

Rebuttal Testimony and Schedules
Laura McCarten

Before the North Dakota Public Service Commission
State of North Dakota

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

Case No. PU-12-813
Exhibit____(LM-2)

Policy

August 12, 2013

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I. INTRODUCTION

1

2 Q. PLEASE STATE YOUR NAME AND TITLE.

3 A. My name is Laura McCarten. I am Regional Vice President for Northern
4 States Power Company – Minnesota (NSPM or Company).

5

6 Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

7 A. Yes. I filed Direct Testimony providing an overview of our electric rate case
8 filing, including the key drivers of our request.

9

10 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

11 A. I summarize our response to the Direct Testimony filed by Advocacy Staff of
12 the North Dakota Public Service Commission and Staff Consultants, and
13 identify the Company witnesses sponsoring Rebuttal Testimony.

14

15 Q. WHAT KEY ISSUES WERE RAISED IN RESPONSE TO THE COMPANY'S DIRECT
16 TESTIMONY?

17 A. Our review of testimony submitted by Advocacy Staff and Staff Consultants
18 indicates that there are several areas of general agreement, including the
19 system investments that drive the need for this case and our proposed class
20 cost of service and class allocation. The key areas of disagreement are:

- 21
- Application of appropriate ratemaking principles, including:
 - 22 ○ The appropriate jurisdictional demand allocator;
 - 23 ○ Use of a historical three-year average for determining 2013
24 operations and maintenance (O&M) expenses;
 - 25 ○ Reliance on other jurisdictional determinations on single issues;
 - 26 • Determination on issues outside of the test year;

- 1 • The Company's management of its investments and expenditures; and
- 2 • Return on equity (ROE).

3
4 Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S RESPONSE TO THESE
5 ISSUES.

6 A. We appreciate the careful review and consideration of our case. While the
7 areas of disagreement may be relatively few, they are significant in terms of
8 both importance and magnitude. In particular, we are concerned by Staff
9 Consultant Dr. Karl R. Pavlovic's recommended change to our long-standing
10 method of allocating the majority of production and transmission costs using
11 the 12-month coincident peak demand allocation method (12 CP). His
12 suggestion of using a 1 CP deviates from widely-accepted ratemaking
13 principles and 20 years of past Commission precedent, and significantly
14 undermines the Company's ability to recover its costs of service and earn a
15 reasonable rate of return.

16
17 We believe Staff's primary issues can be addressed by discussing the following
18 four topics:

- 19 • Potential rate mitigation measures;
- 20 • Appropriate application of ratemaking principles;
- 21 • Management of differences in state energy policy; and
- 22 • Management of system investments and costs.

23
24 In summary, we believe the Commission's decisions in this proceeding should
25 be guided by long-standing ratemaking principles and past precedent. We
26 acknowledge the concerns with our rate increase request, but believe that
27 resolution of these concerns should uphold the regulatory compact and

1 preserve our ability to provide the kind of service our customers depend on
2 and expect. We have indicated areas in our Rebuttal Testimony where we
3 agree to Staff's recommendations or propose an alternative that is based on
4 sound principles.

5
6 Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

7 A. First I provide an overview of our request, as modified by Rebuttal Testimony.
8 I then discuss the key areas of disagreement and the Company's
9 recommendations. Finally, I introduce the Company's Rebuttal witnesses and
10 outline their responsibilities in the proceeding.

11
12 **II. SUMMARY OF REQUEST AND POTENTIAL RATE MITIGATION**

13
14 Q. PLEASE SUMMARIZE THE COMPANY'S INITIAL REQUEST IN THIS PROCEEDING.

15 A. We seek the rate relief needed to support the ongoing costs of providing
16 reliable, high-quality service to our customers. To accomplish this, on
17 December 18, 2012 we requested authority to increase our electric rates by
18 \$16.9 million, or 9.25 percent. We based this request on a forecasted 2013
19 Test Year, using a 10.6 percent ROE and a 52.56 percent equity ratio. Under
20 our proposal, a residential customer using 850 kWh per month would see a
21 monthly bill increase of about \$7 per month or nine percent.

22
23 Q. HAVE YOU MODIFIED YOUR REQUEST SINCE THE FILING OF YOUR CASE?

24 A. Yes. Our Rebuttal Testimony incorporates various corrections and updates to
25 our Application, each offered with the intent of providing the Commission the
26 most current and accurate information. We now seek Commission approval
27 for a \$14.9 million increase, based on corrected and updated financial

1 information and a 10.25 percent return on equity. The Rebuttal Testimony of
2 Company witness Ms. Anne E. Heuer provides detail on our proposed
3 corrections and updates and modified request.
4

5 Q. HAS THE REQUESTED RETURN ON EQUITY BEEN MODIFIED?

6 A. Yes. As explained in the Rebuttal Testimony of Company witness Ms. Ann E.
7 Bulkley, our updated analysis supports an ROE range of 10.00 percent to
8 10.50 percent. Within that range, the Company requests an ROE of 10.25
9 percent based on market conditions and the expectation of and risk associated
10 with rising interest rates. A 10.25 percent ROE is within the range of ROEs
11 approved by other state commissions and sends a signal to investors that the
12 Commission supports utility investment in North Dakota.
13

14 Q. HAS THE COMPANY CONSIDERED ADVOCACY STAFF'S CONCERN ABOUT THE
15 IMPACT OF ITS RATE REQUEST ON ITS NORTH DAKOTA CUSTOMERS?

16 A. Yes. This Commission has recognized the importance of finding the proper
17 balance between ensuring utilities like the Company have the resources needed
18 to ensure continued safe, reliable and economic electric service and just and
19 reasonable rates for our customers. We share this goal.
20

21 As I discussed in my Direct Testimony, the Company is in the midst of a
22 significant investment cycle. We find it encouraging that Staff Consultants
23 have generally agreed with the prudence of our investments and
24 reasonableness of the costs driving our rate increase. However, we recognize
25 Advocacy Staff's concern with the cost of our continued system investments
26 and the corresponding impact on customers. We are willing to work with the
27 Commission and Staff to find appropriate opportunities to help mitigate this

1 impact while still allowing the Company to recover its cost of service and earn
2 a reasonable rate of return.

3
4 Q. PLEASE PROVIDE AN EXAMPLE OF A POTENTIAL OPPORTUNITY TO LESSEN THE
5 RATE IMPACT OF THE COMPANY'S REQUEST.

6 A. One option we could explore is a "smoothing" mechanism to address our
7 pension costs. In my Direct Testimony, I noted that the Company is
8 experiencing higher pension costs in 2013 as a result of amortizing market
9 losses in our pension fund incurred during the 2008 economic downturn,
10 which we call the "2008 market loss." I also noted that the Company is open
11 to considering additional smoothing mechanisms that would reduce the 2013
12 impact of these pension costs while still allowing the Company to recover this
13 cost of service over time.

14
15 A smoothing mechanism would essentially extend the amortization period for
16 2008 market loss and/or cap the expense per year and defer the amount above
17 the cap. The end result is an ability to mitigate the total impact of this cost in
18 the current test year by spreading it out over a number of years.

19
20 Q. HAS THE COMPANY IDENTIFIED OTHER OPPORTUNITIES TO ADDRESS
21 CONCERNS WITH ITS RATE REQUEST?

22 A. Yes. Advocacy Staff has expressed some concern with the rate impacts of our
23 investment cycle. One way to mitigate the rate impacts is to provide
24 predictability to our customers of the rates they pay for electric service.

25
26 Our rigorous planning processes, which I describe further below, allow us to
27 predict with some certainty our major future capital investments that can drive

1 future rate requests. Our currently-forecasted future capital investments are
2 largely (but not totally) driven by transmission and nuclear projects, some of
3 which the Commission has already found to be prudent. When such capital
4 investments are generally known and measurable, the “capital step” is an
5 available ratemaking tool that can alleviate the need for future general rate
6 request proceedings.

7
8 The capital step tool identifies known and measurable capital projects and
9 provides for a “step” increase in rates each year for a specified amount of
10 years beyond the current test year. The step process would include
11 Commission review and evaluation of these projects, without additional
12 general rate request proceedings. By addressing these future costs, our
13 customers would have greater certainty about their electric rates in the years
14 covered by a step. The Company requested and the Commission approved a
15 capital step in our last rate case to account for the 2012 capital costs of our
16 nuclear program.

17
18 We believe that an appropriately crafted capital step or steps can help with the
19 predictability of our electric rates and mitigate the Company’s need to make
20 future general rate requests. The Company is interested in working with the
21 Commission and Staff to identify an appropriate step mechanism to achieve
22 this goal.

23 24 **III. UPHOLDING RATEMAKING PRINCIPLES**

25
26 Q. WHAT IS THE OVERALL OBJECTIVE OF THE RATEMAKING PROCESS FOR
27 REGULATED UTILITIES?

1 A. A regulated utility has both the right and obligation to serve all customers that
2 live or do business in its established service territory. In order to reliably serve
3 customers, the utility must invest in and maintain its infrastructure and operate
4 its business to deliver on this obligation. The overall purpose of the
5 ratemaking process is to set rates that allow the utility to recover the
6 reasonable costs it incurs to satisfy that obligation, including the opportunity
7 to earn a return that is sufficient to attract the capital needed to support
8 continued investment. This is often referred to as the “regulatory compact.”
9 Decades of regulatory proceedings and rulings have established extensive
10 precedent, principles, and standards that promote a fair, constructive, and
11 stable regulatory environment.

12

13 Q. HOW DO CUSTOMERS BENEFIT FROM A CONSTRUCTIVE AND STABLE
14 REGULATORY ENVIRONMENT?

15 A. We share with our North Dakota customers the goal of having reliable, safe,
16 and economical energy available 24 hours a day, 365 days a year. Meeting this
17 goal requires significant ongoing investment that far exceeds what the
18 Company can finance on its own. As a result, we must turn to the capital
19 markets to raise the funds necessary to make improvements to our system.
20 The cost at which we can raise capital depends in large part on investors’
21 perceived risk of investing with us and the expected return, which is a function
22 of the regulatory environment. With a constructive and stable regulatory
23 environment that allows us to keep our balance sheet strong and consistently
24 meet investor expectations, we have been able to achieve record-low
25 borrowing costs that lower the overall cost of service to our customers and
26 will benefit customers for decades to come. Thus, customers have an
27 important interest in keeping the Company financially healthy.

1 Q. HAVE STAFF CONSULTANTS MADE RECOMMENDATIONS IN THIS PROCEEDING
2 THAT WOULD CHALLENGE THE STABILITY OF THE REGULATORY COMPACT?

3 A. Yes. The Staff Consultants have proposed methodological changes that are
4 inconsistent with long-standing ratemaking principles in North Dakota. We
5 believe it is important to maintain a principled approach to ratemaking that
6 preserves the stability of the regulatory compact, and ultimately supports
7 continued safe and reliable electric service to our customers in North Dakota.
8 As I discussed above, we are interested in addressing the Staff's stated
9 concerns with the magnitude and frequency of the Company's proposed rate
10 increases; however, we believe that we can resolve these issues while
11 upholding sound ratemaking principles.

12

13 Q. PLEASE PROVIDE EXAMPLES OF RECOMMENDATIONS THAT MAY DEVIATE
14 FROM LONG-STANDING RATEMAKING PRINCIPLES IN NORTH DAKOTA.

15 A. The most significant deviation is the Staff Consultants' recommendation that
16 the Company change its demand allocator from the 12 CP methodology to the
17 one (annual) coincident peak (1 CP) methodology. Other examples include:
18 using historic data from 2010 to 2012 to set selected future 2013 test-year
19 costs; reliance on the determination of regulatory commissions in other states
20 for certain, single issues; and the recommendation to disallow costs outside of
21 the test year for which the Company has not yet sought recovery.

22

23 **A. Determination of Demand Allocator**

24 Q. WHAT IS THE COMPANY'S METHOD AND DR. PAVLOVIC'S RECOMMENDATION
25 FOR ALLOCATING THE MAJORITY OF PRODUCTION AND TRANSMISSION COSTS
26 TO NORTH DAKOTA CUSTOMERS?

1 A. The Company currently utilizes a 12 CP demand-based allocation. Dr.
2 Pavlovic is recommending that the Company now shift to a 1 CP
3 methodology.

4

5 Q. DOES THE COMPANY AGREE WITH DR. PAVLOVIC'S RECOMMENDATION?

6 A. No. We do not believe there is any need or justification for the Commission
7 to modify the long-standing demand allocation methodology. The Company
8 has used the 12 CP demand allocation methodology in all of our jurisdictions
9 for almost 20 years, as it reasonably reflects the costs caused by each
10 jurisdiction, is used by the Midcontinent Independent System Operator
11 (MISO) and Federal Energy Regulatory Commission (FERC), and promotes
12 more stable jurisdictional cost responsibility over time. The Staff Consultants
13 have not identified any changes to the NSP System that warrant a change in
14 our allocation methodology and are proposing a more volatile allocation
15 methodology. Further, their recommendation does not comport with the
16 Commission's precedent on this issue. Company witness Mr. Scott B.
17 Brockett further explains our position and recommendation.

18

19 **B. Use of Future Test Year**

20 Q. WHAT IS THE RECOMMENDATION OF THE STAFF CONSULTANTS WITH RESPECT
21 TO USING HISTORIC DATA TO DETERMINE CERTAIN TEST-YEAR AMOUNTS?

22 A. Although the Staff Consultants generally support the prudence of the costs
23 that are driving our rate request, they selectively apply a three-year historical
24 average methodology to determine some of our revenue and expenses in our
25 test year.

26

27 Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

1 A. No. Utilizing a three-year historic average fails to match 12 months of
2 expenses with 12 months of revenue and also fails to accurately reflect the
3 revenues and costs the Company will have during the period rates are in effect.
4 Our future test-year methodology is consistent with North Dakota statutes
5 and established practice of the Company and the Commission, and it properly
6 reflects changes in our operations from past years. Utilizing this historic
7 methodology could result in larger future revenue deficiencies, which would
8 cause the Company to seek more, not fewer, rate increases. We believe using
9 this methodology is contrary to stated concerns with the Company's frequency
10 of rate requests. Company witness Ms. Heuer further discusses our concerns
11 with this methodology.
12

13 **C. Reliance on Other Commission Orders for Single Issues**

14 Q. DID A STAFF CONSULTANT RELY ON ANOTHER JURISDICTION'S COMMISSION
15 DECISION TO SUPPORT THIS RECOMMENDATION?

16 A. YES. Staff Consultant, Mr. Dante Mugrace, recommends that all incentive
17 compensation be disallowed in part because the Wisconsin Public Service
18 Commission decided not to allow incentive compensation in rates.
19

20 Q. WHAT IS THE COMPANY'S RESPONSE TO THIS RECOMMENDATION?

21 A. We do not believe it is appropriate to disallow this cost based on ratemaking
22 practices in one state. The Wisconsin Commission decision is inconsistent
23 with all of the other commissions in jurisdictions we serve. Mr. Mugrace also
24 isolated this one issue without considering the other outcomes of the
25 Wisconsin Commission decision.
26

1 Though Mr. Mugrace looked to our Wisconsin proceeding for guidance
2 related to incentive compensation, his recommendation does not reflect the
3 totality of the outcome of our Wisconsin rate case. In its decision, the
4 Wisconsin Commission approved approximately 90 percent of the Company's
5 rate request, a 10.4 percent ROE, and allowed the use of a 12 CP demand
6 allocator. A complete copy of the order is included as Exhibit____(LM-2),
7 Schedule 1.

8
9 Fundamental to the purpose of ratemaking is the establishment of an overall
10 revenue requirement that considers individual issues as part of the larger
11 whole. Selective application of one commission's policy decision on one issue
12 deviates from the application of principled ratemaking methodologies in
13 keeping with the regulatory compact.

14
15 Q. DID MR. MUGRACE RAISE OTHER CONCERNS RELATED TO INCENTIVE
16 COMPENSATION?

17 A. Yes. Mr. Mugrace stated that the Company's application contained
18 insufficient documentation to support its incentive compensation request.

19
20 Q. WHAT IS THE COMPANY'S RESPONSE TO THIS CONCERN?

21 A. The level of documentation we provided in our application is consistent with
22 our prior rate filings in North Dakota. Through the discovery process, we
23 were not made aware of the broader concern about lack of support for our
24 incentive compensation costs.

25
26 However, to supplement the record, we provide Rebuttal Testimony by
27 Company witness Ms. Sharon L. Koenig that provides additional discussion of

1 our incentive compensation request. As Ms. Koenig explains, our overall
2 compensation package impacts our ability to attract and retain the talent
3 necessary to operate our business. Having a market-competitive compensation
4 package is a fundamental requirement for attracting and retaining a skilled
5 workforce.

6
7 **D. Consideration of Issues Outside the Test Year**

8 Q. PLEASE DESCRIBE RECOMMENDATIONS REGARDING COSTS THAT THE
9 COMPANY HAS NOT YET SOUGHT TO RECOVER.

10 A. Advocacy Staff is recommending the Commission:

- 11 • Exclude the costs of the Odell Project from the Fuel Cost Rider (FCR);
- 12 • Exclude the costs of the Pleasant Valley Wind Project from rate base;
- 13 • Deny cost recovery of all solar projects that may be undertaken to
14 comply with Minnesota's new solar mandate; and
- 15 • Reassess our proposal in Case No. PU-13-194 where we request an
16 advanced determination of prudence (ADP) for the construction of
17 new gas combustion turbines in Minnesota and North Dakota.

18
19 Q. WHAT IS THE COMPANY'S RESPONSE TO THESE RECOMMENDATIONS?

20 A. We believe these recommendations are premature, because the Company has
21 not yet sought recovery of these costs in a rate application. Analyses of these
22 resource additions should be made on a complete record, so that the
23 Commission may assess all of the facts and make a reasoned and informed
24 decision.

25
26 Q. WILL THE COMPANY SEEK COMMISSION REVIEW OF THE COSTS OF THESE
27 PROJECTS?

1 A. Yes. The Company has filed timely applications for an advance determination
2 of prudence for the Courtenay, Odell, and Pleasant Valley Projects (Case Nos.
3 PU-13-706, PU-13-707, PU-13-708), as well as for our natural gas turbine
4 proposal (Case No. PU-13-194). In those Cases, the Company is requesting
5 the Commission determine that our intent to procure these resources is
6 prudent. A full and complete record on these issues is necessary, and the
7 Company believes that the current ADP proceedings are the appropriate
8 forum for developing the record. The Company intends to seek recovery of
9 these costs based on the outcomes of those proceedings.

10
11 As I discuss further below, if and when the Company seeks to acquire
12 additional solar resources, we will ensure that there is a process in place for
13 Commission review and input on those resource acquisitions. Thus, we
14 recommend the Commission take no action on these issues in this rate case.

15
16 **E. Review of Transmission Cost Rider**

17 Q. PLEASE DESCRIBE THE STAFF CONSULTANT DR. PAVLOVIC
18 RECOMMENDATION WITH RESPECT TO THE COMPANY'S PROPOSED
19 TRANSMISSION COST RIDER (TCR).

20 A. Dr. Pavlovic recommends that the Commission not approve our proposed
21 TCR, stating our proposal is incomplete. He recommends that the Company
22 re-file its proposal when we have identified the initial set of transmission
23 projects we intend to incorporate into the TCR.

24
25 Q. HOW DO YOU RESPOND TO THIS RECOMMENDATION?

26 A. We disagree with Dr. Pavlovic's recommendation because it is inconsistent
27 with North Dakota statutes and contrary to Advocacy Staff's stated intent that

1 the Company minimize its rate filings. A TCR mechanism, applied based on a
2 Commission approved tariff, provides a sensible and organized approach.
3 With an approved TCR mechanism in place, when qualifying transmission
4 projects are to be placed in service, the focus can be on the merits of the
5 project and not the details of the recovery mechanism. Further, the TCR is
6 permitted by law, and the Commission has approved similar riders for other
7 utilities in North Dakota.

8
9 Q. WHY IS DR. PAVLOVIC'S RECOMMENDATION INCONSISTENT WITH NORTH
10 DAKOTA STATUTE?

11 A. I am not a lawyer, but I have been advised that North Dakota Century Code
12 Section 49-05-04.3 contemplates a two-step process in which the utility first
13 files for its TCR Tariff and then, when it seeks to make a rate adjustment
14 under the approved TCR, the information Dr. Pavlovic identifies as missing
15 would be provided. I am further advised that the while the statute does not
16 prohibit a combined filing, as recommended by Dr. Pavlovic, it does not
17 require one either.

18
19 Q. HOW COULD APPROVAL OF THE TCR HELP MINIMIZE FUTURE GENERAL RATE
20 REQUESTS?

21 A. In the next several years, the Company will be placing into service several
22 transmission investments, including the CapX2020 Group 1 Projects. By
23 utilizing the TCR mechanism, we can recover the costs of these types of
24 investments without a rate case. Our proposed TCR mechanism and North
25 Dakota law provide the Commission with oversight of any transmission
26 projects prior to our inclusion of these projects into the TCR to ensure such
27 costs are prudent. Consequently, the TCR facilitates efficient review and cost

1 recovery of approved transmission investments outside the context of a
2 general rate request.

3
4 **F. Economic Development Expenses and Charitable Contributions**

5 Q. PLEASE DESCRIBE MR. MUGRACE'S RECOMMENDATIONS ON THE COMPANY'S
6 ECONOMIC DEVELOPMENT EXPENSES AND CHARITABLE CONTRIBUTIONS.

7 A. Mr. Mugrace has recommended complete disallowance of all economic
8 development expenses and charitable contributions. We have requested
9 recovery of 50 percent of eligible economic development and charitable
10 contribution expenses.

11
12 Q. DO YOU AGREE WITH THIS RECOMMENDATION?

13 A. No, I do not. As discussed in our response to Data Request No. NDPSC-2-
14 015, (included as Exhibit___(LM-2), Schedule 2), we included 50 percent of
15 our charitable contributions and economic development expenses in our rate
16 request, consistent with our previous requests in North Dakota. We believe
17 this is appropriate, because the contributions provide important support to the
18 communities and organizations in the areas we serve. Given the long-term
19 nature of our relationship to the communities in our service territory, we
20 believe we have a responsibility and expectation to help support the stability
21 and economic vitality of these communities. Charitable contributions and
22 economic development activities help us deliver on that responsibility. We
23 propose only 50 percent recovery to provide added assurance that the
24 charitable and economic development contributions are made in a responsible
25 and reasoned manner.

1 **IV. MANAGING STATE ENERGY POLICY DIFFERENCES**

2
3 Q. PLEASE SUMMARIZE THE CONCERNS RAISED THAT RELATE TO COSTS
4 RESULTING FROM RENEWABLE INVESTMENTS AND EXPENSES.

5 A. We acknowledge the concerns that the Commission and Staff have raised
6 about North Dakota customers sharing costs that are not perceived to be
7 economic for North Dakota customers. These concerns have generally related
8 to the costs of resource acquisitions the Company has undertaken to, in part,
9 meet the higher renewable energy requirements of our Minnesota jurisdiction.

10
11 Q. HOW HAS THE COMPANY RESPONDED TO THESE CONCERNS?

12 A. We are making significant efforts to ensure we are responsive to these
13 concerns. These efforts are mainly focused on meeting our commitments to
14 provide timely information so that the Commission is made aware of our
15 plans in advance and to provide for Commission input into our resource
16 decisions.

17
18 These commitments arise primarily from the Settlement Agreement in Case
19 No. PU-07-776. The Settlement was based on a cooperative approach to
20 providing all of our customers the benefits of an integrated system while
21 acknowledging the different energy priorities of the states we serve. As the
22 Commission has voiced additional concerns or expectations, such as those in
23 Case No. PU-12-59, we have been diligently working to ensure that they are
24 addressed.

1 **A. Compliance with Commitments to the Commission**

2 Q. PLEASE DESCRIBE THE COMPANY'S COMMITMENTS TO KEEP THE COMMISSION
3 INFORMED.

4 A. Consistent with our commitments, we continue to file our Resource Plans for
5 the integrated NSP System with the Commission and provide an alternative
6 system-wide analysis that strictly meets both federal and North Dakota
7 environmental and renewable requirements for the same time period. We also
8 provide a forward-looking five-year plan identifying our intended generation
9 and transmission investments or purchase agreements in our annual Ten Year
10 Plan filings, which also include an anticipated schedule of future ADP
11 applications. We have also agreed to meet with the Commission and Staff as
12 necessary to conduct updates on resource planning efforts and decisions and
13 discuss any plans or updates filed in that year.

14
15 Q. PLEASE DESCRIBE THE COMPANY'S COMMITMENTS TO PROVIDE THE
16 COMMISSION OPPORTUNITIES TO PROVIDE TIMELY INPUT INTO ITS RESOURCE
17 DECISIONS.

18 A. In addition to the Commission's ability to provide comments to our
19 informational filings, and our commitment to meet with the Commission and
20 Staff on our resource acquisitions or rehabilitations, we agreed in the
21 Settlement to file an application for an ADP for any resource addition or
22 rehabilitation where the generating facility is at least 50 MW or the
23 transmission facility is at least 50 miles long. More recently, we made an
24 additional commitment in Case No. PU-12-59 to make such ADP filings
25 within two weeks of making a similar filing in Minnesota. Also in Case No.
26 PU-12-59, the Commission indicated its expectation that our contractual

1 commitments for resource additions should be contingent on Commission
2 approval.

3
4 Q. HOW HAS THE COMPANY MET THESE COMMITMENTS?

5 A. Since the Commission approved the Settlement in Case No. PU-07-776, we
6 have filed Applications for ADPs for projects including the Nobles Wind
7 Farm, Merricourt Wind Farm, CapX2020 transmission projects, significant
8 projects at our Prairie Island nuclear generating facility, Prairie Rose Wind
9 Farm, our proposal for three gas combustion turbines, and our proposed 600
10 MW of wind additions.

11
12 Following the Commission's direction in Case No. PU-12-59, our ADP
13 Applications for our combustion turbine proposal and our wind additions
14 have been made less than two weeks after similar filings with the Minnesota
15 Public Utilities Commission. As I discuss in my testimony in the ADP
16 proceeding for our 600 MW wind proposal, our contracts for those resources
17 are contingent on this Commission's approval.

18
19 **B. Recovery of Power Purchases**

20 Q. PLEASE SUMMARIZE THE RECOMMENDATIONS MADE WITH RESPECT TO THE
21 IMPACT OF RESOURCE RECOVERY ON THESE INTERJURISDICTIONAL ISSUES?

22 A. While not a part of our rate request in this proceeding, Staff Consultant Mr.
23 Mugrace has recommended disallowance of several renewable energy
24 purchased power agreements (PPAs) and all costs of the Prairie Rose Project
25 incurred until the end of this case. Advocacy Staff also recommended that all
26 costs related to meeting the new solar mandate established in Minnesota be
27 preemptively disallowed. Additionally, Advocacy Staff recommends that we

1 issue a refund to North Dakota customers to reflect the Minnesota
2 Commission's disallowance of certain costs associated with the St. Paul
3 Cogeneration biomass facility.

4
5 Q. DOES THE COMPANY AGREE WITH THESE RECOMMENDATIONS?

6 A. No, with the exception of the refund for disallowed St. Paul Cogeneration
7 costs. We are aware of the Commission's concerns and have been seeking to
8 address them through the processes I previously described. Therefore, we do
9 not believe it is necessary for the Commission to take further action on these
10 items at this time.

11
12 Additionally, we believe these recommendations are inconsistent with a
13 cooperative approach to ensuring that the Commission's concerns can be met.
14 The Settlement Agreement in Case No. PU-07-776 recognized the need to
15 address the Commission's concerns while also allowing the Company to
16 recover its cost of service and earn a reasonable return. We are concerned
17 that these recommendations do not reflect this approach.

18
19 We do agree to calculate a refund for North Dakota customers related to
20 disallowed St. Paul Cogeneration PPA costs. This is described by Company
21 witness Mr. Steven W. Wishart in his Rebuttal Testimony.

22
23 *1. Purchased Power Costs*

24 Q. PLEASE ELABORATE ON THE COMPANY'S CONCERNS WITH THE RESPECT TO
25 RECOMMENDATIONS ON PURCHASED POWER COSTS.

26 A. Mr. Mugrace's recommendation to disallow recovery through the FCR of the
27 costs of energy of 17 biomass, solar, and wind PPAs will impact our ability to

1 reliably plan future resource additions for our integrated system. Further, the
2 recommendation is incomplete.

3
4 Q. WHY WILL THESE PURCHASED POWER RECOMMENDATIONS IMPACT THE
5 COMPANY'S PLANNING?

6 A. Our recovery of the PPAs identified by Mr. Mugrace is consistent with the
7 Commission's rules and our Commission-approved FCR. Many of these
8 PPAs have been recovered through the FCR for several years. Because of
9 this, the Company has relied on the availability of these resources and our
10 ability to recover their costs through Commission-approved mechanisms.
11 Abrupt disallowance of cost recovery of these resources, will impact our
12 resource procurement decisions in a way that could leave us vulnerable to
13 volatile market pricing. Mr. Wishart discusses these impacts in his Rebuttal
14 Testimony.

15
16 Most concerning is that Mr. Mugrace's recommendation essentially results in
17 our North Dakota customers receiving energy for free. While he frames this
18 as our North Dakota customers obtaining savings, the savings are in fact the
19 result of our customers receiving energy they do not pay for. Mr. Wishart
20 provides further information with respect to the concept of free energy.

21
22 Q. WHAT IS THE COMPANY'S RECOMMENDATION ON THE ISSUE OF RECOVERY OF
23 CERTAIN PURCHASED POWER COSTS?

24 A. These costs are not part of the revenue requirements in this rate case, because
25 recovery of these costs is through the FCR. If the Commission is interested in
26 further review, we suggest that the Commission open a separate docket to
27 review how costs recoverable via the FCR are to be reviewed in the future.

1 Such a docket may result in changes to the FCR Rider tariff or the
2 establishment of a new process for reviewing purchased power agreements.
3 Addressing these issues in a separate docket would allow the Commission to
4 decline to take action at this time.

5
6 Should the Commission choose to take action in this proceeding, we believe
7 the Company should recover the costs of the PPAs identified by Mr. Mugrace
8 for the reasons explained in the Rebuttal Testimony of Mr. Wishart.

9
10 *2. Prairie Rose Wind*

11 Q. PLEASE ELABORATE ON THE COMPANY'S CONCERNS WITH RESPECT TO MR.
12 MUGRACE'S RECOMMENDATION ON PRAIRIE ROSE WIND.

13 A. The recommendation that the costs incurred for the Prairie Rose Wind project
14 not be recovered prior to the termination of this case does allow us to recover
15 fully the costs of a generation resource that Mr. Mugrace admits is prudent.
16 The Company recommends that since Mr. Mugrace concluded this project is
17 acceptably priced and reasonable, the Company should be able to recover fully
18 all costs of the project.

19
20 *3. Minnesota Solar Mandate*

21 Q. WHAT DOES THE COMPANY PROPOSE IN RESPONSE TO ADVOCACY STAFF'S
22 POSITION ON MINNESOTA SOLAR MANDATE COSTS?

23 A. As I mentioned, we believe that Advocacy Staff's proposal is premature since
24 the Company has not sought to recover any of these costs in this case.
25 However, we recognize that the new solar mandate recently implemented by
26 the Minnesota legislature is part of the Commission's general concerns

1 regarding renewable mandates. Therefore, we believe it is best to proactively
2 address the impact of the solar mandate on our North Dakota customers.

3
4 As part of the development of the solar mandate legislation in Minnesota, we
5 intended to seek a provision that would ensure the costs to comply with the
6 mandate were borne only by Minnesota rate payers. Due to the procedure
7 that was used to pass the bill in the final days of the session, however, we did
8 not have the opportunity to propose that provision. We will continue to work
9 to achieve this goal through future legislation or regulatory applications and
10 commit to the Commission that we will make our best efforts to seek
11 appropriate opportunities to ensure recovery of the costs of complying with
12 the mandate solely from our Minnesota customers. We commit to keeping the
13 Commission's Staff apprised of our efforts and our strategic decisions to
14 achieve this goal.

15 16 **V. MANAGING SYSTEM INVESTMENTS AND COSTS**

17 18 **A. System Investments**

19 Q. WHAT ISSUES DID ADVOCACY STAFF RAISE RELATED TO THE COMPANY'S
20 SYSTEM INVESTMENTS AND COST MANAGEMENT PRACTICES?

21 A. Advocacy Staff expressed concern about the overall level, timing, and planning
22 of the Company's system investments and the Company's renewable energy
23 acquisitions in particular. Advocacy Staff questioned whether the Company is
24 investing in a well-organized and thoughtful way that considers the impacts on
25 ratepayers. Additionally, Advocacy Staff is concerned that the Company is
26 making opportunity purchases that are "not needed" and adding costs for our
27 customers, stating that getting a good price on an investment does not justify

1 its purchase if it is not needed to meet incremental loads. Advocacy Staff is
2 also concerned about the impacts of wind generation on our existing
3 generation fleet.

4
5 Q. WHAT IS THE COMPANY'S RESPONSE TO ADVOCACY STAFF'S CONCERN ABOUT
6 THE LEVEL AND TIMING OF INVESTMENT IN THE SYSTEM?

7 A. The investments we are making are part of an extensive and ongoing resource
8 planning process that encompasses both short- and long-term needs
9 assessments. Such planning ensures that our customers continue to have
10 energy that is reliable, economical and sustainable, and that we comply with
11 regulatory requirements. The Company, like many other utilities, is currently
12 in a cycle of significant system investment, as we replace and refresh
13 infrastructure that was originally built to handle the rapid post-war growth
14 during the 1950's to 1970's. As discussed in my Direct Testimony, a
15 significant driver of this case is our investment to keep our nuclear plants
16 operating safely and reliably for an additional 20 years. This investment
17 cannot be delayed or deferred, because the investments are required as part of
18 our operating license renewals.

19
20 These investments will position us well for the future and will serve and
21 benefit customers over the long run. Additionally, because we are currently
22 able to take advantage of favorable financing, we can ensure these investments
23 have as low a customer impact as possible.

24
25 As discussed in our response to Data Request No. NDPSC-6-016 (included as
26 Exhibit___(LM-2), Schedule 3), capital projects are identified through a
27 rigorous planning process that results in short- and long-term investment

1 plans. We develop our investment plans to ensure projects are completed
2 prior to adverse reliability impacts or compliance issues.

3
4 In addition to prioritizing projects for future years, we also closely monitor
5 our budget and any changing circumstances throughout the year, reprioritizing
6 projects when appropriate.

7
8 Q. CAN YOU PROVIDE EXAMPLES OF HOW THE COMPANY HAS ELIMINATED OR
9 DEFERRED INVESTMENTS?

10 A. We continually monitor our plans and adjust them accordingly to new
11 circumstances and opportunities to ensure that we have the right plan to meet
12 customer needs. Our proposals to reevaluate the Black Dog combined cycle
13 project and Prairie Island uprate projects in light of changed circumstances are
14 examples of our efforts to keep our plans aligned with our true needs and
15 avoid costs where possible. Additionally, the phased approaches to refurbish
16 and repower our King, High Bridge, and Riverside generating plants helped to
17 mitigate the impacts on rates. And our participation with ten other utilities to
18 build the Group I CapX2020 transmission lines over several years will enable
19 us to smooth the rate impacts of those projects over a number of years.

20
21 Additionally, we have undertaken a number of efficiency and productivity
22 initiatives to help offset rising costs, such as adding new productivity metrics,
23 emphasizing preventative maintenance, and capturing supply chain
24 efficiencies.

1 Q. DOES ADVOCACY STAFF OFFER RECOMMENDATIONS RELATED TO THE
2 COMPANY'S INVESTMENTS AND SPENDING?

3 A. Yes. Advocacy Staff recommends the Commission consider:

- 4 • Requiring the Company to prepare and submit forecasted budgets
5 demonstrating projects that the Company can delay to help minimize
6 future increases; and
- 7 • Capping future rate increases so that the Company has an incentive not
8 to spend.

9

10 Q. DOES THE COMPANY AGREE WITH THESE RECOMMENDATIONS?

11 A. While we appreciate the intentions behind Staff's suggestions, we do not
12 believe additional reporting requirements would be beneficial. As previously
13 discussed, the Company has a rigorous process for identifying, evaluating, and
14 prioritizing capital projects, which provides assurance that the right projects
15 are done at the right time to maintain safety and reliability. We are already
16 submitting information about these projects to the Commission in various
17 ways (*i.e.*, Resource Plans, ADPs, Ten Year Plans, etc.), making additional
18 project forecast information unnecessary. Additionally, because the Company
19 identifies several hundred projects each year, it would be burdensome for both
20 the Company and Commission.

21

22 If designed well, prescribed rate caps through a multi-year approach to rate
23 setting, such as the capital step I discuss above, could be an effective way to
24 manage the impacts of a utility's investment program on rates. The Company
25 operated successfully under a formula rate structure while under the "PLUS"
26 performance-based rate plan during the 2001-2005 period. However, it is
27 important that any solution consider current investment needs and trends. It

1 may be counter-productive to merely set a firm cap on future rate increases, as
2 the Company's requests are based on the costs needed to provide quality
3 service.

4
5 **B. Opportunity Purchases**

6 Q. WHAT IS THE COMPANY'S RESPONSE TO ADVOCACY STAFF'S CONCERN THAT
7 THE COMPANY IS MAKING OPPORTUNITY PURCHASES?

8 A. We plan our system to meet the needs of all of the customers we serve, and
9 we are continually seeking opportunities in the marketplace to acquire low-
10 cost energy resources. The renewable energy contracts we have signed will
11 save customers money soon after they go into service because they will
12 displace higher cost fuels, such as natural gas, that would have been otherwise
13 purchased to generate the same energy. Additionally, by making purchases at
14 an attractive price, we will be displacing more expensive generation, which
15 allows us to meet our customers' energy needs at a lower cost. We believe
16 taking advantage of cost-effective pricing when it is available is in the long-
17 term best interest of our customers.

18
19 **C. Other Issues**

20 Q. IS THE COMPANY STUDYING THE POTENTIAL IMPACTS OF WIND GENERATION
21 ON ITS SYSTEM?

22 A. Yes. We will be preparing such a study as part of our next resource plan,
23 which we will provide to the Commission.

24
25 Q. PLEASE RESPOND TO THE CONCERNS RAISED REGARDING THE USE OF
26 OUTSIDE CONSULTANTS AND ATTORNEYS IN THIS CASE.

1 A. We balance our internal and external resources to ensure appropriate coverage
2 of all regulatory and legal matters. A rate case is one example where we
3 balance internal and external resources to address large fluctuations in work
4 requirements as a case proceeds, and the need to rely on specialized expertise
5 that we do not maintain in-house. This balancing requires the use of outside
6 counsel and consultants for some of the work.

7
8 Our internal attorneys and staff work on rate cases, as well as other regulatory
9 filings, including applications for advanced determinations of prudence,
10 service territory matters, and service changes in all of our jurisdictions. We
11 continually review whether it is appropriate to hire additional staff or to rely
12 on outside resources to fill the gaps when needed. Because there can be large
13 fluctuations in workload and individual expertise required in any given matter,
14 such as a general rate case, we have found it makes sense to maintain a
15 baseload resource of staff and supplement with outside resources for large-
16 volume, specialized projects when they occur. Using external resources to
17 supplement ensures that we are not over-staffed for times of lesser work load.

18
19 **VI. PRESENTATION OF REBUTTAL WITNESSES**

20
21 Q. PLEASE INTRODUCE THE COMPANY'S REBUTTAL WITNESSES?

22 A. In addition to my Policy Rebuttal Testimony, the Company sponsors the
23 following witnesses:

- 24 • *Anne E. Heuer*, who responds to recommended financial adjustments and
25 sponsors the Company's revision to the overall revenue requirement for
26 the rate case.

- 1 • *Ann E. Bulkley*, of Concentric Energy Advisors, who responds to
2 recommendations regarding the appropriate return on equity and capital
3 structure.
- 4 • *Timothy J. O'Connor*, who responds to recommended adjustments for our
5 operations and maintenance expenses at Monticello, nuclear retention
6 program and outage amortization.
- 7 • *Sharon L. Koenig*, who sponsors testimony on our incentive compensation
8 request.
- 9 • *Lisa H. Perkett*, who sponsors testimony on depreciation and remaining
10 lives for all plant and plant-related items, and on nuclear decommissioning
11 costs.
- 12 • *Scott B. Brockett*, who provides testimony on the Company's demand
13 allocator methodology.
- 14 • *Steven W. Wishart*, who provides testimony on recovery of power purchase
15 agreements in the Fuel Cost Rider.
- 16 • *Steven V. Huso*, who responds to recommendations related to rate design.

17 18 **VII. CONCLUSION**

19
20 Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

21 A. We appreciate that there are several areas of general agreement. However, the
22 few areas where there is disagreement are significant in terms of both
23 importance and magnitude. In particular, Staff Consultant's recommended
24 change to our long-standing demand allocation methodology would
25 undermine the Company's ability to recover its prudent costs of service. We
26 believe resolution of the outstanding issues should be based on sound and

1 established ratemaking principles that are designed to promote just and
2 reasonable rates.

3

4 Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST TO THE COMMISSION.

5 A. We respectfully request that the Commission approve our proposed increase
6 of \$14.9 million, based on a 2013 test year and a 10.25 percent return on
7 equity.

8

9 Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?


10 A. Yes, it does.

1 STATE OF NORTH DAKOTA
2 BEFORE THE
3 PUBLIC SERVICE COMMISSION
4
5


6 In the Matter of the Application of Northern)
7 States Power Company, a Minnesota Corporation)
8 For Authority to Increase Rates for Electric Service) Case No. PU-12-813
9 in North Dakota)

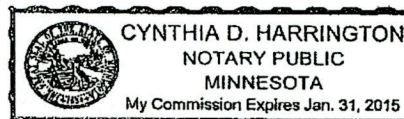
10
11
12
13 **AFFIDAVIT OF**
14 **Laura McCarten**
15

16
17 I, the undersigned, being duly sworn, depose and say that the foregoing is
18 the Rebuttal Testimony of the undersigned, and that such Rebuttal Testimony and
19 the exhibits or schedules sponsored by me to the best of my knowledge,
20 information and belief, are true, correct, accurate and complete, and I hereby adopt
21 said testimony as if given by me in formal hearing, under oath.
22

23 
24 _____
25 Laura McCarten
26

27
28
29
30 Subscribed and sworn to before me, this 7 day of August, 2013.
31

32 
33 _____
34 Notary Public
35 My Commission Expires: 1-31-2015
36



DATE MAILED
Dec 27, 2012

Public Service Commission of Wisconsin
RECEIVED: 12/27/12, 10:48:01 AM

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company-Wisconsin for
Authority to Adjust Electric and Natural Gas Rates

4220-UR-118

FINAL DECISION

This is the Final Decision concerning the application of Northern States Power Company-Wisconsin (NSPW), doing business as Xcel Energy, for authority to increase Wisconsin retail electric and natural gas rates in 2013.

Final overall rate changes are authorized consisting of a \$35,532,000 annual rate increase for Wisconsin retail electric operations, a 6.09 percent increase; and a \$2,717,000 annual rate increase for Wisconsin retail natural gas operations, a 2.53 percent increase, for the test year ending December 31, 2013, based on a 10.40 percent return on common equity.

Introduction

On June 1, 2012, NSPW filed for authority to increase its Wisconsin retail electric and natural gas rates on January 1, 2013. NSPW requested an overall increase in annual Wisconsin retail electric revenues of \$39.1 million, an increase of 6.7 percent over present revenues; or, in the alternative, \$41.7 million, an increase of 7.2 percent over present revenues, depending on the Commission's treatment of cleanup costs for the manufactured gas plant (MGP) site in Ashland, Wisconsin. NSPW also requested an overall increase in annual Wisconsin retail natural gas revenues of \$5.3 million, an increase of 4.9 percent; or, in the alternative, \$2.7 million, an increase of 2.5 percent over present revenues, depending on the Commission's treatment of MGP clean-up costs. NSPW's proposed natural gas increase request was limited solely to recovery of MGP cleanup costs.

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On July 31, 2012, a prehearing conference was held to determine the issues to be addressed in this docket and to establish a schedule for the hearing. A hearing was held on November 7, 2012, in Madison, to receive technical information and public comments into the record.

The Commission considered this matter at its open meeting on December 14, 2012. The parties, for purposes of review under Wis. Stat. §§ 227.47 and 227.53, are listed in Appendix A. Others who appeared are listed in the Commission's files.

Findings of Fact

1. Presently authorized rates for NSPW's Wisconsin retail electric utility operations will produce operating revenues of \$583,411,000 for the test year ending December 31, 2013, which results in an adjusted net operating income of \$46,300,000 and an annual revenue deficiency of \$35,532,000. Presently authorized electric rates of NSPW are insufficient.
2. For the Wisconsin retail electric utility operations, the estimated rate of return on average net investment rate base of \$788,602,000 at current rates for the test year is 5.87 percent, which is inadequate.
3. A reasonable increase in operating revenue for the test year to produce an 8.57 percent return on NSPW's average net investment rate base for Wisconsin retail electric operations is \$35,532,000.
4. NSPW's filed electric operating income statement and net investment rate base for the test year, as adjusted for Commission decisions, are reasonable.
5. Presently authorized rates for NSPW's Wisconsin retail natural gas utility operations will produce operating revenues of \$107,597,000 for the test year ending December 31, 2013.

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6. It is reasonable to limit the scope of the natural gas rate increase request to the sole issue of MGP clean-up costs.
7. A 2013 total NSP system test year fuel cost of \$1,299.17 million is reasonable.
8. A 2013 total NSP system test year fuel rules monitoring level of fuel costs of \$1,130.58 million, or \$0.02555 per kilowatt-hour (kWh), as shown in Appendix D, is reasonable.
9. It is reasonable to reflect the signed contract for Green Whey Dairy in fuel costs.
10. It is reasonable to require Commission staff, utilities, and interested intervenors to work together early in 2013 to resolve the issue of the treatment of System Support Resources (SSR) costs. It is reasonable to require Commission staff to prepare and send to the Commission a briefing memorandum outlining the positions of the parties and the alternatives the Commission has to address this issue.
11. It is reasonable to update fuel costs to reflect market prices for electricity, natural gas and heating oil as of November 15, 2012.
12. It is reasonable to allow NSPW to use the final monitored fuel costs as determined by the Commission in this docket for NSPW's fuel cost plan for 2013.
13. It is reasonable to monitor all monitored fuel costs using an annual bandwidth of plus or minus 2 percent.
14. It is reasonable to incorporate actual payroll increases given in 2012 for all employees, a 1.7 percent payroll merit increase in 2013 for non-union employees and a 2.5 percent payroll merit increase in 2013 for union employees under contract in the development of test-year payroll expense and related taxes.

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15. It is not reasonable to include the payroll and related costs associated with the annual incentive plan costs in revenue requirements.

16. It is reasonable to include all uncontested Commission staff adjustments to NSPW's filed electric revenue requirements.

17. It is reasonable that the amortization period of the MGP clean-up costs for Ashland be amortized over a ten-year period, that estimates of the 2013 costs for clean-up at the terrestrial site, but not the bay area, be included in the 2013 test-year amortization calculation and resulting revenue requirement, and that the revenue requirement include 3 percent interest on the unamortized balance of the clean-up costs.

18. It is reasonable to continue to assess MGP clean-up costs to gas ratepayers only.

19. NSPW's proposed voluntary energy efficiency programs are reasonable.

20. It is not reasonable to include labor dollars for Account Managers or Community Service Managers/Supervisors in the conservation escrow budget. Funding should be included in non-escrow operation and maintenance (O&M).

21. It is reasonable to include dollars in the conservation escrow budget for the call center staff that are Energy Experts.

22. It is not appropriate to provide conservation escrow treatment for the Farm Rewiring Program. Funding should be included in non-escrow O&M.

23. It is not reasonable to provide conservation escrow treatment for the low-income assistance dollars contributed to the 2005 Wisconsin Act 141 (Act 141) statewide low-income programs. Funding should be included in non-escrow O&M.

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24. The reasonable level of expensed conservation costs recoverable in rates for the 2013 test year is \$8,662,412 for electric operations and \$3,014,932 for natural gas operations. The level for electric operations consists of the conservation budget of \$8,191,041 plus an escrow adjustment of \$470,626 to reflect the estimated overspent balance as of January 1, 2013, of \$941,252, amortized over two years. The level for natural gas operations remains at \$3,014,932, the same as that authorized in rate case docket 4220-UR-117.

25. A long-term range of 50 percent to 55 percent for NSPW's common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

26. An appropriate target level for the test-year average common equity measured on a financial basis is 52.5 percent.

27. It is reasonable to explore further the target level for common equity in NSPW's next rate case.

28. A reasonable estimate of the debt-equivalent of NSPW's off-balance sheet obligations to be imputed into the financial capital structure for the test year is \$4,614,306.

29. A reasonable financial capital structure for the test year consists of 52.50 percent equity, 43.96 percent long-term debt, 3.11 percent short-term debt, and 0.43 percent debt equivalence for off-balance sheet obligations.

30. It is reasonable to require NSPW to submit a ten-year financial forecast in its next rate proceeding.

31. It is reasonable to require NSPW to submit in its next rate proceeding, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent.

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32. A reasonable regulatory capital structure for the test year consists of 52.37 percent equity, 44.49 percent long-term debt, and 3.14 percent short-term debt.

33. It is reasonable that NSPW's dividend restriction be based on the financial capital structure in this proceeding.

34. A reasonable interest rate for short-term borrowing through commercial paper is 0.53 percent for the test year.

35. A reasonable cost of the long-term debt issuance in 2012 is the actual yield to maturity of 3.746 percent.

36. A reasonable average embedded cost for long-term debt is 5.71 percent for the test year.

37. The rate of return on utility common stock equity of 10.40 percent established in NSPW's last rate case, docket 4220-UR-117, remains in place as it was not an issue addressed in this proceeding.

38. A reasonable weighted average composite cost of capital is 8.01 percent.

39. The electric revenue allocation and electric rates shown in Appendix B are reasonable.

40. The structure of the NSPW's voluntary green pricing program, marketed under the Windsource trademark, is reasonable.

41. It is reasonable to require NSPW to modify materials used to market the Windsource program in Wisconsin to accurately reflect what the program offers to participating customers, given the constraints of the Interchange Agreement, within 60 days of the effective date of this Final Decision.

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42. It is reasonable for NSPW to continue to provide only a kilowatt (kW) block-based participation option for the Windsorce program.

43. It is reasonable for the final form tariffs authorized in this proceeding to include an update to the Pg-1 tariff so as to preserve the grandfathering treatment for pre-January 1, 2012, vintage customers until a future base rate case proceeding.

44. It is reasonable to allocate the MGP allowance to the natural gas service rate classes on a net investment rate base methodology.

45. It is reasonable to authorize rates for natural gas service for NSPW as shown in Appendix C.

Conclusions of Law

The Commission has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, and 196.395 and Wis. Admin. Code chs. PSC 113, 116, 134, and 137 to enter a Final Decision authorizing NSPW to place in effect the rates and rules for electric and natural gas utility service set forth in Appendices B and C, and the fuel cost treatment set forth in Appendix D, subject to the conditions specified in this Final Decision. The rates and rules for electric and natural gas utility service in Appendices B and C are reasonable and appropriate as a matter of law.

Opinion

Applicant and its Business

NSPW is a public utility, as defined in Wis. Stat. § 196.01(5), operating as an electric and natural gas utility in Wisconsin. NSPW is engaged in providing electric service to approximately 251,000 retail customers in northwestern Wisconsin and the western tip of the Upper Peninsula of

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Michigan. In addition, NSPW provides natural gas service to approximately 107,000 customers in Wisconsin and Michigan. NSPW is a wholly-owned subsidiary of Xcel Energy Inc. (Xcel Energy).

Revenue Requirement

NSPW, intervenors, and Commission staff presented testimony and exhibits at the hearing concerning estimates of NSPW's 2013 electric and natural gas utility operations. NSPW filed its natural gas case showing an estimated deficiency of \$7.0 million, of which \$5.3 million was associated with MGP cleanup costs. The company indicated it would limit its natural gas increase request to \$5.3 million for MGP cleanup costs and forego the remaining \$1.7 million. No parties objected to the proposal to limit the natural gas request to this single issue.

Commission staff reviewed the gas utility forecasted test-year operations to determine that a rate decrease would not be needed, exclusive of NSPW's requested recovery of MGP clean-up costs. Commission staff's review resulted in no proposed adjustments to natural gas sales revenues or rate base and a reduction to operating expenses of \$425,000 on a total company basis exclusive of any adjustment to MGP clean-up cost expenses. This adjustment grossed up for income taxes equates to a reduction to the natural gas deficiency of about \$710,000, which is still less than the \$1.7 million of which the company indicated it will forego requesting recovery. The Commission therefore finds it is reasonable to limit the scope of the natural gas rate increase request to the sole issue of MGP clean-up costs. Significant issues pertaining to electric operations and MGP clean-up costs are presented below.

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Electric Fuel Costs

A reasonable test-year level of monitored fuel costs is \$1,130.58 million, which reflects the cost of fuel as defined by Wis. Admin. Code § PSC 116.02. The test-year monitored fuel costs divided by the test-year estimate of native energy requirements of 44,244,951 megawatt-hours (MWh) results in an average net monitored fuel cost per MWh of \$25.55. Appendix D shows the monthly fuel costs to be used for monitoring purposes. The total fuel costs are based on indices for electric, natural gas, and heating oil prices as of November 15, 2012. It is reasonable to monitor NSP system's fuel costs using a plus or minus 2 percent bandwidth, as provided in Wis. Admin. Code § PSC 116.06(3).

System Support Resources

NSPW requested that the Commission determine, in this proceeding, how SSR charges from the Midwest Independent Transmission System Operator, Inc. (MISO), will be treated in subsequent rate proceedings. MISO may assess SSR charges to NSPW if MISO requires another market participant to run a facility to support the transmission system even if the market participant desires to retire that facility. NSPW requested a determination that SSR charges be treated as a monitored fuel cost. SSR charges have never been assessed by MISO, but are expected to be assessed in the future. The Commission finds that there is not a sufficient basis, at this time, to determine how SSR charges are to be treated.

The Commission finds it reasonable to require Commission staff, investor-owned utilities and interested intervenors to work together after January 1, 2013, to address the SSR issue and for Commission staff to prepare a briefing memorandum outlining the parties' positions and alternatives for the Commission to consider.

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2013 Fuel Cost Plan

NSPW requested that the Commission-authorized monitored fuel costs for 2013 be designated as the NSPW 2013 Fuel Cost Plan for purposes of Wis. Admin. Code § PSC 116.06(3). The Commission finds it reasonable to allow NSPW to use the Commission-authorized monitored fuel costs for NSPW's 2013 Fuel Cost Plan.

Annual Merit Pay Factors

NSPW's filed payroll forecast for the test-year included annual merit wage increases in 2012 of 2.0 percent for non-bargaining non-exempt employees, no increase for non-bargaining exempt employees, and 2.75 percent for all bargaining employees. NSPW's filing included wage increases in 2013 of 2.5 percent for all non-bargaining employees and 3.25 percent for all bargaining employees. Commission staff's forecasted payroll incorporated the 2012 actual wage increases as filed by NSPW and included 2013 wage increases of 3.25 percent for bargaining employees under contract and 1.7 percent for the non-bargaining employees based on inflation. The use of 1.7 percent for the non-bargaining employees resulted in a staff adjustment reducing test-year payroll O&M expense by \$104,000.

The Commission finds that Commission staff's use of 2012 actual wage increases of 2.0 percent for non-bargaining non-exempt employees, no increase for non-bargaining exempt employees, 2.75 percent for all bargaining employees as well as forecasted 2013 wage increases of 3.25 percent for bargaining employees under contract and 1.7 percent for the non-bargaining employees based on inflation is reasonable in the development of test year payroll expense and related taxes. Incorporating these factors appropriately reflects the current economic conditions in Wisconsin.

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Annual Incentive Plan Compensation

Xcel Energy must meet certain financial and operational goals in order for the current Annual Incentive Plan (AIP) to pay out incentive awards for the year to its non-bargaining employees. Incentive payments are in addition to annual base wage increases. According to the overall company performance component, which establishes the company's ability to pay, certain targeted earnings per share goals must be achieved by the company before the program will pay any awards. In addition, the final funding percentage will be determined by the Chief Executive Officer.

Commission staff reduced NSPW's 2013 payroll O&M expense for electric operations by \$2,136,000 to eliminate the costs associated with the AIP. Elimination of costs associated with the incentive pay plan is consistent with the decisions made in the last round of rate cases for other large investor-owned utilities in which the costs associated with incentive pay plans were not included in revenue requirements.

NSPW maintains that the Commission should allow recovery of all or at least a portion of its AIP costs because it is important to compensate employees at a level that is comparable to the relevant market in order to ensure safe and reliable service at a reasonable cost. Because 97 percent of the goals relate to operational excellence, NSPW believes that 97 percent of the AIP costs should be recoverable.

In previous rate cases in which incentive adjustments have been contested, the Commission has excluded incentive plans from revenue requirement when such plans are based primarily on financial results (*e.g.*, prevailing stock price, earnings per share, or achieving a specified net income or return on investments, etc.). The Commission has determined that such

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plans most directly benefit the utility shareholders, and therefore the costs of the plans should not be borne by ratepayers. While the company has modified some of the elements of the AIP, it has not eliminated the financial performance of the company as one of the payout metrics.

Specifically, earnings per share targets must be met before AIP funds can be paid, making it a system of compensation that occurs if and only if the company meets financial benchmarks.

In addition, while the operational goals of the AIP may benefit ratepayers, they also are intertwined in benefiting shareholders, making it difficult to separate which group benefits more.

Consistent with the other large-investor-owned utilities in Wisconsin, in which the costs associated with incentive pay plans are not included in revenue requirements, because of the continued tie to financial performance, the Commission finds it appropriate to exclude these AIP costs from revenue requirement.

U.S. Department of Energy Settlement Proceeds

In the last rate case proceeding in docket 4220-UR-117, the Commission authorized a one-time credit on customer bills for the first payment received in a settlement that was reached with the U.S. Department of Energy (DOE) relating to the partial breach of its contract to take spent nuclear fuel from Northern States Power Company-Minnesota's (NSPM) Monticello and Prairie Island nuclear generating plants. The settlement provides a mechanism for the NSP companies to recover nuclear spent fuel storage damages from January 1, 2009, through December 31, 2013. In 2012, the company received the second and third payments and expects to receive two additional payments at the end of 2013 and 2014, respectively. In this rate proceeding, NSPW proposed that the second and third payments received in 2012, including interest from the separate interest bearing account in which the funds are held, be returned to

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ratepayers by offsetting the 2013 electric revenue deficiency. The company proposed to allocate the settlement payments to the jurisdictions and customer classes in the same manner as the first payment, as approved by the Commission in docket 4220-UR-117. The proceeds from the second and third payments net of outside legal costs incurred in pursuit of the settlement included as a reduction to the 2013 electric revenue deficiency is \$5,358,101 on a Wisconsin retail jurisdictional basis, and is for damages through December 31, 2011.

The Commission finds it reasonable to include the second and third payments from the DOE settlement net of outside legal costs incurred in pursuit of the settlement in the final electric revenue requirement approved in this proceeding. It is appropriate for the company to track, in a regulatory asset or liability account, the actual payments received, plus interest, less any unrecovered outside legal fees, and add or subtract the difference from the credit assumed in this case in future cases. It is appropriate for interest accrual on the sum of the second and third payments of \$5,358,101 to terminate with the beginning of the 2013 test year.

Ashland Manufactured Gas Plant Site Cleanup

NSPW requested that the Commission include costs related to the clean-up of a former MGP site in Ashland in the 2013 test year. The company proposed that 2013 rates include estimates of expenses for the terrestrial and bay area clean-up. NSPW also requested that the Commission make an exception from its policy on the rate recovery of MGP clean-up costs. Specifically, NSPW requested that the amortization period be stretched from four or six years to ten years, that recovery begin immediately for expected costs rather than deferred to a later year, and that the company's imbedded cost of debt for the unamortized clean-up expenses be included in rates. NSPW also proposed an alternative that involved allocating the revenue requirement

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impact to both electric and gas utilities instead of the current practice of allocating MGP costs to just the gas utility. Other intervenors proposed variations on NSPW's proposal.

The Commission must balance many concerns when it addresses rate recovery of MGP clean-up costs. In this case, the magnitude of the clean-up cost relative to the size of the customer base is significant. Applying the current policy to this particular site may cause financial harm to the company and cause significant rate shock to the utility's ratepayers. The Commission finds that making a limited exception to its policy on rate recovery of MGP clean-up costs is reasonable in this case. NSPW's request, as proposed, however, does not appropriately balance the concerns of the ratepayers against the financial health of the company.

It is reasonable that the net clean-up costs of the MGP clean-up for this site be amortized over a ten-year period, that estimates of the 2013 costs for clean-up at the terrestrial site, but not the bay area, be included in the 2013 test-year revenue requirement, and that the rates include 3 percent interest on the average balance of the unamortized clean-up costs. Lengthening the amortization period will help to mitigate the rate shock of large rate increases for this clean-up, while allowing immediate recovery of estimated expenses; and allowing the utility to recover some of the carrying costs of the clean-up will mitigate potential financial harm to NSPW.

Based upon the record in this proceeding, the Commission finds that it is not reasonable to deviate from the Commission's past practice of allocating MGP clean-up costs to just the gas utility. However, the Commission recognizes that neither the gas nor the electric utilities are the cause of this historic MGP liability. Accordingly, the Commission finds that is reasonable to review the practice of allocating the Ashland MGP clean-up costs as gas utility costs in the next rate proceeding to examine more fully whether such costs could or should be allocated to the

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electric utility, if appropriate, and to determine whether these clean-up costs should be included in the Interchange Agreement.

Energy Efficiency and Conservation Activities

The Commission's *Order*, dated August 30, 2011 (PSC REF#: 152745), conditionally approved NSPW's 2012 and 2013 voluntary utility energy efficiency programs. One of the requirements of the *Order* was to continue to work with the Commission and Focus on Energy staff to ensure NSPW offerings remain consistent with Focus on Energy offerings. The Commission determines that to date, the conditions of the *Order* have been met. NSPW's voluntary energy efficiency programs are reasonable, and it is appropriate to include their funding in the conservation escrow budget.

Conservation Budget and Escrow Adjustment

NSPW proposed a 2013 conservation escrow budget of \$12,188,374, with \$9,355,073 allocated to electric operations and \$2,833,301 allocated to natural gas operations. Commission staff's analysis of conservation expenses included forecasting the over-spent balance in the conservation escrow at the beginning of the test year, reviewing the proposed test-year conservation expenditures, and reviewing the company's forecasted amortization expense associated with previously escrowed demand-side management expenditures. The reasonable levels of expensed conservation costs included in revenue requirement for the 2013 test year are \$8,662,412 for electric operations and \$3,014,932 for gas operations. The level for electric operations consists of a conservation budget of \$8,191,786, plus an escrow adjustment of \$470,626 to reflect the estimated overspent balance as of January 1, 2013, of \$941,252, amortized over two years. Since the current natural gas rate case proceeding is limited to the

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single issue of MGP costs, the level of natural gas related expensed conservation costs included in revenue requirement for the 2013 test year remains at \$3,014,932, the same as that authorized in rate case docket 4220-UR-117. Any adjustments to the conservation escrow balance for the natural gas operations will be addressed in a future rate proceeding.

Several adjustments were made to NSPW's proposed conservation escrow budget. In docket 5-BU-105 (PSC REF#: 168310), the Commission provided a definition of customer service conservation activities and services for which conservation escrow treatment is appropriate. Based on this definition, the Commission determines it appropriate to remove \$114,000, \$84,000 from electric operations and \$29,640 from natural gas operations, for Account Managers. These NSPW employees devote less than 51 percent of their time to energy efficiency. Likewise, \$156,912 is removed from the conservation escrow budget, \$116,115 from electric operations and \$40,797 from natural gas operations, for Community Service Managers/Supervisors because less than 51 percent of their time is devoted to energy efficiency. The Commission also finds that NSPW's Farm Rewiring Program does not meet the definition of customer service conservation because the primary purpose of this program is to assist customers in obtaining safe and reliable farm wiring and reduce levels of stray voltage, not energy efficiency. To reflect this, \$752,129 is removed from the electric conservation escrow budget. Finally, low-income assistance dollars are removed from the conservation escrow, \$210,683 from electric operations and \$74,032 from natural gas operations. NSPW is required to contribute these low-income assistance dollars to Act 141 programs that provide both weatherization and bill payment assistance to low income customers. Because the program provides for bill payment assistance in addition to weatherization, and because the contribution

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level remains the same every year, its funding is not appropriate for conservation escrow treatment.

NSPW originally indicated that it has about 400 call center staff that devote about 6 percent of their time to energy efficiency. In response to a Commission staff data request, NSPW clarified that in 2011 it developed an Energy Experts team. This Energy Experts team consists of call center staff that is specially trained to provide residential customers detailed energy efficiency information. NSPW indicates that these Energy Experts devote 100 percent of their time to energy efficiency issues. The Commission finds it reasonable to allow conservation escrow treatment for the Energy Expert staff.

Summary of Income Statement

In addition to the specific items discussed in this Final Decision, all other uncontested Commission staff adjustments to NSPW's filed electric operating income statement are appropriate. Accordingly, the estimated Wisconsin retail electric utility operating income statement at present rates for the 2013 test year, which is considered reasonable for the purpose of determining the electric revenue requirement in this proceeding, is as follows:

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	Retail Electric (000's)
Operating Revenues	
Sales	\$583,411
Other Operating Revenues	<u>1,928</u>
Total Operating Revenues	\$585,339
Operating Expenses	
Production Expense	\$367,614
Transmission Expenses	(8,819)
Distribution Expenses	21,683
Customer Accounts Expenses	8,913
Customer Service & Sales Expenses	11,888
Administrative & General Expenses	<u>36,481</u>
Total Operation & Maintenance Expenses	\$437,760
Depreciation Expense	63,503
Amortization Expense	(125)
Taxes Other Than Income Taxes	21,856
State Income Taxes	1,600
Federal Income Taxes	4,742
Deferred Income Taxes – Net	10,379
Investment Tax Credits Restored	<u>(637)</u>
Total Operating Expenses	\$539,078
Chippewa Flambeau Improvement Company Income	<u>39</u>
Net Operating Income	<u>\$ 46,300</u>

Average Net Investment Rate Base

Allowance for Funds Used During Construction

NSPW requested to accrue excess Allowances for Funds Used During Construction (AFUDC) on all Construction Work in Progress (CWIP), which is consistent with the accrual methodology used by the other Wisconsin utilities.

Consistent with the calculation of AFUDC for other Wisconsin utilities, it is appropriate to permit NSPW to accrue AFUDC on all CWIP at the weighted average cost of capital instead of at the Federal Energy Regulatory Commission (FERC) AFUDC rate. This rate treatment allows NSPW to recover the full carrying costs from retail customers and is appropriate as long

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as the accrual of excess AFUDC above the FERC-calculated AFUDC does not flow through the Interchange Agreement, either from or to NSPW.

Summary of Average Net Investment Rate Bases

The estimated Wisconsin retail electric utility average net investment rate base for the 2013 test year, which is considered reasonable for the purpose of determining the electric revenue requirement in this proceeding, is as follows:

	Retail Electric (000's)
Utility Plant in Service	\$1,911,536
Less: Accumulated Reserve for Depreciation	<u>895,913</u>
Net Utility Plant	\$1,015,623
Add: Fuel Inventory	9,701
Materials and Supplies	4,256
Investments in Associated Companies	537
Less: Accumulated Deferred Income Taxes	228,067
Customer Advances – net of tax	<u>13,448</u>
Average Net Investment Rate Base	<u>\$788,602</u>

Pro Forma Rate of Return

The adjusted net operating income at present rates for purposes of this proceeding for the test year ending December 31, 2013, results in a rate of return on average net investment rate base of 5.87 percent for Wisconsin retail electric utility operations.

Financial Capital Structure and Dividend Restriction

A reasonable long-term range for NSPW's common equity ratio, on a financial basis, is 50 to 55 percent common equity. The exact level of the common equity ratio within that range should not be static, but rather should dynamically reflect the circumstances facing NSPW at a given time. An appropriate target level for the test-year average common equity measured on a

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financial basis is 52.50 percent. This target level shall be further examined in NSPW's next rate proceeding.

In calculating capital structures, on a financial basis, this Commission has imputed debt associated with obligations not reported on balance sheets. Detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent is necessary for the Commission to make an independent judgment regarding NSPW's financial capital structure. This information is most readily available from NSPW and must be provided as part of its next rate case application. The information shall include, at a minimum, the following information:

1. the minimum annual lease and purchased power agreement obligations;
2. the method of calculation, along with the calculated amount of the debt equivalent; and
3. supporting documentation, including all reports, correspondence, and any other justification that clearly established Standard & Poor's (S&P) and other major credit rating agencies' determination of the off-balance sheet debt equivalent to the extent available, and publicly available documentations when S&P and other major credit rating agencies' documentation is not available.

For the test year, the Commission finds that it is reasonable to impute \$4,614,306 of debt equivalent associated with NSPW's off-balance sheet obligations. Incorporating the above off-balance sheet debt equivalents and other Commission determinations, NSPW's financial capital structure for the test year will consist of 52.50 percent equity, 43.96 percent long-term debt, 3.11 percent short-term debt, and 0.43 percent debt equivalence for off-balance sheet obligations.

Assessing the reasonableness of NSPW's capital structure depends upon three important principles. First, capital structure decisions must be based on NSPW's needs, not on the needs of the non-utility operations of the holding company. Second, the capital structure should provide

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adequate flexibility to NSPW and to the Commission to allow proper utility investment now and in the future. Third, the dividend policy of NSPW should be similar to typical electric utility dividend practices as long as NSPW is below the estimated test-year common equity ratio.

In previous dockets, the Commission recognized the need to protect ratepayers and to ensure that utility needs are placed before non-utility needs in capital structure and dividend policy choices. Consequently, NSPW may not pay dividends, including pass-through of subsidiary dividends, in excess of the \$31,189,664 forecasted in this case, if its actual average common equity ratio, on a financial basis, is or will fall below the test-year authorized level of 52.50 percent.

Ten-Year Financial Forecast

NSPW's ten-year financial forecast is useful to the Commission and shall be submitted in future rate cases. The ten-year forecast can be combined with other business risk information to assess capital structure needs and rate of return requirements.

Regulatory Capital Structure and Cost of Capital

As in the previous rate case docket, Commission staff deducted from the utility's equity the non-utility investments or other equity adjustments on which ratepayers should not pay an equity return for ratemaking purposes. Consequently, a reasonable utility rate making capital structure for the purpose of establishing just and reasonable rates for the test year consist of 52.37 percent equity, 44.49 percent long-term debt, and 3.14 percent short-term debt.

Short-Term Debt

NSPW's test-year capital structure contains approximately \$33,144,000 of short-term debt. The interest rate associated with the short-term indebtedness is the commercial paper rate.

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A reasonable estimate of the average cost of short-term commercial paper for NSPW for the test year is 0.53 percent. This forecast is based on the average of test year commercial paper rate estimates provided by the *Blue Chip Financial Forecasts* newsletter, adjusted by 33 basis points to reflect the spread between A-1/P-1 and A-2/P-2 rated commercial paper yields. This is a reasonable and objective method of determining short-term debt costs.

Long-Term Debt

NSPW’s test-year long-term debt included an issuance of 30-year debt aggregating \$100,000,000 principal amount forecasted for issuance in 2012. On October 10, 2012, NSPW issued the debt with a coupon rate of 3.7 percent and a yield to maturity of 3.746 percent. A reasonable interest rate for the debt is 3.746 percent. The resulting embedded cost of long-term debt is 5.71 percent for the test year.

Return on Common Equity

The Commission previously determined, in docket 4220-UR-117, a 10.40 percent return on utility common equity for NSPW to be reasonable. As rate of return on common equity was not an issue addressed in this proceeding, the Commission determines that this return on equity shall remain in place until addressed in a subsequent rate case proceeding. Using a 10.40 percent return on equity, NSPW’s average utility capitalization ratios, annual cost rates, and the composite cost of capital rate considered reasonable and just for setting rates for the test year are as follows:

	Amount (000’s)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	\$552,337	52.37%	10.40%	5.45%
Long-Term Debt	469,183	44.49%	5.71%	2.54%
Short-Term Debt	33,144	3.14%	0.53%	0.02%
Total Utility Capital	<u>\$1,054,664</u>	<u>100.00%</u>		<u>8.01%</u>

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The weighted cost of capital of 8.01 percent is reasonable for NSPW for the test year. It generates an economic cost of capital of 11.66 percent and a pre-tax interest coverage ratio of 4.56 times on the regulatory capital structure.

Rate of Return on Rate Base

The 8.01 percent composite cost of capital must be translated into a rate of return that can then be applied to the average net investment rate base and used to compute the overall return requirement in dollars. The estimate of NSPW's average net investment rate base plus CWIP for the test year is 93.49 percent of capital applicable primarily to utility operations plus deferred investment tax credit. This estimate reflects all appropriate Commission adjustments, and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to the average net investment rate base. Accordingly, the rate of return on average Wisconsin retail electric utility net investment rate base, which is reasonable for the purpose of determining just and reasonable rates in this proceeding, is as follows:

	Retail <u>Electric</u>
Cost of Capital	8.01%
Average Percent of Utility Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	93.49%
Percent Return Requirement Applicable to Net Investment Rate Base	8.57%

Revenue Requirement

On the basis of the findings in this Final Decision, a \$35,532,000 increase in Wisconsin retail electric utility revenues is reasonable for the purpose of determining reasonable and just rates in this proceeding and is computed as follows:

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	Retail Electric (000's)
<i>Pro Forma</i> Return on Average Net Investment Rate Base at Present Rates	5.87%
Required Return on Average net Investment Rate Base	8.57%
Earnings Deficiency as a Percent of Average Net Investment Rate Base	2.70%
Average Net Investment Rate Base (000's)	\$788,602
Amount of Earnings Deficiency on Average Net Investment Rate Base (000's)	\$21,283
Revenue Deficiency to Provide for Earnings Deficiency Plus Federal and State Income Taxes (000's)	\$35,532

Electric Cost-of-Service

Both NSPW and Commission staff submitted the results of several cost-of-service studies. The two major electric cost-of-service issues contested in this proceeding are the allocation of production capacity costs and the allocation of distribution system costs. The allocation of these costs significantly affects the cost responsibility for providing electric service.

The Commission routinely considers electric cost-of-service studies as a guide along with other factors in its decisions regarding the allocation of revenue responsibility. In this proceeding, the Commission determines that it is reasonable to continue its past practice of relying on the results of more than one cost-of-service study, as well as other factors for determining an appropriate allocation of the revenue responsibility.

Electric Revenue Allocation

Allocating the increase in NSPW's revenue requirement for the provision of electric service was also a significant contested issue in this proceeding. Both NSPW and Commission

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staff submitted a comprehensive allocation of the proposed electric revenue increase. NSPW proposed a very narrow range of increases within 0.2 percent of its overall 6.7 percent electric increase for all of the major customer classes. Commission staff's alternative was similar, but included a slightly wider range of increase within 0.5 percent of its overall 5.65 percent electric increase, except the medium commercial and industrial classes get approximately 0.9 percent below the overall average.

The Commission routinely considers factors other than cost-of-service studies such as bill impacts, existing relationships between rate classes, and the overall magnitude of the revenue change, in its decisions regarding the allocation of revenue responsibility. The results of the cost studies introduced in this case support various revenue allocations. The Commission determines that a reasonable allocation of the electric revenue increase is a 7.2 percent increase for the residential classes, a 5.8 percent increase for the medium commercial and industrial classes, a 5.0 percent increase for the large commercial and industrial classes and a 6.8 percent increase for the lighting and miscellaneous classes, as adjusted for the final revenue requirement.

Commissioner Callisto dissents.

Electric Rate Design

NSPW initially proposed a rate design that included increases in energy charges, demand charges and lighting charges, for the various customer classes. NSPW initially proposed similar percentage increases for both the energy and demand charges. That proposal also increases the voltage discounts for the transmission level customers and increases high load factor credits. Commission staff's alternative rate design included similar percentage increases for both the energy charges and demand charges, but included lower increases in the high load factor credit and no increase for the voltage discounts.

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Wisconsin Industrial Energy Group (WIEG) argued that the rate design for the Cg-9, Cp-1 and the RTP-1 classes should include greater than average increases for the demand charges and less than average increases for the energy charges. WIEG also supported NSPW's proposal to increase the voltage discounts for the transmission level customers and increase high load factor credits. NSPW responded by introducing a compromise proposal that included demand charge increases half way between WIEG's proposal and the Commission staff's proposal and energy charge increases that are lower than the average increase percentage for these classes. This proposal also included the increases to the transmission voltage discounts and increases to the high load factor credits that were part of NSPW's initial proposal. The Commission determines that NSPW's compromise proposal for changing the demand and energy charges affecting all of the commercial and industrial customers, and its proposal to increase the transmission voltage discounts and high load factor energy charge credits affecting the large commercial and industrial customers, are reasonable.

Commissioner Callisto dissents on the authorization of the higher transmission voltage discounts.

The Commission also finds NSPW's electric rate design and the changes in energy and lighting charges for the residential, small commercial, lighting and miscellaneous classes, adjusted for the final revenue requirement, are reasonable. The authorized electric rates are shown in Appendix B.

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Act 141 in Electric Rates

Act 141 contains a limitation on how much the “large energy customers”¹ can pay in rates for these Act 141 costs. Act 141 requires the large energy customer “capped rates” increase each year by the lesser of the prior year Consumer Price Index (CPI) or the utility's change in revenue from the prior year. Both NSPW and Commission staff agree that the increase in the “capped rates” should be 3.2 percent for 2013, which reflects inflation based on the prior year CPI. Both NSPW and Commission staff proposed rate factors representing the Act 141 costs in electric rates for the non-large energy customers that are essentially the same except for differences between NSPW’s and Commission staff’s electric sales forecast and a calculation error in the inflation rate NSPW initial used.

The correct reflection of the capped Act 141 costs in the RTP-1 rates was a rate issue that was controversial, but the record was somewhat unclear. NSPW filed a rate and revenue analysis in Ex.-NSPW-Dahl-2 that did not show an explicit amount for the capped Act 141 costs in the RTP-1 rates. Under this approach, it is assumed that the Act 141 costs are in the based rates for the RTP-1 class. Commission staff filed a rate and revenue analysis in Ex.-PSC-Albrecht-2r that included an explicit amount for Act 141 costs that the RTP-1 rate class is required to pay under Wisconsin Statutes. This was a change from how it was handled in NSPW’s last rate case. WIEG argued that NSPW’s approach was correct. Determining the correct approach on this issue is difficult based upon the record in this case. This issue should be fully vetted in NSPW’s next rate case. It is reasonable to maintain the status quo and accept

¹ A “large energy customer” is defined as a customer whose facility consumes at least 1,000 kilowatts of electricity per month or at least 10,000 decatherms of natural gas per month, and who is billed at least \$60,000 in a month for electric and gas services. All of the utility billing accounts of a company are considered to determine if the company qualifies as a large energy customer. A company that qualifies will have all of its accounts treated as a large energy customer for billing purposes, despite the accounts being served under different tariffs.

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NSPW's approach of not showing any explicit capped Act 141 costs in the rate and revenue analysis for the RTP-1 class.

Windsorce Program

Order Point 33 of the *Final Decision* in docket 4220-UR-117, stated that "a full analysis shall be required in NSPW's next rate case on the issue of the company's Windsorce voluntary green pricing program." During that proceeding, the Commission expressed concerns regarding the structure and pricing of the Windsorce program due to the way in which renewable energy is treated under the Interchange Agreement.

Typically, when utility customers elect to participate in green energy pricing programs, the utility purchases more renewable energy than it is otherwise required to purchase. However, because the Interchange Agreement already requires NSPW to purchase more renewable energy than is required to comply with Wisconsin's renewable portfolio standard, a customer's participation in the Windsorce program does not lead to a greater amount of renewable energy on the NSPW system than would have existed otherwise. NSPW retires Renewable Energy Credits not used for compliance with Wisconsin's renewable portfolio standard in order to satisfy renewable energy purchases through Windsorce.

The Commission finds the overall structure of NSPW's Windsorce program to be reasonable. While NSPW does not purchase additional renewable energy as a direct result of a person signing up for Windsorce, the program still offers value to customers seeking ways in which to "green" their energy consumption. However, due to the potential for customer confusion, NSPW shall modify materials used to market the Windsorce program in Wisconsin

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to accurately reflect what the program offers to participating customers, given the constraints of the Interchange Agreement, within 60 days of the effective date of this Final Decision.

Commission staff also proposed that NSPW modify Windsource to allow customers the option of buying a percentage of their energy from the program. NSPW believes that this change to the program would be cost prohibitive. Given the information available in the record, the Commission finds it reasonable for NSPW to continue to provide only a kW block-based participation option for the Windsource program. However, NSPW shall provide in its next base rate case, additional information regarding the billing system costs the company claims would be associated with providing a percentage-based participation option for the Windsource program.

Net Metering

NSPW did not propose any changes to its Pg-1 net metering tariff. Based on the understanding that the company wished to leave the Pg-1 net energy billing tariff as is, and continue grandfathering pre-January 1, 2012, vintage customers until a future proceeding, Commission staff proposed that final form tariffs authorized in this proceeding should include an update to the Pg-1 tariff so as to preserve the grandfathering treatment for pre-January 1, 2012, vintage customers until a future base rate case proceeding. The Commission finds Commission staff's proposed treatment of the Pg-1 tariff to be reasonable.

Electric Tariff Changes

NSPW proposed changes to its electric Distribution Extension Allowances that are shown in Ex.-NSPW-Marx-1, Schedule 6. There were no objections to these changes. The distribution extension allowances are part of NSPW's electric rule and regulation tariffs. The Commission

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finds it reasonable to approve these proposed changes to NSPW's electric rule and regulation tariffs.

NATURAL GAS COST-OF-SERVICE STUDIES AND RATES

Natural Gas Cost-of-Service Studies

The natural gas rate increase will provide for the allowed incremental MGP costs of \$2,717,362. This singular cost allowance did not necessitate a cost-of-service analysis of NSPW's overall costs of providing natural gas service. For purposes of this proceeding, the costs allocation and rate recovery was limited to MGP costs. Several cost allocation methodologies were identified and considered appropriate; however, the Commission determines that final rates for natural gas service shall be based on the net investment rate base cost allocation methodology.

Revenue Recovery Adequacy of Service Class Rates

Overall, the rates authorized for NSPW in Appendix C of this Final Decision will provide for the incremental cost recovery of the allowed MGP costs of \$2,717,362. This represents an increase of 6.42 percent in margin rates and an increase of 2.53 percent in total natural gas sales revenues. Margin rates exclude natural gas costs.

Authorized rates as set forth in Appendix C include a rate "adjustment" over present rates that were determined on a volumetric unit basis given estimated 2013 test-year sales and the MGP cost allocations as discussed above. Summaries of the rate impacts on a service rate class are shown in Appendix C.

As shown in Appendix C, the authorized natural gas rates result in a range of increases in the charges to the various service rate classes. The percentage rate decrease to any individual

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customer will not necessarily equal the overall percentage decrease to the associated service rate class, but will depend on the specific usage level of the customer.

Appendix C also shows some typical natural gas bills for residential service, comparing existing rates with new rates, including the cost of natural gas.

Order

1. This Final Decision takes effect one day after the date of mailing.
2. The authorized rate increases and tariff provisions that restrict the terms of service may take effect January 1, 2013, provided that the utility files these rates and tariff provisions with the Commission and places them in all of the utility's offices and pay stations by that date. If these rate increases and tariff provisions are not filed with the Commission and placed in all offices and pay stations by that date, they take effect on the date they are filed with the Commission and placed in all offices and pay stations.
3. NSPW may revise its existing rates and tariff provisions for electric and natural gas utility service, substituting the rate increases and tariff provisions that restrict the terms of service, as shown in Appendices B and C. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.
4. The electric fuel costs in Appendix D shall be used for monitoring of the NSP system's 2013 fuel costs, pursuant to Wis. Admin. Code § PSC 116.06(3).
5. NSPW shall not include labor dollars in the conservation escrow budget for Account Managers or Community Service Managers/Supervisors.
6. The Farm Rewiring Program shall not receive escrow treatment.

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7. Low-income assistance dollars required by Act 141 to be contributed to statewide low-income programs shall not receive escrow treatment.

8. NSPW shall record annual conservation accrual amounts of \$8,662,412 for electric operations and \$3,014,932 for natural gas operations. The level for electric operations consists of the conservation budget of \$8,191,041 plus an escrow adjustment of \$470,626 to reflect the estimated overspent balance as of January 1, 2013, of \$941,252, amortized over two years. The level for natural gas operations remains at \$3,014,932, the same as that authorized in rate case docket 4220-UR-117.

9. NSPW shall maintain 50 to 55 percent common equity on a financial basis in its capital structure.

10. The appropriate target level for NSPW's common equity shall be further explored in the company's next rate case.

11. NSPW shall submit a ten-year financial forecast in its next rate case.

12. NSPW shall submit, in its next rate case application, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at a minimum: (1) the minimum annual lease and purchase power agreement obligations; (2) the method of calculation, along with the calculated amount of the debt equivalent; and (3) supporting documentation, including all reports, correspondence and any other justification that clearly established S&P's and other major credit rating agencies' determination of the off-balance sheet debt equivalent, to the extent available, and publicly available documentation when S&P and other major credit rating agencies' documentation is not available.

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13. NSPW shall not pay dividends, including pass-through of subsidiary dividends, in excess of \$31,189,664, if its actual average common equity ratio, on a financial basis, is or will fall below the test year authorized level of 52.50 percent.

14. NSPW shall modify materials used to market the Windsorce program in Wisconsin so as to accurately reflect what the program offers to participating customers, given the constraints of the Interchange Agreement, within 60 days of the effective date of this Final Decision.

15. In its next base rate case, NSPW shall provide additional information regarding the billing system costs the company claims would be associated with providing a percentage-based participation option for the Windsorce program.

16. Jurisdiction is retained.

Dissent and Concurrence

Commissioner Callisto dissents in part, concurs, and writes separately (attached).

Dated at Madison, Wisconsin, this 27th day of December, 2012.

By the Commission:



Sandra J. Paske
Secretary to the Commission

SJP:CCS:cmk:DL:00611941

See attached Notice of Rights

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Madison, Wisconsin 53707-7854

**NOTICE OF RIGHTS FOR REHEARING OR JUDICIAL REVIEW, THE
TIMES ALLOWED FOR EACH, AND THE IDENTIFICATION OF THE
PARTY TO BE NAMED AS RESPONDENT**

The following notice is served on you as part of the Commission's written decision. This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

PETITION FOR REHEARING

If this decision is an order following a contested case proceeding as defined in Wis. Stat. § 227.01(3), a person aggrieved by the decision has a right to petition the Commission for rehearing within 20 days of mailing of this decision, as provided in Wis. Stat. § 227.49. The mailing date is shown on the first page. If there is no date on the first page, the date of mailing is shown immediately above the signature line. The petition for rehearing must be filed with the Public Service Commission of Wisconsin and served on the parties. An appeal of this decision may also be taken directly to circuit court through the filing of a petition for judicial review. It is not necessary to first petition for rehearing.

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of mailing of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of mailing of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission mailed its original decision.² The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

If this decision is an order denying rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not permitted.

Revised: December 17, 2008

² See *State v. Currier*, 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

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APPENDIX A
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SERVICE LIST

In order to comply with Wis. Stat. § 227.47, the following parties who appeared before the agency are considered parties for purposes of review under Wis. Stat. § 227.53.

PUBLIC SERVICE COMMISSION OF WISCONSIN

(Not a party, but must be served)

610 North Whitney Way
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Madison, WI 53707-7854

Justin Chasco
Candice Spanjar

NORTHERN STATES POWER COMPANY

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CITIZENS UTILITY BOARD

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WISCONSIN PAPER COUNCIL

Earl Gustafson
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Appleton, WI 54913
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NORTHERN STATES POWER COMPANY (WISCONSIN)

**SUMMARY OF ELECTRIC REVENUE
FOR TEST YEAR 2013**

INDIVIDUAL RATE CLASSES	PRESENT REVENUES	AUTHORIZED REVENUES	DOLLAR INCREASE	PERCENT INCREASE
Rg-1 (Residential)	\$ 200,189,419	\$ 214,305,579	\$ 14,116,160	7.05%
Rg-2 (Residential - Optional Time-of-Day)	11,070,696	11,862,113	791,417	7.15%
Fg-1 (Farm Service)	9,624,585	10,341,693	717,108	7.45%
Cg-6 (Optional Off-Peak Service -- Res.)	85,932	91,589	5,657	6.58%
S-1 (Automatic Protective Lighting -- Res.)	438,673	468,403	29,730	6.78%
Cg-1 (Small General - Optional Time-of-Day)	454,208	487,166	32,958	7.26%
Cg-2 (Small General Non-TOD)	42,534,695	45,608,668	3,073,973	7.23%
S-1 (Automatic Protective Lighting -- Com.)	580,166	619,537	39,371	6.79%
Ms-6 (Underground Area Lighting - Private)	31,576	33,725	2,149	6.81%
Cg-5 (General Service TOD)	84,367,437	89,258,322	4,890,885	5.80%
Cg-6 (Optional Off-Peak Service -- C&I)	225,034	240,552	15,518	6.90%
Cp-2 (Peak Controlled Non-TOD)	3,127,321	3,312,569	185,249	5.92%
Cg-9 (Large General TOD)	157,496,035	165,563,370	8,067,335	5.12%
DS-1 (Military Fac. Distrib. Service)	629,430	643,234	13,804	2.19%
Cp-1 (Peak Controlled Service)	54,126,007	56,777,630	2,651,622	4.90%
RTP-1 (Real-Time Pricing)	12,718,600	13,237,016	518,416	4.08%
Ms-2 (Company Owned Street Lighting)	3,309,285	3,534,299	225,014	6.80%
Ms-3 (Cust. Owned Incand./Fluor. Lighting)	6,971	7,445	474	6.80%
Ms-4 (Customer Owned Lighting)	468,570	500,767	32,197	6.87%
Ms-6 (Underground Area Lighting - Public)	345,477	368,983	23,506	6.80%
Ms-7 (Metered - Customer Owned Lighting)	125,613	133,940	8,327	6.63%
Mp-1 (Municipal Water Pumping)	1,096,849	1,179,235	82,386	7.51%
Mz-3 (Fire Siren Service)	4,878	4,878	0	0.00%
VRE (Voluntary Renewable Energy - Windsourse)	184,950	184,950	0	0.00%
Pg-2 (Parallel Generation Service)	0	0	0	0.00%
TOTAL ELECTRIC RETAIL SALES	583,242,407	618,765,663	35,523,256	6.09%
Interdepartmental Sales	168,592	177,816	9,224	5.47%
TOTAL ELECTRIC	\$ 583,410,999	\$ 618,943,479	\$ 35,532,480	6.09%

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NORTHERN STATES POWER COMPANY (WISCONSIN)
ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS	PRESENT RATES	AUTHORIZED RATES
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RESIDENTIAL SERVICE, Rg-1

Customer Charge (per Month):	Single-Phase	\$8.00	\$8.00
	Three-Phase	\$10.00	\$10.00
Water Heating Meter Chg. (per Month per Meter)		\$2.00	\$2.00
Load Management Credit (per Month):			
Water Heating		\$2.00	\$2.00
Air Conditioning (Summer Only)		\$6.00	\$6.00
Energy Charge (per kWh)	Summer	11.3780 ¢	12.2600 ¢
	Non-Summer	10.2920 ¢	11.0900 ¢

RESIDENTIAL TOD SERVICE, Rg-2

Customer Charge (per Month):	Single-Phase	\$8.00	\$8.00
	Three-Phase	\$10.00	\$10.00
Energy Charge (per kWh):	On-Peak (Summer)	21.2320 ¢	22.8420 ¢
	On-Peak (Non-Summer)	19.6070 ¢	21.0940 ¢
	Off-Peak (Summer)	5.4210 ¢	5.8390 ¢
	Off-Peak (Non-Summer)	5.4210 ¢	5.8390 ¢

FARM SERVICE, Fg-1

Customer Charge (per Month):	Single-Phase	\$8.00	\$8.00
	Three-Phase	\$10.00	\$10.00
Load Management Credit (per Month):			
Water Heating		\$2.00	\$2.00
Air Conditioning (Summer Only)		\$6.00	\$6.00
Energy Charge (per kWh)	Summer	11.3780 ¢	12.2600 ¢
	Non-Summer	10.2920 ¢	11.0900 ¢

SMALL GENERAL SERVICE, Cg-2

Customer Charge (per Month):	Single-Phase	\$8.00	\$8.00
	Three-Phase	\$10.00	\$10.00
Un-metered Cust. Charge (per Month):	Single-Phase	\$4.50	\$4.50
	Three-Phase	\$6.50	\$6.50
Water Heating Meter Chg. (per Month per Meter)		\$2.00	\$2.00
Energy Charge (per kWh)	Summer	11.3780 ¢	12.2600 ¢
	Non-Summer	10.2920 ¢	11.0900 ¢
Act 141 \$ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 \$ in Lg.Cust. Rates		0.0630 ¢	0.0650 ¢

SMALL GENERAL TOD SERVICE, Cg-1

Customer Charge (per Month)	Single-Phase	\$8.00	\$8.00
	Three-Phase	\$10.00	\$10.00
Energy Charge (per kWh):	On-Peak (Summer)	21.2320 ¢	22.8420 ¢
		19.6070 ¢	21.0940 ¢
	Off-Peak (Summer)	5.4210 ¢	5.8390 ¢
		5.4210 ¢	5.8390 ¢

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NORTHERN STATES POWER COMPANY (WISCONSIN)
ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
GENERAL SERVICE, Cg-5			
Customer Charge (per Month):		\$30.00	\$30.00
Demand Charges (per kW):	Secondary (Summer)	\$11.25	\$11.95
	Secondary (Non-Summer)	\$9.25	\$9.95
	Primary (Summer)	\$10.70	\$11.36
	Primary (Non-Summer)	\$8.74	\$9.40
Energy Charge (per kWh)	Summer	6.0050 ¢	6.3275 ¢
	Non-Summer	5.4640 ¢	5.7577 ¢
Act 141 \$ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 \$ in Lg.Cust. Rates		0.0480 ¢	0.0480 ¢
Primary Volt. Energy Discount (per kWh)		2.00%	2.00%
Primary Volt. Demand Discount (per kW)	Summer	\$0.55	\$0.59
	Non-Summer	\$0.51	\$0.55
[Discounts Reflected Above]			
Energy Charge Credit (per kWh in excess of 400 hours x Billed kW)		0.8000 ¢	0.9000 ¢
PEAK CONTROLLED SERVICE, Cp-2			
Customer Charge (per Month):		\$40.00	\$40.00
Demand Charges (per kW):			
Firm Demand:	Secondary (Summer)	\$11.25	\$11.95
	Secondary (Non-Summer)	\$9.25	\$9.95
	Primary (Summer)	\$10.70	\$11.36
	Primary (Non-Summer)	\$8.74	\$9.40
Controlled Demand:	Secondary (Summer)	\$6.54	\$7.05
	Secondary (Non-Summer)	\$6.54	\$7.05
	Primary (Summer)	\$6.08	\$6.56
	Primary (Non-Summer)	\$6.08	\$6.56
Energy Charge (per kWh)	Summer	6.0050 ¢	6.3275 ¢
	Non-Summer	5.4640 ¢	5.7577 ¢
Act 141 \$ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 \$ in Lg.Cust. Rates		0.0230 ¢	0.0230 ¢
Primary Volt. Energy Discount (per kWh)		2.00%	2.00%
Primary Volt. Demand Discount (per kW)	Summer	\$0.55	\$0.59
	Non-Summer	\$0.51	\$0.55
[Discounts Reflected Above]			
Energy Charge Credit (per kWh in excess of 400 hours x Billed kW)		0.900 ¢	0.900 ¢
OPTIONAL OFF-PEAK SERVICE, Cg-6			
Customer Charge (per Month):	Single-Phase	\$4.00	\$4.00
	Three-Phase	\$10.00	\$10.00
Energy Charge (per kWh)	Secondary (Summer)	4.9780 ¢	5.3720 ¢
	Secondary (Non-Summer)	4.9780 ¢	5.3720 ¢
	Primary (Summer)	4.8784 ¢	5.2650 ¢
	Primary (Non-Summer)	4.8784 ¢	5.2650 ¢
Non-Authorized Use Charge (per kWh)		21.9150 ¢	22.4020 ¢

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NORTHERN STATES POWER COMPANY (WISCONSIN)
ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
LARGE GENERAL TOD SERVICE, Cg-9			
Customer Charge (per Month):	Mandatory	\$155.00	\$155.00
	Optional	\$55.00	\$55.00
On-Peak Demand Charges (per kW):	Secondary (Summer)	\$9.75	\$10.45
	Secondary (Non-Summer)	\$7.75	\$8.45
	Primary (Summer)	\$9.56	\$10.24
	Primary (Non-Summer)	\$7.60	\$8.28
	Trans. Transformed (Sum.)	\$9.12	\$9.72
	Tr. Transform. (Non-Sum.)	\$7.25	\$7.86
	Transmission (Summer)	\$9.07	\$9.67
	Transmission (Non-Sum.)	\$7.21	\$7.82
Customer Demand Charges (per kW):	Secondary	\$1.30	\$1.39
	Primary	\$0.97	\$1.04
	Trans. Transformed	\$0.55	\$0.59
	Transmission	\$0.00	\$0.00
Energy Charge (per kWh):	On-Peak (Summer)	7.6960 ¢	8.0210 ¢
	On-Peak (Non-Summer)	6.9420 ¢	7.2350 ¢
	Off-Peak (Summer)	4.5380 ¢	4.7300 ¢
	Off-Peak (Non-Summer)	4.5380 ¢	4.7300 ¢
Act 141 \$ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 \$ in Lg.Cust. Rates		0.0370 ¢	0.0370 ¢
Voltage Discounts - Energy:	Primary	2.00%	2.00%
	Trans. Transformed	6.50%	7.00%
	Transmission	7.00%	7.50%
Voltage Discounts = [Reflected in Demand Charges Above]:			
On-Peak (per kW):	Primary (Summer)	\$0.19	\$0.21
	Primary (Non-Summer)	\$0.15	\$0.17
	Trans. Transformed (Sum.)	\$0.63	\$0.73
	Tr. Transform. (Non-Sum.)	\$0.50	\$0.59
	Transmission (Summer)	\$0.68	\$0.78
	Transmission (Non-Sum.)	\$0.54	\$0.63
Customer (per kW):	Primary	\$0.33	\$0.35
	Trans. Transformed	\$0.75	\$0.80
	Transmission	\$1.30	\$1.39
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.8000 ¢	0.9000 ¢

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NORTHERN STATES POWER COMPANY (WISCONSIN)
ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
PEAK CONTROLLED TOD SERVICE, Cp-1			
Customer Charge (per Month):	Demands >200 kW	\$175.00	\$175.00
	Demands ≤ 200 kW	\$75.00	\$75.00
On-Peak Demand Charges (per kW):	Secondary (Summer)	\$9.75	\$10.45
	Secondary (Non-Summer)	\$7.75	\$8.45
	Primary (Summer)	\$9.56	\$10.24
	Primary (Non-Summer)	\$7.60	\$8.28
	Trans. Transformed (Sum.)	\$9.12	\$9.72
	Tr. Transform. (Non-Sum.)	\$7.25	\$7.86
	Transmission (Summer)	\$9.07	\$9.67
	Transmission (Non-Sum.)	\$7.21	\$7.82
Customer Demand Charges (per kW):	Secondary	\$1.30	\$1.39
	Primary	\$0.97	\$1.04
	Trans. Transformed	\$0.55	\$0.59
	Transmission	\$0.00	\$0.00
Controlled Demand Charges (per kW):	Secondary (Summer)	\$5.04	\$5.55
	Secondary (Non-Summer)	\$5.04	\$5.55
	Primary (Summer)	\$4.94	\$5.44
	Primary (Non-Summer)	\$4.94	\$5.44
	Trans. Transformed (Sum.)	\$4.72	\$5.16
	Tr. Transform. (Non-Sum.)	\$4.72	\$5.16
	Transmission (Summer)	\$4.71	\$5.14
	Transmission (Non-Sum.)	\$4.70	\$5.14
Energy Charge (per kWh):	On-Peak (Summer)	7.6960 ¢	8.0210 ¢
	On-Peak (Non-Summer)	6.9420 ¢	7.2350 ¢
	Off-Peak (Summer)	4.5380 ¢	4.7300 ¢
	Off-Peak (Non-Summer)	4.5380 ¢	4.7300 ¢
Act 141 \$ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 \$ in Lg.Cust. Rates		0.0310 ¢	0.0310 ¢
Voltage Discounts - Energy:	Primary	2.00%	2.00%
	Trans. Transformed	6.50%	7.00%
	Transmission	7.00%	7.50%
Voltage Discounts [Reflected in Demand Charges Above]:			
On-Peak (per kW):	Primary (Summer)	\$0.19	\$0.21
	Primary (Non-Summer)	\$0.15	\$0.17
	Trans. Transformed (Sum.)	\$0.63	\$0.73
	Tr. Transform. (Non-Sum.)	\$0.50	\$0.59
	Transmission (Summer)	\$0.68	\$0.78
	Transmission (Non-Sum.)	\$0.54	\$0.63
Customer (per kW):	Primary	\$0.33	\$0.35
	Trans. Transformed	\$0.75	\$0.80
	Transmission	\$1.30	\$1.39
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.800 ¢	0.900 ¢

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NORTHERN STATES POWER COMPANY (WISCONSIN)
ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS	PRESENT RATES	AUTHORIZED RATES
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MILITARY FACILITY DISTRIBUTION SERVICE, DS-1

Distribution Service Charge (per kW)	\$4.56	\$4.66
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EXPERIMENTAL REAL TIME PRICING, RTP-1

Customer Charge (per Month)		\$300.00	\$300.00
Contract Demand Charges (per kW):	Secondary	\$9.09	\$9.12
	Primary	\$8.91	\$8.93
	Trans. Transformed	\$8.50	\$8.48
	Transmission	\$8.45	\$8.44
Distribution Demand Charges (per kW):	Secondary	\$1.30	\$1.39
	Primary	\$0.97	\$1.04
	Trans. Transformed	\$0.55	\$0.59
	Transmission	\$0.00	\$0.00
Energy Charges (per kWh):		Authorized Hourly Energy Prices included in the table below	
Energy Voltage Discounts (per kWh):	Primary	0.100 ¢	0.100 ¢
	Trans. Transformed	0.331 ¢	0.376 ¢
	Transmission	0.356 ¢	0.403 ¢
Limited Energy Surcharge (per kWh)		10.9500 ¢	11.6500 ¢
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.7000 ¢	0.9000 ¢

Energy Chgs. \$ per kWh	Day Types							
	1	2	3	4	5	6	7	8
12 am - 6 am	0.05502	0.04995	0.04744	0.04288	0.04047	0.03605	0.03571	0.03395
6 am - 9 am	0.09550	0.07812	0.06412	0.06501	0.06210	0.04680	0.04636	0.03934
9 am - 12 pm	0.24700	0.17101	0.10770	0.08563	0.07065	0.06046	0.04961	0.04285
12 pm - 6 pm	0.41163	0.27233	0.15836	0.09828	0.07065	0.06046	0.04961	0.04285
6 pm - 9 pm	0.29765	0.22167	0.13303	0.08741	0.07065	0.06046	0.04961	0.04285
9 pm - 12 pm	0.09297	0.07526	0.06755	0.06007	0.04971	0.04448	0.04072	0.03821

AUTOMATIC PROTECTIVE LIGHTING, S-1

Monthly Charges (per Unit):		
175 Watt MV Lamps (Closed)	\$8.51	\$9.09
250 Watt MV Lamps (Closed)	\$11.33	\$12.10
400 Watt MV Lamps (Closed)	\$15.24	\$16.28
70 Watt HPS Lamps	\$6.08	\$6.49
100 Watt HPS Lamps	\$7.40	\$7.90
150 Watt HPS Lamps	\$8.93	\$9.54
250 Watt HPS Lamps	\$12.11	\$12.93
400 Watt HPS Lamps	\$17.31	\$18.49

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NORTHERN STATES POWER COMPANY (WISCONSIN)
ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS	PRESENT RATES	AUTHORIZED RATES
COMPANY OWNED STREET LIGHTING, Ms-2		
<u>Monthly Charges (per Lamp):</u>		
<u>Overhead:</u>		
175 Watt MV Lamps (Closed)	\$12.43	\$13.28
250 Watt MV Lamps (Closed)	\$14.16	\$15.12
400 Watt MV Lamps (Closed)	\$17.51	\$18.70
70 Watt HPS Lamps	\$10.21	\$10.90
100 Watt HPS Lamps	\$11.13	\$11.89
150 Watt HPS Lamps	\$12.40	\$13.24
250 Watt HPS Lamps	\$15.42	\$16.47
400 Watt HPS Lamps	\$20.05	\$21.41
<u>Underground:</u>		
175 Watt MV Lamps (Closed)	\$18.21	\$19.45
250 Watt MV Lamps (Closed)	\$19.82	\$21.17
70 Watt HPS Lamps	\$15.28	\$16.32
100 Watt HPS Lamps	\$16.21	\$17.31
150 Watt HPS Lamps	\$17.48	\$18.67
250 Watt HPS Lamps	\$20.74	\$22.15
400 Watt HPS Lamps	\$25.12	\$26.83
<u>Decorative Underground:</u>		
100 Watt HPS Lamps	\$34.65	\$34.65
150 Watt HPS Lamps	\$36.21	\$36.21
250 Watt HPS Lamps	\$39.36	\$39.36
400 Watt HPS Lamps	\$43.94	\$43.94
<u>Maintenance Option:</u>		
100 Watt HPS Lamps	\$8.28	\$8.84
150 Watt HPS Lamps	\$9.88	\$10.55
250 Watt HPS Lamps	\$13.02	\$13.91
400 Watt HPS Lamps	\$17.60	\$18.80

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NORTHERN STATES POWER COMPANY (WISCONSIN)
ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS	PRESENT RATES	AUTHORIZED RATES
CUSTOMER OWNED STREET LIGHTING, Ms-4		
Monthly Charges (per Lamp):		
Group I - Energy and Maintenance:		
175 Watt MV Lamps (Closed)	\$6.91	\$7.38
250 Watt MV Lamps (Closed)	\$8.49	\$9.07
400 Watt MV Lamps (Closed)	\$12.05	\$12.87
700 Watt MV Lamps (Closed)	\$19.06	\$20.36
50 Watt HPS Lamps	\$4.19	\$4.47
70 Watt HPS Lamps	\$4.66	\$4.98
100 Watt HPS Lamps	\$5.56	\$5.94
150 Watt HPS Lamps	\$6.60	\$7.05
250 Watt HPS Lamps	\$9.66	\$10.32
400 Watt HPS Lamps	\$13.24	\$14.14
Group I - Energy and Maintenance (No Paint):		
175 Watt MV Lamps (Closed)	\$6.66	\$7.13
250 Watt MV Lamps (Closed)	\$8.24	\$8.82
400 Watt MV Lamps (Closed)	\$11.80	\$12.62
700 Watt MV Lamps (Closed)	\$18.81	\$20.11
50 Watt HPS Lamps	\$3.94	\$4.22
70 Watt HPS Lamps	\$4.41	\$4.73
100 Watt HPS Lamps	\$5.31	\$5.69
150 Watt HPS Lamps	\$6.35	\$6.80
250 Watt HPS Lamps	\$9.41	\$10.07
400 Watt HPS Lamps	\$12.99	\$13.89
Group II - Energy Only:		
100 Watt MV Lamps (Closed)	\$2.69	\$2.87
175 Watt MV Lamps (Closed)	\$4.30	\$4.59
400 Watt MV Lamps (Closed)	\$9.48	\$10.12
700 Watt MV Lamps (Closed)	\$16.18	\$17.28
35 Watt HPS Lamps	\$0.90	\$0.96
50 Watt HPS Lamps	\$1.30	\$1.39
70 Watt HPS Lamps	\$1.72	\$1.84
100 Watt HPS Lamps	\$2.59	\$2.77
150 Watt HPS Lamps	\$3.99	\$4.26
200 Watt HPS Lamps	\$5.07	\$5.41
250 Watt HPS Lamps	\$6.16	\$6.58
400 Watt HPS Lamps	\$9.70	\$10.36
1000 Watt HPS Lamps	\$21.98	\$23.47

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NORTHERN STATES POWER COMPANY (WISCONSIN)
ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS	PRESENT RATES	AUTHORIZED RATES
COMPANY OWNED STREET LIGHTING, Ms-4.2 (Closed)		
Ornamental:		
250 Watt MV Lamps	\$15.84	\$16.92
400 Watt MV Lamps	\$18.87	\$20.15
150 Watt HPS Lamps	\$15.74	\$16.81
250 Watt HPS Lamps	\$18.65	\$19.92
UNDERGROUND AREA LIGHTING, Ms-6		
Monthly Charges (per Lamp):		
175 Watt MV Lamps (Closed)	\$16.01	\$17.10
100 Watt HPS Lamps	\$14.26	\$15.23
150 Watt HPS Lamps	\$16.26	\$17.37
METERED CUSTOMER OWNED STREET LIGHTING, Ms-7		
Customer Charge (per Month)	\$7.25	\$7.25
Energy Charge (per kWh)	5.8780 ¢	6.2890 ¢
COMPANY OWNED STREET LIGHTING, Ms-3 (Closed)		
Monthly Charges (per Lamp):		
2,500 Lumen - Incand. (AN)	\$7.92	\$8.46
4,000 Lumen - Incand. (AN)	\$9.66	\$10.32
6,000 Lumen - Incand. (AN)	\$11.65	\$12.44
10,000 Lumen - Incand. (AN)	\$15.53	\$16.59
F72H0 - Fluorescent (4AN)	\$15.77	\$16.84
F72H0 - Fluor. (2AN+2MN)	\$13.88	\$14.82
MUNICIPAL WATER PUMPING, Mp-1		
Customer Charge (per Month)	\$10.00	\$10.00
Minimum Charge: Cust. Chg. + All hp > 5 (per hp)	\$0.80	\$0.80
Energy Charge (per kWh)		
Summer	11.3780 ¢	12.2600 ¢
Non-Summer	10.2920 ¢	11.0900 ¢
Primary Voltage Energy Discount (per kWh)	2.00%	2.00%
FIRE SIREN SERVICE, Mz-3		
Minimum Charge (per Month)	\$2.00	\$2.00
Rate per hp of Connected Capacity	38.30 ¢	38.30 ¢
WINDSOURCE, VRE (Green Pricing Tariff)		
Energy Charge Adder	1.37 ¢	1.37 ¢

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NORTHERN STATES POWER COMPANY (WISCONSIN)
ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS	PRESENT RATES	AUTHORIZED RATES
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PARALLEL GENERATION, Pg-2A

Customer Charge (per Month):		
For Generator Rating: 21-100 kW:	Delivering < 200 amps	\$6.40
	Delivering > 200 amps	\$8.60
For Generator Rating: > 100 kW		\$13.80
NSPW 's Energy payments are based on LMP prices and are adjusted by Delivery Voltage to reflect losses.		\$13.80
Historic Day Ahead LMP payments (per kWh):		Rates are automatically adjusted in
On-Peak		0.03640
On-Peak		0.02309
		November for the TY 2013

HYDRO ENERGY PURCHASE, Pg-2.2 (Closed)

Customer Charge (per Month):		
For Generator Rating: 21-100 kW:	Delivering < 200 amps	\$6.40
	Delivering > 200 amps	\$8.60
For Generator Rating: > 100 kW		\$13.80
Capacity Rate (Primary) paid per kWh:		
20-Year Option:		
Service beginning in 1992		4.220 ¢
Average Energy Rate (Primary):		
For Service in 1996 & After Until Changed by PSC Order		3.000 ¢

ELECTRIC SERVICE EXTENSION ALLOWANCES

Residential & Farm Service:		
(for Rg-1, Rg-2, Fg-1)		\$452.00
General Service -- Non-Demand:		
(for Cg-1, Cg-2, Mp-1, Mz-3)		\$490.00
General Service -- Demand:		
(for Cg-5 and Cp-2) per kW:		\$67.00
Large General Service -- Demand:		
(for Cg-9 and Cp-1)		
Secondary (per kW):		\$59.00
Primary (per kW):		\$50.00
Street and Area Lighting:		
(for Ms-2, Ms-4, Ms-6)		\$82.00
		\$108.00

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Northern States Power Company

Gas Revenue Summary

Service Rate Classes	Volumes	Current Margin & Admin Revenues	+ Cost of Gas Revenues	= Rebundled Service Class Revenues	+ Proposed Distribution Rev Change/Class	= Total Bundled Rev. by Dist. Class	Percent Change Rebundled	
							w/COG	w/o COG
Residential								
Residential (Rg-1)	61,622,593	\$ 26,154,965	\$ 29,265,354	\$ 55,420,319	\$ 1,731,595	\$ 57,151,914	3.12%	6.62%
Subtotal	61,622,593	\$ 26,154,965	\$ 29,265,354	\$ 55,420,319	\$ 1,731,595	\$ 57,151,914	3.12%	6.62%
Commercial & Industrial, Cg-1 (0 to 29,999)								
Commercial - Firm (Cg1-SSS-F)	50,407,832	\$ 11,264,064	\$ 23,576,958	\$ 34,841,022	\$ 650,261	\$ 35,491,283	1.87%	5.77%
Commercial - Contract (Cg1-SSS-CD)	3,558,475	\$ 621,533	\$ 1,980,765	\$ 2,602,298	\$ 45,904	\$ 2,648,202	1.76%	7.39%
Commercial - Interdepart. (Cg1-SSS-F)	153,802	\$ 29,177	\$ 73,442	\$ 102,619	\$ 1,984	\$ 104,603	1.93%	6.80%
Commercial - Transport (Cg-1-CSS)	522,920	\$ 75,935	\$ -	\$ 75,935	\$ 6,746	\$ 82,680	8.88%	8.88%
Subtotal Cg-1	54,643,029	\$ 11,990,708	\$ 25,631,166	\$ 37,621,873	\$ 704,895	\$ 38,326,768	1.87%	5.88%
Commercial & Industrial, Cg-2 (30,000 to 199,999)								
Commercial - Interruptible (Cg-2-SSS-CD)	11,805,217	\$ 237,904	\$ -	\$ 237,904	\$ 22,430	\$ 260,334	9.43%	9.43%
Commercial - Interruptible (Cg-2-SSS-I)	9,216,682	\$ 1,381,434	\$ 3,515,780	\$ 4,897,214	\$ 71,890	\$ 4,969,104	1.47%	5.20%
Commercial - Transport (Cg-2-CSS)	571,315	\$ 58,017	\$ -	\$ 58,017	\$ 4,456	\$ 62,474	7.68%	7.68%
Subtotal Cg-2	21,593,214	\$ 1,677,355	\$ 3,515,780	\$ 5,193,135	\$ 98,776	\$ 5,291,912	1.90%	5.89%
Commercial & Industrial, Cg-3 (200,000 to 499,999)								
Commercial - Interruptible (Cg-3-SSS-I)	2,784,555	\$ 271,389	\$ 1,051,448	\$ 1,322,837	\$ 10,303	\$ 1,333,140	0.78%	3.80%
Commercial - Transport (Cg-3-CSS)	1,918,203	\$ 122,917	\$ -	\$ 122,917	\$ 7,097	\$ 130,014	5.77%	5.77%
Subtotal Cg-3	4,702,758	\$ 394,306	\$ 1,051,448	\$ 1,445,754	\$ 17,400	\$ 1,463,154	1.20%	4.41%
Commercial & Industrial, Cg-4 (500,000 to 1,999,999)								
Commercial - Interruptible (Cg-4-SSS-I)	10,398,729	\$ 761,555	\$ 3,926,560	\$ 4,688,115	\$ 38,475	\$ 4,726,590	0.82%	5.05%
Commercial - Transport (Cg-4-CSS-I)	6,050,718	\$ 283,947	\$ -	\$ 283,947	\$ 22,388	\$ 306,335	7.88%	7.88%
Commercial - Contract (Contract)	1,415,600	\$ 14,016	\$ -	\$ 14,016	\$ 5,662	\$ 19,678	40.40%	40.40%
Subtotal Cg-4	17,865,047	\$ 1,059,518	\$ 3,926,560	\$ 4,986,078	\$ 66,525	\$ 5,052,603	1.33%	6.28%
Commercial & Industrial, Cg-5 (2,000,000 to 5,999,999)								
Commercial - Interruptible (Cg-5-SSS-I)	3,823,508	\$ 238,341	\$ 1,443,757	\$ 1,682,098	\$ 15,294	\$ 1,697,392	0.91%	6.42%
Commercial - Inter-InterD (Cg-5-CSS-I)	1,051,300	\$ 90,576	\$ 406,669	\$ 497,245	\$ 4,205	\$ 501,450	0.85%	4.64%
Commercial - Transport (Cg-5-CSS-I)	13,554,927	\$ 534,426	\$ -	\$ 534,426	\$ 54,220	\$ 588,645	10.15%	10.15%
Subtotal Cg-5	18,429,735	\$ 863,342	\$ 1,850,426	\$ 2,713,768	\$ 73,719	\$ 2,787,487	2.72%	8.54%
Commercial & Industrial, Cg-6 (6,000,000+)								
Commercial - Transport (Cg-6-CSS-I)	6,387,405	\$ 202,560	\$ -	\$ 202,560	\$ 25,550	\$ 228,110	12.61%	12.61%
Subtotal Cg-6	6,387,405	\$ 202,560	\$ -	\$ 202,560	\$ 25,550	\$ 228,110	12.61%	12.61%
Total Gas Sales Revenues		\$ 42,342,754	\$ 65,240,733	\$ 107,583,487	\$ 2,718,460	\$ 110,301,948	2.53%	6.42%
Plus:								
Other Gas Revenue				\$ 452,907		\$ 452,907	0.00%	0.00%
Total Gas Operating Revenue				\$ 108,036,394		\$ 110,754,855	2.52%	6.35%

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Northern States Power Company

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
<u>Residential</u>		
Monthly Customer Charge - (Rg-1)	\$ 10.25	\$ 10.25
Volumetric Charges:		
Distribution Service Charge - (Rg-1)	\$ 0.2077	\$ 0.2358
Peak Day Backup Charge (SSS-F)	\$ 0.0020	\$ 0.0020
Gas Acquisition Charge (SSS-F)	\$ 0.0336	\$ 0.0336
<u>Commercial (Cg-1, Annual Usage < 30,000 therms)</u>		
Monthly Customer Charge	\$ 20.00	\$ 20.00
Additional Meter Charge	\$ 4.00	\$ 4.00
Volumetric Charges:		
Distribution Service Charge	\$ 0.1420	\$ 0.1549
Peak Day Backup Charge (SSS-F)	\$ -	\$ -
Gas Acquisition Charge (SSS-F, SSS-CD)	\$ 0.0321	\$ 0.0321
<u>Commercial (Cg-2, Annual Usage 30,000 - 199,999 therms)</u>		
Monthly Customer Charge	\$ 100.00	\$ 100.00
Transportation Administrative Charge	\$ 50.00	\$ 50.00
Volumetric Charges:		
Distribution Service Charge - (Cg-2-SSS-CD)	\$ 0.0984	\$ 0.1062
Distribution Service Charge - (Cg-2-SSS-I)	\$ 0.0984	\$ 0.1062
Peak Day Backup Charge (SSS-F)	\$ 0.0047	\$ 0.0047
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	\$ 0.0256	\$ 0.0256

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Northern States Power Company

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
<u>Commercial (Cg-3, Annual Usage 200,000 - 499,999 therms)</u>		
Monthly Customer Charge	\$ 300.00	\$ 300.00
Transportation Administrative Charge	\$ 50.00	\$ 50.00
Volumetric Charges:		
Distribution Service Charge	\$ 0.0653	\$ 0.0690
Peak Day Backup Charge (SSS-F)	\$ -	\$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	\$ 0.0256	\$ 0.0256
<u>Commercial (Cg-4, Annual Usage 500,000 - 1,999,999 therms)</u>		
Monthly Customer Charge	\$ 350.00	\$ 350.00
Transportation Administrative Charge	\$ 50.00	\$ 50.00
Volumetric Charges:		
Distribution Service Charge	\$ 0.0549	\$ 0.0586
Peak Day Backup Charge (SSS-F)	\$ -	\$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	\$ 0.0256	\$ 0.0256
<u>Commercial (Cg-5, Annual Usage 2,000,000 - 5,999,999 therms)</u>		
Monthly Customer Charge	\$ 550.00	\$ 550.00
Transportation Administrative Charge	\$ 50.00	\$ 50.00
Volumetric Charges:		
Distribution Service Charge	\$ 0.0480	\$ 0.0520
Peak Day Backup Charge (SSS-F)	\$ -	\$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	\$ 0.0256	\$ 0.0256

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Northern States Power Company

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
<u>Commercial (Cg-6, Annual Usage 6,000,000+ therms)</u>		
Monthly Customer Charge	\$ 625.00	\$ 625.00
Transportation Administrative Charge	\$ 50.00	\$ 50.00
Volumetric Charges:		
Distribution Service Charge	\$ 0.0443	\$ 0.0483
Peak Day Backup Charge (SSS-F)	\$ -	\$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	\$ 0.0256	\$ 0.0256
<u>Base Average Cost of Gas Rates:</u>		
Commodity ("Comm") rate	\$ 0.5904	\$ 0.3686
Peak Day Demand ("D1") rate	\$ 0.0975	\$ 0.1144
Annual Demand ("D2") rate	\$ 0.0100	\$ 0.0090
Balancing ("Bal") rate	\$ 0.0039	\$ -
<u>Act 141 Volumetric Distribution Rates 1/</u>		
Residential	\$ 0.0113	\$ 0.0113
Commercial (Cg-1, Annual Usage < 30,000 therms)	\$ 0.0152	\$ 0.0152
Commercial (Cg-2, Annual Usage 30,000 - 199,999 therms)	\$ 0.0152	\$ 0.0152
Commercial (Cg-3, Annual Usage 200,000 - 499,999 therms)	\$ 0.0152	\$ 0.0152
Commercial (Cg-4, Annual Usage 500,000 - 1,999,999 therms)	\$ 0.0152	\$ 0.0152
Commercial (Cg-5, Annual Usage 2,000,000 - 5,999,999 therms)	\$ 0.0152	\$ 0.0152
Commercial (Cg-6, Annual Usage 6,000,000+ therms)	\$ 0.0152	\$ 0.0152

1/ Act 141 volumetric distribution rates are included in the above volumetric Distribution Service Charges.

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Northern States Power Company
Monthly Residential Bill Comparison

DL: 00633617

Monthly Use Therms	Gas Costs		Summer		Winter		Firm Sales Service		Authorized Customer Charges	Authorized Distribut'n Charges	Total Monthly Cost	Gas Costs	Total Costs	Monthly Bill Increase (Decrease)	Monthly Percent Increase (Decrease)
	Current Customer Charge	Current Distribut'n Charges	Total Monthly Cost	Gas Costs	Total Costs	Gas Costs	Total Costs								
Rg-1: Residential Firm Sales Service During Summer Months															
5	\$ 10.25	\$ 1.22	\$ 11.47	\$ 1.89	\$ 13.35	\$ 10.25	\$ 1.36	\$ 11.61	\$ 1.89	\$ 13.50	\$ 0.14	\$ 1.05%			
10	\$ 10.25	\$ 2.43	\$ 12.68	\$ 3.78	\$ 16.46	\$ 10.25	\$ 2.71	\$ 12.96	\$ 3.78	\$ 16.74	\$ 0.28	\$ 1.71%			
18 avg.	\$ 10.25	\$ 4.38	\$ 14.63	\$ 6.80	\$ 21.43	\$ 10.25	\$ 4.89	\$ 15.14	\$ 6.80	\$ 21.93	\$ 0.51	\$ 2.36%			
25	\$ 10.25	\$ 6.08	\$ 16.33	\$ 9.44	\$ 25.77	\$ 10.25	\$ 6.79	\$ 17.04	\$ 9.44	\$ 26.48	\$ 0.70	\$ 2.73%			
50	\$ 10.25	\$ 12.17	\$ 22.42	\$ 18.88	\$ 41.30	\$ 10.25	\$ 13.57	\$ 23.82	\$ 18.88	\$ 42.70	\$ 1.41	\$ 3.40%			
75	\$ 10.25	\$ 18.25	\$ 28.50	\$ 28.32	\$ 56.82	\$ 10.25	\$ 20.36	\$ 30.61	\$ 28.32	\$ 58.93	\$ 2.11	\$ 3.71%			
95	\$ 10.25	\$ 23.11	\$ 33.36	\$ 35.87	\$ 69.24	\$ 10.25	\$ 25.78	\$ 36.03	\$ 35.87	\$ 71.91	\$ 2.67	\$ 3.86%			
125	\$ 10.25	\$ 30.41	\$ 40.66	\$ 47.20	\$ 87.86	\$ 10.25	\$ 33.93	\$ 44.18	\$ 47.20	\$ 91.38	\$ 3.51	\$ 4.00%			
150	\$ 10.25	\$ 36.50	\$ 46.75	\$ 56.64	\$ 103.39	\$ 10.25	\$ 40.71	\$ 50.96	\$ 56.64	\$ 107.60	\$ 4.22	\$ 4.08%			
200	\$ 10.25	\$ 48.66	\$ 58.91	\$ 75.52	\$ 134.43	\$ 10.25	\$ 54.28	\$ 64.53	\$ 75.52	\$ 140.05	\$ 5.62	\$ 4.18%			
300	\$ 10.25	\$ 72.99	\$ 83.24	\$ 113.28	\$ 196.52	\$ 10.25	\$ 81.42	\$ 91.67	\$ 113.28	\$ 204.95	\$ 8.43	\$ 4.29%			
Rg-1: Residential Firm Sales Service During Winter Months															
5	\$ 10.25	\$ 1.22	\$ 11.47	\$ 2.46	\$ 13.93	\$ 10.25	\$ 1.36	\$ 11.61	\$ 2.46	\$ 14.07	\$ 0.14	\$ 1.01%			
10	\$ 10.25	\$ 2.43	\$ 12.68	\$ 4.92	\$ 17.60	\$ 10.25	\$ 2.71	\$ 12.96	\$ 4.92	\$ 17.88	\$ 0.28	\$ 1.60%			
18	\$ 10.25	\$ 4.38	\$ 14.63	\$ 8.86	\$ 23.49	\$ 10.25	\$ 4.89	\$ 15.14	\$ 8.86	\$ 23.99	\$ 0.51	\$ 2.15%			
25	\$ 10.25	\$ 6.08	\$ 16.33	\$ 12.30	\$ 28.63	\$ 10.25	\$ 6.79	\$ 17.04	\$ 12.30	\$ 29.34	\$ 0.70	\$ 2.45%			
50	\$ 10.25	\$ 12.17	\$ 22.42	\$ 24.60	\$ 47.02	\$ 10.25	\$ 13.57	\$ 23.82	\$ 24.60	\$ 48.42	\$ 1.41	\$ 2.99%			
75	\$ 10.25	\$ 18.25	\$ 28.50	\$ 36.90	\$ 65.40	\$ 10.25	\$ 20.36	\$ 30.61	\$ 36.90	\$ 67.51	\$ 2.11	\$ 3.22%			
95	\$ 10.25	\$ 23.11	\$ 33.36	\$ 46.74	\$ 80.10	\$ 10.25	\$ 25.78	\$ 36.03	\$ 46.74	\$ 82.77	\$ 2.67	\$ 3.33%			
125 avg.	\$ 10.25	\$ 30.41	\$ 40.66	\$ 61.50	\$ 102.16	\$ 10.25	\$ 33.93	\$ 44.18	\$ 61.50	\$ 105.68	\$ 3.51	\$ 3.44%			
150	\$ 10.25	\$ 36.50	\$ 46.75	\$ 73.80	\$ 120.55	\$ 10.25	\$ 40.71	\$ 50.96	\$ 73.80	\$ 124.76	\$ 4.22	\$ 3.50%			
200	\$ 10.25	\$ 48.66	\$ 58.91	\$ 98.40	\$ 157.31	\$ 10.25	\$ 54.28	\$ 64.53	\$ 98.40	\$ 162.93	\$ 5.62	\$ 3.57%			
300	\$ 10.25	\$ 72.99	\$ 83.24	\$ 147.60	\$ 230.84	\$ 10.25	\$ 81.42	\$ 91.67	\$ 147.60	\$ 239.27	\$ 8.43	\$ 3.65%			
Avg. Annual Residential Billing															
678	\$ 123.00	\$ 164.96	\$ 287.96	\$ 321.22	\$ 609.18	\$ 123.00	\$ 184.01	\$ 307.01	\$ 321.22	\$ 628.23	\$ 19.05	\$ 3.13%			

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Northern States Power Company-Wisconsin
 Docket 4220-UR-118
 Monitored Fuel Costs for 2013

	<u>Total Fuel Rules Cost</u>	<u>System Requirements</u>	<u>Monthly \$/kWh</u>	<u>Cumulative \$/kWh</u>
January	\$ 99,502,442	3,908,277,000	\$ 0.02546	\$ 0.02546
February	86,010,289	3,464,646,000	\$ 0.02483	\$ 0.02516
March	91,692,462	3,605,956,000	\$ 0.02543	\$ 0.02525
April	87,900,287	3,294,527,000	\$ 0.02668	\$ 0.02558
May	92,710,473	3,471,330,000	\$ 0.02671	\$ 0.02580
June	94,736,702	3,849,584,000	\$ 0.02461	\$ 0.02559
July	108,281,873	4,280,612,000	\$ 0.02530	\$ 0.02554
August	106,092,692	4,128,944,000	\$ 0.02569	\$ 0.02556
September	90,802,480	3,555,480,000	\$ 0.02554	\$ 0.02556
October	88,557,671	3,455,883,000	\$ 0.02563	\$ 0.02556
November	90,075,118	3,419,131,000	\$ 0.02634	\$ 0.02563
December	<u>94,217,160</u>	<u>3,810,581,000</u>	<u>\$ 0.02473</u>	\$ 0.02555
Total	<u>\$ 1,130,579,649</u>	<u>44,244,951,000</u>	<u>\$ 0.02555</u>	

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company-Wisconsin for
Authority to Adjust Electric and Natural Gas Rates

4220-UR-118

**DISSENT AND CONCURRENCE
OF COMMISSIONER ERIC CALLISTO**

While I generally concur in the Final Decision, I write separately to explain my dissenting position on two issues.

I also write separately here in concurrence, as I did in the recent rate decisions for Superior Water, Light and Power Company, Madison Gas and Electric Company, and We Energies, to highlight a recurring inequity associated with how Wisconsin law treats certain large energy customer contributions to Focus on Energy, the state's utility-funded energy efficiency and renewable resource program.¹

Revenue Allocation

The electric rate increase in this case is substantial—just a bit over 6 percent.² The allocations proposed by both Northern States Power Company-Wisconsin (NSPW) and Commission staff recognized the magnitude of this increase and were similar, though Commission staff had a wider range from the average. Commission staff had a range of 0.45 percent above the average to 0.95 percent below the average, while NSPW had a range of

¹ See *Final Decisions* in dockets 5820-UR-113 (Commissioner Callisto, concurring), 3270-UR-118 (Commissioner Callisto, concurring and dissenting in part), and 5-UR-106 (Commissioner Callisto, concurring and dissenting in part).

² For those electric customers who also take gas from NSPW, they will also experience an increase in their gas rates, approximately 2.53 percent.

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0.30 percent above the average to 0.20 percent below the average.³ The Wisconsin Industrial Energy Group and the Citizens Utility Board argued for lesser increases to their constituencies.

I proposed an increase that was based upon an approximate 0.25 percent spread from the average, with the residential class receiving the highest increase (6.30 percent) and large commercial and industrial (C&I) class receiving the smallest (5.8 percent). In acknowledgement of the collaborative process the Commission has on these issues, I indicated receptivity to a wider range, and explicitly agreed to Commissioner Nowak's alternate proposal, which had the residential class at 6.4 percent and the large C&I class at the same increase I proposed, 5.8 percent.

By the time the majority reached consensus, it agreed to a 7.2 percent increase for the residential class and only a 5.0 percent increase for the large C&I class.⁴ In an effort to reach a 3-0 vote on this important issue, and to mitigate this large increase over the average to the residential class, I indicated my willingness to cap the residential class at 7.0 percent. This was not acceptable to my colleagues.

Thus the swing from Commissioner Nowak's original proposal, a proposal to which I agreed, is approximately \$1.8 million more to the residential and small C&I classes, all largely to the benefit of the large C&I classes. This is contrary to the reasonable allocations proposed by Commission staff and NSPW, and is too skewed to the benefit of a small number and type of customers.

³ NSPW's allocation assumed an overall increase of 6.7 percent, its filed request, while Commission staff's allocation assumed an increase of 5.65 percent, the result of their audit. The ultimate increase, after late adjustments, is 6.09 percent.

⁴ Commission staff has rerun its models in an effort to reach the majority's desired conclusion. The final allocations lead to a 7.07 percent increase to residential customers, and an unanticipated (at least as reflected by our discussion of record) 7.23 percent increase for small C&I customers. Large C&I is at 5.0 percent. See Appendix B.

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Discounts for C&I Customers

The majority agreed to both the high load factor energy charge credit and voltage discount changes proposed by NSPW. I believe the high load factor change that the Commission agreed to in this case, which provides approximately \$679,000 of benefit to high load factor customers, is appropriate and appropriately incremental. While a reasonable argument is made to change the transmission voltage discounts, it benefits only eight customers, many of whom are also benefitting from the high load factor change. These two changes, together, amount to more than \$900,000, and collectively go too far.

2005 Wisconsin Act 141 Large Energy Customer Contributions

Energy efficiency programs in Wisconsin are governed by 2005 Wisconsin Act 141 (Act 141). Among other things, Act 141 requires the state's utilities to collectively establish and fund a statewide energy efficiency program (Focus on Energy), establishes priorities for the expenditure of those funds, and creates a system of joint oversight, involving the state's utilities, the Commission, and the third party contractor that administers the program. *See generally* Wis. Stat. § 196.374.

Focus on Energy is funded through ratepayer dollars, at an amount equal to 1.2 percent of utility revenues. Wis. Stat. §§ 196.374(3)(b)2. and (5)a. However, each individual ratepayer's contribution to Focus on Energy is not equal to 1.2 percent of their utility bills. While the Commission has determined that the rate classes should generally pay an amount equal to the amount of Focus on Energy incentives distributed to their class, a limited number of large customers pay much less. That disparity and the subsidy that it necessitates is the result of a section of Act 141 which specifically directs that certain "Large Energy

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Customers⁵ (LECs) pay into Focus on Energy the amount they paid towards similar programs in 2005, rather than the amount determined by the Commission. Wis. Stat. § 196.374(5)(b)1. and 2005 Wisconsin Act 141, § 102(8)(c). There are currently 869 LECs in Wisconsin, and specifically 50 LECs in the service territory of NSPW.

Most LECs pay less into Focus on Energy than they otherwise would in the absence of the statutory exemption. Some LECs pay no money into Focus on Energy because they were paying no money to similar programs in 2005. Regardless of how much they pay into the program, all LECs remain eligible to receive the benefits of Focus on Energy, at an undiminished level.

In the NSPW rate case we approve today, LECs are paying about \$1.4 million less than they would if all customers were required to pay proportionally equal amounts.⁶ The amount last year was about the same.⁷ Accounting for the state's six largest utilities, in 2010, the most recent year for which full data is available, LECs paid \$16.2 million less than they would have if the statutory exemption didn't exist.⁸ Because the utilities are required to fund the program at 1.2 percent of revenues, that missing LEC money must come from somewhere else, and indeed it does. Those costs are allocated to other non-residential customers. In this case, all of NSPW's commercial, industrial, and lighting customers that do not meet the LEC threshold are

⁵ A "large energy customer" is a customer that has a demand of at least 1,000 kilowatts of electricity per month or of at least 10,000 decatherms of natural gas per month and, in a month, is billed at least \$60,000 for electric service, natural gas service, or both. Wis. Stat. § 196.374(1)(em).

⁶ This includes both gas and electric large energy customers of the utility.

⁷ On average, the NSPW LECs enjoy a 63 percent discount on the electric rate they pay for Act 141 programs when compared against proportionally equal amounts. The rate for all of the non-residential customers to pay for Act 141 programs would have been approximately \$0.00091/kilowatt-hour (kWh), if not for this legislation. Under the approved rates for 2013, LECs will pay \$0.00034/kWh for Act 141 program contributions, while non-LECs will pay \$0.00128/kWh. Under present rates, the disparity is \$0.00040/kWh vs. \$0.00121/kWh.

⁸ See Wisconsin Legislative Audit Bureau Report 11-13, Evaluation of the Focus on Energy Program, pp. 21-22 (December 2011).

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required to pick up these extra amounts, and essentially subsidize the rate break enjoyed by 50 LECs.

And while, generally, under-collection from LECs is the result of the Act 141 exemption, some LECs in Wisconsin have actually paid more than their proportional share of utility revenues because of the operation of the exemption.⁹ Either way, the result is inequitable.

Furthermore, the LEC exemption creates perverse incentives that may not be readily apparent. If a LEC is close to the cutoff line for retaining this designation (*i.e.*, its monthly energy use and/or bill amounts are dropping close to the statutory thresholds), it may not choose to pursue energy efficiency because the energy savings may have a value less than the likely “full” Focus on Energy payment it would be required to make as a non-LEC. Conversely, those customers falling just short of the LEC threshold may have an incentive to use more energy—even when they don’t need it—if they believe getting the LEC designation (and the resulting lower Focus on Energy payment) will be more valuable than the energy costs incurred to get to the threshold. It cannot be that Act 141 was intended to create economic incentives for inefficient and wasteful energy usage, which is precisely what the LEC exemption promotes.

Freezing the LEC contributions to Focus on Energy at 2005 levels was meant to be temporary.¹⁰ Act 141 required the Commission, by no later than the end of 2008, to provide the Legislature with a recommendation for equitable cost recovery from all rate classes. Wis. Stat. § 196.374(5)(bm)1. While the Commission did submit a proposal recommending a 3-year

⁹ See *id.* at p. 22, Table 7 (illustrating how Wisconsin Power & Light Company’s LECs pay \$616,000 more than they would without Act 141’s exemption).

¹⁰ See *id.* at p. 20 (“Legislative documents describe [the Act 141 LEC exemption] as a ‘first step’ . . .”).

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phase-in to proportionally equal funding for LECs, no legislative action was undertaken.¹¹ As a result, most LECs continue to enjoy proportionally lower contributions to Focus on Energy than other customers in their own rate classes, and in other non-residential customer classes.¹² And those rate breaks for the LECs continue to be subsidized by other commercial and industrial customers.

Not every inequity created by the statutes warrants the Commission's attention. However, where the Legislature empowered the Commission to make a recommendation to resolve an acknowledged disparity in the initial statutory scheme, where that recommendation was not acted on, and where the inequity persists, it is reasonable to make a run at it again. I encourage the Legislature to resolve this issue in the next legislative session.

¹¹ The Commission's 2008 recommendation can be found at PSC REF#: 106987.

¹² LEC contributions to Focus on Energy are subject to annual adjustments equal to the lesser of the percentage increase in the host utility's operating revenues in the preceding year or the increase in the consumer price index. Wis. Stat. § 196.374(5)(bm)2.

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Xcel Energy

Case No.: PU-12-813

Response To: North Dakota Public Service Commission Data Request No. NDPSC-2-015

Requestor: Michael Diller and Sara Cardwell

Date Received: March 8, 2013

Question:

Heuer Question:

- A. For the Charitable Donations information provided in Heuer's Exhibit (AEH-1), Schedule 16 and workpapers, Section VIII Adjustments, Tab A13, pages A13-3 and 4, please provide complete information regarding the recipients of the Electric Corporate Contributions, Focus Area Grants, and Matching Gifts Program. What are the organizations and amounts received by each?
- B. Please explain the Management Reductions amount and what it means.
- C. Does the Company include Xcel Energy Foundation administrative costs in its proposed test-year revenue requirement in ND? If so, what is the amount?
- D. According to page 67 of Heuer's testimony, ND ratepayers are being asked to cover 50% of the costs of corporate charitable contributions that benefit the state of ND in the test year. Please explain why and how each of the following benefits ND customers. Note that in some cases there is a list of organizations that follow the heading "Made up of Following Organizations". And for Big Brothers Big Sisters, are these locations in the state of ND?

Charitable Contributions	
Organization	Amount
National Conference on LGBT Equality	\$ 15.00
University of Minnesota	\$ 735.00
Made up of Following Organizations	\$ 116.00
Diversity & Inclusion Events	\$ 185.00
Made up of Following Organizations	\$ 788.00
Made up of Following Organizations	\$ 462.00
Made up of Following Organizations	\$ 237.00
Journal Communications	?
Made up of Following Organizations	\$ 9,709.00
Big Brothers Big Sisters	\$ 316.00
Made up of Following Organizations	\$ 3,459.00
Women's Innovation Network	\$ 46.00
	<u>\$ 16,068.00</u>

E. If the Company records charitable contributions below the line, why does the Company believe that customers should pay even 50% of these contributions?

Response:

A. Please see Attachment A to this response, Pages 1 and 2, which identifies each grant by Focus Area, City served, Applicant Name, the brief purpose as provided by the applicant, the communities served by the projects and the dollar amount of the 2012 grant.

We have also supplied our 2012 Employee Giving/Company Match data. Please see Attachment A, Page 3. The information is identified by Program, Program Segment, Organization Name, City, number of hours volunteered, employee/retiree contribution and the amount of the Company Match (of which we would be seeking 50% recovery).

B. The Foundation itself is a 501(c)3 and does not operate from a corpus. It receives its funding from Xcel Energy Inc. In the fall of 2012, the Company reviewed 2013 budgets to identify, if any, reductions that could be made to operating expenses across the Xcel Energy Operating Companies. Based on management discussion, it was determined that the Foundation could reduce its 2013 budget by \$400,000 without reducing support to our communities by dipping into a small operating reserve for the \$400,000.

C. Yes, the Company included \$21,904 in Xcel Energy Foundation administration costs in the 2013 test-year revenue requirements for North Dakota. This

amount includes \$21,096 in administrative and general costs and \$808 in payroll taxes. This is the North Dakota electric jurisdiction portion of the Foundation costs, which are allocated across all four Xcel Energy Operating Companies and eight retail jurisdictions.

- D. Charitable contributions demonstrate the Company's commitment to be a good "corporate citizen" and support the communities and organizations in the areas served. These charitable contributions in turn provide assistance to customers that reside in those service areas.

The organizations provided in Part A of the inquiry are a subset of organizations that may receive a charitable contribution from the Company via a business area operating budget. The entire list was provided in the Revenue Analysis Workpapers Volume, Tab VIII. Adjustments, Tab A13. Donations, pages A13-5 through A13-7 of the rate case application.

When operating budgets are developed, it is not always known which specific organizations will solicit contributions from the Company. Historical recipients were listed under the heading "Made up of Following Organizations" to illustrate the types of organizations that may receive contributions during the test year. Each organization that receives a charitable contribution from the Company must be an IRS designated 501(c)3 or governmental entity for charitable purposes, be non-discriminatory and non-profit, and provide services related to education, fine arts and culture, mentoring, or cruelty prevention.

For example, the Big Brothers Big Sisters organization, located in Fargo, matches at-risk youth in the Fargo-Moorhead community with adult volunteers who spend consistent time building a friendship with a child.

- E. The Company records all charitable contributions below the line, and then includes 50% of the contributions amount in its rate case recovery request through an adjustment, as summarized in the Revenue Analysis Workpapers Volume, Tab VIII. Adjustments, Tab A13, Donations, page 13-3. The Company believes it is appropriate to include in rates 50% of the charitable contributions made in the communities in which we provide utility service area, because such contributions are a reasonable, recognized cost of doing business in the states we serve. We believe the communities we serve expect their local businesses to be good corporate citizens, support local charitable organizations and be involved in the community.

A regulated utility is unlike other businesses in that it has a defined service territory and is literally connected to each community it serves – virtually every household, every business. Our contributions through the Foundation are not a

promotional effort, nor are they about increasing sales or building brand recognition. Rather, they are about long-term commitments to our customers and communities, because we want these communities to be stable, economically healthy places to live and work.

As an example, when communities are in crisis – whether caused by economic conditions or a natural disaster (such as the Minot flood) – our Foundation allows us to provide support in the form of disaster relief donations to our communities.

Also, demonstrated care for our communities increases job satisfaction among employees; this can have a broad impact on our ability to deliver safe, quality service to our customers. We match employee contributions to organizations such as The American Red Cross and United Way to help create even more support for our communities. Many of our employees who give and volunteer during our United Way campaign report that the Company match provides an incentive to give or to give more.

Allowing 50% recovery of charitable contributions encourages utilities to act as responsible corporate citizens in their support of the communities in which they serve. Limiting the amount of charitable contribution recovery to 50% also ensures that utilities make contributions in a responsible and reasoned manner. The limit reflects a reasonable sharing of the responsibility that both shareholders and ratepayers have for the well-being of the communities they live in.

Witness: Anne E. Heuer
Preparer: Julie A. Rushton / Mary Pope
Title: Representative, Sponsorship Data / Senior Rate Analyst
Department: Contributions / Revenue Requirements North
Telephone: 651-458-4443 / 612-330-6574
Date: April 10, 2013

Northern States Power Company
Electric Utility - State of North Dakota
Year End 2012 Focus Area Grants

Case No. PU-12-813
NDPSC Data Request 2-015
Attachment A - Page 1 of 3

Focus Area	City	Applicant Name	Brief Purpose	Project Area	Total	
Arts and Culture	Fargo	City of Fargo Park District	The Fargo Park District would like to request \$4000 in funding to continue to expand free and low cost programming for the residents of Fargo-Moorhead. The grant would focus on providing quality arts experiences throughout the community. The outreach would focus on low income neighborhoods and underserved populations. The program reached over 2800 participants, up from the previous year of 2100.	Southeast Cass County, Western Clay County	\$4,000	
		Plains Art Museum	To increase and enhance our capacity to provide affordable programs for area low income youth and families in conjunction with the opening of the museum's Katherine Kilbourne Burgum Center for Creativity. We are requesting \$5000 for a NO WAITING LIST Kid Quest and a one time \$3000 grant to provide families in need class/workshop scholarships until an ongoing scholarship fund can be established.	Fargo-Moorhead-West Fargo metro area, including surrounding communities.	\$8,000	
		Red River Human Services Foundation	To increase and enhance our capacity to provide affordable programs for area low income youth and families in conjunction with the opening of the museum's Katherine Kilbourne Burgum Center for Creativity. We are requesting \$5000 for a NO WAITING LIST Kid Quest and a one time \$3000 grant to provide families in need class/workshop scholarships until an ongoing scholarship fund can be established.	Fargo, ND and surrounding areas; Moorhead, MN and surrounding areas, Wahpeton, ND	\$1,000	
	Fargo Total					\$13,000
	Grand Forks	ArtWise	To increase and enhance our capacity to provide affordable programs for area low income youth and families in conjunction with the opening of the museum's Katherine Kilbourne Burgum Center for Creativity. We are requesting \$5000 for a NO WAITING LIST Kid Quest and a one time \$3000 grant to provide families in need class/workshop scholarships until an ongoing scholarship fund can be established.	Grand Forks, Thompson, Manvel, North Dakota	\$500	
		Fire Hall Theatre	3200 local elementary students will receive 16 hours of art instruction through the ArtWise artist in the classroom program. They will showcase their visual artwork in a free and open to the public venue in March 2013. The 3 day Art Show will be a festival of children's activities, art demonstrations and community performances. 350 volunteers help prepare and run this amazing event for children.	Greater Grand Forks, ND	\$1,000	
		North Dakota Museum of Art	Family Day is a free, fun, and casual event where families enjoy art activities, educational games, and more. Each Family Day, children and adults of all ages create and learn through projects inspired by the current exhibition on display in the Museum galleries. This successful event offers families the chance to spend time together and also learn about the Museum and it's exhibitions.	Grand Forks County, ND and Polk County, MN	\$1,500	
	Grand Forks Total					\$3,000
	Minot	Lillian and Coleman Taube Museum of Art	To provide 4,000 elementary children in the Minot Public Schools with a unique hands on art experience, due to lack of an art elementary program. The students will learn proper art techniques and vocabulary. Provide teachers with follow up activities that connect the project with North Dakota Standards. Students will learn about the artist role in our society from masters, contemporary, to local.	Ward County, McHenry County, Mountrail County, Renville County, McLean County	\$2,300	
		Minot Area Council of the Arts Inc.	The Minot Area Council of the Arts requests funds for the expansion and development of the Arts in the Parks free outdoor summer concert series. Each of the season concerts features a performance and a visual arts display and demonstration. Funding will be used to promote the season and to further develop audience favorites - "At the Hop", and the Sousa Concert.	Minot, Ward County communities within a 75 mile radius of Minot	\$2,300	
Norsk Hestfest Association		Funding maintains and enhances the educational outreach programs of Norsk Hestfest known as Hestfest in the Schools and Scandinavian Youth Camp, both designed to reach children who otherwise might not be exposed to lessons of the heritage prevalent in this region. Programs are offered free of charge to thousands of area youth. Students participate in both the festival and hands on activities.	Cities of Minot, Surrey, Burlington, Glenburn, Nedrose and South Prairie School Districts, Ward and Renville Counties, State of North Dakota	\$5,200		
Minot Total					\$9,800	
Moorhead		Bluestem Center for the Arts in support of Trollwood Performing Arts School requests \$10,000 to support at-risk youth through the Students At Risk program. STAR uses the arts as a tool to support youth facing extraordinary challenges in their lives including economic hardship, physical, social and/or emotional disabilities, cultural disparity, low academic standing, and substance abuse.	Cass County, ND, Clay County, MN	\$5,000		
Moorhead Total					\$5,000	
Arts and Culture Total					\$30,800	
Economic Sustainability	Fargo	Cultural Diversity Resources, Inc	Cultural Diversity Resources will assist 250-300 low income and minority individuals to obtain the necessary education and skills to achieve economic sustainability. The Education and Development Center was established to provide job readiness (i.e. resume creation, job searches, online applications and job placements), computer and financial literacy in Cass County, ND and Clay County, MN.	Cass County, North Dakota and Clay County, Minnesota	\$2,380	
		SouthEastern North Dakota Community Action Agency	This grant will provide energy conservation information, education, and materials to low-income households served by Xcel Energy in the Agency's six county service area.	Cass, Ransom, Richland, Sargent, Steele, and Trail Counties of North Dakota	\$13,200	
	Fargo Total					\$15,580
	Grand Forks	Community Violence Intervention Center, Inc.	Our program assists low-income individuals impacted by domestic violence in Grand Forks and Nelson counties to become economically self-sufficient, providing: (1) transitional housing and support for at least four single-parent families, (2) assistance in securing accessible housing for 170 individuals, and (3) employment and educational counseling for 70 individuals.	Grand Forks County, Nelson County	\$5,000	
		Red River Valley Community Action	Funding provided through this grant will assist 150+ low income households to make daily living more affordable by reducing the impact of energy costs. Our continuing priority is to provide energy conservation education and materials including shrink and seal window kits, energy conservation kits and set back thermostats and have funds available to assist clients who have energy related emergencies.	Cities of Grand Forks, Larimore, Emerado, Reynolds and Thompson, ND	\$12,000	
Grand Forks Total					\$17,000	
Jamestown		Energy Share of North Dakota	To assist elderly, low-income, unemployed and under employed households who are in crisis to meet their utility obligation and prevent shut-offs. Energy Share of North Dakota served 1400 clients in 2011.	The entire state of North Dakota is served by this program.	\$20,000	
Jamestown Total					\$20,000	
Economic Sustainability	Minot	Young Women's Christian Association, Minot, ND	To assist up to 75 women with skills to obtain a job. This includes dressing skills, interview skills, financial skills, housekeeping skills and anything else that would assist them in obtaining a job and permanent housing.	Minot	\$7,500	
Minot Total					\$7,500	
Economic Sustainability Total					\$60,080	

Northern States Power Company
Electric Utility - State of North Dakota
Year End 2012 Focus Area Grants

Case No. PU-12-813
NDPSC Data Request 2-015
Attachment A - Page 2 of 3

Focus Area	City	Applicant Name	Brief Purpose	Project Area	Total	
Education	Bismarck	Bismarck State College Foundation	To assist 5 students with scholarship funds to complete their studies in Power Plant Technology, Process Plant Technology or Electrical Transmission Systems Technology and to provide a competent, diverse, and stable workforce for the energy industry through directly applicable education. Scholarships will enable deserving and qualified students to prepare for careers in the energy industry.	The Online Energy Technology Programs are available nationwide and serve placebound students.	\$2,000	
	Bismarck Total					\$2,000
	Fargo	Fargo Public Schools Development Foundation	To provide grants to classroom teachers, so they can introduce creative techniques to excite students to learn science, math, and technology.	City of Fargo, ND	\$1,000	
		Junior Achievement of the Upper Midwest- North Dakota	Junior Achievement teaches 5,300 Fargo-Moorhead area students in K-5th grade about personal financial responsibility in an ever-changing market. From the basic concepts of needs and wants to the more complex ideas of credit, philanthropy and budgeting, JA programs expose children to a world beyond their neighborhoods and inspire opportunity in every young mind.	Fargo-Moorhead area	\$3,000	
		North Dakota State University Development Foundation	This grant request is for funds to support scholarships for NDSU engineering students.	North Dakota and Minnesota	\$17,000	
		Northern Lights Council, Boy Scouts of America	The purpose of the grant is to provide scholarship assistance for families who are unable to pay the full cost of the Scouting program.	The Northern Lights Council, Boy Scouts of America serves the greater Fargo-Moorhead area and requests \$1,500 for scholarships in this area. We also serve the greater Minot area and request \$500 to help provide scholarship funding in the Minot area. In addition, we serve the entire State of North Dakota, 18 counties in NW Minnesota and 2 counties each in South Dakota and Montana.	\$2,000	
		Prairie Public Broadcasting	To provide underwriting support for educational public television programming for children and adults, focusing on science and math. Prairie Public delivers these unparalleled educational programs to the Science Kid, Cyberchase, NOVA, and Nature to over 600,000 households of every socio-economic status, along with outreach services to schools and dynamic web-based educational resources.	North Dakota: Berthold, Bismarck, Buffalo, Burlington, Buxton, Casselton, Cummings, Des Lacs, Emerado, Fargo, Grand Forks, Grand Forks A.F.B., Hankinson, Hatton, Horace, Larimore, Lone Tree, Mapleton, Mayville, Minot, Orliska, Portland, Reynolds, Thompson,	\$3,520	
	Fargo Total					\$26,520
		Grand Forks Public Schools Junior Achievement Program	Junior Achievement (JA) teaches basic economics, workforce readiness, entrepreneurship & financial literacy. All teachers in 18 elementary schools of the Grand Forks Consortium may request JA for their students. Kits contain materials for 5 lessons, including interdisciplinary activities, covering areas in science, language arts, math, career & character education, as well as social studies.	Grand Forks, Grand Forks Air Force Base, Emerado, Manvel, Larimore, Buxton, Reynolds, Northwood, Thompson - ND	\$3,000	
		University of North Dakota Foundation	Funding will support the University of North Dakota and provide scholarships to students in the areas of math, science, technology, and the environment.	Grand Forks, East Grand Forks, Thompson, Buxton, Reynolds, Hatton, Mayville, Portland, and Emerado.	\$15,000	
	Grand Forks Total					\$18,000
		Minot	Junior Achievement, Inc., Minot	Junior Achievement is designed to teach young people about the importance of the free enterprise system. Those in Minot public and private schools in grades K through 6 are taught about saving money, staying away from credit card debt and how a community works, among many other topics.	Minot, ND	\$2,000
		Minot	Minot State University Development Foundation	To assist 10 or more students by providing scholarship awards.	The world	\$4,000
	Minot Total					\$6,000
		Moorhead	Concordia College	To provide scholarship funding for Concordia College students pursuing degrees in Science and Mathematics. Concordia enrolls 2746 undergraduate students, including 1,845 from Minnesota and 447 from North Dakota.	Minnesota, North Dakota, South Dakota, Wisconsin and Colorado.	\$2,500
		Minnesota State University Moorhead Alumni Foundation	To provide scholarships to students majoring in 1) Operations Management, a 2+2 degree program accepting technically oriented AAS degrees as the first 2 yrs of study; 2) Industrial Education with Industrial Management or Industrial Distribution emphasis. These two degrees are offered by the College of Business and Industry and are accredited by the National Association of Industrial Technology.	Scholarship support will assist in recruiting and retaining students from across the nation. Minnesota and North Dakota employers receive the most benefit from an educated and talented workforce.	\$5,000	
Moorhead Total					\$7,500	
Education Total					\$60,020	
Environment	Fargo	Audubon	This project will identify/prioritize Important Bird Areas in support of statewide wind energy siting and mitigation; involve Xcel/partners in on-the-ground habitat restoration in the Grand Forks County Prairie IBA, and connect underserved youth in our DakotaLark Youth Leadership Program with mentors at Xcel through a Conservation Action Project restoring Tallgrass urban prairie in Fargo-Moorhead.	Fargo, Grand Forks, and West Fargo, with potential inclusion of Casselton, Horace, Moorhead (MN), Thompson, and Reile's Acres. (IBAs - statewide)	\$1,200	
	Fargo Total					\$1,200
		Grand Forks	City of Grand Forks	The City of Grand Forks has partnered with Xcel Energy through the Xcel Energy Foundation in projects and activities that enhance the environment as well as engaging and educating the community. Grand Forks would like to continue its partnership with Xcel Energy by developing a "Natural Playground" in an appropriate location in the City.	Grand Forks, ND, Moorhead, MN	\$10,000
Grand Forks Total					\$10,000	
Environment Total					\$11,200	
Grand Total					\$162,100	

Northern States Power Company
Electric Utility -State of North Dakota
Year End 2012 Focus Area Grants

Case No. PU-12-813
NDPSC Data Request 2-015
Attachment A - Page 3 of 3

Program	Program Segment	Organization Name	City	Sum of Gift Hours	Sum of Emp/Retiree Contribution	Sum of Company Gift or Matched Amount	Sum of Total Gifts	
Matching Gift	Higher Education	Minot State University Development Foundation	Minot		\$ 300.00	\$ 300.00	\$ 600.00	
		North Dakota State University Development Foundation	Fargo		\$ 6,170.00	\$ 6,070.00	\$ 12,240.00	
		University of North Dakota Foundation	Grand Forks		\$ 5,255.83	\$ 5,255.83	\$ 10,511.66	
	Higher Education Total					\$ 11,725.83	\$ 11,625.83	\$ 23,351.66
	Non-Profit		Altru Health Foundation	Grand Forks		\$ 2,100.00	\$ 2,100.00	\$ 4,200.00
			American Heart Association, Lake Park Minnesota	Jamestown		\$ 50.00	\$ 50.00	\$ 100.00
			Boy Scouts of America Council	Fargo		\$ 1,450.00	\$ 1,450.00	\$ 2,900.00
			Dakota Boys and Girls Ranch Foundation	Minot		\$ 1,000.00	\$ 750.00	\$ 1,750.00
			Empire Arts Center	Grand Forks		\$ 160.00	\$ 160.00	\$ 320.00
			Friends of Chimbote	West Fargo		\$ 500.00	\$ 150.00	\$ 650.00
			Great Plains Food Bank	Fargo		\$ 300.00	\$ 300.00	\$ 600.00
			North Dakota Association for the	Grand Forks		\$ 950.00	\$ 950.00	\$ 1,900.00
			Prairie Public Broadcasting Inc	Fargo		\$ 50.00	\$ 50.00	\$ 100.00
			Salvation Army	Fargo		\$ 100.00	\$ 100.00	\$ 200.00
			YMCA of Cass and Clay Counties	Fargo		\$ 750.00	\$ 750.00	\$ 1,500.00
Zone 2A Relief Fund	Minot		\$ 1,000.00	\$ 750.00	\$ 1,750.00			
Non-Profit Total					\$ 8,410.00	\$ 7,560.00	\$ 15,970.00	
Matching Gift Total					\$ 20,135.83	\$ 19,185.83	\$ 39,321.66	
Volunteering	Dollars for Doing	Make-A-Wish Foundation of North Dakota	Fargo	100		\$ 1,000.00	\$ 1,000.00	
	Dollars for Doing Total				100		\$ 1,000.00	\$ 1,000.00
	Team Volunteer		I Help Inc.	Minot	3		\$ 500.00	\$ 500.00
			Lutheran Social Service of North Dakota	Fargo	34		\$ 500.00	\$ 500.00
			Minot Indoor Rodeo, Inc.	Minot	8		\$ 500.00	\$ 500.00
			ND Association for the Disabled	Grand Forks	39		\$ 1,000.00	\$ 1,000.00
			ND Special Olympics Inc.	Grand Forks	30		\$ 500.00	\$ 500.00
			North Dakota State Fair Foundation	Minot	59		\$ 500.00	\$ 500.00
			Sanford Health Foundation North	Fargo	12		\$ 500.00	\$ 500.00
			Team Volunteer Total				185	
Volunteering Total				285	Attachment A	\$ 5,000.00	\$ 5,000.00	
United Way	United Way	Missouri Slope Areawide United Way	Bismarck		\$ 65.00	\$ 65.00	\$ 130.00	
		Souris Valley United Way	Minot		\$ 7,887.92	\$ 6,996.92	\$ 14,884.84	
		United Way of Barnes County	Valley City		\$ 20.00	\$ 10.00	\$ 30.00	
		United Way of Cass-Clay	Fargo		\$ 17,856.20	\$ 17,337.70	\$ 35,193.90	
		United Way of Grand Forks, East Grand Forks and Area	Grand Forks		\$ 7,369.32	\$ 6,051.82	\$ 13,421.14	
		United Way of Richland-Wilkin	Wahpeton		\$ 1,136.04	\$ 1,136.04	\$ 2,272.08	
United Way Total					\$ 34,334.48	\$ 31,597.48	\$ 65,931.96	
United Way Total					\$ 34,334.48	\$ 31,597.48	\$ 65,931.96	
Grand Total				285	\$ 54,470.31	\$ 55,783.31	\$ 110,253.62	

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 Public Document

Xcel Energy

Case No.: PU-12-813
Response To: North Dakota Public Service Commission Data Request No. NDPSC-6-016
Requestor: Snavelly King Majoros & Associates
Date Received: April 2, 2013

Question:

Please refer to page 1, lines 22-26 of the Direct Testimony of Stephen R. Foss. Please (1) describe and explain in detail NSPM's system planning and capital budgeting processes for its Distribution, Transmission, and Energy Supply business units, (2) provide documentation of NSPM's planning and budgeting procedures and guidelines, and (3) provide a map or maps of NSPM's system showing the location of distribution and transmission planning load centers.

Response:

Please refer to Company witness Anne Heuer's Direct testimony pages 5 through 10 for discussion related to the Company's O&M and capital budget development process. In addition, Corporate Budget Instructions for budgeting operating and maintenance (O&M) and capital expenses for Xcel Energy are provided as Attachment A in the Company's response to information request NDPSC-1-019.

- (1) Describe and explain in detail NSPM's system planning and capital budgeting processes for its Distribution, Transmission, and Energy Supply business units,

Distribution:

Distribution Operations has a well-defined process for identifying, ranking and budgeting electric line and distribution substation projects. The key steps necessary to ensure the preparation of a comprehensive capital budget are summarized as follows. Engineering and operations personnel identify potential problems or risks on the system and solutions. "Risks" are potential detrimental impacts or threats to safety, the quality/reliability of our service, environmental quality, our ability to meet our legal obligations, or our financial standing. These identified risks drive the need for

initiatives to address the risks. These initiatives, in turn, often require capital expenditures. In the capital budgeting process, potential “solutions” or “mitigations” are essentially “projects;” *i.e.*, work to be performed that will mitigate a certain risk, or set of risks. These projects are the focus of the capital budget process. Projects are screened and evaluated against each other based on their costs, how effectively they address certain risks, and how critical the risks are. The evaluation or scoring of risks, mitigations and solutions is only an intermediate step. The ultimate goal is to determine which projects will be funded and at what levels.

Each risk and mitigation is reviewed for accuracy, completeness and reasonableness. As each risk and solution is considered, it is scored based on certain criteria, likelihood of occurring, and the consequences of not addressing it. All potential mitigations are ranked or prioritized. After the ranking is completed, business leadership reviews the list, the level of risk associated with the various projects, as well as capital levels based on financial criteria. Projects chosen to be funded are assigned a capital project number based on the type of work. These capital projects are classified as either “specific” or “routine.” Capital project numbers for large pools of small projects (e.g., underground extensions, overhead services, etc.) are automatically tied to closing patterns based on the attributes of the work. For larger individual projects, in-service dates are assigned. Project managers then forecast expenditures based on the particulars of a project and its projected in-service date. All capital projects that are included are reviewed and approved, both at the business area level and at the corporate level.

Transmission:

The Capital budget for Transmission begins with the Planning Group identifying new projects to be added for consideration to the new five year budget. The projects are entered into the Tamcasting system along with the description, need and benefits of the project. At minimum, a scoping level estimate is required to be done for the proposed budget and the project must have gone through the first level of constructability meetings to justify the need for the project. All projects in the current approved budget are “refreshed” by the engineering and planning groups who provide the best available data for the project for this budget cycle. All data is compiled and reviewed in detail by project by Project Management and Portfolio Delivery to further vet the need, amount and the timing of the proposed projects. Existing projects that have changed significantly in scope or forecast may require further scrutiny during a “challenge session” to take a deeper look at the details of the project and its associated forecast. A second layer of management review is done at the Vice President of Transmission level before the budget is submitted for corporate review and approval. Projects meeting the criteria for Investment Review Committee or Board approval are presented as part of the budget process.

Energy Supply:

There are multiple factors driving Energy Supply capital requirements. The most significant factors include safety, generation load growth, environmental regulations, and unit operational condition.

Each year, projects submitted by the plants are evaluated and ranked according to their financial and operational merits, such as impact on safety, availability and environmental compliance. Each capital project is reviewed and prioritized using multiple criteria, including safety, financial merit (such as Present Value of Revenue Requirements) and operational factors (such as impact on Unplanned Outage Rate, equipment condition, environmental compliance and/or regulation). Projects that are evaluated include those that may be completed in a single year as well as those that will require multiple years to execute and complete.

A ranked list of projects is evaluated against the available capital budget for the next year, as well as the planned unit outage schedule for the next several years and known regulatory factors, such as new environmental regulations. This process allows the Company to develop a capital plan that covers a five-year period, thus allowing the Company to utilize the five-year capital expenditures and estimated in-service dates in the capital budget process. As this list of projects is finalized in each jurisdiction (NSPM, NSPW, PsCo and SPS), it is reviewed and approved by Plant Directors, General Managers, Vice Presidents and Xcel Energy's Financial Council.

Capital budgets are established at least 12-18 months prior to their execution. Part of the project development process includes the identification of key schedule dates and budgetary milestones. Once a capital project has been approved for execution, it is assigned to a Project Manager ("PM"). The PM is responsible for working with the plant to review and more fully develop the schedule and monthly cash flow requirements for the assigned project. The PM will typically contact vendors and contractors to firm up cost and schedule data and begin engineering and purchasing activities. As the PM works through the project details, they develop detailed cash flows and schedules for the project. Those schedules and cash flows are entered into corporate accounting. Monthly review activities include verifying that planned activities have been undertaken as scheduled. If cost or schedule variances arise, they are discussed at the monthly project meetings along with corrective actions. As the project is completed and placed in-service, the PM follows close-out activities to update plant drawings and procedures.

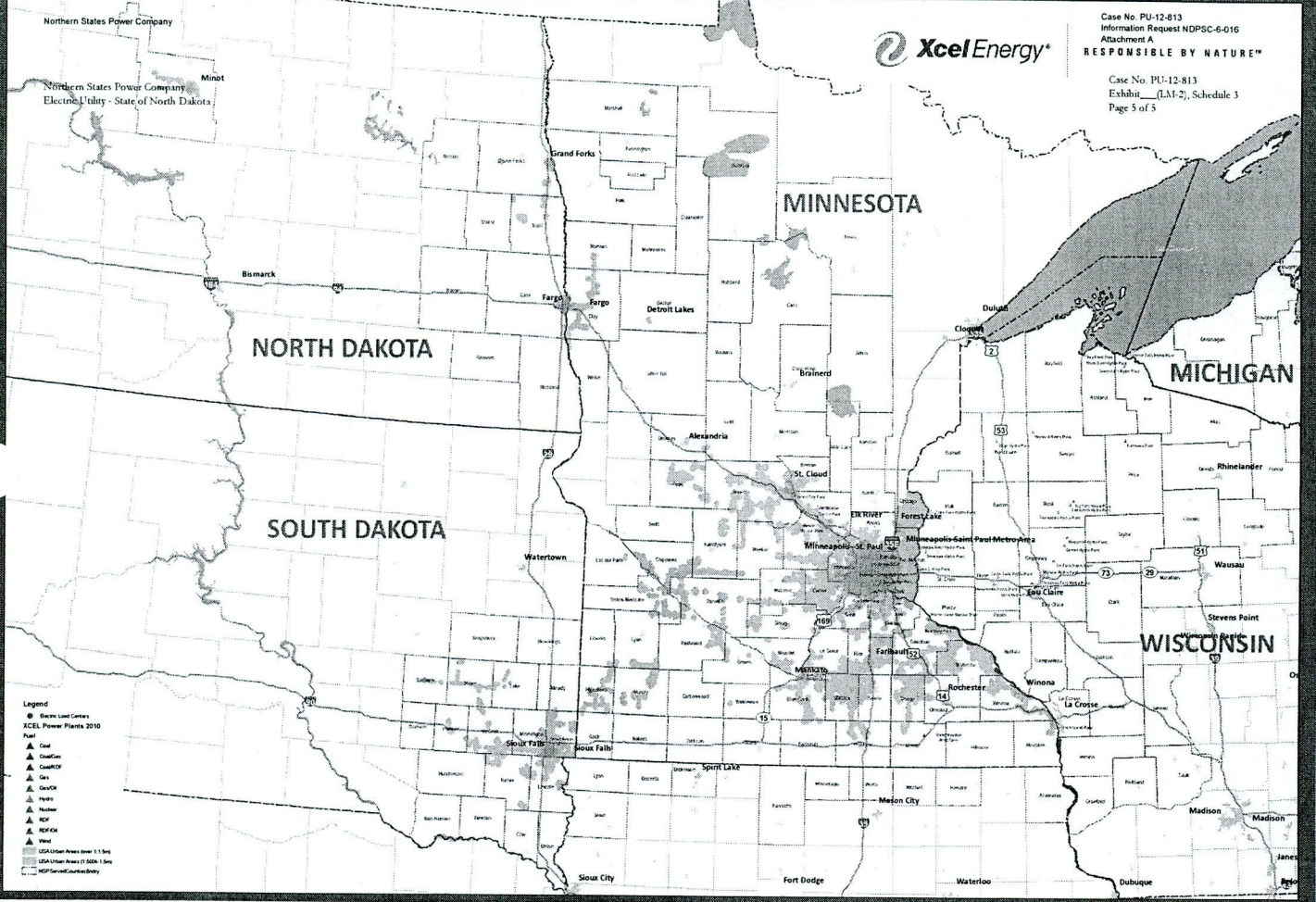
(2) Provide documentation of NSPM's planning and budgeting procedures and guidelines,

Please see Attachment A to the Company's response to information request NDPSC-1-019. The budget instructions include the schedule and describe the guiding principles used to establish the corporate O&M and capital budgets.

(3) Please see Attachment A for a map of NSPM load centers.

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Date: May 3, 2013

XCEL ENERGY IN NSP LOAD AREAS



Case No. PU-12-813
Information Request NDPS-6-016
Attachment A
RESPONSIBLE BY NATURE™
Case No. PU-12-813
Exhibit (LM-2), Schedule 3
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- Legend**
- Black Load Centers
 - XCEL Power Plants 2010
 - Coal
 - Gas
 - Nuclear
 - Wind
 - Hydro
 - Geothermal
 - USA Urban Areas (over 1.1 km)
 - USA Urban Areas (1.000 - 1.000 km)
 - NSP Service Territory