/GR-12-961, E002/GR-
12 10-971, and E002/GR-08-1065.

13
14 Q. DO CUSTOMERS BENEFIT FROM NSPM'S CAPITAL STRUCTURE AND EQUITY
15 RATIO?

16 A. Yes. NSPM's capital structure and equity ratio have a significant effect on its
17 financial integrity. NSPM's financial integrity is essential to: (i) its ability to
18 finance its investments and operations at a reasonable cost; and (ii) its credit
19 ratings. NSPM's capital structure has allowed it to simultaneously finance its
20 investments, achieve upgrades of its credit ratings, and reduce its cost of LTD.
21 NSPM's Standard & Poor's (S&P) corporate credit rating improved from BBB
22 (in 2005) to A- (beginning in 2010 and continuing today). The Company's
23 capital structure has also allowed it to access the capital markets in various
24 market conditions at favorable rates. NSPM's strong credit ratings have
25 enabled NSPM to issue debt at lower costs over the last several years, which
26 provides both current and long-term cost benefits to our customers. All of
27 these benefits are reflected in NSPM's test year cost of capital in this

1 proceeding. In addition, NSPM has maintained its financial strength to ensure
2 consistent access to capital markets under a range of financial market
3 conditions that will enable it to raise the future capital required to complete its
4 capital investment plan.

5
6 **IV. NSPM'S CAPITAL EXPENDITURE PLAN,**
7 **INVESTOR PERCEPTIONS, AND DEBT RATINGS**
8

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

11 A. The most significant points are as follows:

- 12 • To date, NSPM's capital expenditure program has resulted in significant
13 issuances of debt and equity capital.
- 14 • NSPM continues to make significant capital investments in Minnesota,
15 which requires future access to capital at favorable rates.
- 16 • Regulatory decisions are very important to both debt and equity
17 investors, rating agencies, and financial analysts.
- 18 • NSPM's credit ratings remain strong, but they are dependent on
19 NSPM's business and financial risk ratings, which can be affected by
20 unfavorable regulatory decisions, especially during periods of large
21 capital expenditures.

22
23 **A. NSPM Capital Expenditures and Financial Implications**

24 Q. PLEASE SUMMARIZE THE HISTORIC CONTEXT FOR NSPM'S CAPITAL
25 EXPENDITURES PROGRAM.

26 A. The Company has engaged in a large scale capital expenditure program for
27 necessary investments in its system. As shown on Exhibit____(BVA-1),

1 Schedule 3, during the period 2005 through 2014, NSPM made capital
2 expenditures of approximately \$10.1 billion in its combined gas and electric
3 utility business, with approximately \$1.8 billion in capital expenditures in 2015.
4 The Company's Metro Emissions Reduction Project (MERP), investments in
5 wind generation, nuclear investments, and new transmission projects all
6 required significant capital investment during this period. In addition, the
7 Company has been making ongoing investments to support its aging
8 distribution infrastructure. While the level of capital expenditures over the
9 next few years may decline slightly from 2015, the Company expects to
10 continue making significant investments, such as its investment in the
11 Courtenay Wind Farm Project and the Black Dog Project, discussed by
12 Company witness Mr. Steven H. Mills. Additionally, our early action to
13 achieve renewable energy goals, as described in our Integrated Resource Plan,
14 would increase expenditures in the coming five years above our current plan.

15
16 These and other ongoing investments make it critical that the Company
17 maintain a strong financial position, so that it can access the capital markets at
18 favorable rates, as necessary. Investors are aware of the ROE trend that has
19 accompanied the Company's significant capital expenditures, and this pattern
20 provides a context against which investors will evaluate the results of this
21 proceeding.

22
23 Q. HAS THE PATTERN OF NOT ACHIEVING AUTHORIZED RETURNS AFFECTED THE
24 FREQUENCY OF NSPM RATE CASES?

25 A. Yes. The combination of persistent under-earnings and consistently high
26 levels of capital expenditures have significantly affected NSPM's need to
27 submit rate case filings and those filings have come at a more frequent pace

1 than the Company would have preferred. As Company witness Mr. Aakash
2 H. Chandarana describes in his testimony, this pattern has caused the
3 Company to consider new approaches to traditional ratemaking. A
4 constructive regulatory outcome that sets forth a longer-term compact will
5 help the Company maintain its strong financial position and execute on its
6 investment plans.

7
8 Q. HOW DO FORECAST CAPITAL EXPENDITURE LEVELS COMPARE TO PRIOR
9 YEARS?

10 A. Exhibit____(BVA-1), Schedule 3 shows that NSPM's forecasted capital
11 expenditures for 2015 through 2019 are approximately \$6.0 billion or average
12 approximately \$1.2 billion per year. This level of forecasted capital
13 expenditures is approximately the same as the historical average during 2010
14 through 2014. As I mentioned, it is important to note that this capital
15 expenditure forecast does not include any incremental capital for the early
16 action plan outlined in our Integrated Resource Plan.

17
18 Q. HOW DOES THE COMPANY'S CAPITAL EXPENDITURE FORECAST AFFECT THE
19 COMPANY'S FINANCING PLANS AND INVESTOR EXPECTATIONS?

20 A. To fund its forecasted capital expenditures, the Company will need to access
21 the capital markets periodically over the next several years. It is therefore
22 important for the Company to meet investor expectations and maintain its
23 credit ratings during this time to continue to be able to obtain low cost
24 financing. To do so, it is important that the Company receives timely
25 recovery of the costs of its investments.

1 Q. HAS NSPM RECENTLY ISSUED LTD, AND WILL NSPM NEED TO ISSUE MORE
2 LTD IN THE 2016 TO 2018 TIME PERIOD?

3 A. Yes. NSPM issued \$600 million in August 2015 to repay STD incurred to
4 finance utility operations and capital expenditures and to repay the principal
5 on \$250 million of first mortgage bonds maturing in August. Additionally, the
6 August LTD issuance ensures the Company has the liquidity to meet the
7 large payments later in 2015 that are needed for the Borders and Pleasant
8 Valley Wind Farms. In 2016, NSPM is planning to issue an additional \$250
9 million in LTD to repay STD. In 2018, NSPM projects issuing \$500 million
10 in LTD to meet a \$500 million maturity. The size of these future LTD
11 issuances could be increased depending on the amount of cash flow available
12 from operations. Further, any large scale capital expenditures related to early
13 action in the Integrated Resource Plan would require additional access to the
14 capital markets.

15
16 Q. DO CURRENT INTEREST RATES REMAIN ADVANTAGEOUS?

17 A. Yes. While interest rate forecasts show an increase in rates given the
18 expectation of the change in Federal Reserve Policy, they are still relatively low
19 by long-term historical measures. Market conditions provide an opportunity
20 to obtain favorable costs of LTD that will remain fixed for a long period of
21 time. Positive credit rating agency and bond market perceptions will remain
22 very important to our long-term cost of service and will allow the Company to
23 take advantage of the low rate environment.

1 **B. Credit Rating Agency and Investor Reactions to**
2 **Regulatory Decisions**

3 Q. PLEASE SUMMARIZE THE SIGNIFICANCE OF REGULATORY DECISIONS TO
4 UTILITY INVESTORS, INCLUDING INVESTORS IN NSPM.

5 A. Regulatory climate is one of the principle investment risk factors considered
6 for a regulated utility. Credit rating agencies and utility investors are very
7 interested in regulatory decisions, particularly when utilities commit to
8 substantial capital expenditure programs. The Commission's decisions in
9 this proceeding, including the ROE that it authorizes, will affect the
10 Company's ability to finance capital expenditures internally and affect investor
11 and rating agency perceptions of NSPM.

12
13 Q. PLEASE EXPLAIN THE IMPACT OF THE COMMISSION'S DECISION ON INTERNAL
14 FUNDING OF CAPITAL EXPENDITURES AND ITS SIGNIFICANCE.

15 A. The level of earnings authorized by the Commission will directly impact
16 NSPM's ability to fund capital investment with internally generated funds.
17 Internally generated funds are a significant source of investment funding for
18 NSPM, and both debt and equity investors expect NSPM to be able to
19 generate a substantial portion of its investment funding. Therefore, an
20 adverse decision will negatively impact both debt and equity investors' views
21 of NSPM.

22
23 Q. CAN YOU FURTHER EXPLAIN WHY THE COMMISSION'S DECISIONS ARE
24 PARTICULARLY IMPORTANT TO THE INVESTOR COMMUNITY?

25 A. Investors – both debt and equity – and credit rating agencies understand the
26 importance of the regulatory environment to the business risks of utilities.
27 Investors and rating agencies closely observe the decisions of regulatory

1 agencies, as these decisions directly affect the risk profile of the company. In
2 fact, investors and rating agencies categorize the state regulatory environments
3 and incorporate these environments in their assessment of a utility's risk
4 profile.

5
6 Credit rating agencies and investors know that NSPM has investments
7 weighted heavily toward its electric business. They also know that NSPM's
8 customers are concentrated in Minnesota, making the Minnesota retail electric
9 jurisdiction NSPM's primary jurisdiction. Rating agencies and bond and equity
10 investors also know that the Commission is fully informed about NSPM's
11 investment plans. As a result, these agencies and investors will likely consider
12 the Commission's decisions regarding the financial components of our overall
13 ROR and electric rates as a reflection of the level of support for the
14 Company's investment plans. Therefore, the Commission's decisions have an
15 important impact on the Company's ability to maintain its financial integrity
16 and allow us to access low cost capital.

17
18 Q. ARE EQUITY INVESTORS EXPOSED TO RELATIVELY GREATER RISKS THAN DEBT
19 INVESTORS?

20 A. Yes. Like all debt investors, NSPM's debt investors are focused on the
21 Company's ability to make timely interest payments and to repay its principal
22 obligations in full. The claims of debt holders have a clear priority over
23 equity, which means that equity holders do not have any claim unless and until
24 obligations to debt holders are fully satisfied. A common equity investment,
25 including an investment in NSPM (through ownership of XEI common stock)
26 differs substantially from an investment in NSPM's LTD. An equity
27 investment is subordinate to every other source of capital in NSPM's capital

1 structure. There is no certainty that the principal investment will be recovered,
2 and dividends may be declared only to the extent that current and retained
3 earnings remain sufficient. As a result, the value of equity investments in
4 regulated utilities is particularly sensitive to regulatory decisions. Therefore,
5 both debt and equity investors (and the credit rating agencies) become
6 concerned when regulatory decisions reflect instability.

7
8 Q. WHY IS REGULATORY STABILITY IMPORTANT TO INVESTORS AND TO CREDIT
9 RATING AGENCIES?

10 A. One of the greatest risks that the Company's investors face is related to
11 regulatory treatment, because the Company depends on regulatory decisions
12 for timely recovery of its operating expenses and investments. A regulatory
13 environment that lacks predictability and consistency introduces a higher level
14 of risk from the perspective of investors and the credit rating agencies. This
15 type of situation has the potential to increase the cost of capital – both debt
16 and equity – to the detriment of our customers over the long term. If a
17 regulated utility receives an adverse regulatory decision that is a significant
18 departure from past rulings or with rulings from other jurisdictions, the credit
19 rating agencies and the debt and equity investors react quickly to reassess the
20 Company's financial outlook and to re-price its debt and equity securities.

21
22 Q. HAS MINNESOTA TRADITIONALLY HAD A STABLE AND PREDICTABLE
23 REGULATORY ENVIRONMENT?

24 A. Yes. The Commission has historically provided a stable and predictable
25 approach in regard to the significant financial issues associated with ROE,
26 capital structure, and cost of debt that have supported the Company's credit
27 ratings and its ability to raise needed capital. Prior Commission decisions have

1 allowed us to improve and maintain our current credit quality and are
2 consistent with supporting the S&P A- corporate credit rating as a stand-alone
3 company that issues its own debt securities.
4

5 **C. Credit and Debt Ratings**

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

7 A. Yes. Banks and fixed income investors rely on a company's credit and debt
8 ratings to determine the return that they require on their capital. As a result,
9 credit and debt ratings impact the cost of LTD and STD required to fund the
10 Company's large scale investments. Credit ratings also affect a company's cost
11 of equity. A decrease in the credit quality of a company will increase the
12 required equity return needed by equity investors to compensate for the
13 additional risk.
14

15 Q. CAN THESE IMPACTS ON COST OF DEBT AND ACCESS TO CAPITAL ALSO IMPACT
16 CUSTOMERS?

17 A. Absolutely. The increased cost of capital is ultimately borne by customers,
18 increasing the cost of service. For example, if the rate on a planned 2018 debt
19 issuance rose ten basis points, annual interest expense would increase roughly
20 \$0.5 million. If that 10-basis point extended to the rest of the debt issuances
21 over time, the result would be an annual interest expense increase of over \$4.6
22 million based on the 2016 test year LTD. Additionally, if the Company has
23 difficulty accessing capital, the quality of service can be impacted if the
24 Company cannot fund needed improvements.
25

26 Q. HOW DO RATING AGENCIES TAKE BUSINESS RISKS AND FINANCIAL METRICS
27 INTO ACCOUNT WHEN ESTABLISHING RATINGS?

1 A. Credit rating agencies look at both a utility's business risks and its financial risk
2 (based on credit metrics) when making rating determinations. For the utility
3 industry, the business risk evaluation includes analysis of management
4 decisions, the Company's operational performance, competitive issues, and
5 the regulatory environment affecting the utility. The utility's regulatory
6 environment is a key element of its business risk assessment and ranking.
7 Financial risk assessment includes an evaluation of a company's corporate
8 governance, risk management and financial policies, the economic capital
9 structure, and liquidity measures. The rating agencies evaluate several financial
10 ratios to further quantify the financial risk of a company. As a utility's business
11 risk increases, the utility's required credit metrics become more stringent to
12 maintain a given rating. Accordingly, unfavorable regulatory decisions will
13 tend to increase the utility's business risk and put downward pressure on
14 credit ratings.

15
16 Q. HOW ARE BUSINESS RISK AND FINANCIAL RISK ASSESSED?

17 A. The credit rating agencies all have similar approaches to assessing the business
18 and financial risk of a utility. S&P has detailed its approach to assessing the
19 business and financial risks of a utility in the report "*Key Credit Factors For the*
20 *Regulated Utilities Industry*" published on November 19, 2013, included as
21 Exhibit___(BVA-1), Schedule 4. For U.S. utilities operating in regulated
22 environments, business risk is generally assessed as being very low, based
23 primarily on cyclicalities and competitive risk and growth. However, S&P states
24 specifically on page 6 of that report that "[t]he regulatory framework/regime's
25 influence is of critical importance when assessing regulated utilities' credit
26 risk" and observes further that, "[w]e base our assessment of the regulatory
27 framework's credit supportiveness on our view of how regulatory stability,

1 efficiency of tariff setting procedures, financial stability, and regulatory
2 independence protect a utility's credit quality and its ability to recover its costs
3 and earn a timely return." These observations confirm how important it is for
4 the Commission to maintain its current credit-supportive policies and a stable
5 regulatory environment.

6
7 Q. HAVE THE RATING AGENCIES COMMENTED ON THE REGULATORY
8 ENVIRONMENT UNDER WHICH NSPM OPERATES?

9 A. Yes. Most recently in the August 12, 2015 Moody's Credit Opinion on
10 NSPM, the summary rating rationale states that NSPM has benefitted from a
11 regulatory environment that has historically provided better-than-average
12 recovery mechanisms for utility costs. However, Moody's also notes the series
13 of large, litigated rate cases in recent years. Moody's states that "the ratings
14 could be downgraded if adverse regulatory rulings or a change in financial
15 policy to use more debt financing for capital expenditures...result in weaker
16 credit metrics....". The complete article is attached as Exhibit____(BVA-1)
17 Schedule 5.

18
19 In addition, the Fitch Rating report dated July 16, 2015 states that a relatively
20 balanced and stable regulatory environment exists for NSPM and that Fitch
21 expects reasonable outcomes in future rate case filings. Developments that
22 could lead to a negative rating action include a material deterioration of the
23 regulatory environment. See Exhibit____(BVA-1), Schedule 6. These
24 comments illustrate that the rating agencies factor in the regulatory
25 environment and outcomes of regulatory proceedings when assessing business
26 risk and the corresponding impact of adverse regulatory rulings on financial
27 risk and credit metrics.

1 Q. WHAT CAN YOU CONCLUDE FROM THE RATING AGENCY REPORTS?

2 A. These reports confirm that credit rating agencies and investors closely follow
3 NSPM's regulatory environment. They also show that NSPM has historically
4 had a stable regulatory environment in Minnesota, which has supported the
5 Company's investment grade credit ratings. Finally, the reports show that the
6 Commission's decisions have an effect on NSPM's credit ratings and cost of
7 capital.

8
9 Q. DO CAPITAL EXPENDITURE PLANS ALSO AFFECT HOW RATING AGENCIES
10 EVALUATE CREDIT METRICS?

11 A. Yes. When a utility undertakes a substantial capital investment plan relative to
12 the amount of internally generated funds that are available to support that
13 plan, the utility becomes subject to greater capital market risk because it needs
14 to raise external capital regardless of the financial market conditions. Credit
15 rating agencies expect companies that need significant amounts of external
16 capital to maintain a strong credit profile, not just a profile that is marginal for
17 the current credit rating, because these companies are constantly exposed to
18 external financial market risks and they may need to raise cost effective capital
19 under any financial market scenario. The August 12, 2015 Moody's Credit
20 Opinion discussed above states, "While capital expenditures will remain
21 higher than the run-rate over the next 12 to 18 months, the stable outlook
22 anticipates that the company will get adequate, timely rate relief in its
23 regulatory proceedings." Rating agencies anticipate adequate and timely cost
24 recovery in their ratings assessment.

25
26 Q. DOES A UTILITY'S INVESTMENT LEVEL AFFECT ITS DEPENDENCE ON
27 REGULATORY DECISIONS IN RELATION TO ITS BUSINESS RISK RATING?

1 A. Yes. During significant capital expenditure periods, the public utility is very
2 dependent on favorable regulatory decisions to support cost recovery.
3 Moreover, such a utility is more vulnerable to cost recovery shortfalls as a
4 result of inadequate interim rates or regulatory lag. A utility in this situation is
5 also subject to the capital market risk of requiring capital when it may not be
6 available or is too costly. For all of these reasons, a utility engaged in a
7 substantial capital investment program depends on a favorable regulatory
8 environment to maintain a favorable business risk rating.

9
10 Q. WHAT IS NSPM'S CURRENT BUSINESS RISK RATING AND HOW IMPORTANT IS
11 THE BUSINESS RISK RATING TO ITS CREDIT RATINGS?

12 A. NSPM currently has an "Excellent" business risk rating from S&P. NSPM's
13 Excellent business risk rating is essential to maintaining its current A-
14 corporate credit rating, because NSPM's credit metrics alone are not
15 sufficiently strong to maintain the current rating if the business risk rating
16 were moved down to "Strong" from "Excellent." If NSPM's business risk
17 rating slipped to Strong, then it would be more likely that NSPM would have a
18 rating in the BBB range. Table 4 below summarizes these relationships:

19
20 **Table 4**
21 **S&P Business and Financial Risk Relationship**

Business Risk	Financial Risk	Financial Risk
	<i>Significant</i>	<i>Aggressive</i>
Excellent	A-	BBB
Strong	BBB	BB

22
23
24
25
26 Q. WHAT ARE THE COMPANY'S CURRENT CREDIT RATINGS?

27 A. The Company's current credit ratings are:

Table 5
NSPM Current Debt Ratings

	Fitch	Moody's	Moody's S&P Equivalent*	S&P
Corporate Rating	A-	A2	A	A-
Senior Secured	A+	Aa3	AA-	A
Senior Unsecured	A	A2	A	A-

* S&P equivalent rating of Moody's rating

Table 5 reflects the January 2014 upgrade to NSPM by Moody's. Moody's upgraded Xcel and its operating companies as well as many U.S. utilities based on a more favorable view of the relative credit supportiveness of the U.S. regulatory environment. S&P's and Fitch's ratings are the same that the Company had in its last electric rate case. NSPM's S&P corporate rating has improved from BBB in 2005 to A- in several steps during 2007, 2008 and 2010.

Q. HOW DOES THE PROPOSED 52.50 PERCENT REGULATED EQUITY RATIO COMPARE TO NSPM'S A- CORPORATE CREDIT RATING FROM S&P?

A. NSPM's equity ratio is consistent with the S&P guidelines for NSPM's A- corporate credit rating and its stable ratings outlook. S&P includes certain debt-equivalent adjustments for purchased power agreements and operating leases in their calculation of credit metrics for a utility's economic capital structure. As a result, there is approximately a 250 basis point differential between NSPM's economic equity ratio during 2014 when these additional debt equivalent obligations (approximately \$400 million for 2014) are included in the capital structure. As a result, the 52.50 percent target for NSPM's regulated equity ratio corresponds to an S&P economic equity ratio of

1 approximately 50.0 percent, which is the low end of S&P's guideline on this
2 credit metric for our A- corporate rating. Years 2015 through 2018 have
3 similar forecasted levels of off balance sheet data.
4

5 Q. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN A REGULATED CAPITAL
6 STRUCTURE AND AN ECONOMIC CAPITAL STRUCTURE.

7 A. Credit rating agencies focus on the economic capital structure of a utility in
8 assessing its credit quality because the economic capital structure accurately
9 reflects all of a company's financial obligations. The economic capital
10 structure includes all debt and debt-like instruments and, therefore, reflects the
11 total financial leverage of a company. Specifically, the economic capital
12 structure includes NSPM's regulated capital structure components of STD,
13 LTD, and common equity, but also includes the imputed debt from operating
14 leases and power purchase agreement (PPAs). In addition, the rating agencies
15 use public capitalization data and do not make regulatory adjustments to
16 balances or costs.
17

18 NSPM manages to its economic capital structure because it is the capital
19 structure that the credit rating agencies use in their financial assessment to
20 determine NSPM's credit ratings. The Company strives to maintain an
21 economic equity ratio of 50 to 51 percent to be consistent with the low-end of
22 the S&P guidelines for our target objectives.
23

24 Q. PLEASE EXPLAIN THE PRIOR REFERENCE TO "IMPUTED DEBT."

25 A. NSPM has over \$400 million of imputed debt in 2015 and 2016 consisting of
26 PPAs and operating leases. As explained in the Financial Risk Analysis
27 section of Exhibit____(BVA-1), Schedule 4 at pages 14 to 16, S&P views PPAs

1 as fixed, debt-like financial obligations that represent substitutes for debt-
2 financed capital investments in generation capacity. S&P accounts for this
3 debt-like obligation of PPAs (reflected in both traditional fossil-fuel PPAs and
4 in energy-only contracts typical of renewable resource PPAs) by explicitly
5 adding a calculated amount of: (1) debt to the utility's balance sheet; (2) the
6 associated interest expense to the utility's income statement; and (3) an
7 implied amount of depreciation to the cash flow statement to calculate funds
8 from operations. Operating leases are long-term lease obligations that are also
9 viewed by S&P as being debt-like obligations.

10
11 Q. WHAT IS THE RANGE OF NSPM'S ECONOMIC EQUITY RATIO DURING THE
12 PROPOSED MULTI-YEAR RATE PLAN?

13 A. Using S&P's methodology, the forecasted range of NSPM's economic debt
14 ratio is between 49.6 percent and 50.1 percent resulting in a corresponding
15 economic equity ratio of 50.4 percent to 49.9 percent during the years 2015
16 through 2018, which is near the minimum target of 50.0 percent. These
17 metrics are shown on Exhibit____(BVA-1), Schedule 7, pages 1 and 2.

18
19 Q. HOW DO THE COMPANIES' CREDIT METRICS COMPARE TO THE S&P CRITERIA?

20 A. Exhibit____(BVA-1), Schedule 7, Page 1 of 2, shows NSPM's historic and
21 forecasted credit metrics as compared to S&P guidelines. The debt to capital
22 ratios have historically been slightly over the benchmark and are projected to
23 be slightly under the maximum of 50 percent for the A/A- objective. The
24 other metrics are within the target ranges. Overall, the Company expects that
25 its recommended capital structure and the forecasted financial metrics will
26 continue to support its current credit ratings over the multi-year time period.

1 **V. PROPOSED CAPITAL STRUCTURE,**
2 **COST OF DEBT, AND RATE OF RETURN**
3

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

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

- 7 • The components of LTD, STD, and common equity for 2016, 2017
8 and 2018 have been determined using the same approaches that we
9 have used in prior rate cases.
- 10 • NSPM's proposed capital structures for 2016, 2017 and 2018 are very
11 similar to the capital structure adopted in our last rate case.
- 12 • The costs of LTD and STD have also been determined using the same
13 approaches that we have used in prior cases.
- 14 • The cost of LTD has declined from the level approved in the
15 Company's last rate case.
- 16 • The size of NSPM's short term credit facility is reasonable.
- 17 • The Utility Money Pool provides public interest benefits to NSPM's
18 customers.

19
20 Q. PLEASE SUMMARIZE THE COMPONENTS OF THE COMPANY'S RECOMMENDED
21 CAPITAL STRUCTURE AND ROR.

22 A. The Company's proposed 2016, 2017 and 2018 capital structures include
23 LTD, STD, and common equity. The Company's proposed revenue
24 requirement for 2016 reflects an overall cost of capital or ROR of 7.49
25 percent, which includes the Company's average common equity ratio of 52.50
26 percent and a 10.0 percent ROE as recommended in Mr. Coyne's Direct
27 Testimony. The Company's proposed ROR for both 2017 and 2018 is 7.51

1 percent, which includes the Company's average common equity ratio of 52.50
2 percent, again using the 10.0 percent ROE as recommended in Mr. Coyne's
3 Direct Testimony.

4
5 **A. Capital Structure**

6 Q. HOW DO THE COMPANY'S 2016, 2017 AND 2018 CAPITAL STRUCTURES
7 COMPARE WITH ITS CURRENT AUTHORIZED CAPITAL STRUCTURE FROM THE
8 LAST ELECTRIC RATE CASE?

9 A. The capital structures for all three years are generally comparable to the capital
10 structure approved by the Commission in the Company's 2013 rate case
11 (Docket No. E002/GR-13-868). The proposed 52.50 percent equity ratio for
12 all three years match the equity ratio approved in that case. The 46.24
13 percent, 46.04 percent and 46.41 percent LTD ratios for years 2016, 2017 and
14 2018 respectively are slightly higher than the 45.60 percent ratio from the 2013
15 rate case. The STD ratios of 1.26 percent, 1.46 percent and 1.09 percent for
16 years 2016, 2017 and 2018 respectively are slightly lower than the 1.90 percent
17 ratio from that case.

18
19 Q. WHAT METHODOLOGY DID THE COMPANY USE TO DEVELOP BALANCES AND
20 COSTS FOR THE VARIOUS COMPONENTS OF CAPITAL STRUCTURE?

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

- 24 • Future long and short-term debt interest rates are based on the July
25 2015 Global Insight forecast with an added credit spread. The July
26 2015 Global Insight forecast is attached as Exhibit____(BVA-1),
27 Schedule 8.

- 1 • The Company proposes to update STD and LTD forecast interest rates
- 2 at a future date during the case to reflect more current information;
- 3 • For forecast purposes, STD is in the form of commercial paper;
- 4 • STD balances are based on the average of month end balances for the
- 5 12 months in the respective year;
- 6 • LTD balances are based on the average of 12 month-end balances from
- 7 January through December of the respective year and include
- 8 forecasted LTD issuances and retirements during that period.
- 9 • LTD costs include the coupon rate on all bonds expected to be
- 10 outstanding for each month of the respective year. In addition to the
- 11 interest expense, the cost of LTD also includes amortization expense
- 12 for debt issuance costs, discounts or premiums, losses on reacquired
- 13 debt, gains and losses from hedging transactions, and the annual
- 14 amortization of the upfront fees associated with the Company's
- 15 multi-year credit agreement.
- 16 • Common equity balances represent the average of 13 month-end equity
- 17 balances from December of the prior year through December of the
- 18 year analyzed. The common equity balance averages the accounting
- 19 month-end balances consistent with Generally Accepted Accounting
- 20 Principles (GAAP) and eliminates the non-regulated investments.

21
22 1. *2016 Long-Term Debt*

23 Q. WHAT IS THE COMPANY'S RECOMMENDED 2016 LTD BALANCE AND COST?

24 A. The Company's recommended LTD balance for 2016 is \$4.6 billion at a cost

25 of 4.81 percent, as shown on Exhibit__(BVA-1), Schedule 9, Page 1 of 1.

1 Q. HAS NSPM RECENTLY ISSUED LTD?

2 A. Yes. In August 2015, NSPM issued \$300 million of 2.20 percent 5-year first
3 mortgage bonds and \$300 million of 4.00 percent 30-year first mortgage
4 bonds. The proceeds from this LTD issuance were used to repay STD that
5 had been incurred to fund our utility operations and capital expenditures and
6 to meet the August 15, 2015 1.95 percent \$250 million FMB maturity.

7
8 Q. ARE THERE SCHEDULED ISSUANCES OF LTD IN 2016?

9 A. Yes. NSPM plans to issue \$250 million of 30-year bonds in May 2016, with
10 an estimated coupon rate of 4.625 percent. This 2016 issuance is reflected in
11 8 of the 12 monthly balances of the test year (May through December, 2016).

12
13 Q. HOW DOES THE COMPANY DETERMINE ITS LTD ISSUANCES?

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

20
21 When determining the maturity of a new bond, the Company considers the
22 existing debt portfolio maturity profile, market conditions, investor demand,
23 the life of the underlying asset portfolio, and the effects on the cost of LTD.
24 We review the existing debt portfolio maturity profile and identify potential
25 years where maturities will not stack on top of each other. The Company
26 staggers new LTD maturities to mitigate the risk of having large future
27 maturities in any one year that could be exposed to capital market volatility
28 and the associated interest rate risk.

1 Q. PLEASE EXPLAIN THE TERM “INDEX ELIGIBLE” AND WHY IT IS IMPORTANT.

2 A. To be included in the Barclays Capital Aggregate Bond Index, a bond must be
3 a minimum size of \$250 million. Bonds that trade as a component of the
4 index are more liquid and will generally be priced at a lower credit risk
5 premium over prevailing U.S. Treasury rates than less liquid bonds.

6
7 Q. HAS THE COMPANY CONSIDERED THE POSSIBILITY OF EARLY RETIREMENT OF
8 COMPONENTS OF ITS LTD PORTFOLIO?

9 A. Yes. In 2012 NSPM retired a series of bonds that had provisions that allowed
10 the Company to “call” the bonds without incurring significant added financial
11 obligations known as “make whole” redemption obligations. The bonds
12 currently in the NSPM debt portfolio either: (i) have no call options; (ii) are
13 only callable at par value 3 to 6 months prior to maturity; or (iii) have make
14 whole redemption provisions that are too expensive to exercise because they
15 result in very large premium payments to existing debt holders. The
16 economics of a make whole redemption feature are generally unfavorable and
17 are provided primarily as a last resort means of retiring debt (such as in
18 connection with a corporate merger transaction that may require retirement of
19 debt). To date, the Company has taken advantage of the refinancing
20 opportunities that could result in lower customer costs.

21
22 Q. HOW DO THE PROJECTED LTD BALANCE AND COSTS COMPARE TO THE LAST
23 ELECTRIC RATE CASE?

24 A. The projected \$4.6 billion average LTD balance for the 2016 test year is
25 approximately \$600 million higher than the LTD balance in the Company’s
26 2013 rate case (\$4.0 billion). The 4.81 percent rate is 9 basis points lower
27 than the cost in that case (4.90 percent) and approximately 150 basis points

1 lower than the cost of LTD in 2010. NSPM's financial strength and strong
2 credit ratings have contributed to this significant decline.

3
4 Q. HOW WAS THE PROPOSED 4.81 PERCENT COST OF LTD DETERMINED?

5 A. As shown on Exhibit____(BVA-1), Schedule 9, the overall 4.81 percent cost of
6 LTD includes the coupon rate on all bonds expected to be outstanding for
7 each month of 2016 and the amortizations discussed above.

8
9 Q. WHAT FACTORS LED TO THE DECREASE IN 2016 LTD COSTS?

10 A. The \$600 million of long-term debt issued in August 2015 is reflected for a
11 full year in the projected 2016 capital structure, which explains a part of the
12 reduction. The 2015 bonds were issued at a lower interest rate than the
13 overall cost of the NSPM debt portfolio, thus decreasing the overall cost of
14 debt. In addition, the Company projects an issuance of \$250 million of 4.625
15 percent 30-year bonds in May 2016. Consistent with past practices, the
16 Company will update the cost of LTD with actual costs and updated forecasts
17 as available.

18
19 Q. HAVE NSPM'S FINANCIAL STRENGTH AND DEBT RATINGS HAD A POSITIVE
20 EFFECT ON ITS COST OF LTD AND ITS RECENT LTD ISSUANCES?

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

2. *2016 Short-Term Debt*

Q. WHAT IS THE COMPANY'S PROPOSED STD BALANCE AND ASSOCIATED COST?

A. The Company forecasts an average test year STD balance of approximately \$126 million and a cost of 1.84 percent as shown on Exhibit___(BVA-1), Schedule 10.

Q. HOW WAS THE COST OF STD DETERMINED?

A. The 1.84 percent cost of STD in 2016 includes 1.46 percent interest expense for commercial paper and 0.38 percent financing fee for the fixed annual commitment fees associated with the Company's October 2014 "Amended and Restated Credit Agreement."

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

A. The 2016 short-term debt cost is forecast at 1.84 percent. The STD cost from the 2014 case is 0.62 percent. This increase is driven by the forecasted rise in short term interest as shown by the Global Insights interest rate forecast in Exhibit___(BVA-1), Schedule 8.

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

A. No. NSPM's credit facility remains at the \$500 million level. In determining the size of NSPM's credit facility, we consider the following factors that significantly impact liquidity requirements when we evaluate the amount of short term credit capacity required: (i) the total capital commitments over the life of the revolving credit agreement, including projected capital investment and scheduled LTD maturities; (ii) the projected level and volatility of natural gas purchase requirements; (iii) liquidity required to manage variability in

1 operating cash flow due to changes in sales and operating expenses; and (iv)
2 the expected change in sales and operating expenses. Each of these factors
3 continues to support our \$500 million credit facility. However, the current
4 size of the credit facility may need to be reassessed in the future depending on
5 potential changes in these factors.

6
7 Q. DOES NSPM'S USE OF COMMERCIAL PAPER REDUCE THE REQUIRED LEVEL OF
8 NSPM'S CREDIT FACILITY?

9 A. No. NSPM expects to have continued access to the capital and commercial
10 paper markets, but it is necessary to have adequate back up liquidity in the
11 event of a capital market disruption. For example, the 2008 capital market
12 crisis caused commercial paper to become unavailable for a period of time. If
13 a comparable event occurred again, or commercial paper required
14 unreasonable terms or costs, NSPM would be reliant on its credit facility for
15 its liquidity needs.

16
17 Q. DOES NSPM PARTICIPATE IN A UTILITY MONEY POOL WITH OTHER
18 OPERATING UTILITY SUBSIDIARIES OF XEI?

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

23
24 Q. HAS THE COMMISSION REVIEWED AND APPROVED NSPM'S PARTICIPATION IN
25 THE UTILITY MONEY POOL?

26 A. Yes. The Commission's July 9, 2004 Order in Docket No. E002/AI-04-100
27 approved our participation in the Utility Money Pool, and required NSPM to

1 demonstrate in future rate cases that NSPM's participation in the Utility
2 Money Pool continues to be consistent with the public interest. NSPM has
3 submitted the required information in this case and in all prior rate cases since
4 2004. NSPM also submits information regarding its participation in the Utility
5 Money Pool for Commission review and approval in its annual capital
6 structure filings.

7
8 Q. IS THE UTILITY MONEY POOL CONSISTENT WITH THE PUBLIC INTEREST?

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

17
18 Q. DOES THE UTILITY MONEY POOL PROVIDE A SUBSTITUTE FOR THE NSPM
19 CREDIT FACILITY IN RELATION TO NEEDED LIQUIDITY?

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

24
25 Q. DOES THE UTILITY MONEY POOL IMPOSE RISKS ON NSPM OR ITS CREDIT
26 FACILITY?

27 A. No. The borrowings under the Utility Money Pool are payable on demand.

1 Further, the other two participants in the Utility Money Pool (PSCo and SPS)
2 are also A- rated by S&P. NSPM's credit facility is limited to NSPM and its
3 own subsidiaries, and does not place NSPM at risk for any default by other
4 affiliates, including XEI, NSP-Wisconsin, PSCo, or SPS.

5
6 Q. HAVE YOU PREPARED A SCHEDULE SHOWING BORROWING AND LENDING
7 BETWEEN NSPM AND THE UTILITY MONEY POOL?

8 A. Yes. Exhibit____(BVA-1), Schedule 11 provides a record of Utility Money
9 Pool activity, including lending to and borrowing from the Utility Money Pool
10 from January 2013 through June 2015.

11
12 *3. 2016 Common Equity*

13 Q. HOW DID YOU DETERMINE NSPM'S 2016 COMMON EQUITY BALANCE?

14 A. The proposed test year common equity balance reflects the average of 13
15 month-end equity balances from December 2015 through December 2016
16 and eliminates the non-regulated investments. Exhibit____(BVA-1), Schedule
17 12 shows the test year equity balance by month.

18
19 Q. HOW DOES THE COMMON EQUITY BALANCE COMPARE TO THE BALANCE IN
20 THE LAST RATE CASE?

21 A. The \$5.2 billion common equity balance is approximately \$600 million greater
22 than the \$4.6 billion balance in our last rate case.

23
24 Q. HAS XEI ISSUED COMMON STOCK IN THE LAST FEW YEARS?

25 A. Yes. In August 2010, XEI issued approximately \$450 million of common
26 stock. XEI also issued approximately \$395 million of common stock during
27 2013 and 2014 through a \$400 million SEC-registered "At the Market"
28 program under which XEI issued common stock to the public from time to

1 time at then-prevailing market prices.

2
3 Q. HAVE YOU PROVIDED INFORMATION REGARDING FLOTATION COSTS FOR
4 PUBLIC AND NON-PUBLIC EQUITY ISSUANCES BY XEI?

5 A. Yes. Information regarding flotation costs for public and non-public offerings
6 by XEI is included in Exhibit____(BVA-1), Schedule 13. This information was
7 used by Mr. Coyne in making his flotation cost adjustment.

8
9 **B. 2017 Capital Structure**

10 *1. 2017 Long-Term Debt*

11 Q. WHAT IS THE COMPANY'S RECOMMENDED LTD BALANCE AND COST FOR
12 2017?

13 A. The Company's recommended LTD balance for 2017 is \$4.7 billion, and has a
14 cost of 4.81 percent, as shown on Exhibit____(BVA-1), Schedule 14.

15
16 Q. HOW WAS THE LTD BALANCE FOR 2017 DETERMINED?

17 A. The LTD balance is based on the average of 12 forecasted month-end
18 balances from January 2017 through December 2017. There are no scheduled
19 retirements or forecasted LTD issuances during that period.

20
21 Q. ARE YOU PROJECTING A DEBT ISSUANCE IN 2017?

22 A. No, there are no new issuances planned for 2017.

23
24 Q. HOW WAS THE PROPOSED 4.81 PERCENT COST OF LTD DETERMINED?

25 A. As shown on Exhibit____(BVA-1), Schedule 14, the overall 4.81 percent cost
26 of LTD includes the coupon rate on all bonds expected to be outstanding for
27 each month of 2017 and the amortization expense discussed previously.

1 2. *2017 Short-Term Debt*

2 Q. WHAT IS THE COMPANY'S PROPOSED STD BALANCE AND ASSOCIATED COST?

3 A. The Company's forecasted test year STD balance is approximately \$149
4 million and has a cost of 3.57 percent as shown on Exhibit____(BVA-1),
5 Schedule 15.

6
7 Q. HOW WAS THE COST OF STD DETERMINED?

8 A. The 3.57 percent cost of STD includes a 3.24 percent interest expense for
9 commercial paper and the 0.33 percent monthly financing fees associated with
10 having a credit facility to provide back-up liquidity for the commercial paper
11 program.

12
13 Q. HOW DO THE PROJECTED 2017 STD BALANCE AND COST COMPARE TO THE
14 2016 TEST YEAR?

15 A. The projected \$149 million STD 12-month average balance for 2017 year is
16 approximately \$23 million higher than the STD balance in the 2016 test year.
17 The cost is 173 basis points higher than the cost in 2016 due to the Global
18 Insight projection of higher interest rates.

19
20 3. *2017 Common Equity*

21 Q. HOW DID YOU DETERMINE THE COMPANY'S COMMON EQUITY BALANCE?

22 A. Consistent with prior year and rate case methodology, the proposed 2017
23 common equity balance reflects the average of 13 month-end equity balances
24 from December 2016 through December 2017 as shown on
25 Exhibit____(BVA-1), Schedule 16.

1 **C. 2018 Capital Structure**

2 1. *2018 Long-Term Debt*

3 Q. WHAT IS THE COMPANY'S RECOMMENDED LTD BALANCE AND COST FOR
4 2018?

5 A. The Company's recommended LTD balance for 2018 is \$4.7 billion and has a
6 cost of 4.77 percent, as shown on Exhibit____(BVA-1), Schedule 17. The \$4.7
7 billion LTD balance is approximately equal to the balance in 2017.

8
9 Q. HOW WAS THE LTD BALANCE FOR 2018 DETERMINED?

10 A. The LTD balance is based on the average of 12 forecasted month-end
11 balances from January 2018 through December 2018, and includes a 5.25
12 percent \$500 million scheduled bond retirement in March 2018 and two
13 forecasted issuances of \$250 million during that period.

14
15 Q. WHAT ARE THE INTEREST RATES ON THE TWO \$250 MILLION ISSUANCES IN
16 2018 AND HOW WERE THEY DETERMINED?

17 A. The interest rates are based on the term of the bond offering, the forecasted
18 Global Insight treasury yield for the respective term and a credit spread to
19 reflect NSPM's risk over the U.S. Treasury market. The 10-year, \$250 million
20 first mortgage bond has a projected coupon rate of 4.75 percent and the 30-
21 year \$250 million first mortgage bond has a coupon rate of 5.25 percent in
22 March 2018. The Global Insight forecast indicates a general rise in future
23 interest rates and a flattening of the yield curve as the projected differential
24 between the 10- and 30-year treasury yields narrow.

25
26 Q. HOW WAS THE PROPOSED 4.77 PERCENT COST OF LTD DETERMINED?

27 A. As shown on Exhibit____(BVA-1), Schedule 17 the overall 4.77 percent cost

1 of LTD includes the coupon rate on all bonds expected to be outstanding for
2 each month of 2018 and amortization of related bond features as discussed
3 above in the methodology section.
4

5 *2. 2018 Short-Term Debt*

6 Q. WHAT IS THE COMPANY'S PROPOSED 2018 STD BALANCE AND ASSOCIATED
7 COST?

8 A. The Company forecasts a STD balance of approximately \$110 million and a
9 cost of 4.45 percent as shown on Exhibit____(BVA-1), Schedule 18.
10

11 Q. HOW WAS THE COST OF STD DETERMINED?

12 A. The 4.45 percent cost of STD includes 4.00 percent interest expense for
13 commercial paper and the 0.45 percent monthly financing fees associated with
14 having a credit facility to provide back-up liquidity for the commercial paper
15 program.
16

17 *3. Common Equity*

18 Q. HOW DID YOU DETERMINE THE COMPANY'S COMMON EQUITY BALANCE?

19 A. The proposed 2018 common equity balance reflects the average of 13
20 month-end equity balances from December 2017 through December 2018.
21 Exhibit____(BVA-1), Schedule 19 shows the test year equity balance by
22 month.

1 **VI. COMPLIANCE MATTERS**

2
3 Q. IN PRIOR CASES, NSPM HAS ADJUSTED THE COST OF LTD TO REFLECT THE
4 EFFECT OF FINANCIAL DIFFICULTIES OF NRG ENERGY INC. (NRG). WAS
5 SUCH AN ADJUSTMENT MADE TO THE COST OF LTD FOR THE 2016 TEST YEAR?

6 A. No. The early redemption of the Becker Bonds in 2012 eliminates the need
7 for a further adjustment because those were the only bonds outstanding with
8 any possible adverse effect from NRG. Given this fact, the Company has
9 now removed the NRG matters from the Completeness Checklist attached to
10 Mr. Chandarana's testimony.

11
12 Q. HAVE YOU MADE ADJUSTMENTS REGARDING MERP THAT HAVE BEEN MADE
13 IN SOME PRIOR CASES?

14 A. No. In rate cases since the Commission's March 8, 2004 Order approving the
15 MERP Settlement in Docket No. E002/M-02-633, adjustments were made to
16 reflect the capital structure and cost of debt reflected in MERP cost recovery.
17 The need for those MERP related adjustments was eliminated by the roll-in of
18 MERP costs to base rates in the final rates in Docket No. E002/GR-10-971.
19 Again, this item has been removed from the Completeness Checklist, given
20 that it is no longer relevant.

21
22 **VII. SUMMARY AND RECOMMENDATIONS**

23
24 Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

25 A. I recommend that the Commission approve NSPM's proposed 2016 test year
26 capital structure with 52.50 percent common equity and an overall rate of
27 return of 7.49 percent, as follows:

2016 Test Year
Recommended Capital Structure Ratios and Costs (NSPM)
(as presented in Table 1 on Page 4)

	Percent of Total Capital	Cost	Weighted Cost
Short-Term Debt	1.26%	1.84%	0.02%
Long-Term Debt	46.24%	4.81%	2.22%
Common Equity	52.50%	10.00%	5.25%
Total Capital	100.00%		7.49%

I also recommend that the Commission approve a proposed 2017 capital structure with 52.50 percent common equity and an overall rate of return of 7.51 percent, as follows:

2017
Recommended Capital Structure Ratios and Costs (NSPM)
(as presented in Table 2 on Page 4)

	Percent of Total Capital	Cost	Weighted Cost
Short-Term Debt	1.46%	3.57%	0.05%
Long-Term Debt	46.04%	4.81%	2.21%
Common Equity	52.5%	10.00%	5.25%
Total Capital	100.00%		7.51%

And, I recommend that the Commission approve a proposed 2018 capital structure with 52.50 percent common equity and an overall rate of return of 7.51 percent, as follows:

2018
Recommended Capital Structure Ratios and Costs (NSPM)
(as presented in Table 3 on Page 5)

	Percent of Total Capital	Cost	Weighted Cost
<i>Short-Term Debt</i>	1.09%	4.45%	0.05%
<i>Long-Term Debt</i>	46.41%	4.77%	2.21%
<i>Common Equity</i>	52.50%	10.00%	5.25%
<i>Total Capital</i>	100.00%		7.51%

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

Q. WHY DOES THE COMPANY RECOMMEND THE COMMISSION APPROVE THE ABOVE CAPITAL STRUCTURES AND COSTS?

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

1 evidenced by the Company's cost of LTD improvement from 6.31 percent in
2 2010 to 4.81 percent projected for 2016.

3

4 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

5 A. Yes, it does.

Statement of Qualifications

Brian J. Van Abel

Education:

Bachelor of Arts – Economics 2004

Dartmouth College

Master of Business Administration – Finance 2010

University of Michigan – Ross School of Business

Employment:

Dove/Hitachi Consulting – Management Consulting

September 2004 – February 2006	Financial Analyst, Retail Banking
March 2006 – February 2007	Consultant, Retail Banking
March 2007– June 2008	Senior Consultant, Retail Banking

Xcel Energy Inc.

July 2010 – December 2010	Principal Consultant, Revenue Requirements
January 2011 – April 2014	Principal Consultant, Treasury Forecasting
May 2014 – June 2015	Assistant Treasurer
July 2015 – Present	Vice President and Treasurer

RATE OF RETURN COST OF CAPITAL SCHEDULES
Cost of Capital**PROPOSED TEST YEAR 2016 COST OF CAPITAL**

<u>Capitalization:</u>	<u>(\$000's) Amount</u>	<u>Percent of Total Capitalization</u>	<u>Cost of Capital</u>	<u>Weighted Cost of Capital*</u>
Long-Term Debt	\$4,618,004	46.24%	4.81%	2.22%
Short-Term Debt	<u>\$126,134</u>	<u>1.26%</u>	1.84%	<u>0.02%</u>
Total Debt	\$4,744,138	47.50%		2.24%
Net Common Equity	<u>\$5,243,944</u>	<u>52.50%</u>	10.00%	<u>5.25%</u>
Total Capitalization	<u><u>\$9,988,082</u></u>	<u><u>100.00%</u></u>		<u><u>7.49%</u></u>

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

RATE OF RETURN COST OF CAPITAL SCHEDULES

Cost of Capital

PROPOSED ADDITIONAL TEST YEAR 2017 COST OF CAPITAL

<u>Capitalization:</u>	<u>(\$000's) Amount</u>	<u>Percent of Total Capitalization</u>	<u>Cost of Capital</u>	<u>Weighted Cost of Capital*</u>
Long-Term Debt	\$4,707,856	46.04%	4.81%	2.21%
Short-Term Debt	<u>\$149,241</u>	<u>1.46%</u>	3.57%	<u>0.05%</u>
Total Debt	\$4,857,097	47.50%		2.26%
Net Common Equity	<u>\$5,367,564</u>	<u>52.50%</u>	10.00%	<u>5.25%</u>
Total Capitalization	<u>\$10,224,661</u>	<u>100.00%</u>		<u>7.51%</u>

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

Equity Amounts are 13-Month Average Balances.

RATE OF RETURN COST OF CAPITAL SCHEDULES

Cost of Capital

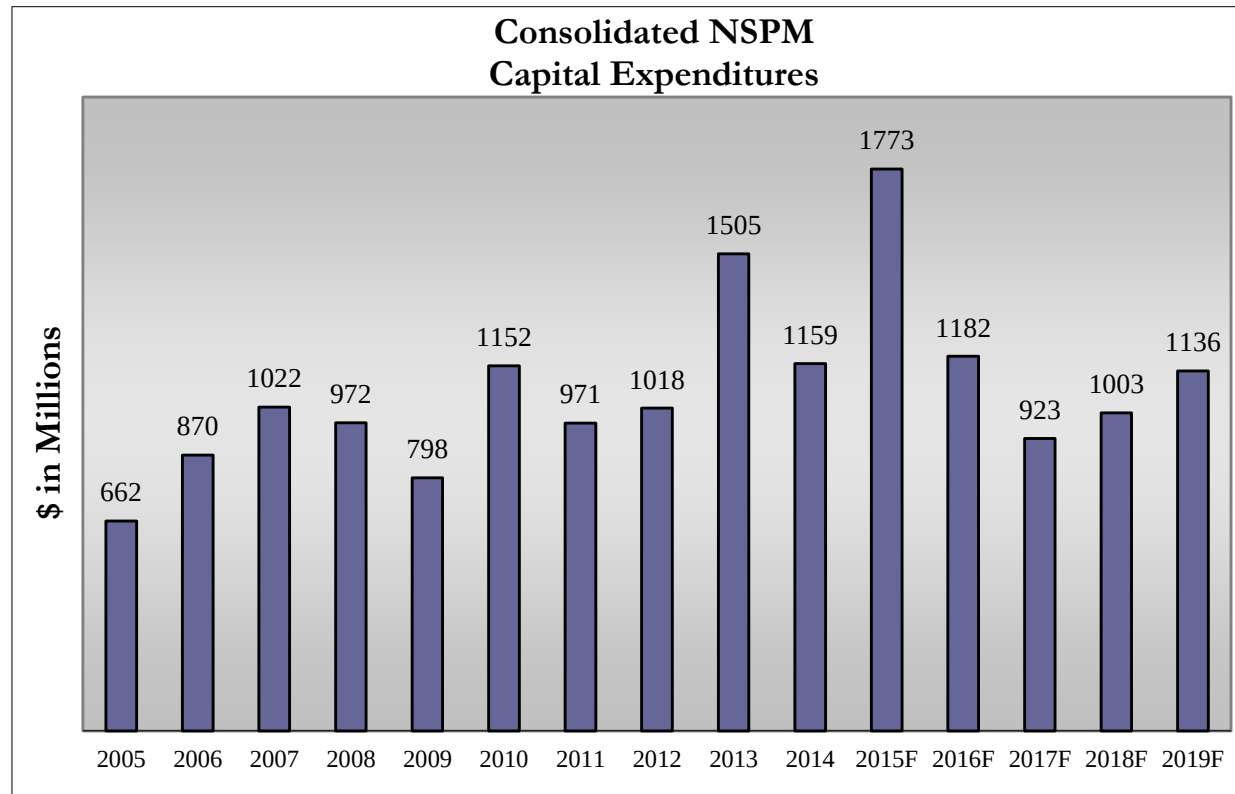
PROPOSED ADDITIONAL TEST YEAR 2018 COST OF CAPITAL

<u>Capitalization:</u>	<u>(\$000's) Amount</u>	<u>Percent of Total Capitalization</u>	<u>Cost of Capital</u>	<u>Weighted Cost of Capital*</u>
Long-Term Debt	\$4,710,626	46.41%	4.77%	2.21%
Short-Term Debt	<u>\$110,302</u>	<u>1.09%</u>	4.45%	<u>0.05%</u>
Total Debt	\$4,820,928	#VALUE!		2.26%
Net Common Equity	<u>\$5,328,427</u>	<u>52.50%</u>	10.00%	<u>5.25%</u>
Total Capitalization	<u>\$10,149,355</u>	<u>#VALUE!</u>		<u>7.51%</u>

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

Equity Amounts are 13-Month Average Balances.

RATE OF RETURN COST OF CAPITAL SCHEDULES



- (a) 2005 - 2014 actual 10-year expenditures = \$10.1B, average spend per year = \$933M
- (b) 2010 - 2014 actual 5-year expenditures = \$5.8B, average spend per year = \$1,161M
- (c) 2015 - 2019 forecast 5-year expenditures = \$6.0B, average spend per year = \$1,203M



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Criteria | Corporates | Utilities:

Key Credit Factors For The Regulated Utilities Industry

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RELATED CRITERIA AND RESEARCH

Criteria | Corporates | Utilities:

Key Credit Factors For The Regulated Utilities Industry

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

1. Standard & Poor's Ratings Services is refining and adapting its methodology and assumptions for its Key Credit Factors: Criteria For Regulated Utilities. We are publishing these criteria in conjunction with our corporate criteria (see "Corporate Methodology, published Nov. 19, 2013). This article relates to our criteria article, "Principles Of Credit Ratings," Feb. 16, 2011.
2. This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," Nov. 26, 2008, "Criteria: Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.

SCOPE OF THE CRITERIA

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

SUMMARY OF THE CRITERIA

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

Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry

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

IMPACT ON OUTSTANDING RATINGS

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

EFFECTIVE DATE AND TRANSITION

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

METHODOLOGY

Part I--Business Risk Analysis

Industry risk

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

Cyclical

9. We assess cyclical 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' cyclical assessment calibrates to low risk ('2'). We generally consider that the higher the level of profitability cyclical in an industry, the higher the credit risk of entities operating in that industry. However, the overall effect of cyclical 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.

Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry

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:

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

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

Table 1

Preliminary Regulatory Advantage Assessment		
Qualifier	What it means	Guidance
Strong	The utility has a major regulatory advantage due to one or a combination of factors that support cost recovery and a return on capital combined with lower than average volatility of earnings and cash flows.	The utility operates in a regulatory climate that is transparent, predictable, and consistent from a credit perspective.
	There are strong prospects that the utility can sustain this advantage over the long term.	The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base).
	This should enable the utility to withstand economic downturns and political risks better than other utilities.	The tariff set may include a pass-through mechanism for major expenses such as commodity costs, or a higher return on new assets, effectively shielding the utility from volume and input cost risks.
		Any incentives in the regulatory scheme are contained and symmetrical.
		The tariff set includes mechanisms allowing for a tariff adjustment for the timely recovery of volatile or unexpected operating and capital costs.
		There is a track record of earning a stable, compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.
		There is support of cash flows during construction of large projects, and pre-approval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs.
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.	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.
	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.	It operates in a regulatory environment that is less transparent, less predictable, and less consistent from a credit perspective.
		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.

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

29. After determining the preliminary regulatory advantage assessment, we then assess the utility's business strategy. Most importantly, this factor addresses the effectiveness of a utility's management of the regulatory risk in the jurisdiction(s) where it operates. In certain jurisdictions, a utility's regulatory strategy and its ability to manage the tariff-setting process effectively so that revenues change with costs can be a compelling regulatory risk factor. A utility's approach and strategies surrounding regulatory matters can create a durable "competitive advantage" that differentiates it from peers, especially if the risk of political intervention is high. The assessment of a utility's business strategy is informed by historical performance and its forward-looking business objectives. We evaluate these objectives in the context of industry dynamics and the regulatory climate in which the utility operates, as evaluated through the factors cited in paragraphs 24-27.
30. We modify the preliminary regulatory advantage assessment to reflect this influence positively or negatively. Where business strategy has limited effect relative to peers, we view the implications as neutral and make no adjustment. A positive assessment improves the preliminary regulatory advantage assessment by one category and indicates that management's business strategy is expected to bolster its regulatory advantage through favorable commission rulings beyond what is typical for a utility in that jurisdiction. Conversely, where management's strategy or businesses decisions result in adverse regulatory outcomes relative to peers, such as failure to achieve typical cost recovery or allowed returns, we adjust the preliminary regulatory advantage assessment one category worse. In extreme cases of poor strategic execution, the preliminary regulatory advantage assessment is adjusted by two categories worse (when possible; see table 2) to reflect management decisions that are likely to result in a significantly adverse regulatory outcome relative to peers.

*Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry***Table 2****Determining The Final Regulatory Advantage Assessment**

Preliminary regulatory advantage score	--Strategy modifier--			
	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.,

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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 cyclicity 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.

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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

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operating efficiency is generally otherwise considered adequate.

Profitability

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

Level of profitability

48. Key measures of general profitability for regulated utilities commonly include ratios, which we compare both with those of peers and those of companies in other industries to reflect different countries' regulatory frameworks and business environments:
- EBITDA margin,
 - Return on capital (ROC), and
 - Return on equity (ROE).
49. In many cases, EBITDA as a percentage of sales (i.e., EBITDA margin) is a key indicator of profitability. This is because the book value of capital does not always reflect true earning potential, for example when governments privatize or restructure incumbent state-owned utilities. Regulatory capital values can vary with those of reported capital because regulatory capital values are not inflation-indexed and could be subject to different assumptions concerning depreciation. In general, a country's inflation rate or required rate of return on equity investment is closely linked to a utility company's profitability. We do not adjust our analysis for these factors, because we can make our assessment through a peer comparison.
50. For regulated utilities subject to full cost-of-service regulation and return-on-investment requirements, we normally measure profitability using ROE, the ratio of net income available for common stockholders to average common equity. When setting rates, the regulator ultimately bases its decision on an authorized ROE. However, different factors such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of-service-based utilities centers on the utility's ability to consistently earn the authorized ROE.
51. We will use return on capital when pass-through costs distort profit margins--for instance congestion revenues or collection of third-party revenues. This is also the case when the utility uses accelerated depreciation of assets, which in our view might not be sustainable in the long run.

Volatility of profitability

52. We may observe a clear difference between the volatility of actual profitability and the volatility of underlying regulatory profitability. In these cases, we could use the regulatory accounts as a proxy to judge the stability of earnings.
53. We use actual returns to calculate the standard error of regression for regulated utility issuers (only if there are at least

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

Part II--Financial Risk Analysis

D. Accounting

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

Accounting characteristics

55. Some important accounting practices for utilities include:
- For integrated electric utilities that meet native load obligations in part with third-party power contracts, we use our purchased power methodology to adjust measures for the debt-like obligation such contracts represent (see below).
 - Due to distortions in leverage measures from the substantial seasonal working-capital requirements of natural gas distribution utilities, we adjust inventory and debt balances by netting the value of inventory against outstanding short-term borrowings. This adjustment provides an accurate view of the company's balance sheet by reducing seasonal debt balances when we see a very high certainty of near-term cost recovery (see below).
 - We deconsolidate securitized debt (and associated revenues and expenses) that has been accorded specialized recovery provisions (see below).
 - For water utilities that report under U.K. GAAP, we adjust ratios for infrastructure renewals accounting, which permits water companies to capitalize the maintenance spending on their infrastructure assets (see below). The adjustments aim to make those water companies that report under U.K. GAAP more comparable to those that report under accounting regimes that do not permit infrastructure renewals accounting.
56. In the U.S. and selectively in other regions, utilities employ "regulatory accounting," which permits a rate-regulated company to defer some revenues and expenses to match the timing of the recognition of those items in rates as determined by regulators. A utility subject to regulatory accounting will therefore have assets and liabilities on its books that an unregulated corporation, or even regulated utilities in many other global regions, cannot record. We do not adjust GAAP earnings or balance-sheet figures to remove the effects of regulatory accounting. However, as more countries adopt International Financial Reporting Standards (IFRS), the use of regulatory accounting will become more scarce. IFRS does not currently provide for any recognition of the effects of rate regulation for financial reporting purposes, but it is considering the use of regulatory accounting. We do not anticipate altering our fundamental financial analysis of utilities because of the use or non-use of regulatory accounting. We will continue to analyze the effects of regulatory actions on a utility's financial health.

*Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry***Purchased power adjustment**

57. We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates. (See "Standard & Poor's Methodology For Imputing Debt for U.S. Utilities' Power Purchase Agreements," May 7, 2007, for more background and information on the adjustment.)
58. We calculate the present value (PV) of the future stream of capacity payments under the contracts as reported in the financial statement footnotes or as supplied directly by the company. The discount rate used is the same as the one used in the operating lease adjustment, i.e., 7%. For U.S. companies, notes to the financial statements enumerate capacity payments for the coming five years, and a thereafter period. Company forecasts show the detail underlying the thereafter amount, or we divide the amount reported as thereafter by the average of the capacity payments in the preceding five years to get an approximation of annual payments after year five.
59. We also consider new contracts that will start during the forecast period. The company provides us the information regarding these contracts. If these contracts represent extensions of existing PPAs, they are immediately included in the PV calculation. However, a contract sometimes is executed in anticipation of incremental future needs, so the energy will not flow until some later period and there are no interim payments. In these instances, we incorporate that contract in our projections, starting in the year that energy deliveries begin under the contract. The projected PPA debt is included in projected ratios as a current rating factor, even though it is not included in the current-year ratio calculations.
60. The PV is adjusted to reflect regulatory or legislative cost-recovery mechanisms when present. Where there is no explicit regulatory or legislative recovery of PPA costs, as in most European countries, the PV may be adjusted for other mitigating factors that reduce the risk of the PPAs to the utility, such as a limited economic importance of the PPAs to the utility's overall portfolio. The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor.
61. Risk factors based on regulatory or legislative cost recovery typically range between 0% and 50%, but can be as high as 100%. A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity. These utilities are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties that act as intermediaries between retail customers and electricity suppliers. We employ a 50% risk factor in cases where regulators use base rates for the recovery of the fixed PPA costs. If a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed. In certain jurisdictions, true-up mechanisms are more favorable and frequent than the review of base rates, but still do not amount to pure fuel adjustment clauses. Such mechanisms may be triggered by financial thresholds or passage of prescribed periods of time. In these instances, a risk factor between 25% and 50% is

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

62. Where there is no explicit regulatory or legislative recovery of PPA costs, the risk factor is generally 100%. We may use a lower risk factor if mitigating factors reduce the risk of the PPAs on the utility. Mitigating factors include a long position in owned generation capacity relative to the utility's customer supply needs that limits the importance of the PPAs to the utility or the ability to resell power in a highly liquid market at minimal loss. A utility with surplus owned generation capacity would be assigned a risk factor of less than 100%, generally 50% or lower, because we would assess its reliance on PPAs as limited. For fixed capacity payments under PPAs related to renewable power, we use a risk factor of less than 100% if the utility benefits from government subsidies. The risk factor reflects the degree of regulatory recovery through the government subsidy.
63. Given the long-term mandate of electric utilities to meet their customers' demand for electricity, and also to enable comparison of companies with different contract lengths, we may use an evergreening methodology. Evergreen treatment extends the duration of short- and intermediate-term contracts to a common length of about 12 years. To quantify the cost of the extended capacity, we use empirical data regarding the cost of developing new peaking capacity, incorporating regional differences. The cost of new capacity is translated into a dollars-per-kilowatt-year figure using a proxy weighted-average cost of capital and a proxy capital recovery period.
64. Some PPAs are treated as operating leases for accounting purposes--based on the tenor of the PPA or the residual value of the asset on the PPA's expiration. We accord PPA treatment to those obligations, in lieu of lease treatment; rather, the PV of the stream of capacity payments associated with these PPAs is reduced to reflect the applicable risk factor.
65. Long-term transmission contracts can also substitute for new generation, and, accordingly, may fall under our PPA methodology. We sometimes view these types of transmission arrangements as extensions of the power plants to which they are connected or the markets that they serve. Accordingly, we impute debt for the fixed costs associated with such transmission contracts.
66. Adjustment procedures:
 - Data requirements:
 - Future capacity payments obtained from the financial statement footnotes or from management.
 - Discount rate: 7%.
 - Analytically determined risk factor.
 - Calculations:
 - Balance sheet debt is increased by the PV of the stream of capacity payments multiplied by the risk factor.
 - Equity is not adjusted because the recharacterization of the PPA implies the creation of an asset, which offsets the debt.
 - Property, plant, and equipment and total assets are increased for the implied creation of an asset equivalent to the

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debt.

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

Natural gas inventory adjustment

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

68. Adjustment procedures:

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

Securitized debt adjustment

69. For regulated utilities, we deconsolidate debt (and associated revenues and expenses) that the utility issues as part of a securitization of costs that have been segregated for specialized recovery by the government entity constitutionally authorized to mandate such recovery if the securitization structure contains a number of protective features:
- An irrevocable, non-bypassable charge and an absolute transfer and first-priority security interest in transition property;
 - Periodic adjustments ("true-up") of the charge to remediate over- or under-collections compared with the debt service obligation. The true-up ensures collections match debt service over time and do not diverge significantly in the short run; and,
 - Reserve accounts to cover any temporary short-term shortfall in collections.

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

71. Adjustment procedures:

- Data requirements:
- Amount of securitized debt on the utility's balance sheet at period end;
- Interest expense related to securitized debt for the period; and
- Principal payments on securitized debt during the period.
- Calculations:
- Adjustment to debt: We subtract the securitized debt from total debt.
- Adjustment to revenues: We reduce revenue allocated to securitized debt principal and interest. The adjustment is the sum of interest and principal payments made during the year.
- Adjustment to operating income after depreciation and amortization (D&A) and EBIT: We reduce D&A related to the securitized debt, which is assumed to equal the principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.
- Adjustment to interest expense: We remove the interest expense of the securitized debt from total interest expense.
- Operating cash flows:
- We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

Infrastructure renewals expenditure

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

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

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

74. Adjustment procedures:

- Data requirements:
- U.K. GAAP accounts typically provide little information on the portion of capital spending that relates to renewals accounting, or the related depreciation, which is referred to as the infrastructure renewals charge. The information we use for our adjustments is, however, found in the regulatory cost accounts submitted annually by the water companies to the Water Services Regulation Authority, which regulates all water companies in England and Wales.
- Calculations:
- EBITDA: Reduced by the value of IRE that was capitalized in the period.
- EBIT: Adjusted for the difference between the adjustment to EBITDA and the reduction in the depreciation expense, depending on the degree to which the actual cash spending in the current year matches the planned spending over the five-year regulatory review period.
- Cash flow from operations and FFO: Reduced by the value of IRE that was capitalized in the period.
- Capital spending: Reduced by the value of infrastructure renewals spending that we reclassify to cash flow from operations.
- Free operating cash flow: No impact, as the reduction in operating cash flows is exactly offset by the reduction in capital spending.

E. Cash flow/leverage analysis

75. In assessing the cash flow adequacy of a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology"). We assess cash flow/leverage on a six-point scale ranging from ('1') minimal to ('6') highly leveraged. These scores are determined by aggregating the assessments of a range of credit ratios, predominantly cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations.
76. The corporate methodology provides benchmark ranges for various cash flow ratios we associate with different cash flow leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.
77. If an industry's volatility levels are low, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment are less stringent, although the width of the ratio range is narrower. Conversely, if an industry has standard levels of volatility, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment may be elevated, but with a wider range of values.
78. We apply the "low-volatility" table to regulated utilities that qualify under the corporate criteria and with all of the following characteristics:
- A vast majority of operating cash flows come from regulated operations that are predominantly at the low end of the utility risk spectrum (e.g., a "network," or distribution/transmission business unexposed to commodity risk and with very low operating risk);
 - A "strong" regulatory advantage assessment;

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

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

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

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

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

Part III--Rating Modifiers

F. Diversification/portfolio effect

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

G. Capital structure

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

H. Liquidity

83. In assessing a utility's liquidity/short-term factors, our analysis is consistent with the methodology that applies to corporate issuers (See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," Nov. 19, 2013) except for the standards for "adequate" liquidity set out in paragraph 84 below.
84. The relative certainty of financial performance by utilities operating under relatively predictable regulatory monopoly frameworks make these utilities attractive to investors even in times of economic stress and market turbulence compared to conventional industrials. For this reason, utilities with business risk profiles of at least "satisfactory" meet our definition of "adequate" liquidity based on a slightly lower ratio of sources to uses of funds of 1.1x compared with the standard 1.2x. Also, recognizing the cash flow stability of regulated utilities we allow more discretion when calculating covenant headroom. We consider that utilities have adequate liquidity if they generate positive sources over uses, even if forecast EBITDA declines by 10% (compared with the 15% benchmark for corporate issuers) before covenants are breached.

*Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry***I. Financial policy**

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

J. Management and governance

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

K. Comparable ratings analysis

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

Appendix--Frequently Asked Questions**Does Standard & Poor's expect that the business strategy modifier to the preliminary regulatory advantage will be used extensively?**

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

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

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

What is your definition of regulatory jurisdiction?

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

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

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

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

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

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

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

RELATED CRITERIA AND RESEARCH

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

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MOODY'S
INVESTORS SERVICE**Credit Opinion: Northern States Power Company (Minnesota)**

Global Credit Research - 12 Aug 2015

*Minneapolis, Minnesota, United States***Ratings**

Category	Moody's Rating
Outlook	Stable
Issuer Rating	A2
First Mortgage Bonds	Aa3
Sr Unsec Bank Credit Facility	A2
Commercial Paper	P-1
Parent: Xcel Energy Inc.	
Outlook	Stable
Issuer Rating	A3
Sr Unsec Bank Credit Facility	A3
Senior Unsecured	A3
Subordinate Shelf	(P)Baa1
Pref. Shelf	(P)Baa2
Commercial Paper	P-2

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Key Indicators**[1]Northern States Power Company (Minnesota)**

	6/30/2015(L)	12/31/2014	12/31/2013	12/31/2012	12/31/2011
CFO pre-WC + Interest / Interest	6.5x	6.8x	6.0x	5.5x	5.6x
CFO pre-WC / Debt	25.4%	26.2%	23.7%	23.6%	27.0%
CFO pre-WC - Dividends / Debt	19.4%	20.6%	18.3%	17.8%	20.8%
Debt / Capitalization	38.6%	39.5%	39.1%	40.6%	41.0%

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

Note: For definitions of Moody's most common ratio terms please see the accompanying [User's Guide](#).

Opinion**Rating Drivers**

Seeking to get off the rate case treadmill as another filing is planned

Capex remains elevated, at least for another year

Strong, consistent credit metrics

Corporate Profile

Northern States Power Company (Minnesota) (NSP-Minnesota, A2 senior unsecured) is the largest utility in Minnesota with 1.4 million electric and 0.5 million natural gas customers. Its operations are concentrated in Minnesota (almost 90% of revenues), mostly around Minneapolis-St. Paul, with a small remainder in North Dakota and South Dakota. NSP-Minnesota is the second-largest and the legacy subsidiary of Xcel Energy Inc. (Xcel, A3 senior unsecured), a holding company with utility operations in eight states serving 5.5 million electric and natural gas customers. NSP-Minnesota and its smaller neighboring sister company Northern States Power (Wisconsin) (NSP-Wisconsin, A2 senior unsecured) operate their electric production and transmission systems as an integrated system known as the NSP System. This operational integration contributes to their ratings being the same.

SUMMARY RATING RATIONALE

NSP-Minnesota's A2 senior unsecured rating is based on the stable, low-risk nature of its regulated operations. Although its service territory is concentrated in Minnesota, NSP-Minnesota has benefited from a regulatory environment there that has historically provided better-than-average recovery mechanisms for utility costs. A series of large, litigated rate cases in recent years have created noise, but the company's steady, above-average credit metrics indicate that Minnesota regulation remains supportive of its credit quality. Longer term, we expect that the company to maintain its historically robust credit metrics through sufficient rate relief, cost control, and equity contributions from Xcel.

DETAILED RATING CONSIDERATIONS

SEEKING TO GET OFF THE RATE CASE TREADMILL AS ANOTHER FILING IS PLANNED

Electric operations in Minnesota, representing about 90% of its rate base, is NSP-Minnesota's most important business. Xcel attributes the majority of its consolidated earnings shortfall to these Minnesota operations; therefore, the 2013 and 2014 electric rate cases were a material matter for both the company and Xcel. NSP-Minnesota's frequent rate cases (four concluded in the last six years) are a result of a large capital program that the company has sustained over the past decade.

In July 2015, the Minnesota Public Utilities Commission's (MPUC) final decision on the 2014 electric case resulted in a total rate increase of \$149 million (a 5.3% increase, about 67% of its request) over two years: \$59 million in 2014, and \$90 million in 2015. The MPUC authorized a 9.7% ROE on a 52.5% equity ratio.

This rate decision was credit positive in that it granted not only additional revenues, but also two precedent-setting features: a multi-year rate plan and full decoupling for the residential and small C&I classes. The two-year rate plan extends revenue visibility through the end of this year and indicates the potential for future rate plans that would allow the company to stay out of rate cases longer. The three-year decoupling pilot will help stabilize NSP-Minnesota's margins from fluctuations due to conservation and weather. Decoupling will be helpful as the company continues to see downward pressure on customer usage.

On the other hand, as part of the rate decision, the MPUC disallowed NSP-Minnesota from earning a return on the \$333 million cost-overrun in the refurbishment of its Monticello nuclear facility. Furthermore, the rate case took well over a year, leaving less than a year before the term of its rate plan expired, and necessitating yet another rate filing.

NSP-Minnesota is pursuing legislative means to get off the rate case treadmill. For example, it advocated the Energy and Jobs Bill that Minnesota recently passed into law. In its 2016 electric case, the company may test some new rate mechanisms now allowed under this law, such as multi-year rate plans of up to five years, as well as a formulaic recovery of O&M and capital costs.

CAPEX REMAINS ELEVATED, AT LEAST FOR ANOTHER YEAR

For much this past decade, NSP-Minnesota's annual capex has averaged around \$1.1 billion. With rate relief, cash flows have risen to around that level. The big-ticket items in this capital program are done (e.g., the Monticello refurbishment) or winding down (the \$1.1 billion CapX 2020 transmission projects). Without such big projects, NSP-Minnesota's annual capex could fall over the next couple of years to the \$900 million range.

Capex will remain elevated at least through 2015 with the \$580 million Pleasant Valley and Border Winds wind

farm projects. In 2016, NSP-Minnesota expects to complete the \$300 million Courtenay Wind Farm, subject to regulatory approval.

STRONG, CONSISTENT CREDIT METRICS

NSP-Minnesota's credit ratios are strong and have varied little over the past three years 2012- 2015. Notwithstanding the large capital program underway during this time, as of June 2015, the three-year average ratio of cash flow from operations before changes in working capital (CFO pre-W/C) to debt was 24.8%, while the average ratio of CFO pre-W/C plus interest to interest was 6.3 times. NSP-Minnesota also received regular equity contributions from Xcel which offset some of the dividends it paid to its parent. This financial policy has kept NSP-Minnesota well capitalized at an average book debt to capitalization of 39.4%, using our standard adjustments, and an equity ratio around its authorized level of 52%.

Liquidity Profile

NSP-Minnesota has adequate liquidity supported by stable cash flow, its own credit facility, and a money pool arrangement with two other Xcel utilities. In the last twelve months ended June 2015, NSP-Minnesota reported cash flow from operations of \$1.3 billion, less than the \$1.6 billion of capital expenditures budgeted for 2015 and the \$250 million debt maturity due on 15 August 2015. In August 2015, it issued \$600 million of debt to refinance the maturing debt and to meet the funding need for its capex. The company has been paying dividends to Xcel in the \$200 million range, but gets much of it back in equity contributions.

NSP-Minnesota has a \$500 million five-year credit facility, expiring in October 2019. The agreement does not require a MAC representation for borrowings but contains one financial covenant, requiring debt to total capitalization to be below 65%. The company has ample headroom under this covenant with the ratio, as defined in the agreement, at 48% as of 30 June 2015. The credit facility provides for same-day funding and serves as back-up support for the utility's \$500 million commercial paper program and letters of credit. As of 30 June 2015, NSP-Minnesota had approximately \$72 million of cash on hand and \$356 million of unused capacity under the credit facility.

Another source of alternate liquidity is a money pool that NSP-Minnesota shares with its sister companies Public Service Company of Colorado and Southwestern Public Service. Under this money pool, these affiliates make short-term loans to each other, as well as borrow on a short-term basis from Xcel. Xcel, on the other hand, is precluded from borrowing from the money pool. As of 30 June 2015, NSP-Minnesota had full availability under its \$250 million money pool limit.

Rating Outlook

NSP-Minnesota's stable outlook is supported by the predictable nature of the utility and its solid financial profile. While capital expenditures will remain higher than the run-rate over the next 12 to 18 months, the stable outlook anticipates that the company will get adequate, timely rate relief in its regulatory proceedings, control its O&M costs, and that Xcel will maintain prudent financial policies to keep CFO pre-W/C to debt generally in the mid 20% range.

A change in Xcel's rating or outlook could cause a similar change at NSP-Minnesota.

What Could Change the Rating - Up

A rating upgrade is unlikely in the foreseeable future with some key regulatory activity ahead of it and a flat outlook for its credit metrics. Longer term, however, an upgrade is possible if rate increases and cost savings sustain improved credit metrics, as demonstrated by CFO pre-W/C to debt remaining in the high 20% range for an extended period.

What Could Change the Rating - Down

The ratings could be downgraded if adverse regulatory rulings or a change in financial policy to use more debt financing for capital expenditures result in weaker credit metrics with CFO pre-W/C to debt falling to the low 20% range for an extended period.

Rating Factors

Northern States Power Company (Minnesota)

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 6/30/2015		[3]Moody's 12-18 Month Forward ViewAs of 8/11/2015	
Factor 1 : Regulatory Framework (25%)	Measure	Score	Measure	Score
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.3x	Aa	6.3x - 6.5x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	24.8%	A	24% - 26%	A
c) CFO pre-WC - Dividends / Debt (3 Year Avg)	19.2%	A	17% - 19%	A
d) Debt / Capitalization (3 Year Avg)	39.4%	A	38% - 40%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching				
a) Indicated Rating from Grid		A2		A2
b) Actual Rating Assigned				(P)A2

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. [2] As of 6/30/2015(L); Source: Moody's Financial Metrics [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

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Corporates

Utilities, Power & Gas / U.S.A.

Northern States Power Co.-Minnesota

Subsidiary of Xcel Energy Inc.
Full Rating Report

Ratings

Long-Term IDR	A-
Senior Secured	A+
Short-Term IDR	F2
Commercial Paper	F2

IDR – Issuer Default Rating.

Rating Outlook

Stable

Financial Summary

Northern States Power Co.-Minnesota

		LTM	
(\$ Mil.)		3/31/15	2014
Adjusted Revenue		4,856	4,988
Operating EBITDAR		1,052	1,186
Cash Flow from Operations		1,332	1,112
Total Adjusted Debt		4,348	4,414
Total Capitalization		8,995	9,034
Capex/Depreciation (%)		2.9	3.0
FFO Fixed-Charge Coverage (x)		6.6	6.7
FFO-Adjusted Leverage (x)		3.1	3.2
Total Adjusted Debt/EBITDAR (x)		4.1	3.7

Related Research

Northern States Power Co. – Minnesota
– Ratings Navigator (March 2015)
Fitch Affirms XEL and Subsidiaries
Ratings; Outlook Stable
(November 2014)

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Key Rating Drivers

Balanced Regulation: Northern States Power Company-Minnesota's (NSP-Minnesota) ratings reflect a relatively balanced and stable regulatory environment across three states, and Fitch Ratings expects reasonable outcomes to future rate case filings. Supportive regulatory mechanisms include fuel cost and purchased power adjustments and capital investment riders for environmental improvement, renewable generation, and electric transmission.

Minnesota Electric Rate Order: Fitch believes the Minnesota Public Utilities Commission's (MPUC) recent rate order is slightly punitive with respect to the low authorized return on equity (ROE) of 9.72% and the Monticello nuclear plant uprate and life extension project ruling. The MPUC disallowed a return on \$333 million of cost overruns and determined the project is not used-and-useful until approved by the Nuclear Regulatory Commission (NRC).

The electric rate order will somewhat weaken NSP-Minnesota's credit metrics over the near term. However, Fitch considers the overall regulatory environment in Minnesota to remain supportive of credit quality, as evidenced by a balanced rate increase, the authorized 52.5% equity capital structure, and the implementation of a revenue decoupling pilot program.

Capex Peaking in 2015: NSP-Minnesota is nearing the end of a large, multi-year capex program, having spent an average of \$1.25 billion per year over 2011–2014. The utility is expected to spend \$1.625 billion in 2015, not including an additional \$300 million over 2015–2016 on the 200-MW Courtenay wind project that is pending regulatory approvals. In 2016, capex is expected to return to more modest levels, averaging \$950 million per year over 2016–2019, excluding potential costs in 2016 related to the Courtenay wind project.

Robust Credit Metrics: For the LTM ended March 31, 2015, FFO fixed-charge coverage stood at 6.6x, FFO-adjusted leverage at 3.1x, and adjusted debt/EBITDAR at 4.1x. Fitch forecasts FFO fixed-charge coverage to average 6.2x, FFO-adjusted leverage 3.3x, and adjusted debt/EBITDAR 3.6x over 2015–2018. The FFO metrics include the favorable impact of production tax credits associated with the utility's wind investments in 2015.

Parent Support: Fitch views the relationship between NSP-Minnesota and its parent, Xcel Energy Inc. (Xcel; BBB+/Stable), as a credit positive for the utility. Xcel provides equity funding to NSP-Minnesota to support its long-term growth and to optimize its capital mix within an appropriate targeted range. Xcel's strategy continues to be focused on successfully managing rate cases and reducing regulatory lag.

Rating Sensitivities

Positive Rating Action: Given the disallowance of certain returns on the Monticello plant, a positive rating action is unlikely in the near term, but could occur if adjusted debt/EBITDAR were to improve to 3.0x and FFO-adjusted leverage to 3.2x on a sustained basis.

Negative Rating Action: Future developments that may, individually or collectively, lead to a negative rating action include a material deterioration of the regulatory environment in Minnesota; adjusted debt/EBITDAR weakening to 4.0x on a sustained basis; and a shift in management strategy that results in weaker financial support from Xcel.



Corporates

Financial Overview

Liquidity and Debt Structure

Fitch considers NSP-Minnesota's liquidity to be adequate. NSP-Minnesota primarily meets its short-term obligations through the issuance of commercial paper (CP) under its \$500 million revolving credit facility, which expires in October 2019. At March 31, 2015, NSP-Minnesota had \$76 million of CP issued and \$24 million of letters of credit drawn, leaving \$400 million of availability under this five-year unsecured facility. The utility has the right to request two additional one-year extensions of the revolving credit facility and an increase in the size of the facility of up to \$100 million, both subject to majority bank group approval.

Liquidity is also available through participation in a money pool with its sister utilities Public Service Company of Colorado (PSCo; A-/Stable) and Southwestern Public Service Company (SPS; BBB/Stable). Xcel may make investments in the utility subsidiaries at market-based interest rates, but the utilities are not permitted to lend to the parent under the money pool arrangement. NSP-Minnesota has a borrowing limit of \$250 million, which was fully available at March 31, 2015. As is typical for a utility, NSP-Minnesota's operations require modest cash on hand, and the utility had \$91 million as of March 31, 2015, all of which was unrestricted.

Long-term debt maturities are manageable. NSP-Minnesota has \$250 million of 1.95% First Mortgage Bonds (FMBs) due in August 2015. The next long-term debt maturity is in March 2018, when \$500 million of 5.25% FMBs comes due. NSP-Minnesota has no other long-term debt maturities until 2022.

At March 31, 2015, NSP-Minnesota had \$4.2 billion of long-term debt on its balance sheet, all of which were FMBs. Fitch expects NSP-Minnesota to maintain ready access to the debt capital markets to fund capex and refinance maturing long-term debt.

Fitch makes adjustments to total debt to account for operating leases. This has resulted in an additional \$83 million of debt included in Fitch's adjusted leverage metrics for 2014 and the LTM ended March 31, 2015.

Related Criteria

Recovery Ratings and Notching Criteria for Utilities (March 2015)

Corporate Rating Methodology — Including Short-Term Ratings and Parent and Subsidiary Linkage (May 2014)

Rating U.S. Utilities, Power and Gas Companies (Sector Credit Factors) (March 2014)

Parent and Subsidiary Rating Linkage (Fitch's Approach to Rating Entities within a Corporate Group Structure) (August 2013)

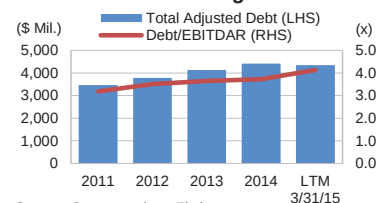
Debt Maturities and Liquidity

(\$ Mil., as of March 31, 2015)

2015	250
2016	—
2017	—
2018	500
Thereafter	3,450
Cash and Cash Equivalents	91
Undrawn Committed Facilities	400

Source: Company data, Fitch.

Total Debt and Leverage



Source: Company data, Fitch.



Corporates

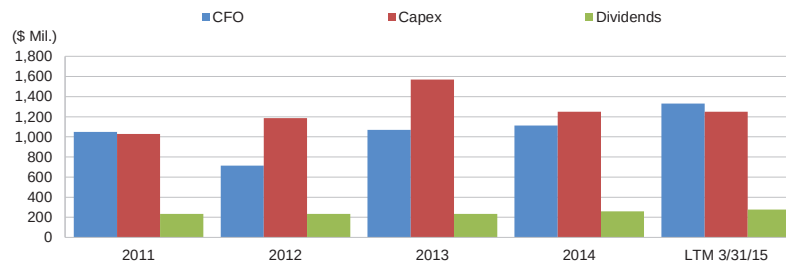
Cash Flow Analysis

Fitch expects NSP-Minnesota to refinance its \$250 million of FMBs maturing in August 2015. Due to the very large level of capex expected to be incurred this year — \$1.625 billion, not including \$300 million over 2015–2016 for the Courtenay wind power project — NSP-Minnesota will need to raise funds externally to finance its capital spending for the rest of the year. Fitch expects NSP-Minnesota to issue additional FMBs during the second half of 2015, with at least part of this issuance likely coinciding with the aforementioned refinancing. The remainder of external funds would likely come in the form of equity infusions from Xcel to maintain the utility's debt-to-capital ratio at or near 47%–48%.

NSP-Minnesota will be significantly FCF negative in 2015. However, the expected sharp slowdown in capital spending starting in 2016, along with operating cash flows that should become much stronger as capex from previous years is added to rate base, could result in positive FCF as soon as 2017. An increase in dividends corresponding to the additional shares of common equity expected to be issued later this year to help fund this growth will have a partially offsetting effect, but Fitch expects cash flows overall to be much stronger going forward.

FFO and cash flow from operating activities (CFO) were nearly \$1.2 billion and more than \$1.3 billion, respectively, for the LTM ended March 31, 2015. Fitch expects both of these cash flow metrics to grow over the next few years, benefiting from NSP-Minnesota's large capex program this year as projects go into service.

CFO and Cash Use



Source: Company data, Fitch.



Corporates

Peer and Sector Analysis

Peer Group

Issuer	Country
A	
Duke Energy Carolinas, LLC	United States
A-	
Public Service Company of Colorado	United States
Gulf Power Company	United States

Issuer Rating History

	LT IDR (FC)	Outlook/Watch
April 24, 2015	A-	Stable
Nov. 20, 2014	A-	Stable
April 7, 2014	A-	Stable
Nov. 14, 2013	A-	Stable
Nov. 14, 2012	A-	Stable
Nov. 18, 2011	A-	Stable
Nov. 23, 2010	A-	Stable
July 22, 2010	A-	Stable
July 22, 2009	A-	Stable
May 22, 2008	A-	Stable
March 15, 2007	A-	Stable
Dec. 6, 2005	A-	Stable
Aug. 9, 2005	A	Stable
Dec. 8, 2003	A-	Stable
June 9, 2003	BBB+	Stable
June 3, 2003	BBB	RWP
Nov. 8, 2002	BBB	RWN
Aug. 29, 2002	BBB	Negative
July 30, 2002	BBB	Negative
June 24, 2002	A	RWN
Dec. 20, 2001	A+	RWN
Aug. 17, 2000	A+	Stable
June 11, 1999	A+	—

LT IDR – Long-term Issuer Default Rating.
FC – Foreign currency. RWP – Rating Watch Positive. RWN – Rating Watch Negative.
Source: Fitch.

Peer Group Analysis

	Northern States Power Co.-Minnesota	Gulf Power Company	Public Service Company of Colorado	Duke Energy Carolinas, LLC
As of	3/31/15	3/31/15	3/31/15	3/31/15
IDR	A-	A-	A-	A
Outlook	Rating Outlook Stable	Rating Outlook Stable	Rating Outlook Stable	Rating Outlook Stable
Fundamental Ratios (x)				
Operating EBITDAR/ (Gross Interest Expense + Rents)	4.96	5.84	6.48	6.45
FFO Fixed-Charge Coverage	6.62	5.15	7.37	6.82
Total Adjusted Debt/Operating EBITDAR	4.13	3.64	3.38	3.05
FFO/Total Adjusted Debt (%)	32.3	27.2	33.6	34.6
FFO-Adjusted Leverage	3.10	3.68	2.98	2.89
Common Dividend Payout (%)	91.4	89.3	72.1	34.7
Internal Cash/Capex (%)	86.1	41.9	79.1	100.5
Capex/Depreciation (%)	290.5	265.4	273.6	187.1
Return on Equity (%)	6.5	10.6	9.3	9.9
Financial Information (\$ Mil.)				
Revenue	4,856	1,541	4,315	7,252
Revenue Growth (%)	(1.1)	1.4	0.6	0.4
EBITDA	1,045	412	1,196	2,920
Operating EBITDA Margin (%)	13.1	25.8	27.8	40.2
FCF	(195)	(205)	(252)	9
Total Adjusted Debt with Equity Credit	4,348	1,552	4,099	9,040
Cash and Cash Equivalents	91	55	3	30
Funds Flow from Operations	1,192	340	1,191	2,670
Capex	(1,249)	(353)	(1,056)	(1,901)

IDR – Issuer Default Rating.
Source: Company data, Fitch.

NSP-Minnesota has supportive financial metrics that are in line with those of its peer group.

Key Rating Issues

Regulatory Developments

NSP-Minnesota's credit quality reflects a regulatory environment in Minnesota, North Dakota and South Dakota that has been relatively constructive and stable. The utility benefits from several retail adjustment clauses that recover costs associated with fuel, purchased power, environmental improvement projects, new renewable generation, and electric transmission investments.

Minnesota 2014 Multi-Year Electric Rate Order

In July 2015, the MPUC issued its final order authorizing a 2014 rate increase of \$58.9 million and a 2015 step increase of \$108.5 million. However, the 2015 step increase was reduced by \$18.0 million due to a negative ruling related to the Monticello nuclear plant. The net result of the rate order for 2014 and 2015 was a combined increase of \$149.4 million, which is 67% of NSP-Minnesota's requested increase, although the 2014 portion was only 50%. Fitch considers the overall rate increase, the preservation of the authorized 52.5% equity capital structure, and the implementation of a revenue decoupling pilot program for residential and small commercial and industrial customers to be supportive of credit quality.

However, the MPUC's authorized ROE of 9.72% is below the nationwide average and below the 9.83% ROE that NSP-Minnesota was authorized in its 2013 rate case. Sister utility



Corporates

Northern States Power Company-Wisconsin (NSP-Wisconsin; A-/Stable) operates in Wisconsin under a 10.2% authorized ROE. In addition, the MPUC disallowed a return on \$333 million of cost overruns for an uprate and life extension project at the Monticello nuclear plant and determined that the project is not used-and-useful until it receives the NRC's final approval, which is expected in third quarter 2015. These rulings will somewhat weaken NSP-Minnesota's credit metrics over the near term.

South Dakota 2015 Multi-Year Electric Rate Order

On June 15, 2015, the South Dakota Public Utilities Commission (SDPUC) issued its electric rate order approving a multi-year settlement agreement, which Fitch views as being constructive. NSP-Minnesota received a base rate increase and a revision to the existing infrastructure rider that results in a total increase to electric rates of \$7.8 million, or 4.0%. New rates became effective July 1, 2015, and there is a moratorium on additional base rate increases until Jan. 1, 2018. A refund for an interim rate increase that NSP-Minnesota implemented Jan. 1, 2015, will be returned to customers beginning in August 2015.

As part of the settlement, the infrastructure rider may be updated annually and trued-up for actual costs, subject to SDPUC approval. In addition, future incremental property taxes not otherwise included in base rates will be recovered through the fuel clause rider, which for 2015 is expected to be \$1 million. Also included in the settlement is an earnings test with a sharing mechanism that will refund 50% of excess weather-normalized earnings to customers.

Federal Energy Regulatory Commission ROE Complaint

There is an ongoing complaint by a group of customers arguing for a reduction in the ROE in the transmission formula rates in the Midcontinent Independent System Operator, Inc. (MISO) region. Initially, the requested reduction in the ROE was to 9.15% from 12.38%, although a second group of customers has since requested a reduction in the ROE to 8.67%. Federal Energy Regulatory Commission (FERC) action is pending, and NSP-Minnesota's current best estimate is a reduction in transmission revenue, net of expense, of \$7 million–\$9 million annually for the NSP system, most of which is at NSP-Minnesota.

Capital Spending Slowdown

NSP-Minnesota is approaching the end of a multi-year elevated capex program. In the four-year period of 2011–2014, NSP-Minnesota had aggregate capex in excess of \$5 billion, averaging more than \$1.25 billion per year. Capex is expected to peak in 2015 at \$1.625 billion, and then drop off significantly to less than \$1 billion in 2016. Total capex in 2016–2019 is expected to be less than \$3.8 billion, averaging less than \$950 million per year, not including costs in 2016 related to the Courtenay wind project.

The majority of the elevated capex has been for FERC-regulated transmission projects, wind and solar renewable energy generation projects, and the Monticello nuclear uprate and life extension project that was completed in 2013.

Transmission

The ongoing multi-year CapX2020 joint initiative transmission project has represented the majority of transmission capex and is expected to be completed in 2017. NSP-Minnesota and NSP-Wisconsin are responsible for \$1.1 billion of the total \$2 billion cost to construct four 345-kv electric transmission lines and one 230-kv line in phases, designed to meet higher customer demand and support renewable energy expansion in the upper Midwest. As of March 31, 2015,



Corporates

NSP-Wisconsin and NSP-Minnesota have invested an aggregate of \$911.2 million in these five transmission projects, leaving roughly \$200 million in remaining project costs.

The 230-kv line was placed into service in September 2012, and two of the 345-kv lines were placed into service in March 2015 and April 2015. The third 345-kv line is expected to go into service in the fall of 2016, and construction on the fourth 345-kv line is expected to begin this year and be completed in 2017.

Wind Projects

NSP-Minnesota expects to spend \$575 million in 2015 on two wind projects totaling 350 megawatts (MW), not including an additional \$300 million in expected costs over 2015–2016 for the 200-MW Courtenay project, which is pending regulatory approvals. Excluding capex for the Courtenay project, spending on wind projects in 2016 is expected to drop to near zero, given the planned late 2015 in-service dates for the two wind projects under construction and no other major wind projects planned for the near future.

Financing Capex

This is expected to be the peak capital spending year for NSP-Minnesota, and the utility will likely need to issue debt in the second half of 2015 to help finance its large capex program. Fitch expects at least part of this debt issuance to coincide with a refinancing of the \$250 million of FMBs in August 2015. Moderate levels of annual equity infusions from Xcel have occurred to help maintain a balanced capital ratio of roughly 47%–48% debt and 52%–53% equity, and Fitch expects the \$76 million of parent capital contributions in first-quarter 2015 to be supplemented by additional equity infusions later this year.

Given the planned significant drop-off in capex in 2016, with moderate spending levels through 2019, Fitch expects NSP-Minnesota's external financing needs to be minimal over 2016–2019.



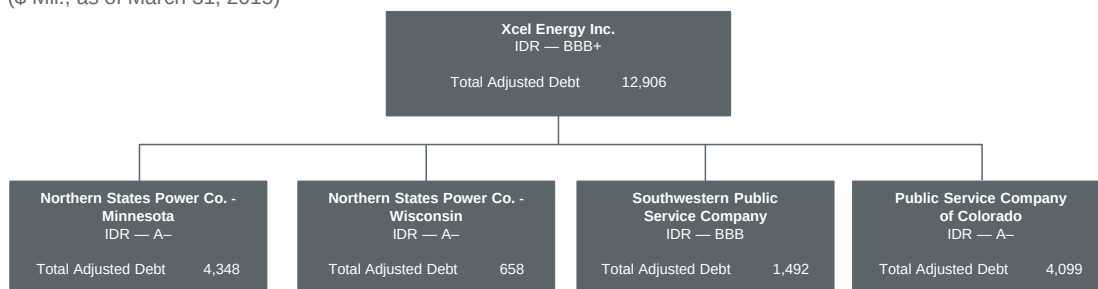
Corporates

Organizational Structure

NSP-Minnesota generally contributes 35%–45% of Xcel's consolidated net income and accounts for approximately 34% of Xcel's total consolidated debt.

Fitch views the Xcel group structure as supportive of credit quality. NSP-Minnesota upstreams cash distributions to Xcel to support holding company debt obligations and the common dividend. In turn, Xcel supports utility capital funding needs through equity infusions.

Organizational and Debt Structure (\$ Mil., as of March 31, 2015)



IDR – Issuer Default Rating.
Source: Company filings, Fitch.



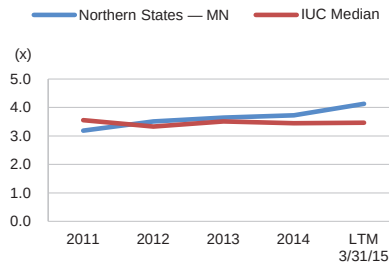
Corporates

Key Metrics

Definitions

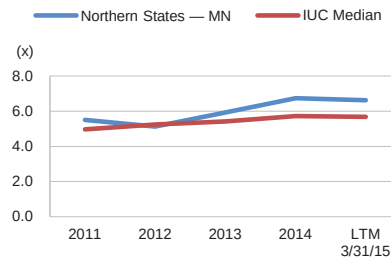
- Total Adjusted Debt/Op. EBITDAR: Total balance sheet adjusted for equity credit and off-balance sheet debt divided by operating EBITDAR.
- FFO Fixed-Charge Coverage: FFO plus gross interest minus interest received plus preferred dividends plus rental payments divided by gross interest plus preferred dividends plus rental payments.
- FFO-Adjusted Leverage: Gross debt plus lease adjustment minus equity credit for hybrid instruments plus preferred stock divided by FFO plus gross interest paid plus preferred dividends plus rental expense.

Total Adjusted Debt/Op. EBITDAR



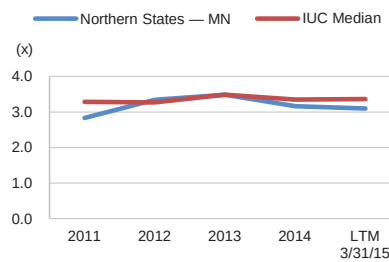
Source: Company data, Fitch.

FFO Fixed-Charge Coverage



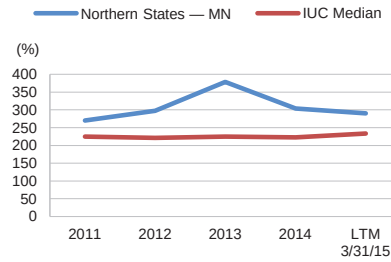
Source: Company data, Fitch.

FFO-Adjusted Leverage



Source: Company data, Fitch.

Capex/Depreciation



Source: Company data, Fitch.



Corporates

Company Profile

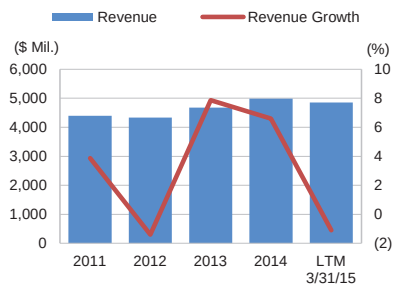
NSP-Minnesota is a utility that operates primarily in Minnesota (88% of retail electric revenues). Roughly 92% of NSP-Minnesota's gross margin is derived from the utility's integrated electric business, which serves an aggregate of more than 1.4 million customers in Minnesota, North Dakota, and South Dakota. The remaining 8% of NSP-Minnesota's gross margin is derived from the utility's natural gas distribution business, which serves an aggregate of nearly 500,000 customers in Minnesota and North Dakota.

NSP-Minnesota and sister utility NSP-Wisconsin combine-generate 73% of their power needs, sharing the electric production and transmission costs of the entire NSP system. The balance of power needs is obtained through purchased power. In 2014, the NSP system obtained 39% of its power from coal-fired facilities, with the remainder from nuclear (29%), wind (14%), hydroelectric (8%), natural gas (7%), and other (3%).

NSP-Minnesota has a relatively large exposure to commercial and industrial customers, with those two segments in aggregate contributing more than 62% of retail electric revenues. Less than 37% of retail electric revenues are derived from residential customers.

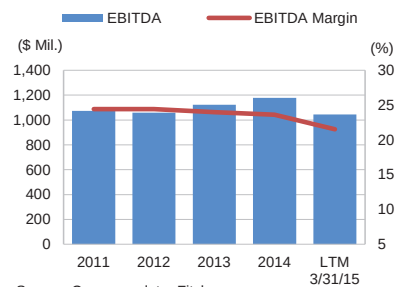
Business Trends

Revenue Dynamics



Source: Company data, Fitch.

EBITDA Dynamics



Source: Company data, Fitch.



Corporates

Financial Summary — Northern States Power Co. - Minnesota

(IDR — A-/Stable) (\$ Mil., as of March 31, 2015)	2011	2012	2013	2014	LTM Ended 2015
Fundamental Ratios (x)					
Operating EBITDAR/(Gross Interest Expense + Rents)	4.9	4.9	5.7	5.7	5.0
FFO Fixed-Charge Coverage (x)	5.5	5.1	5.9	6.7	6.6
Total Adjusted Debt/Operating EBITDAR	3.2	3.5	3.6	3.7	4.1
FFO/Total Adjusted Debt (%)	35.4	30.0	28.7	31.6	32.3
FFO-Adjusted Leverage	2.8	3.3	3.5	3.2	3.1
Common Dividend Payout (%)	66.0	68.8	59.8	64.0	91.4
Internal Cash/Capex (%)	82.4	41.8	54.5	69.6	86.1
Capex/Depreciation (%)	270.1	297.5	378.3	303.9	290.5
Return on Equity (%)	9.8	8.8	9.2	8.8	6.5
Profitability					
Revenues	4,399	4,338	4,679	4,988	4,856
Revenue Growth (%)	3.9	(1.4)	7.9	6.6	(1.1)
Net Revenues	2,450	2,475	2,599	2,762	2,750
Operating and Maintenance Expense	1,203	1,102	1,172	1,223	1,219
Operating EBITDA	1,074	1,059	1,123	1,179	1,045
Operating EBITDAR	1,089	1,079	1,131	1,186	1,052
Depreciation and Amortization Expense	381	399	415	411	430
Operating EBIT	693	660	708	768	615
Gross Interest Expense	208	201	192	200	205
Net Income for Common	353	340	393	405	304
Operating Maintenance Expense % of Net Revenues	49.1	44.5	45.1	44.3	44.3
Operating EBIT % of Net Revenues	28.3	26.7	27.2	27.8	22.4
Cash Flow					
Cash Flow from Operations	1,050	715	1,069	1,112	1,332
Change in Working Capital	46	(198)	85	(76)	140
Funds from Operations	1,004	913	984	1,188	1,192
Dividends	(233)	(234)	(235)	(259)	(278)
Capex	(1,029)	(1,187)	(1,570)	(1,249)	(1,249)
FCF	(212)	(706)	(736)	(396)	(195)
Net Other Investment Cash Flow	(16)	227	126	27	47
Net Change in Debt	91	267	339	272	91
Net Equity Proceeds	125	215	285	95	76
Capital Structure					
Short-Term Debt	91	221	165	142	76
Total Long-Term Debt	3,339	3,489	3,889	4,189	4,189
Total Debt with Equity Credit	3,430	3,710	4,054	4,331	4,265
Total Adjusted Debt with Equity Credit	3,470	3,786	4,126	4,414	4,348
Total Hybrid Equity and Minority Interest	—	—	—	—	—
Total Common Shareholders' Equity	3,725	4,036	4,481	4,703	4,730
Total Capital	7,155	7,746	8,535	9,034	8,995
Total Debt/Total Capital (%)	47.9	47.9	47.5	47.9	47.4
Total Hybrid Equity and Minority Interest/Total Capital (%)	—	—	—	—	—
Common Equity/Total Capital (%)	52.1	52.1	52.5	52.1	52.6

IDR – Issuer Default Rating.
Source: Company data, Fitch.




The ratings above were solicited by, or on behalf of, the issuer, and therefore, Fitch has been compensated for the provision of the ratings.

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RATE OF RETURN COST OF CAPITAL SCHEDULES

CREDIT RATING STANDARDS AND PERFORMANCE**AS PROVIDED TO THE COMPANY BY
STANDARD & POOR'S (S&P)**

	CCR Standards by S&P (a)			Northern States Power MN (b)							
	AA	<i>A/A- Company Objective</i>	BBB	2018 Forecast	2017 Forecast	2016 Forecast	2015 Forecast	2014	2013	2012	2011
Debt to Earnings Before Interest, Taxes, Depreciation and Amortization	1.5 – 2.0	<i>2.0 – 4.0</i>	4.0 – 5.0	3.2	3.3	3.4	3.7	3.6	3.5	3.5	3.2
Funds from Operations to Total Debt (%)	60 – 45	<i>45 – 20</i>	20 – 12	26.1	25.1	24.3	23.4	21.5	21.5	24.6	25.0
Debt to Total Capital (%)	25 – 35	<i>35 – 50</i>	50 – 60	49.6	49.8	49.9	50.1	52.4	51.8	51.6	51.9

- (a) For a company with a business risk of “excellent”.
- (b) All NSP- MN credit statistics are adjusted by S&P for inclusion of off balance sheet obligations. The 2011 through 2014 metrics are from S&P. The 2015 through 2018 forecasted metrics are calculated by the Company following S&P’s methodology.

Northern States Power Company
RATE OF RETURN COST OF CAPITAL SCHEDULES
CREDIT RATING STANDARDS AND PERFORMANCE -DETAIL

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Schedule 7
Page 2 of 2

NSPM

Credit Metrics

As of August 17, 2015

Dollars in Millions

	Projected Year End ³ 2015	Projected Year End ³ 2016	Projected Year End ³ 2017	Projected Year End ³ 2018
Adjusted Funds from Operations	\$1,156	\$1,270	\$1,327	\$1,372
Interest Expense				
Interest Charges and Financing Costs	\$183	\$202	\$205	\$204
AFUDC-Debt	\$13	\$17	\$19	\$19
Imputed Interest Operating Leases ⁽¹⁾	\$6	\$5	\$5	\$5
Imputed Interest for PPAs ⁽²⁾	\$25	\$25	\$23	\$21
Adjusted Interest Expense	\$227	\$249	\$252	\$250
EBITDA				
Operating Income	\$671	\$844	\$836	\$853
Depreciation & Amortization	\$610	\$623	\$715	\$739
EBITDA	\$1,281	\$1,467	\$1,551	\$1,592
Implied Depreciation Adjustment for Operating Leases ⁽¹⁾	\$1	\$2	\$3	\$3
Implied Depreciation Adjustment for PPAs ⁽²⁾	\$24	\$22	\$22	\$23
Imputed Interest for Operating Leases ⁽¹⁾	\$6	\$5	\$5	\$5
Imputed Interest for PPAs ⁽²⁾	\$25	\$25	\$23	\$21
Adjusted EBITDA	\$1,338	\$1,520	\$1,604	\$1,644
Capitalization				
Short-Term Debt	\$195	\$102	\$99	\$108
Long-Term Debt (Includes Current Portion)	\$4,534	\$4,785	\$4,786	\$4,787
Capital Leases	\$0	\$0	\$0	\$0
Total Balance Sheet Debt	\$4,729	\$4,887	\$4,885	\$4,895
Off-Balance Sheet Debt for Operating Leases ⁽¹⁾	\$75	\$73	\$71	\$68
Off-Balance Sheet Debt for PPAs ⁽²⁾	\$364	\$340	\$317	\$295
Adjusted Total Debt	\$5,168	\$5,300	\$5,273	\$5,258
Common Equity from Balance Sheet	\$5,147	\$5,319	\$5,325	\$5,339

Adjusted Ratios: S&P Methodology

FFO/Debt (%)	23.4	24.3	25.1	26.1
FFO/Interest (x)	6.1	6.1	6.3	6.5
Debt/EBITDA (x)	3.7	3.4	3.3	3.2
Total Debt/Total Capitalization (%)	50.1	49.9	49.8	49.6
Total Equity/Total Capitalization (%)	49.9	50.1	50.2	50.4

Unadjusted Ratios

FFO/Debt (%)	24.9	25.9	26.7	27.5
FFO/Interest	6.8	6.7	6.8	7.0
Debt/EBITDA (x)	3.5	3.3	3.1	3.1
Total Debt/Total Capitalization (%)	47.9	47.9	47.8	47.8
Total Equity/Total Capitalization (%)	52.1	52.1	52.2	52.2

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

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

3.) The financial data for the Projected Year End 2015 - 2018 is from Treasury Forecasting Five-Year Model.

RATE OF RETURN COST OF CAPITAL - BACK UP FOR INTEREST RATES

Cost of Capital

Mnemonic	Description	2016 Q1	2016 Q2	2016 Q3	2016 Q4	2017 Q1	2017 Q2	2017 Q3	2017 Q4	2018 Q1	2018 Q2	2018 Q3	2018 Q4
<u>The 3-month eurodollar rates are basis for projected short-term debt costs</u>													
RMEUROD3M	Rate on 3-month eurodollar deposits, percent per annum,	0.9907	1.2777	1.5326	1.8067	2.2601	2.7710	3.3188	3.7458	3.7968	3.7968	3.7968	3.7968
	Rounding Adjustment	-0.0007	0.0023	-0.0026	0.0033	-0.0001	-0.0010	0.0012	0.0042	0.0032	0.0032	0.0032	0.0032
	Spread to Calculate NSPM's STD Rate	0.1500	0.1500	0.1500	0.1500	0.1500	0.1500	0.1500	0.1500	0.1500	0.1500	0.1500	0.1500
	Total Short-Term Debt Interest Rate	1.1400	1.4300	1.6800	1.9600	2.4100	2.9200	3.4700	3.9000	3.9500	3.9500	3.9500	3.9500
	Total Calculated on 365/360 Basis - Multiplied by Average Balance				1.46%				3.24%				4.0%
<u>The 10 and 30-year yields on U.S. Treasuries are the basis for new long-term debt</u>													
RMTCM10Y	Yield on 10-year treasury notes, percent per annum, FRB	2.6198	2.7556	2.8481	3.0060	3.2016	3.3480	3.5318	3.6877	3.7474	3.7474	3.7474	3.7474
	Credit Spread									1.0026			
	Total LTD Coupon Interest Rate									4.7500			
RMTCM25AY	Yield on 30-year treasury bonds, percent per annum, FRB	3.3745	3.4379	3.4842	3.5944	3.7640	3.8676	3.9857	4.0942	4.1403	4.1403	4.1403	4.1403
	Credit Spread		1.1871							1.1097			
	Total LTD Coupon Interest Rate		4.6250							5.2500			

Source: IHS Global Insight, July 2015.

RATE OF RETURN COST OF CAPITAL SCHEDULES

Composite Cost of Long-Term Debt

(\$000's)

TEST YEAR - 2016 FORECASTED LONG-TERM DEBT AND COST

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or			3/ Capital Employed	Total Bond Cost						
					Hedge Gain/(Loss)	Bond Discount	Bond Expense		4/ Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	Cost of Capital	Capital Cost %	
First Mortgage Bonds															
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	696	567	248,737	17,813	-	78	63	17,953	7.22%	
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	683	572	148,746	9,750	-	59	49	9,858	6.63%	
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	307	1,922	247,771	13,125	-	16	101	13,242	5.34%	
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	10,830	929	3,230	406,671	25,000	546	47	163	24,664	6.06%	
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	177	1,388	3,029	345,759	21,700	190	66	144	21,721	6.28%	
Series Due March 1, 2018 (FMB)	5.2500	Mar-08	Mar-18	500,000	(841)	248	786	498,125	26,250	(520)	153	484	27,406	5.50%	
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(2,494)	443	3,231	293,832	16,050	(107)	19	139	16,315	5.55%	
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	568	2,423	247,009	12,125	-	24	101	12,249	4.96%	
Series Due August 15, 2022 (FMB)	2.1500	Aug-12	Aug-22	300,000	-	277	1,880	297,843	6,450	-	46	310	6,806	2.28%	
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(39,057)	3,320	5,455	452,168	17,000	(1,501)	128	210	18,838	4.17%	
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	500	3,097	396,402	10,400	-	73	455	10,928	2.76%	
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	810	3,546	295,644	12,375	-	29	128	12,532	4.24%	
Series Due Aug 15, 2020 (FMB)	2.2000	Aug-15	Aug-20	300,000	-	449	2,425	297,126	6,600	-	110	600	7,310	2.46%	
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	4,747	3,485	291,768	12,000	-	164	120	12,284	4.21%	
Series Due Aug 1, 2046 (FMB) 1/	4.6250	May-16	May-46	166,667	-	-	1,975	164,692	7,708	-	-	67	7,775	4.72%	
Other Debt															
Right of Way Notes	var	var	var	33	-	-	-	33	-	-	-	-	-	0.00%	
TOTAL DEBT				4,716,700	(31,384)	15,366	37,622	4,632,328	214,346	(1,392)	1,010	3,133	219,881	4.75%	
Unamortized Loss on Reacquired Debt								(14,323)	1,933						
Fees on Five-Year Credit Facility 2/								-	474						
GRAND TOTAL and COST OF DEBT								4,618,004	222,288						4.81%

1/ NSPM Issuances - May 2016 30 Year \$250M - Balances are 8 of 12 Months /Maturities - None

2/ Fees associated with the Five-Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.

3/ Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.

4/ Interest Expense is a Straight Interest Expense calculation.

RATE OF RETURN COST OF CAPITAL SCHEDULES
Cost of Short-Term Debt**TEST YEAR - 2016 FORECASTED SHORT-TERM DEBT AND COST**

Cost of Short-Term Debt					
	Month End Balances	Average Of Month End Balances (1)	Monthly Interest Expense 2/	Monthly Fees Expense 3/	Average Short-Term Debt Cost
2016 Jan	\$285,848,623	\$240,516,010	\$236,107	\$42,028	
2016 Feb	\$222,100,821	\$253,974,722	\$233,233	\$39,397	
2016 Mar	\$171,187,536	\$196,644,178	\$193,039	\$42,028	
2016 Apr	\$187,676,784	\$179,432,160	\$213,823	\$40,713	
2016 May	\$50,637,557	\$119,157,170	\$146,729	\$42,028	
2016 June	\$52,675,159	\$51,656,358	\$61,557	\$40,713	
2016 Jul	\$112,963,338	\$82,819,249	\$119,812	\$42,028	
2016 Aug	\$60,377,683	\$86,670,511	\$125,383	\$42,028	
2016 Sep	\$30,198,665	\$45,288,174	\$63,403	\$40,713	
2016 Oct	\$118,393,667	\$74,296,166	\$125,395	\$42,028	
2016 Nov	\$119,353,420	\$118,873,543	\$194,160	\$40,713	
2016 Dec	\$102,196,292	\$110,774,856	\$186,963	\$42,028	
Average	\$126,134,129	\$130,008,591			
Total			\$ 1,899,606	\$ 496,443	
			1.46%	0.38%	1.84%

1/ January Through December Average of Month End Balances

2/ Monthly Interest Expense based on weighted average of short-term debt outstanding
Interest Rates based on July 2015 Global Insights Inc. Forecast.3/ Ongoing fees for NSP-MN's Five-year credit facility that was re-syndicated October 14, 2014.
This expense represents the monthly cost of NSP-MN unused portion of the credit facility.
Credit facility is used primarily as back up for commercial paper and letters of credit.
(Upfront expenses for the five-year credit facility are amortized over the life of the facility
and are included in the cost of long-term debt.)

NSPM Utility Money Pool Activity**Summary - January 2013 Through June 2015**

Date	Borrowings			Investments		
	Average Amount Outstanding	Actual Interest Rate	Alternative Interest Rate *	Average Amount Outstanding	Actual Interest Rate	Alternative Interest Rate **
<u>2013</u>						
Jan	\$ 322,581	0.3645%	3.2500%	\$ 1,548,387	0.3645%	0.1500%
Feb	\$ 2,678,571	0.3267%	3.2500%	\$ 285,714	0.3267%	0.1000%
Mar	\$ 35,774,194	0.3392%	3.2500%			
Apr	\$ 160,433,333	0.3075%	3.2500%			
May	\$ 100,741,935	0.2918%	3.2500%			
Jun	\$ 4,733,333	0.2750%	3.2500%			
Jul	\$ 18,903,226	0.2900%	3.2500%			
Aug	\$ 21,870,968	0.2800%	3.2500%			
Sep	\$ 21,166,667	0.2625%	3.2500%			
Oct	\$ 33,903,226	0.3875%	3.2500%			
Nov	\$ 73,600,000	0.2975%	3.2500%			
Dec	\$ 28,161,290	0.2500%	3.2500%			
<u>2014</u>						
Jan	\$ 25,354,839	0.2141%	3.2500%			
Feb	\$ 6,250,000	0.2068%	3.2500%			
Mar	\$ 105,838,710	0.2141%	3.2500%			
Apr	\$ 2,366,667	0.2120%	3.2500%	\$ 500,000	0.2120%	0.0200%
May	\$ -	0.2429%	3.2500%	\$ 15,322,581	0.2429%	0.0200%
Jun	\$ 300,000	0.2348%	3.2500%	\$ 12,933,333	0.2348%	0.0300%
Jul	\$ 645,161	0.2635%	3.2500%	\$ 774,196	0.2635%	0.0300%
Aug	\$ -	0.2685%	3.2500%	\$ 2,774,194	0.2685%	0.0400%
Sep	\$ -	0.2446%	3.2500%	\$ 17,900,000	0.2446%	0.0300%
Oct	\$ 161,290	0.2580%	3.2500%	\$ 3,032,258	0.2580%	0.0400%
Nov	\$ 66,667	0.2833%	3.2500%	\$ 500,000	0.2833%	0.0300%
Dec	\$ -	0.4485%	3.2500%	\$ 419,355	0.4485%	0.0400%
<u>2015</u>						
Jan	\$ 1,451,613	0.5708%	3.2500%			
Feb	\$ 500,000	0.4009%	3.2500%	\$ 535,714	0.4009%	0.0500%
Mar	\$ -	0.5166%	3.2500%			
Apr	\$ 100,000	0.4659%	3.2500%	\$ 800,000	0.4659%	0.0600%
May	\$ -	0.4993%	3.2500%	\$ 29,032	0.4993%	0.0800%
Jun	\$ 19,083,333	0.5361%	3.2500%			

* Based on overnight borrowing rate under NSP-MN credit facility.

** Based on investment in a money market account.

RATE OF RETURN COST OF CAPITAL SCHEDULES

Common Equity

(\$000's)

<u>Month</u>	<u>GAAP Common Equity Outstanding</u>	<u>Non-Regulated Subsidiaries*</u>	<u>Regulated Common Equity</u>
<u>TEST YEAR - 2016 FORECASTED EQUITY BALANCES</u>			
2015 Dec	\$5,146,674	\$1,107	\$5,145,567
2016 Jan	\$5,190,567	\$1,107	\$5,189,460
2016 Feb	\$5,224,232	\$1,107	\$5,223,125
2016 Mar	\$5,173,511	\$1,107	\$5,172,404
2016 Apr	\$5,188,308	\$1,107	\$5,187,201
2016 May	\$5,206,546	\$1,107	\$5,205,439
2016 Jun	\$5,179,946	\$1,107	\$5,178,839
2016 Jul	\$5,247,779	\$1,107	\$5,246,672
2016 Aug	\$5,333,766	\$1,107	\$5,332,659
2016 Sep	\$5,299,203	\$1,107	\$5,298,096
2016 Oct	\$5,324,915	\$1,107	\$5,323,808
2016 Nov	\$5,351,089	\$1,107	\$5,349,982
2016 Dec	\$5,319,127	\$1,107	\$5,318,020
13 Month Average	\$5,245,051	\$1,107	\$5,243,944

* United Power and Land.

RATE OF RETURN COST OF CAPITAL SCHEDULES

Common Equity Flotation Costs

Date	Issuing Company	Shares Issued	Market Price	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds	Total Flotation Costs	Gross Equity Issue before Costs	Net Proceeds	Flotation Cost Percentage
11/16/1949	Northern States Power	1,584,238	\$10.750	\$10.250	\$0.124	\$0.137	\$9.989	\$1,205,605	\$17,030,559	\$15,824,953	7.079%
6/4/1952	Northern States Power	1,108,966	\$10.500	\$10.500	\$0.098	\$0.162	\$10.240	\$288,331	\$11,644,143	\$11,355,812	2.476%
4/14/1954	Northern States Power	1,219,856	\$15.250	\$14.000	\$0.060	\$0.124	\$13.816	\$1,749,274	\$18,602,804	\$16,853,530	9.403%
2/29/1956	Northern States Power	670,920	\$17.825	\$16.750	\$0.050	\$0.221	\$16.479	\$903,058	\$11,959,149	\$11,056,091	7.551%
7/22/1959	Northern States Power	952,033	\$23.375	\$22.000	\$0.069	\$0.191	\$21.740	\$1,556,574	\$22,253,771	\$20,697,197	6.995%
7/28/1965	Northern States Power	772,008	\$35.250	\$33.000	\$0.092	\$0.225	\$32.683	\$1,981,745	\$27,213,282	\$25,231,537	7.282%
1/22/1969	Northern States Power	1,080,811	\$29.000	\$27.000	\$0.119	\$0.187	\$26.694	\$2,492,350	\$31,343,519	\$28,851,169	7.952%
10/21/1970	Northern States Power	1,729,298	\$23.125	\$21.500	\$0.175	\$0.149	\$21.176	\$3,370,402	\$39,990,016	\$36,619,614	8.428%
7/26/1972	Northern States Power	1,902,228	\$25.000	\$23.500	\$0.129	\$0.166	\$23.205	\$3,414,499	\$47,555,700	\$44,141,201	7.180%
10/10/1973	Northern States Power	2,092,451	\$25.825	\$24.500	\$0.128	\$0.153	\$24.219	\$3,360,476	\$54,037,547	\$50,677,071	6.219%
11/20/1974	Northern States Power	2,300,000	\$17.625	\$17.500	\$0.910	\$0.069	\$16.521	\$2,539,200	\$40,537,500	\$37,998,300	6.264%
8/14/1975	Northern States Power	1,750,000	\$23.000	\$23.000	\$0.740	\$0.077	\$22.183	\$1,429,750	\$40,250,000	\$38,820,250	3.552%
6/3/1976	Northern States Power	2,000,000	\$24.000	\$24.000	\$0.720	\$0.064	\$23.216	\$1,568,000	\$48,000,000	\$46,432,000	3.267%
5/31/1993	Northern States Power	3,041,955	\$44.125	\$43.625	\$1.200	\$0.048	\$42.377	\$5,317,337	\$134,226,264	\$128,908,927	3.961%
9/23/1997	Northern States Power	4,500,000	\$49.938	\$49.563	\$1.230	\$0.133	\$48.200	\$7,821,000	\$224,721,000	\$216,900,000	3.480%
9/29/1997	Northern States Power	400,000	\$50.500	\$49.563	\$1.230	\$0.133	\$48.200	\$920,000	\$20,200,000	\$19,280,000	4.554%
2/25/2002	Xcel Energy, Inc.	20,000,000	\$22.950	\$22.500	\$0.730	\$0.015	\$21.755	\$23,900,000	\$459,000,000	\$435,100,000	5.207%
9/9/2008	Xcel Energy, Inc.	17,250,000	\$20.860	\$20.200	\$0.100	\$0.006	\$20.094	\$13,218,352	\$359,835,000	\$346,616,648	3.673%
8/3/2010	Xcel Energy, Inc.	21,850,000	\$22.100	\$21.500	\$0.645	\$0.013	\$20.571	\$33,407,927	\$482,885,000	\$449,477,073	6.918%
March 2013	Xcel Energy, Inc.	7,757,449	\$29.057	\$29.057	\$0.291	\$0.052	\$28.714	\$2,657,558	\$225,407,642	\$222,750,085	1.179%
June 2014	Xcel Energy, Inc.	5,693,946	\$30.663	\$30.663	\$0.307	\$0.030	\$30.326	\$1,915,210	\$174,592,340	\$172,677,130	1.097%
Total Public Issuances								\$115,016,648	\$2,491,285,237	\$2,376,268,590	4.617%
Total Non-Public Issuances								\$0	\$1,548,782,000	\$1,548,782,000	0.000%
NSP/NCE Merger ¹		N/A	N/A	N/A	N/A	N/A	N/A	N/A	\$1,944,007,000	N/A	
NRG stock for stock exchange									<u>\$1,077,456,000</u>		
Total									<u>\$5,512,748,237</u>		

¹ Additional paid in capital for NSP/NCE Merger = \$1,944,007,000

Additional paid in capital for NRG = \$1,077,456,000

These are balance sheet adjustments to additional paid in capital which did not incur any flotation costs.

RATE OF RETURN COST OF CAPITAL SCHEDULES

Composite Cost of Long-Term Debt

(\$000's)

TEST YEAR - 2017 FORECASTED LONG-TERM DEBT AND COST

Description 1/ & 2/	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or		Bond Expense	4/ Capital Employed	Total Bond Cost						
					Hedge Gain/(Loss)	Bond Discount			5/ Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	Cost of Capital	Capital Cost %	
First Mortgage Bonds															
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	618	504	248,878	17,813	-	78	63	17,953	7.21%	
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	624	522	148,854	9,750	-	59	49	9,858	6.62%	
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	291	1,820	247,888	13,125	-	16	101	13,242	5.34%	
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	10,285	883	3,067	406,335	25,000	545	47	162	24,665	6.07%	
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	18	1,322	2,885	345,811	21,700	91	66	144	21,819	6.31%	
Series Due March 1, 2018 (FMB)	5.2500	Mar-08	Mar-18	500,000	(322)	95	302	499,280	26,250	(518)	153	484	27,405	5.49%	
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(2,387)	424	3,092	294,097	16,050	(107)	19	139	16,315	5.55%	
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	544	2,322	247,134	12,125	-	24	101	12,249	4.96%	
Series Due August 15, 2022 (FMB)	2.1500	Aug-12	Aug-22	300,000	-	232	1,571	298,198	6,450	-	46	309	6,805	2.28%	
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(37,560)	3,193	5,246	454,001	17,000	(1,496)	127	209	18,833	4.15%	
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	427	2,644	396,929	10,400	-	73	453	10,927	2.75%	
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	781	3,419	295,800	12,375	-	29	127	12,531	4.24%	
Series Due Aug 15, 2020 (FMB)	2.2000	Aug-15	Aug-20	300,000	-	339	1,825	297,836	6,600	-	110	600	7,310	2.45%	
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	4,584	3,365	292,051	12,000	-	163	120	12,283	4.21%	
Series Due May 1, 2046 (FMB)	4.6250	May-16	May-46	250,000	-	-	2,879	247,121	11,563	-	-	100	11,663	4.72%	
Other Debt															
Right of Way Notes	var	var	var	33	-	-	-	33	-	-	-	-	-	0.00%	
TOTAL DEBT				4,800,033	(29,966)	14,357	35,464	4,720,247	218,200	(1,486)	1,009	3,162	223,857	4.74%	
Unamortized Loss on Reacquired Debt								(12,391)	1,932						
Fees on Five-Year Credit Facility 3/								-	472						
GRAND TOTAL and COST OF DEBT								4,707,856	226,261						4.81%

1/ NSPM maturity - none

2/ NSPM issuances - none

3/ Fees associated with the Five-Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.

4/ Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.

5/ Interest Expense is a Straight Interest Expense calculation.

RATE OF RETURN COST OF CAPITAL SCHEDULES

Cost of Short-Term Debt

TEST YEAR - 2017 FORECASTED SHORT-TERM DEBT AND COST

Cost of Short-Term Debt					
	Month End Balances	Average Of Month End Balances (1)	Monthly Interest Expense 2/	Monthly Fees Expense 3/	Average Short Term Debt Cost
2017 Jan	\$180,419,046	\$141,307,669	\$293,253	\$42,028	
2017 Feb	\$110,928,144	\$145,673,595	\$273,057	\$38,082	
2017 Mar	\$73,282,005	\$92,105,075	\$191,144	\$42,028	
2017 Apr	\$93,011,333	\$83,146,669	\$202,324	\$40,713	
2017 May	\$243,502,151	\$168,256,742	\$423,072	\$42,028	
2017 June	\$206,880,888	\$225,191,520	\$547,966	\$40,713	
2017 Jul	\$219,029,854	\$212,955,371	\$636,322	\$42,028	
2017 Aug	\$196,868,447	\$207,949,151	\$621,364	\$42,028	
2017 Sep	\$108,829,421	\$152,848,934	\$441,988	\$40,713	
2017 Oct	\$152,332,638	\$130,581,029	\$438,535	\$42,028	
2017 Nov	\$107,201,628	\$129,767,133	\$421,743	\$40,713	
2017 Dec	\$98,603,851	\$102,902,739	\$345,582	\$42,028	
Average	\$149,240,784	\$149,390,469			
Total			\$ 4,836,349	\$ 495,127	
			3.24%	0.33%	3.57%

1/ January Through December Average of Month End Balances

2/ Monthly Interest Expense based on weighted average of short-term debt outstanding
Interest Rates based on July 2015 Global Insights Inc. Forecast.

3/ Ongoing fees for NSP-MN's Five-Year credit facility that was re-syndicated October 14, 2014.
This expense represents the monthly cost of NSP-MN unused portion of the credit facility.
Credit facility is used primarily as back up for commercial paper and letters of credit.
(Upfront expenses for the five year credit facility are amortized over the life of the facility and are included in the cost of long-term debt.)

RATE OF RETURN COST OF CAPITAL SCHEDULES

Common Equity

(\$000's)

<u>Month</u>	<u>GAAP Common Equity Outstanding</u>	<u>Non-Regulated Subsidiaries*</u>	<u>Regulated Common Equity</u>
<u>TEST YEAR - 2017 FORECASTED EQUITY BALANCES</u>			
2016 Dec	\$5,319,127	\$1,107	\$5,318,020
2017 Jan	\$5,361,993	\$1,107	\$5,360,886
2017 Feb	\$5,389,081	\$1,107	\$5,387,974
2017 Mar	\$5,340,608	\$1,107	\$5,339,501
2017 Apr	\$5,353,846	\$1,107	\$5,352,739
2017 May	\$5,369,899	\$1,107	\$5,368,792
2017 Jun	\$5,338,074	\$1,107	\$5,336,967
2017 Jul	\$5,406,304	\$1,107	\$5,405,197
2017 Aug	\$5,401,950	\$1,107	\$5,400,843
2017 Sep	\$5,369,919	\$1,107	\$5,368,812
2017 Oct	\$5,394,061	\$1,107	\$5,392,954
2017 Nov	\$5,423,028	\$1,107	\$5,421,921
2017 Dec	\$5,324,827	\$1,107	\$5,323,720
13 Month Average	\$5,368,671	\$1,107	\$5,367,564

* United Power and Land.

RATE OF RETURN COST OF CAPITAL SCHEDULES

Composite Cost of Long-Term Debt

(\$000's)

TEST YEAR - 2018 FORECASTED LONG-TERM DEBT AND COST

Total Bond Cost														
Description	Coupon Rate	Issue Date	Maturity Date	Premium or			Premium/							
				Amount	Hedge Gain/(Loss)	Bond Discount	Bond Expense	4/ Capital Employed	5/ Interest Charge	Hedge Amortization	Discount Amortization	Expense Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds														
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	541	440	249,019	17,813	-	78	63	17,953	7.21%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	565	473	148,961	9,750	-	59	49	9,858	6.62%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	275	1,719	248,006	13,125	-	16	101	13,242	5.34%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	9,741	836	2,905	406,000	25,000	545	47	162	24,665	6.08%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	1,256	2,740	346,004	21,700	-	66	144	21,911	6.33%
Series Due March 1, 2018 (FMB) 2/	5.2500	Mar-08	Mar-18	83,333	(3)	1	3	83,326	4,375	(84)	25	80	4,563	5.48%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(2,280)	405	2,954	294,361	16,050	(107)	19	139	16,315	5.54%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	521	2,221	247,258	12,125	-	24	101	12,249	4.95%
Series Due August 15, 2022 (FMB)	2.1500	Aug-12	Aug-22	300,000	-	186	1,262	298,552	6,450	-	46	309	6,805	2.28%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(36,063)	3,066	5,037	455,834	17,000	(1,496)	127	209	18,833	4.13%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	354	2,190	397,456	10,400	-	73	453	10,927	2.75%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	752	3,292	295,957	12,375	-	29	127	12,531	4.23%
Series Due Aug 15, 2020 (FMB)	2.2000	Aug-15	Aug-20	300,000	-	229	1,225	298,546	6,600	-	110	600	7,310	2.45%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	4,420	3,245	292,335	12,000	-	163	120	12,283	4.20%
Series Due May 1, 2046 (FMB)	4.6250	May-16	May-46	250,000	-	-	2,779	247,221	11,563	-	-	100	11,663	4.72%
Series Due Mar 1, 2028 (FMB) 1/	4.7500	Mar-18	Mar-28	208,333	-	-	1,988	206,345	9,896	-	-	208	10,104	4.90%
Series Due Mar 1, 2048 (FMB) 1/	5.2500	Mar-18	Mar-48	208,333	-	-	2,462	205,872	10,938	-	-	83	11,021	5.35%
Other Debt														
Right of Way Notes	var	var	var	33	-	-	-	33	-	-	-	-	-	0.00%
TOTAL DEBT				4,800,033	(28,606)	13,406	36,936	4,721,086	217,158	(1,143)	881	3,050	222,232	4.71%
Unamortized Loss on Reacquired Debt								(10,460)						
Fees on Five-Year Credit Facility 3/								-						
GRAND TOTAL and COST OF DEBT								4,710,626						
													224,635	4.77%

1/ NSPM issuances - Mar 2018 10 Year \$250M and 30 Year \$250M. Balances are 10 of 12 Months.

2/ NSPM Maturity Mar 2018 \$500M. Balance is 2 of 12 months.

3/ Fees associated with the Five-Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.

4/ Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.

5/ Interest Expense is a Straight Interest Expense calculation.

RATE OF RETURN COST OF CAPITAL SCHEDULES

Cost of Short-Term Debt

TEST YEAR - 2018 FORECASTED SHORT-TERM DEBT AND COST

Cost of Short-Term Debt					
	Month End Balances	Average Of Month End Balances (1)	Monthly Interest Expense 2/	Monthly Fees Expense 3/	Average Short-Term Debt Cost
2018 Jan	\$180,769,025	\$139,686,438	\$475,128	\$42,028	
2018 Feb	\$77,131,046	\$128,950,035	\$396,163	\$38,082	
2018 Mar	\$14,436,048	\$45,783,547	\$155,728	\$42,028	
2018 Apr	\$15,504,971	\$14,970,510	\$49,278	\$40,713	
2018 May	\$193,975,529	\$104,740,250	\$356,262	\$42,028	
2018 June	\$167,258,774	\$180,617,151	\$594,531	\$40,713	
2018 Jul	\$147,854,505	\$157,556,639	\$535,911	\$42,028	
2018 Aug	\$83,249,536	\$115,552,021	\$393,037	\$42,028	
2018 Sep	\$38,977,523	\$61,113,530	\$201,165	\$40,713	
2018 Oct	\$159,480,307	\$99,228,915	\$337,516	\$42,028	
2018 Nov	\$136,686,199	\$148,083,253	\$487,441	\$40,713	
2018 Dec	\$108,301,062	\$122,493,631	\$416,648	\$42,028	
Average	\$110,302,044	\$109,897,993			
Total			\$ 4,398,810	\$ 495,127	
			4.00%	0.45%	4.45%

1/ January Through December Average of Month End Balances

2/ Monthly Interest Expense based on weighted average of short-term debt outstanding
Interest Rates based on July 2015 Global Insights Inc Forecast.

3/ Ongoing fees for NSP-MN's Five year credit facility that was re-syndicated October 14, 2014.
This expense represents the monthly cost of NSP-MN unused portion of the credit facility.
Credit facility is used primarily as back up for commercial paper and letters of credit.
(Upfront expenses for the Five-Year credit facility are amortized over the life of the facility and are included in the cost of long-term debt.)

RATE OF RETURN COST OF CAPITAL SCHEDULES

Common Equity

(\$000's)

<u>Month</u>	<u>GAAP Common Equity Outstanding</u>	<u>Non-Regulated Subsidiaries*</u>	<u>Regulated Common Equity</u>
<u>TEST YEAR - 2018 FORECASTED EQUITY BALANCES</u>			
2017 Dec	\$5,324,827	\$1,107	\$5,323,720
2018 Jan	\$5,317,022	\$1,107	\$5,315,915
2018 Feb	\$5,346,119	\$1,107	\$5,345,012
2018 Mar	\$5,299,775	\$1,107	\$5,298,668
2018 Apr	\$5,308,666	\$1,107	\$5,307,559
2018 May	\$5,285,851	\$1,107	\$5,284,744
2018 Jun	\$5,264,069	\$1,107	\$5,262,962
2018 Jul	\$5,332,552	\$1,107	\$5,331,445
2018 Aug	\$5,395,442	\$1,107	\$5,394,335
2018 Sep	\$5,363,092	\$1,107	\$5,361,985
2018 Oct	\$5,338,917	\$1,107	\$5,337,810
2018 Nov	\$5,368,606	\$1,107	\$5,367,499
2018 Dec	\$5,339,004	\$1,107	\$5,337,897
13 Month Average	<u>\$5,329,534</u>	<u>\$1,107</u>	<u>\$5,328,427</u>

* United Power and Land.

**Capital Structure Prefiled Discovery - 2016 TY Minnesota Electric Rate Case
Index**

Case	IR No.		Description	Addressed in 2016 TY Case
12-961	DOC	162	Subject: Allowance for Funds Used During Construction (AFUDC) A. Please provide NSPM's AFUDC rates or projected rates for 2012 to 2016. B. Please provide the NSPM's calculations to support its AFUDC rates for 2012 to 2016, including a narrative to describe the calculations.	Appendix A
12-961	DOC	209	Please provide a copy of the July 2015 Global Insight Inc. forecast referenced on page 30 of witness Mr. Brian Van Abel's Testimony.	Schedule 8
12-961	DOC	211	Please explain the term: index-eligible bond size of \$250 million.	Direct Testimony, Page 33
12-961	DOC	213	Please provide historic short-term debt levels from January 2014 through June 2015 showing both month-end and average daily STD balances.	Appendix A
12-961	OAG	96	Reference AFUDC and CWIP. Provide the dollar level of short-term debt, long-term debt, preferred stock, and common stock at year-end 2016 (the test year.). Provide the balances used for the test year AFUDC calculation.	Appendix A
13-868	OAG	176	Provide the calculation of free cash flow for NSP and Xcel Energy for each year 2012 through 2015 and the test year 2016.	Appendix A
13-868	OAG	203	Reference AFUDC and funding construction. Explain how cash provided by operations for NSP is used to finance construction work in progress. Explain how much cash from operations NSP used to finance its construction work in progress for each of the years 2012 through 2015 and projected for the test year 2016. Explain and quantify the use of cash from operations for purposes other than financing construction projects for each of those years.	Appendix A
13-868	OAG	203.1	Reference: For the years 2012 through 2015 and projected for the test year 2016, provide the date and amount of equity infusion for NSP, Xcel Energy, and each of its other affiliates.	Appendix A
13-868	OAG	315	Please provide data on all issuances of common stock by each of the companies included in your proxies over the last five years on the number of shares issued, the share price, the issuance costs, the dates of the issuances, and whether the shares were over-subscribed and if so, to what extent.	Appendix A

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix ADocket No. E002/GR-12-961
Information Request No. DOC-162Question:

Subject: Allowance for Funds Used During Construction (AFUDC)

- A. Please provide NSPM's AFUDC rates/projected rates for 2012 to 2016.
- B. Please provide the NSPM's calculations to support its AFUDC rates for 2012 to 2016, including a narrative to describe the calculations.

Response:

- A) NSPM's AFUDC rates or projected rates for 2012 to 2016 are shown below:

2012 Rate.....7.327%...as of September Month End 10/1/2012*
 2013 Rate.....6.735%...as of November Month End 12/2/2013*
 2014 Rate.....6.591%...as of October Month End 11/03/2014*
 2015 Projected Rate...6.233%...as of 8/3/2015 Monthly Update
 2016 Projected Rate...6.593%...Budget as of 6/3/2015 Multi-Year Update

* Subsequent calculations did not change by + / - 25 basis points so the AFUDC rate was the final rate used in that year.

- B) Please see the file "Att A.xls" for a calculations workbook.

The Company calculates AFUDC in compliance with FERC Order Number 561. The FERC methodology for the AFUDC calculation assumes construction is first funded with short-term debt and then long-term debt and equity.

Balances: Per FERC Order 561, the balances for long-term debt and common equity are the actual book balances at the end of the prior year. The short-term debt and construction work in progress balances are estimated for the current year with appropriate adjustments as actual data becomes available.

Costs: Per FERC Order 561, the long-term debt cost reflects the weighted average cost of the outstanding debt for the prior year. The cost of common equity is the rate authorized in the last rate proceeding.

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix A

The cost of short-term debt is the forecast/actual cost for the current year.

Ongoing Monitoring: The Company calculates the AFUDC rate on a monthly basis updating both short-term debt and CWIP balances for actuals and revised monthly forecast numbers if appropriate. Consistent with the FERC methodology, if the AFUDC rate has changed by 25 basis points or more in any jurisdiction, we recommend that Capital Asset Accounting update the rates used in the AFUDC dollar calculation.

Witness:	Brian J. Van Abel
Preparer:	Robert LaBahn
Title:	Forecast / Financial Consultant - Corporate Finance
Department:	Corporate Financial Policy / Treasury

Northern States Power Company

Docket No. E002/GR-12-961

Information Request No. DOC-162, Attachment A, Page 1 of 5

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix A**AFUDC RATE CALCULATION FORECAST 2012**NSP-MN
(000's)

The AFUDC rate is 7.327% This calculation is
presented below and includes CWIP Actuals through August 2012

Input Values

(000s)

S = Average Short-Term Debt for year (2012 12 Mo. Avg.)	= \$	146,841	ST DEBT TABLE
RS = Short-Term Debt Interest Rate	=	0.379%	ST DEBT TABLE
D = Long-Term Debt (2011 YR. END)	= \$	3,338,897 1/	LTD/Equity DEBT TABLE
RD = Long-Term Debt Interest Rate	=	6.171% 1/	LTD/Equity DEBT TABLE
P = Preferred Stock (2011 YR. END)	= \$	0	
RP = Preferred Stock Cost Rate	=	0.00%	
C = Common Equity (2011 YR. END)	= \$	3,724,776 1/	LTD/Equity DEBT TABLE
RC = Common Equity Cost Rate (Authorized)	=	10.37% 1/	Authorized Rate - Docket E-002/GR-10-971. Dated 05/14/2012
W = Average CWIP plus Nuclear Fuel in Process (2012 13 Mo. Av	= \$	990,170	CAA

1/ These are 2011 year-end balances and will not change with subsequent 2012 updates.

Statistical Percentage of Short Term Debt to CWIP 14.83%

Calculated Values

AI = Rate for Gross Allowance for Borrowed Funds used during Construction

$$AI = (RS * (S/W)) + (RD * (D/(D+P+C))) * (1-S/W))$$

AI 2.54% debt % = 35.30% 2.54%

AE = Rate for Allowance for Other Funds used during Construction

$$AE = (1-S/W) * (RP * (P/(D+P+C))) + RC * (C/(D+P+C)))$$

AE 4.66% equity % = 64.70% 4.66%

Simple Rate = 2.540 + 4.657 = 7.198%

Effective Annual Rate (Semi-Annual Compounding)

$$((1 + (\text{Tot Nominal Rate} / 2)) ^ 2) - 1 =$$

7.327%

Effective Monthly Rate (Semi-Annual Compounding)

$$((1 + (\text{Tot Nominal Rate} / 2)) ^ 2)^{(1/12)} - 1 =$$

0.5910%

Note: Per FERC Order 561-A, if STD exceeds CWIP, the STD rate becomes the AFUDC rate (100% debt). Thus, the AFUDC rate is the STD rate. (all ABFUDC, no AEFUDC).

Monthly AFUDC by Debt or Equity:

Debt Forecast as an Expense Adj	0.002086
Equity Forecast as Other Income	0.003824
	0.005910

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix A

Docket No. E002/GR-12-961

Information Request No. DOC-162, Attachment A, Page 2 of 5

NOVEMBER AFUDC RATE CALCULATION FORECAST 2013NSP-MN
(000's)

The forecast AFUDC rate is 6.735% This calculation is presented below and includes CWIP Actuals thru. October 2013

Input Values**(000s)**

S = Average Short-Term Debt for year (2013 12 Mo. Avg.)	= \$	163,251	ST DEBT TABLE
RS = Short-Term Debt Interest Rate	=	0.326%	ST DEBT TABLE
D = Long-Term Debt (2012 YR. END)	= \$	3,488,638 1/	LTD/Equity TABLE
RD = Long-Term Debt Interest Rate	=	5.122% 1/	LTD/Equity TABLE
P = Preferred Stock (2012 YR. END)	= \$	0	
RP = Preferred Stock Cost Rate	=	0.00%	
C = Common Equity (2012 YR. END)	= \$	4,036,369 1/	LTD/Equity TABLE
RC = Common Equity Cost Rate (Authorized)	=	9.83% 1/	Authorized Rate - Docket E-002/GR-12-961. Dated 09/03/2
W = Average CWIP plus Nuclear Fuel in Process (2013 13 Mo. Avg.)	= \$	1,225,562	Capital Asset Accounting

1/ These are 2012 year-end balances and will not change with subsequent 2013 updates.

Calculated Values

AI = Rate for Gross Allowance for Borrowed Funds used during Construction

$$AI = (RS * (S/W)) + (RD * (D/(D+P+C)) * (1-S/W))$$

AI 2.10% debt % = 31.50% 2.10%

AE = Rate for Allowance for Other Funds used during Construction

$$AE = (1-S/W) * (RP * (P/(D+P+C))) + RC * (C/(D+P+C))$$

AE 4.57% equity % = 68.50% 4.57%

Simple Rate = 2.1016% + 4.5704% = 6.6720%

Effective Annual Rate (Semi-Annual Compounding)

$((1 + (\text{Tot Nominal Rate} / 2))^2 - 1)$ 2.1126% 4.6226% **6.735%**

Effective Monthly Rate (Semi-Annual Compounding)

$((1 + (\text{Tot Nominal Rate} / 2))^2)^{(1/12)}$ 0.1744% 0.3773% **0.5517%**

Note: Per FERC Order 561-A, if STD exceeds CWIP, the STD rate becomes the AFUDC rate (100% debt). Thus, the AFUDC rate is the STD rate. (all ABFUDC, no AEFUDC).

Monthly AFUDC by Debt or Equity:

Debt Forecast as an Expense Adj.	0.001744
Equity Forecast as Other Income	0.003773
	0.005517

Northern States Power Company

Docket No. E002/GR-12-961

Information Request No. DOC-162, Attachment A, Page 3 of 5

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix A**OCTOBER MONTH-END AFUDC RATE CALCULATION 2014 FORECAST**

NSP-MN

(000's)

The forecast AFUDC rate is 6.591% This calculation is
presented below and includes CWIP Actuals thru. September 2014

Input Values

(000s)

S = Average Short-Term Debt for year (2014 12 Mo. Avg.)	= \$	135,438	ST DEBT TABLE
RS = Short-Term Debt Interest Rate	=	0.244%	ST DEBT TABLE
D = Long-Term Debt (2013 YR. END)	= \$	3,888,684 1/	LTD/Equity TABLE
RD = Long-Term Debt Interest Rate	=	4.885% 1/	LTD/Equity TABLE
P = Preferred Stock (2013 YR. END)	= \$	0	
RP = Preferred Stock Cost Rate	=	0.00%	
C = Common Equity (2013 YR. END)	= \$	4,480,794 1/	LTD/Equity TABLE
RC = Common Equity Cost Rate (Authorized)	=	9.83% 1/	Authorized Rate - Docket E-002/GR-12-961. Dated 09/03/2011
W = Average CWIP plus Nuclear Fuel in Process (2014 13 Mo. Avg.)	= \$	984,808	Capital Asset Accounting

1/ These are 2013 year-end balances and will not change with subsequent 2014 updates.

Calculated Values**AI = Rate for Gross Allowance for Borrowed Funds used during Construction**

$$AI = (RS * (S/W)) + (RD * (D/(D+P+C))) * (1-S/W))$$

$$AI = 1.99\% \quad \text{debt \%} = 30.49\% \quad 1.99\%$$

AE = Rate for Allowance for Other Funds used during Construction

$$AE = (1-S/W) * (RP * (P/(D+P+C))) + RC * (C/(D+P+C)))$$

$$AE = 4.54\% \quad \text{equity \%} = 69.51\% \quad 4.54\%$$

$$\text{Simple Rate} = 1.9910\% + 4.5389\% = 6.5299\%$$

Effective Annual Rate (Semi-Annual Compounding)

$$((1 + (\text{Tot Nominal Rate} / 2)) ^ 2) - 1 = 2.0009\% \quad 4.5904\% \quad \boxed{6.591\%}$$

Effective Monthly Rate (Semi-Annual Compounding)

$$((1 + (\text{Tot Nominal Rate} / 2)) ^ 2)^{(1/12)} = 0.1652\% \quad 0.3747\% \quad \boxed{0.5399\%}$$

Note: Per FERC Order 561-A, if STD exceeds CWIP, the STD rate qcomes the AFUDC rate (100% debt). Thus, the AFUDC rate is the STD rate. (all ABFUDC, no AEFUDC).

Monthly AFUDC by Debt or Equity:

Debt Forecast as an Expense Adj.	0.001652
Equity Forecast as Other Income	0.003747
	<u>0.005399</u>

10/16/2015

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Northern States Power Company

Docket No. E002/GR-12-961

Information Request No. DOC-162, Attachment A, Page 4 of 5

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix A**JULY MONTH-END AFUDC RATE CALCULATION 2015 FORECAST**NSP-MN
(000's)

The forecast AFUDC rate is 6.233% This calculation is presented below and includes CWIP Actuals thru. June 2015

Input Values**(000s)**

S = Average Short-Term Debt for year (2015 12 Mo. Avg.)	= \$	147,493	ST DEBT TABLE
RS = Short-Term Debt Interest Rate	=	0.640%	ST DEBT TABLE
D = Long-Term Debt (2014 YR. END)	= \$	4,188,635 1/	LTD/Equity TABLE
RD = Long-Term Debt Interest Rate	=	4.837% 1/	LTD/Equity TABLE
P = Preferred Stock (2014 YR. END)	= \$	0	
RP = Preferred Stock Cost Rate	=	0.00%	
C = Common Equity (2014 YR. END)	= \$	4,703,173 1/	LTD/Equity TABLE
RC = Common Equity Cost Rate (Authorized)	=	9.72% 1/	Authorized Rate - 8K Filing. Dated 03/26/2015
W = Average CWIP plus Nuclear Fuel in Process (2015 13 Mo. Avg.)	= \$	805,855	Capital Asset Accounting

1/ These are 2013 year-end balances and will not change with subsequent 2014 updates.

Calculated Values**AI = Rate for Gross Allowance for Borrowed Funds used during Construction**

$$AI = (RS * (S/W)) + (RD * (D/(D+P+C)) * (1-S/W))$$

AI:	1.98%	debt % =	32.02%	1.98%
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AE = Rate for Allowance for Other Funds used during Construction

$$AE = (1-S/W) * (RP * (P/(D+P+C)) + RC * (C/(D+P+C)))$$

AE	4.20%	equity % =	67.98%	4.20%
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Simple Rate =	1.9786% +	4.2003% =	6.1789%
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Effective Annual Rate (Semi-Annual Compounding)

$$((1 + (\text{Tot Nominal Rate} / 2)) ^ 2) - 1 =$$

	1.9884%	4.2444%	6.233%
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Effective Monthly Rate (Semi-Annual Compounding)

$$((1 + (\text{Tot Nominal Rate} / 2)) ^ 2)^{(1/12)}$$

	0.1642%	0.3470%	0.5112%
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Note: Per FERC Order 561-A, if STD exceeds CWIP, the STD rate becomes the AFUDC rate (100% debt). Thus, the AFUDC rate is the STD rate. (all ABFUDC, no AEFUDC).

Monthly AFUDC by Debt or Equity:

Debt Forecast as an Expense Adj.	0.001642
Equity Forecast as Other Income	0.003470
	0.005112

10/16/2015

FINANC\AFUDC\01a_12-961 DOC 162_Attach A_AFUDC 2012 thru 2016.xls

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Northern States Power Company

Docket No. E002/GR-15-826
Exhibit___(BVA-1), Appendix A

Docket No. E002/GR-12-961

Information Request No. DOC-162, Attachment A, Page 5 of 5

AFUDC RATE CALCULATION FORECAST 2016NSP-MN
(000's)

The forecast AFUDC rate is 6.593% This calculation is presented below and includes CWIP Forecast through 2016

Input Values**(000s)**

S = Average Short-Term Debt for year (2016 12 Mo. Avg.)	= \$	121,275	ST DEBT TABLE
RS = Short-Term Debt Interest Rate	=	1.541%	Libor/Prime Rates
D = Long-Term Debt (2015 YR. END)	= \$	4,550,037 1/	LTD/Equity DEBT TABLE
RD = Long-Term Debt Interest Rate	=	4.802% 1/	LTD/Equity DEBT TABLE
P = Preferred Stock (2015 YR. END)	= \$	0	
RP = Preferred Stock Cost Rate	=	0.00%	
C = Common Equity (2015 YR. END)	= \$	5,155,655 1/	LTD/Equity DEBT TABLE
RC = Common Equity Cost Rate (Authorized)	=	9.72% 1/	Authorized Rate - 8K Filing. Dated 03/26/201
W = Average CWIP plus Nuclear Fuel in Process (2016 13 Mo. Avg.)	= \$	808,561	Capital Asset Accounting

1/ These are 2015 year-end balances and will not change with subsequent updates.

Calculated Values

AI = Rate for Gross Allowance for Borrowed Funds used during Construction

$$AI = (RS * (S/W)) + (RD * (D/(D+P+C)) * (1-S/W))$$

AI 2.14% debt % = 32.83% 2.14%

AE = Rate for Allowance for Other Funds used during Construction

$$AE = (1-S/W) * (RP * (P/(D+P+C)) + RC * (C/(D+P+C)))$$

AE 4.39% equity % = 67.17% 4.39%

Simple Rate = 2.1447% + 4.3888% = 6.5335%

Effective Annual Rate (Semi-Annual Compounding)

$$((1 + (\text{Tot Nominal Rate} / 2)) ^ 2) - 1$$

2.1562% 4.4370% **6.593%**

Effective Monthly Rate (Semi-Annual Compounding)

$$((1 + (\text{Tot Nominal Rate} / 2)) ^ 2)^{(1/12)}$$

0.1779% 0.3624% **0.5403%**

Note: Per FERC Order 561-A, if STD exceeds CWIP, the STD rate becomes the AFUDC rate (100% debt). Thus, the AFUDC rate is the STD rate. (all ABFUDC, no AEFUDC).

Monthly AFUDC by Debt or Equity:

Debt Forecast as an Expense Adj.	0.001779
Equity Forecast as Other Income	0.003624
	0.005403

10/16/2015

FINANC\AFUDC\01a_12-961 DOC 162_Attach A_AFUDC 2012 thru 2016.xls

15-Oct-2015
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Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix A

Docket No. E002/GR-12-961
Information Request No. 209

Question:

Please provide a copy of the July 2015 Global Insight Inc. forecast referenced on page 30 of Company witness Mr. Brian Van Abel's Direct Testimony.

Response:

Please see Schedule 8 to Mr. Van Abel's Direct Testimony in Docket No. E002/GR-15-826.

Witness: Brian J. Van Abel
Preparer: Mary Schell
Title: Director, Corporate Financial Policy
Department: Financial Operations, Treasury

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix A

Docket No. E002/GR-12-961
Information Request No. 211

Question:

Please explain the term: index-eligible bond size of \$250 million.

Response:

Please see Page 33 of Company witness Mr. Brian Van Abel's Direct Testimony in Docket No. E002/GR-15-826.

Witness:	Brian J. Van Abel
Preparer:	Mary Schell
Title:	Director, Corporate Financial Policy
Department:	Financial Operations, Treasury

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix ADocket No. E002/GR-12-961
Information Request No. DOC-213Question:

Please provide historic short-term debt levels from January 2014 through June 2015 showing both month-end and average daily STD balances.

Response:

Please see the table below for the requested information

	Month-End	Average
Month	Balance	Daily Balance
2015 Jan Actual	\$ 204,000,000	\$ 216,741,935
Feb Actual	\$ 158,000,000	\$ 158,750,000
Mar Actual	\$ 76,000,000	\$ 101,935,484
Apr Actual	\$ 48,000,000	\$ 30,800,000
May Actual	\$ 204,000,000	\$ 103,580,645
Jun Actual	\$ 117,000,000	\$ 169,416,667
2014 Jan Actual	\$ 360,000,000	\$ 274,580,645
Feb Actual	\$ 364,000,000	\$ 333,035,714
Mar Actual	\$ 280,000,000	\$ 283,483,871
Apr Actual	\$ 239,000,000	\$ 226,266,667
May Actual	\$ 28,000,000	\$ 92,064,516
Jun Actual	\$ 27,000,000	\$ 8,900,000
Jul Actual	\$ 64,000,000	\$ 51,645,161
Aug Actual	\$ 60,000,000	\$ 30,032,258
Sep Actual	\$ -	\$ 10,133,333
Oct Actual	\$ 74,000,000	\$ 37,032,258
Nov Actual	\$ 118,000,000	\$ 66,700,000
Dec Actual	\$ 142,000,000	\$ 81,032,258

Witness: Brian J. Van Abel
 Preparer: Robert LaBahn
 Title: Forecast / Financial Consultant - Corporate Finance
 Department: Corporate Financial Policy / Treasury

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix ADocket No. E002/GR-12-961
Information Request No. OAG-96Question:

Reference AFUDC and CWIP. Provide the dollar level of short-term debt, long-term debt, preferred stock, and common stock at year-end 2016 (the test year.). Provide the balances used for the Test Year AFUDC calculation.

Response:

	(\$000's)
1) NSPM Forecast Balances at Year End 12/31/2016 - Per 2016 Rate Case Test Year	
	<u>Balance</u>
Short-Term Debt	\$102,196
Long-Term Debt Balance	\$4,703,780
Preferred Stock	\$0
Equity Balance	\$5,318,020
2) NSPM For 2016 Test Year AFUDC Rate Calculation - from a June 2015 Forecast	
	<u>Balance</u>
Short-Term Debt is Calculated Using a 12 Month Average Balance for 2016	\$121,275
Long-Term Debt is Calculated Using the Prior Year 2015 Ending Balance	\$4,550,037
Preferred Stock	\$0
Equity Balance is Calculated Using the Prior Year 2015 Ending Balance	\$5,155,655

Witness: Brian J. Van Abel
 Preparer: Mary Schell / Lisa Perkett
 Title: Director, Corp. Financial Policy / Director
 Department: Financial Operations, Treasury / Capital Asset Accounting

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix A

Docket No. E002/GR-13-868
Information Request No. OAG-176

Question:

Provide the calculation of free cash flow for NSP and Xcel Energy for each year 2012 through 2015 and the test year 2016.

Response:

Please see Attachment A to this response for the requested information.

Witness: Brian J. Van Abel
Preparer: Robert LaBahn
Title: Financial Consultant/Forecast - Corporate Finance
Department: Corporate Financial Policy / Treasury

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix A

Docket No. E002/GR-13-868

Information Request No. OAG-176, Attachment A, Page 1 of 1

Xcel Energy Inc. Northern States Power Company Minnesota (NSPM) 2012 Through 2016 Test Year Free Cash Flow (Amounts In Thousands)					
	<u>2012</u>	<u>2013</u>	<u>2014</u>	Forecast Year <u>2015</u>	Test Year <u>2016</u>
<u>Xcel Energy</u>					
Net cash provided by operating activities	2,004,756	2,584,036	2,648,192	2,937,000	3,104,000
Plus: Allowance for equity funds used during construction	62,840	87,683	89,750	54,000	49,000
Less: Utility capital/construction expenditures	<u>(2,570,209)</u>	<u>(3,395,325)</u>	<u>(3,199,791)</u>	<u>(3,689,000)</u>	<u>(2,999,000)</u>
Free Cash Flow Total	(502,613)	(723,606)	(461,849)	(698,000)	154,000
<u>NSPM</u>					
Net cash provided by operating activities	714,974	1,068,881	1,112,097	1,262,000	1,310,000
Plus: Allowance for equity funds used during construction	37,109	40,064	23,788	27,000	34,000
Less: Utility capital/construction expenditures	<u>(1,172,403)</u>	<u>(1,548,952)</u>	<u>(1,241,940)</u>	<u>(1,814,000)</u>	<u>(1,233,000)</u>
Free Cash Flow Total	(420,320)	(440,007)	(106,055)	(525,000)	111,000

Source: 2012 through 2014 Xcel Energy Inc. and Northern States Power Company Minnesota 10K Consolidated Statements of Cash Flows,
2015 and 2016 is from the Corporate Treasury Department September 2015 Rating Agency Forecast.

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix A

Docket No. E002/GR-13-868

Information Request No. OAG-203

Question:

For all responses show amounts for Total Company and the Minnesota jurisdictional electric unless indicated otherwise. Total Company is meant to include costs incurred by Xcel Energy Services and NSP Minnesota, both regulated and non-regulated operations.

Reference AFUDC and funding construction.

Explain how cash provided by operations for NSP is used to finance construction work in progress. Explain how much cash from operations NSP used to finance its construction work in progress for each of the years 2012 through 2015 and projected for the test year 2016. Explain and quantify the use of cash from operations for purposes other than financing + projects for each of those years.

Response:

NSP and the other Xcel Energy operating companies finance their construction programs with a combination of internal funds, short-term debt, long-term debt and equity infusions from its parent, Xcel Energy Inc. NSP finances consistent with maintaining a certain target capital structure. NSP and the other operating companies do not trace internal funds, but those funds are co-mingled with other forms of financing to fund our capital expenditures and operations. NSP will use cash on hand and short-term debt to initially fund its operations and construction. When the short-term debt levels reach an elevated sustained level, NSP will issue long-term debt and equity to pay off the short-term debt.

The Company's response to the Office of the Attorney General's Information Request No. 176 shows the cash from operations and also the utility capital and construction expenditures for the years 2012 through 2016. For the majority of the years, the cash from operations is not sufficient to finance our capital expenditure programs, and therefore NSP must look to other sources of funding such as short- and long-term debt and equity infusions.

We do not manage our internal funds and external funds by electric jurisdiction and therefore do not have those numbers available in that format.

Witness: Brian J. Van Abel
Preparer: Mary Schell
Title: Director, Corporate Financial Policy
Department: Treasury/CFO

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix ADocket No. E002/GR-13-868
Information Request No. OAG-203.1Question:

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Response to OAG IR 203. For the years 2012 through 2015 and projected for the test year 2016, provide the date and amount of equity infusion for NSP, Xcel Energy, and each of its other affiliates.

Response:

The chart below shows the timing and the amount of equity infusions into NSPM. The equity infusions into NSPM are not split by jurisdiction. In addition, there have been no equity infusions from NSPM into non-regulated entities.

Xcel Energy does not receive equity infusions but issues public equity in the capital markets.

NSP Minnesota, Equity Infusions Received (Amounts In Thousands)

	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>
January	100,000	60,000	75,000	75,000	0
February	0	0	0	0	0
March	0	60,000	20,000	0	0
April	0	0	0	0	0
May	40,000	0	0	0	0
June	5,621	0	0	50,100	4,841
July	0	0	0	0	0
August	0	0	0	0	25,000
September	0	-9,898	29	0	0
October	0	25,000	0	75,000	0
Nov	0	60,000	0	40,000	0
December	69,489	90,000	22	102,937	4,912
Total	215,110	285,102	95,051	343,037	34,753

Witness: Brian J. Van Abel
 Preparer: Robert LaBahn, Gregory Niemela
 Title: Consultant / Financial Forecast Analysts
 Department: Treasury/CFO

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix ADocket E002/GR-13-868
Information Request No. OAG-315

Question:

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and nonregulated operations.

Please provide data on all issuances of common stock by each of the companies included in your proxies over the last five years on the number of shares issued, the share price, the issuance costs, the dates of the issuances, and whether the shares were over-subscribed and if so, to what extent.

Response:

We have interpreted this question as referencing Xcel Energy's stock issuances, which are the source of the flotation cost included in the proposed return on equity. We are willing to work with the Office of the Attorney General if other information is being sought.

Please see Attachment A to this response with regards to the issuances of Xcel Energy common stock. Issuance costs can be found in the column titled "Total Flotation Costs."

Witness: Brian J. Van Abel
Preparer: Mary Schell
Title: Director, Financial Policy and Forecasting.
Department: Financial Policy

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit____(BVA-1), Appendix A

Docket No. E002/GR-13-868

Information Request No. OAG-315, Attachment A, Page 1 of 1

Common Equity Flotation Costs

Date	Issuing Company	Shares Issued	Market Price	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds	Total Flotation Costs	Gross Equity Issue Before Costs	Net Proceeds	Flotation Cost Percentage
August 3, 2010	Xcel Energy, Inc.	21,850,000	\$22.100	\$21.500	\$0.645	\$0.013	\$20.571	\$33,407,927	\$482,885,000	\$449,477,073	6.918%
March 2013	Xcel Energy, Inc.	7,757,449	\$29.057	\$29.057	\$0.291	\$0.052	\$28.714	\$2,657,558	\$225,407,642	\$222,750,085	1.179%
June 2014	Xcel Energy, Inc.	5,693,946	\$30.663	\$30.663	\$0.307	\$0.030	\$30.326	\$1,915,210	\$174,592,340	\$172,677,130	1.097%