

PUBLIC DOCUMENT
TRADE SECRET INFORMATION EXCISED

Supplemental Testimony and Schedules
David H. Sederquist

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

Settlement Terms and Implementation

January 15, 2014

Application of Northern States Power Company,
a Minnesota Corporation, for Authority to Increase Rates
for Electric Service in North Dakota

Case No. PU-12-813

Northern States Power Company
Advanced Determination of Prudence
Courtenay Wind Project Application

Case No. PU-13-706

Northern States Power Company
Advance Determination of Prudence
Odell Wind Project Application

Case No. PU-13-707

Northern States Power Company
Advance Determination of Prudence
Pleasant Valley Wind Project Application

Case No. PU-13-708

Northern State Power Company
Advance Determination of Prudence
Border Winds Project Application

Case No. PU-13-742

Northern State Power Company
150 MW Border Winds Project
Rolette County Public Convenience and Necessity

Case No. PU-13-743

Northern States Power Company
Advance Determination of Prudence
NG Generator Application

Case No. PU-13-194

Northern States Power Company
Red River Valley NG Units 1 & 2
Hankinson, ND Public Convenience and Necessity

Case No. PU-13-195

80 PU-13-707 Filed 01/23/2014 Pages: 48
Exhibit NSP-41

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1 **I. INTRODUCTION**

2

3 Q. PLEASE STATE YOUR NAME AND OCCUPATION.

4 A. My name is David Sederquist. I am a Senior Regulatory Consultant with
5 Northern States Power Company (Xcel Energy, NSP, or the Company) in
6 Fargo, North Dakota. I am responsible for NSP's regulatory affairs in the
7 State of North Dakota. I have held positions relating to NSP's North
8 Dakota operations for 22 years. My resume is attached as Exhibit___(DHS-
9 1), Schedule 1.

10

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

12 A. No. However, I presented information about the Settlement at the
13 Commission's January 7, 2014 Informal Hearing.

14

15 Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

16 A. I provide support for the Settlement reached between the Company and
17 Advocacy Staff of the North Dakota Public Service Commission. I will
18 describe the major features of the Settlement and explain how they work
19 together to support the overall agreement. I will also discuss the issues in
20 this case and other dockets before the Commission that we were able to
21 resolve in this Settlement. Finally, I will describe how the Settlement
22 provides value for our customers in North Dakota and addresses some of
23 the Commission's most important policy concerns.

24

25 Q. DO YOU HAVE ANY PRELIMINARY COMMENTS YOU WANT TO MAKE ABOUT
26 THE SETTLEMENT?

1 A. Yes. This is a historic Settlement that resolves a number of significant issues
2 in this rate case and several other dockets before the Commission. It
3 contains a number of unprecedented reforms and initiatives that will
4 influence the way regulation works in North Dakota for years to come. The
5 Settlement is the product of collaborative problem-solving by Commission
6 and Company representatives who share a common interest in the future of
7 North Dakota.

8
9 I'd like to acknowledge the hard work and constructive approach
10 demonstrated by Advocacy Staff throughout the Settlement process. The
11 Settlement resolves issues from eight separate dockets and contains 32 pages
12 of substantive terms. Getting to a comprehensive resolution was made more
13 challenging by the complexity of the issues and the various areas of
14 disagreement at the outset. While neither party was able to get everything
15 hoped for, this comprehensive Settlement was achieved overall in large part
16 because of the collaborative and innovative efforts of Advocacy Staff.

17 18 **II. OVERVIEW**

19
20 Q. CAN YOU PROVIDE AN OVERVIEW OF THE SETTLEMENT?

21 A. Overall, the Settlement proactively addresses a number of key concerns that
22 have been expressed by the Commission. Those concerns include:

- 23 • Minimizing customer rate impacts: The Settlement provides additional
24 rate certainty for our customers through 2016 with a series of moderate
25 and fixed base rate increases that, combined with the two proposed
26 riders, provides essentially the "bare minimum" revenues necessary to
27 meet our current investment needs while shifting some of the financial

1 risk of unforeseen costs during the rate plan period (through 2016) to the
2 Company. The annualized increase in 2013 of just over \$9 million
3 compares to our rebuttal position of \$14.8 million, and will produce an
4 interim rate refund of at least \$4 million.

- 5 • Addressing divergent state energy policies: This Settlement recognizes
6 that the energy policies in some other states in which we do business are
7 increasingly different from the energy priorities of North Dakota. We
8 continue to believe that operating a large multi-state system provides
9 value to all of our customers despite some of these policy differences.
10 Nevertheless, the Settlement provides a path to likely lower North
11 Dakota rates in the future by insulating North Dakota from the cost
12 impacts of differing state energy policies. The near-term reduction in
13 rates is contemplated to be roughly \$4 million to \$7 million per year.
14 This will be accomplished through the development of a customized
15 resource portfolio for North Dakota (referred to as a “restack” of our
16 portfolio) that will be used to set rates for our North Dakota customers.
- 17 • Investing in North Dakota generation: In the Settlement, the Company
18 makes a firm commitment to construct a natural gas generating plant in
19 North Dakota, subject to need and prudent resource planning principles.
- 20 • Reviewing Demand Allocation: This Settlement provides the
21 Commission with a process to develop a comprehensive record to
22 support consideration of various alternative jurisdictional demand
23 allocation methods. With this information, the Commission would be in
24 a position to better determine whether the long-standing 12-month
25 coincident peak methodology should remain in place or be changed in
26 our next rate proceeding. We recognize this issue is very important to
27 the Commission. Our goal in Settlement was to identify a path to ensure

1 The Rate Plan is shaped primarily by the Company's current capital
2 expenditure program, which includes very substantial investments to extend
3 the lives and increase the capacity of our nuclear fleet, maintain our coal and
4 natural gas generation fleets, significantly invest in our transmission system,
5 and refresh and automate our distribution system. The investments made
6 prior to and during the plan term alone not only create a revenue deficiency
7 in the 2013 test year, but are forecasted to drive revenue shortfalls in 2014
8 and beyond. For context, these investments will add an estimated \$20
9 million to \$25 million in annual revenue requirements.

10
11 The multi-year Rate Plan in the Settlement includes the following elements:

- 12 • A four-year term from 2013 through 2016;
- 13 • A 5.0 percent base rate increase in each of 2013, 2014 and 2015;
- 14 • A rate freeze in 2016;
- 15 • An interim rate refund of at least \$4.0 million in 2014;
- 16 • A 50/50 sharing between customers and the Company if weather-normal
17 earnings exceed the authorized level during any year of the plan, while
18 the Company bears the risk of any earnings shortfall;
- 19 • A reasonable range of authorized returns on equity (ROE) over the four-
20 year term, including a historically low ROE of 9.75 percent in 2013; and
- 21 • Fuel Cost Rider (FCR) reform, and implementation of a Transmission
22 Cost Rider (TCR) tariff and a North Dakota Renewable Energy Rider
23 (RER) tariff.

24
25 Q. PLEASE DESCRIBE THE BASE RATE INCREASE ALLOWED IN THE SETTLEMENT.

26 A. The Rate Plan agreed to by the Parties in this Settlement allows the
27 Company to implement a series of fixed 5.0 percent annual electric base rate

1 increases in 2013, 2014, and 2015 in lieu of filing additional and separate rate
2 cases to address the forecasted deficiencies during the plan term. The Rate
3 Plan then imposes a rate moratorium for the final year (2016) even though
4 our projected capital expenditures remain substantial. The Settlement also
5 establishes separate rider tariffs to enable recovery of future transmission
6 and North Dakota-based renewable energy generation investments.

7
8 As a condition of the Rate Plan, the Company would be precluded from
9 filing another general rate application that would increase base rates by any
10 additional amount before January 1, 2017. Again, the fixed nature of the
11 revenue increases and the base rate freeze shifts the risks of unforeseen costs
12 to the Company. The Rate Plan was designed based on a consideration of
13 the Company's longer-range financial forecasts and agreed to by Staff and
14 the Company out of a common desire to lessen bill impacts through
15 moderate and gradual rate provisions.

16
17 The proposed increases to base revenues are shown in Table 1 below:

18
19 **Table 1**

Plan Year	Increase	Estimated Revenue Increase
2013	5.0 %	\$7,950,000*
2014	5.0 %	\$9,570,000
2015	5.0 %	\$10,300,000
2016	0.0 %	\$0

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22
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28 * Reflects Feb. 16, 2013 effective date of increase

1 Q. HOW ARE THE BASE RATE INCREASES CALCULATED UNDER THE SETTLEMENT?

2 A. The Company's forecast of the base rate and FCR revenues for each year
3 will be used as the baseline revenue for applying the annual 5.0 percent
4 increase. The baseline revenue forecast will not include any anticipated TCR
5 or RER Rider revenues forecasted for the upcoming year. The annual
6 increase amount is determined by multiplying the baseline revenue forecast
7 by 5.0 percent. The result is the allowable base rate increase for the given
8 year.

9
10 For example, projected 2013 test year retail revenues as filed were
11 \$182,724,000 (including both base and FCR revenues). Multiplying this
12 amount by 5.0 percent yields an annualized increase of \$9,136,000.
13 However, since interim rates went into effect on February 16, 2013, only
14 about 87 percent of the annual amount, or \$7,950,000, will be recoverable in
15 the 2013 calendar year. In 2014, projected revenues will include the
16 annualized 2013 increase of \$9,136,000, and likely reflect some sales growth.
17 This 2014 baseline revenue forecast would again be multiplied by 5.0 percent
18 to yield the applicable increase in 2014. For purposes of the Settlement, we
19 estimated an increase of \$9,570,000 as shown in Table 1 above and
20 Attachment F to the Settlement. The same process would be followed to
21 determine the 2015 increase.

22
23 Q. HOW WILL THE PROPOSED INCREASES AFFECT EACH CUSTOMER CLASS?

24 The 2013 increase will be apportioned to customer classes based
25 proportionately on the original class apportionment filed in Case No. PU-12-
26 813 and shown in Attachment F to the Settlement. For residential
27 customers, it is expected that the 2013 increase will be fully reflected in the

1 increase to the fixed monthly customer charge (there may actually be a slight
2 decrease in the residential energy charge). For 2014 and 2015, the
3 Settlement calls for the Company to implement an across-the-board 5.0
4 percent increase to all customer classes with no further changes to the fixed
5 monthly customer charges for any class.

6
7 Q. WHY IS THE PROPOSED MULTI-YEAR RATE PLAN BENEFICIAL FOR XCEL
8 ENERGY'S NORTH DAKOTA CUSTOMERS?

9 A. The series of smaller, fixed, and level increases during the first three years,
10 coupled with the base rate freeze in 2016, helps to moderate the impact on
11 customers' bills of the needed investments the Company has made and will
12 continue to make during the plan term. In addition, because the moderate
13 increases are fixed, they offer customers better rate predictability over the
14 term of the Settlement compared to the alternative; multiple, back-to-back
15 rate cases would more than likely result in varying levels of rate relief and
16 effective at different times of the year. The outcomes of those cases cannot
17 be foreseen with any certainty.

18
19 It should also be noted that, while not specific to the Rate Plan provisions,
20 the terms around the resource portfolio "restack" for North Dakota are
21 expected to lower North Dakota rates in the near term by at least several
22 million dollars beginning as early as 2016. I will discuss the Restack later in
23 my testimony.

24
25 Q. WILL THE SETTLEMENT RATE PLAN GENERATE ANY INTERIM RATE
26 REFUNDS?

1 Yes, it will. The 5.0 percent rate increase agreed to for 2013 is just over half
2 of our original 9.25 percent request and only about 60 percent of the 8.1
3 percent interim rate increase. It will result in an interim refund for
4 customers in 2014 that is expected to exceed \$4.0 million (or over \$20 per
5 residential customer). The Company will calculate the refund consistent
6 with past practice and will also include the St. Paul cogeneration refund
7 requested by Staff.

8
9 It should be noted that the 5.0 percent increase in 2014 will have the effect
10 of bringing rates back up to a level only a little higher than the interim levels
11 currently in effect. So, customers will not experience a significant change in
12 base rates until at least 2015.

13
14 Q. COULD THERE BE REFUNDS BEYOND 2014?

15 We do not expect that refunds will occur after 2014. However, if earnings
16 (normalized for weather) during any plan year are higher than anticipated
17 and exceed the authorized level for the year, the revenues contributing to the
18 over-earnings would be shared 50/50 with customers through a sharing
19 mechanism refund. It should also be noted that the earnings sharing
20 framework is asymmetrical; while customers share in any over earnings, if
21 earnings are lower than authorized, there is no ability for the Company to
22 surcharge customers for any of the shortfall.

23
24 Q. ARE THERE ANY OTHER RATE BENEFITS FOR NORTH DAKOTA CUSTOMERS?

25 A. Yes. The multi-year approach of the Settlement eliminates the additional
26 costs, time, and resource commitments of filing and hearing each rate case.

1 These costs can easily exceed \$0.5 million per case, and those costs are
2 recoverable in rates as well.

3

4 Q. YOU MENTION THAT THE RATE PLAN IS SET TO PROVIDE THE MINIMUM OF
5 NECESSARY REVENUES. WHAT DO YOU MEAN BY THIS?

6 A. The rate plan is intended to balance our customers' need to have reliable and
7 competitively-priced electricity with the Company's objective to recover its
8 costs of service and have an opportunity to earn a reasonable rate of return.

9

10 Table 2 shows how our projected earnings compare to the authorized ROEs
11 agreed to in the Settlement. Except for 2016, the forecasted ROEs indicate
12 that the agreed-to pattern of revenue increases in the Rate Plan closely
13 matches our cost structure.

14

15 **Table 2**

16

Year	2013	2014	2015	2016
Authorized ROE	9.75%	10.0%	10.0%	10.25%
Forecasted ROE*	9.86%	9.68%	10.04%	8.40%

17
18
19

20 * Assumes recovery of future TCR and RCR rider costs not yet approved by the
21 Commission. 2016 reflects disallowance of certain resource costs in ND that will
22 result if parties fail to negotiate and file a restack agreement (the earnings impact is yet
23 to be determined if the restack agreement is filed).

24

25 As Table 2 indicates, in two of the years of the rate plan the Company is
26 already projected to earn less than its authorized ROE. In the other two
27 years, the Company's earnings are just meeting the authorized ROE. Since
28 these projections are based on long-term forecasts, our acceptance of the

1 fixed rate increases now places the risk on the Company to manage to these
2 revenue amounts, since there is no mechanism for sharing under-earnings.

3
4 **B. Cost Drivers**

5 Q. HOW DOES THE RATE PLAN ADDRESS THE COMPANY'S NEED FOR COST
6 RECOVERY?

7 A. The Rate Plan provides level and predictable base rate increases for three
8 years that, when combined with projected revenues from the TCR and RER
9 tariffs, match up closely with our forecasted O&M and investment-related
10 costs.

11
12 Q. HAS THE COMPANY'S INVESTMENT CYCLE CONTRIBUTED TO THE FILING OF
13 RECENT RATE CASES IN NORTH DAKOTA?

14 A. Yes. Our significant investments, along with general increases in the costs of
15 running our business, have been driving recent cases in *all* of our state
16 jurisdictions. Our initial North Dakota rate case within this investment cycle
17 was filed in late 2007 (with a 2008 test year). This ended a fifteen year
18 period during which we had not filed a North Dakota rate case. Three years
19 later, another case was filed in late 2010 (with a 2011 test year and a small
20 2012 "step" increase). Two years after that case, in December 2012, we filed
21 the present request with its 2013 test year.

22
23 Q. WHAT HAS BEEN DRIVING THE COMPANY'S LARGE CAPITAL EXPENDITURE
24 OUTLAYS IN RECENT YEARS?

25 A. Starting in around 2006, the Company began making significant investments
26 to ensure that we have the necessary generation and electric grid facilities to
27 provide safe and reliable service to our customers now and in the future.

1 These investments were made to refurbish and repower some of our existing
2 generation fleet (including the King, High Bridge, and Riverside plants),
3 refresh our aging grid infrastructure, and build new facilities (such as the
4 CapX2020 transmission project) so that we are well positioned to meet our
5 customers' future needs.

6
7 Q. PLEASE ELABORATE FURTHER ON THE COMPANY'S CAPITAL INVESTMENTS.

8 A. Several years ago we began planning to extend the life of our nuclear fleet
9 since their operating licenses were set to expire in the 2012-2014 timeframe.
10 This work culminated in the 20-year extension of the licenses for both our
11 Monticello and Prairie Island nuclear power plants as well as a 72 MW
12 capacity uprate of the Monticello plant. These investments, along with
13 replacement of a steam generator at our Prairie Island Plant, implementation
14 of new Nuclear Regulatory Commission (NRC) requirements to meet cyber-
15 security and Fukushima-driven requirements, and refueling and fuel storage
16 investments, are significant drivers of our revenue needs during the Rate
17 Plan. Our workhorse baseload coal fleet is also in need of significant
18 refreshing to comply with new environmental requirements as well as replace
19 aging infrastructure. These investments include replacement of major
20 components at our Sherco and King plants as well as installation of new
21 emissions controls.

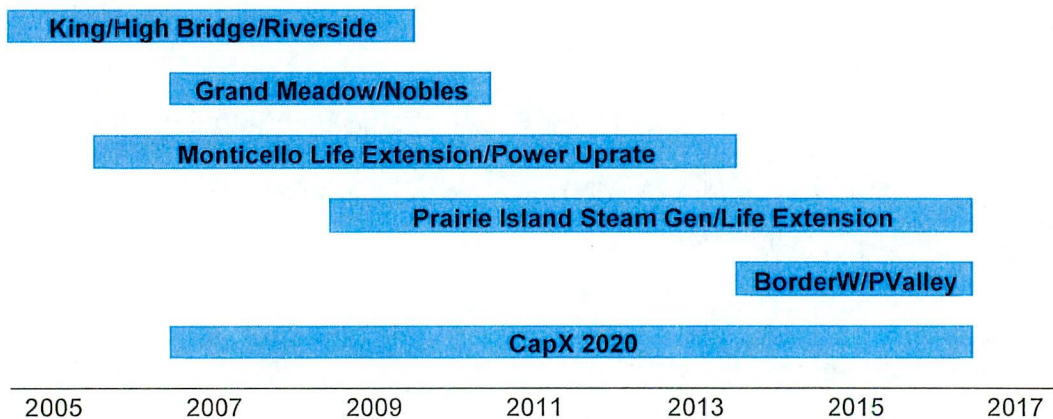
22
23 In addition, as the MISO transmission system was developing we began to
24 plan to invest in significant transmission additions on a scale not seen since
25 the 1970s. This effort ultimately led to our CapX2020 Initiative which
26 allowed us to share the costs of these needed investments among several
27 utility partners and to consolidate planning to provide comprehensive

1 regional solutions. These transmission investments are likely to continue
2 with the Big Stone – Brookings project (which will ultimately be extended to
3 Ellendale through a separate project undertaken by Otter Tail Power
4 Company and Montana-Dakota Utilities) and other, smaller transmission
5 expansions.

6
7 Finally we face the need to refresh and upgrade our distribution system, an
8 effort which has been supported in the past by the Commission.

9
10 Figure 1 below is a graphical representation of some of the significant
11 projects the Company has undertaken in recent years to refresh its system
12 and prepare for the future energy needs of our customers.

13
14 **Figure 1**



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24 Q. WHAT ARE SOME OF THE MAIN CAPITAL DRIVERS OF THE COMPANY'S
25 INVESTMENT CYCLE DURING THE SETTLEMENT RATE PLAN TERM?

1 A. As I mentioned, the Company will be making significant investments in its
2 nuclear and non-nuclear generation fleet as well as investments in
3 transmission during the rate plan term in the Settlement.

4

5 For our nuclear fleet, we are investing:

- 6 • \$809 million in investments at our Prairie Island nuclear power plant
7 including:
- 8 ○ Life extension projects to implement our license extension;
 - 9 ○ Installation of a new steam generator (for which the Commission has
10 granted an ADP in Case No. PU-10-127); and
 - 11 ○ Construction of additional spent fuel storage casks.
- 12 • \$581 million at our Monticello nuclear power plant including:
- 13 ○ Continuation of the power uprate project;
 - 14 ○ Modifications to the plant to comply with new Nuclear Regulatory
15 Commission (NRC) requirements developed in response to the
16 Fukushima Daiichi events;
 - 17 ○ Implementation of NRC cyber security requirements;
 - 18 ○ Construction of additional dry fuel storage facilities; and
 - 19 ○ New fire model investments.

20

21 We are also making \$1.0 billion in investments in our non-nuclear generating
22 fleet including \$667 million in owned wind facilities. Other investments
23 include:

- 24 • \$168 million in investments at our Sherco plant for:
- 25 ○ Installation of emissions control equipment at Sherco Units 1 and 2;
 - 26 ○ Replacement of the worn boiler sections of Sherco Unit 1;

- 1 ○ Replacement of the aging high-pressure feed water pumps, main station
- 2 auxiliary transfers and other refurbishments at Sherco Unit 2; and
- 3 ○ Replacement of the cooling water tower at Sherco Unit 3.
- 4 ● \$72 million in investments at our King plant for:
- 5 ○ Replacement of aging boiler sections including the steam reheater and
- 6 water wall; and
- 7 ○ New coal and turbines controls to replace the outdated controls
- 8 installed almost 30 years ago.
- 9 ● \$58 million in investments at our natural gas generation plants.

10

11 With respect to transmission, we are investing over \$1.4 billion for projects

12 including:

- 13 ● The CapX2020 Group 1 Projects;
- 14 ● Expansion of the Cass County Substation;
- 15 ● Replacement of transformers at the Red River Substation;
- 16 ● Investments at our Sheyenne and Prairie Substation to comply with new
- 17 NERC requirements;
- 18 ● Initial development costs of the Big Stone – Brookings Project; and
- 19 ● Installation of fault recorders and other upgrades at the Maple River and
- 20 Red River Substations.

21

22 Q. IS THE COMPANY SEEING O&M INCREASES AS WELL?

23 A. Yes. Many of these increases are related to our investments. For example,

24 as we invest in our plants we increase their value, which in turn generates

25 higher property taxes. Installing emissions control facilities on our plants

26 puts upward pressure on the costs of our emissions reduction chemicals.

27

1 Q. WHAT ARE SOME OF THE MAIN O&M DRIVERS DURING THE RATE PLAN?

2 A. Some of the main drivers of our O&M increases include:

- 3 • The return of Sherco 3 to production after the significant equipment
4 failure in 2011;
- 5 • Increased property taxes related to our generation and transmission
6 investments;
- 7 • Increased emissions-reduction chemical costs due to the installation of
8 new control technologies at our plants;
- 9 • Increased nuclear O&M costs due to overhauls and new plant additions;
- 10 • New IT expenditures to ensure we can continue to provide safe and
11 reliable service; and
- 12 • Increased costs related to compliance with increased NERC reliability
13 standards.

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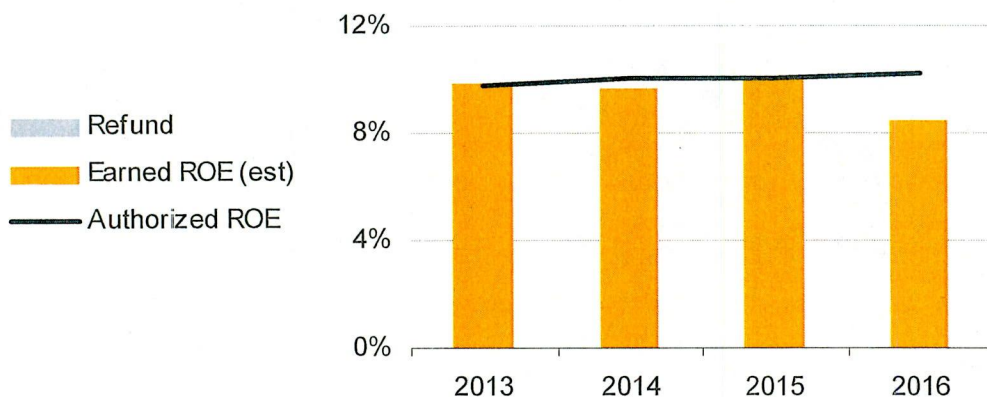
15 Q. HOW DOES THE RATE PLAN ADDRESS THESE PROJECTED INCREASES?

16 A. As mentioned previously, the rate plan provides the Company with an
17 opportunity to barely meet the authorized ROEs during the plan term. But
18 by locking in the fixed base rate increases in the Rate Plan, the risk of
19 unforeseen cost increases related to capital and O&M expenditures is shifted
20 from our customers to the Company, because the Settlement precludes
21 further base rate increases other than by the fixed percent increases allowed
22 by the Rate Plan. While this creates management challenges for the
23 Company, it provides real benefits to our customers. In addition, customers
24 will share in any earnings above authorized levels, which adds another layer
25 of customer protection.

1 Q. DID THE COMPANY ANALYZE SPREADING EVEN SMALLER RATE INCREASES
2 OVER THE FOUR YEAR PERIOD OF THE RATE PLAN TO MITIGATE CUSTOMER
3 IMPACTS?

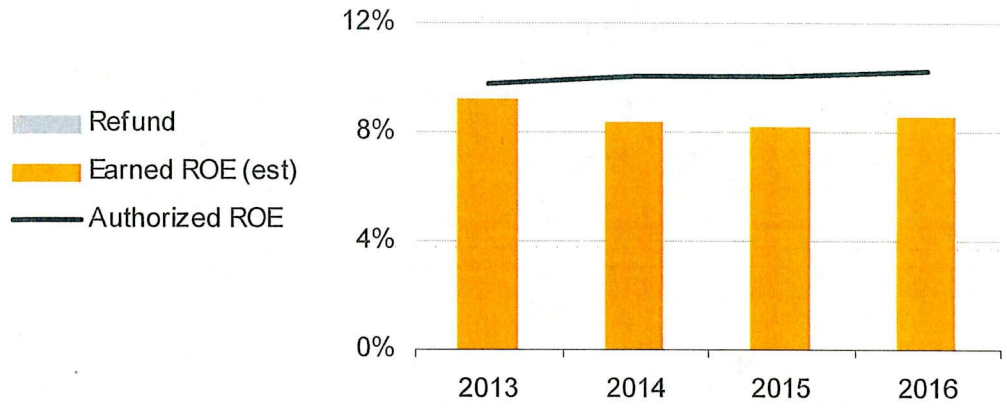
4 A. We have performed this analysis and as Figure 2, below shows, this results in
5 a poor matching of revenues with projected annual costs. This approach
6 further depresses earnings each year to levels below the authorized ROEs.
7 The increase mitigates some of the earnings shortfall in 2016, but not
8 enough to approach the authorized ROE. We believe this outcome is
9 insufficient to offset the shift-of-cost risk to the Company that occurs
10 through a multi-year plan with fixed increases. See Figure 3 below for the
11 forecasted ROEs compared to the authorized ROEs under the Settlement
12 Rate Plan and then using the approach of spreading smaller increases across
13 all four plan years.

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15 **Figure 2**
16 **(5%-5%-5%-0% Plan)**



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Figure 3
(3.75% all four years)

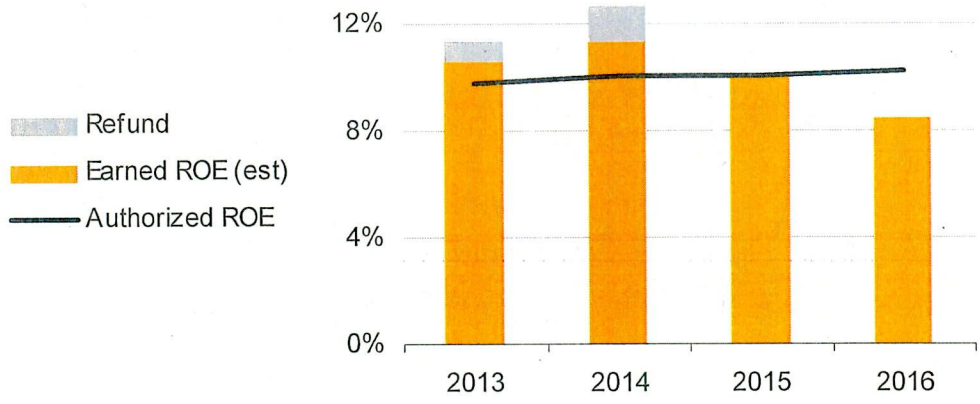


Q. DID THE COMPANY ANALYZE FRONT LOADING THE RATE INCREASE PATTERN THEREBY PROVIDING MORE YEARS IN THE FUTURE WITHOUT BASE RATE INCREASES?

A. We have performed this analysis by assuming 8.1 percent and 7.3 percent increases in years one and two. Implementing larger increases earlier in the plan term is not a practical option for structuring our multi-year rate plan because the Company would significantly over-earn in the early years of the rate plan, and under our ROE sharing mechanism a substantial portion of these overearnings would need to be refunded to customers. In addition, this approach has a larger rate impact on customers during a time when the additional revenues are not needed.

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Figure 4
(8.1%-7.0%-0%-0%)



Q. DOES THE SETTLEMENT PRECLUDE COMMISSION REVIEW OF THE PRUDENCE OF THE COMPANY'S INVESTMENTS DURING THE TERM OF THE RATE PLAN?

A. No. We recognize that there will be investments during the term of the Rate Plan that the Commission will not have had an opportunity to consider until a future proceeding. We believe that the bulk of our investments are consistent with the Commission's priorities (such as investments in our nuclear power plants) and that a multi-year solution is in the best interest of our customers' and should be adopted. That said, we view the Rate Plan as a "revenue solution" and not a determination of prudence of any of the Company's investments. We would expect that the Commission would review our investments in a subsequent rate case and make any prudence determinations at that time, on a prospective basis.

C. ROE

Q. HOW DOES THE SETTLEMENT ADDRESS ROE?

1 A. To ensure a balance between rate affordability and the utility's financial
2 health, the Settlement provides an authorized ROE of 9.75 percent for 2013,
3 10.0 percent in both 2014 and 2015, and 10.25 percent in 2016. In addition,
4 the parties agreed in the Settlement to using a 10.0 percent ROE for
5 purposes of determining interim rates in the Company's next electric rate
6 application.

7

8 Q. ARE THESE ROES REASONABLE?

9 A. Yes. These ROEs are significantly lower than the Company's originally
10 proposed ROE of 10.60 percent and its current rebuttal position of 10.25
11 percent. In addition, they are historically consistent with (if not below)
12 current rate making practices in North Dakota. The Company is unaware of
13 any previous or current authorized ROE in North Dakota as low as 9.75
14 percent, and a 10.0 percent ROE is consistent with a recent rate decision of
15 the Commission for another utility in the state. The 10.25 percent ROE in
16 the 2016 moratorium year will not trigger a base rate increase (rates are
17 frozen in 2016) and recognizes the increased business risk to the Company
18 that results from the Company's commitment to a rate moratorium three
19 years in the future while investments continue at a significant level.

20

21 **D. Rider Reform and Implementation**

22 Q. WHAT DOES THE SETTLEMENT INCLUDE WITH RESPECT TO RIDERS?

23 A. In addition to the base rate changes established in the Settlement, the Parties
24 have agreed to implement reforms to the Company's FCR. The Parties have
25 also agreed to implement a TCR tariff and a North Dakota RER tariff.

26

27 Q. PLEASE EXPLAIN THE FCR REFORMS INCLUDED IN THE SETTLEMENT.

1 A. The FCR reforms included in the Settlement are meant to help ensure the
2 Company's recovery of its power purchase agreements (PPAs) is fully
3 transparent.

4
5 The FCR reforms in the Settlement require the Company to provide
6 additional information in monthly filings and an annual report to notify and
7 provide opportunity for the Commission to evaluate the prudence of all the
8 PPAs under 50 MW included in the FCR calculation. The Settlement also
9 requires Commission approval of all future PPAs over 50 MW before such
10 costs are included for recovery in the Company's FCR.

11
12 Q. PLEASE EXPLAIN THE PROPOSED TCR.

13 A. A significant component of the Company's investment cycle is the
14 substantial investment in transmission infrastructure to support the
15 Company's integrated system. Key among these investments is development
16 of the CapX2020 Group 1 Projects for which the Commission granted an
17 ADP in Case No. PU-09-678. The Company requested the Commission
18 approve the proposed TCR tariff to allow for future rider recovery of these
19 and other investments. The Settlement establishes only the TCR tariff. The
20 Company must request to include specific costs for recovery through the
21 TCR in a separate proceeding.

22
23 Q. WHAT BENEFITS WILL THE PROPOSED TCR PROVIDE?

24 A. Establishing a TCR tariff will facilitate ongoing transmission investments by
25 allowing for cost recovery as qualifying projects are developed. Timely
26 recovery benefits customers by reducing carrying costs and smoothing the
27 rate impacts resulting from these investments. A TCR mechanism, applied

1 based on a Commission-approved tariff, provides an organized and efficient
2 means for recovery of qualifying transmission projects and a reasonable
3 mechanism for the management of MISO revenue.
4

5 Q. PLEASE EXPLAIN THE PROPOSED RENEWABLE ENERGY RIDER (RER).

6 A. To facilitate the timely recovery of future renewable energy projects in
7 North Dakota, the Settlement implements a North Dakota RER as part of
8 the Company's rate structure. The Company may only include the costs of
9 renewable projects that are located in North Dakota and for which the
10 Commission has granted an ADP.
11

12 Q. WILL THESE RIDERS ALLOW THE COMPANY TO OVEREARN OR RECOVER
13 REVENUES IN EXCESS OF THE AUTHORIZED ROE?

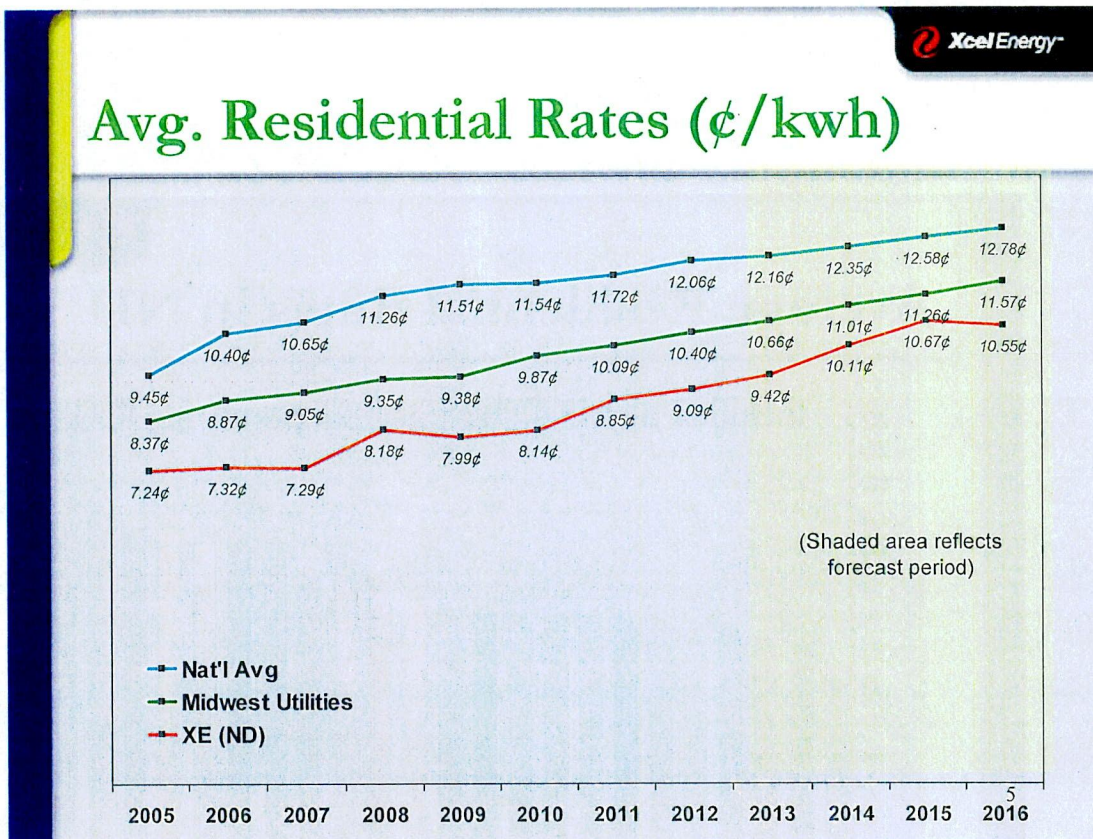
14 A. These riders allow for efficient recovery of our fuel costs and prudent
15 investments, but as shown in Exhibit____(DHS-1), Schedule 2, even if the
16 assumed revenue from these riders is realized, we project earnings just at or
17 below the authorized ROE. In the unlikely event that additional rider
18 revenue results in overearnings, the ROE sharing mechanism will require us
19 to refund 50 percent of that amount to our customers.
20

21 **E. Competitive Rate Position**

22 Q. WILL THE COMPANY'S RATES REMAIN COMPETITIVE UNDER THE RATE PLAN?

23 A. Yes. We expect our North Dakota rates to remain below the national and
24 regional averages throughout the plan term as shown in Figure 5.

Figure 5

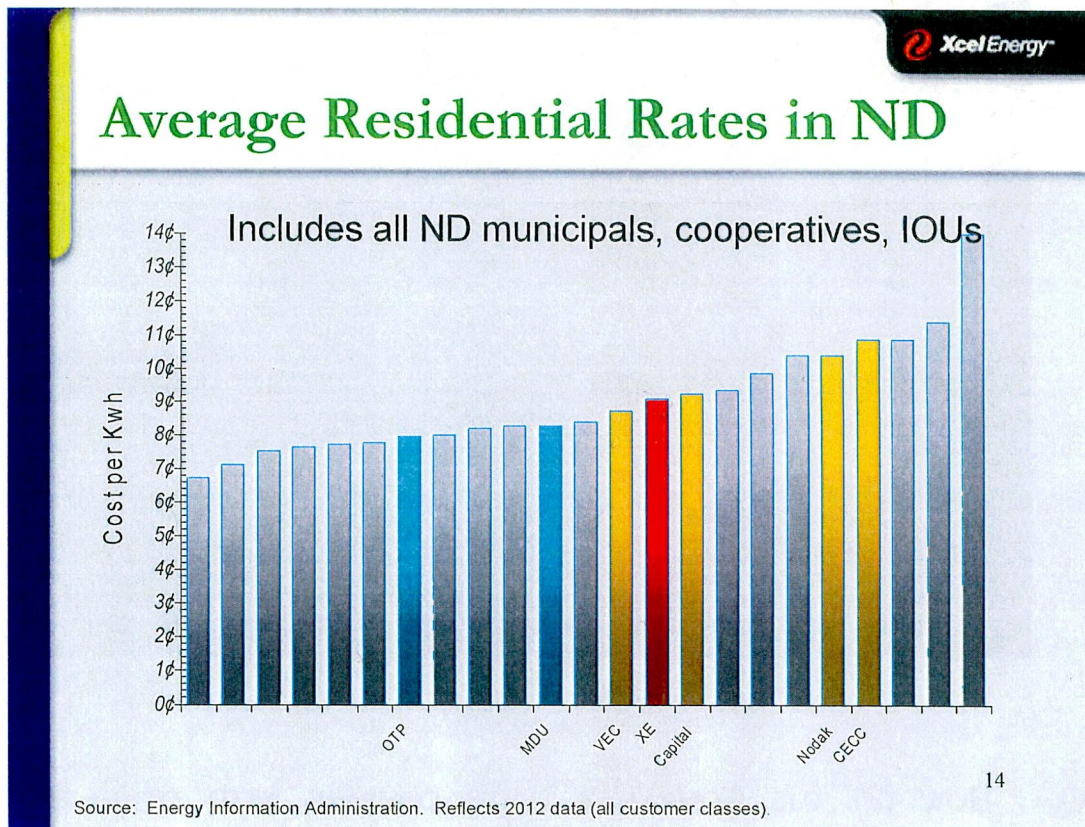


18 Q. HOW DO THE COMPANY'S RATES COMPARE WITH OTHER ELECTRIC
19 PROVIDERS IN NORTH DAKOTA?

20 A. In spite of the fact we are currently in an elevated capital expenditure cycle
21 and that North Dakota is typically among the three or four lowest priced
22 states in the nation in terms of average electric rates, we are "with the pack"
23 of all utilities who reported data to the Energy Information Administration
24 (EIA) in 2012 (see Figure 6 below for comparison of residential average
25 rates for reporting municipal, cooperative, and investor-owned utilities).
26 While our rates will likely remain higher than the other two IOUs in North
27 Dakota during the Rate Plan, we believe we will be well positioned in the

1 future to remain competitive given the timing differences of our investment
2 needs and those of the other utilities in the state.

3
4 **Figure 6**



29
30
31 **IV. MEETING NORTH DAKOTA POLICY GOALS**

32 Q. WHAT IS THE PURPOSE OF THIS SECTION OF THE SETTLEMENT?

33 A. In addition to settling the revenue issues presented in the rate case, the
34 Settlement is intended to address the long-standing policy concerns of the
35 Commission. I believe the proposed policy changes in the Settlement
36 address the Commission's dissatisfaction stemming from the multi-
37 jurisdictional nature of the Company's operations.
38

1 As Mr. Sparby discusses, our size and scope provides significant benefits to
2 our customers but it can create significant management challenges to deliver
3 these benefits. Through the policy terms of the Settlement, we are creating a
4 framework to meet the Commission's policy preferences while adding
5 certainty so the Company can better manage our multi-jurisdictional system.

6
7 As with any settlement, the policy provisions in the Settlement are
8 negotiated outcomes based on significant give and take. However, on
9 balance, we believe that the policy provisions go a long way in meeting the
10 expressed interests of the Commission and insulate our North Dakota
11 customers from the multi-jurisdictional impacts on our system planning.

12
13 Q. WHAT POLICY ISSUES DOES THE SETTLEMENT ATTEMPT TO ADDRESS?

14 A. The Company and Advocacy Staff spent significant amounts of time in
15 addressing three fundamental policy issues:

- 16 • Resource development consistent with North Dakota energy priorities;
- 17 • Locating generation in North Dakota; and
- 18 • Allocation of fixed production and transmission costs through an
19 appropriate "demand allocator."

20
21 Q. HOW DOES THE SETTLEMENT ADDRESS RESOURCE DEVELOPMENT
22 CONSISTENT WITH NORTH DAKOTA ENERGY PRIORITIES?

23 A. The Settlement provides a set of principles to guide the negotiations
24 between the Company and Advocacy Staff. These guidelines will help
25 ensure that our North Dakota customers pay the costs of a resource mix (or
26 proxy mix) that is consistent with North Dakota energy policy and not the
27 energy priorities of other states in which we provide service. This

1 negotiating framework is also intended to put mechanisms in place to
2 address future resource additions as well. We call this a “restack” of the
3 Company’s resource portfolio for North Dakota.

4
5 The Company and Advocacy Staff view this as a historic provision of the
6 Settlement and one that applies an original and creative approach to address
7 an ongoing significant concern of the Commission. We are not aware of any
8 other agreement to “restack” that has been undertaken where a utility did
9 not also have the guarantee of recovery from its other jurisdictions.
10 However, the Company recognizes that the divergence of energy policies in
11 the states we serve has been a continuing concern of this Commission and
12 we are willing to bear the risk to meet this Commission’s desires.

13
14 Q. HOW DOES THE SETTLEMENT ADDRESS THE COMMISSION’S INTEREST IN
15 DEVELOPMENT OF NORTH DAKOTA BASED GENERATION?

16 A. Quite simply, the Company has committed to building a dispatchable power
17 plant in North Dakota by 2036 if it can be done cost effectively and it meets
18 a capacity need on our system.

19
20 Q. HOW DOES THE SETTLEMENT ADDRESS THE ALLOCATION OF FIXED
21 PRODUCTION AND TRANSMISSION COSTS THROUGH THE “DEMAND
22 ALLOCATOR?”

23 A. The Settlement helps ensure that our North Dakota customers pay their fair
24 share - and only their fair share - of fixed costs by requiring a thorough,
25 balanced and unbiased study identifying and explaining the many different
26 allocation methodologies that can be used, and how they apply to the NSP
27 System. We believe that this approach is consistent with the record in this

1 proceeding and provides an appropriate, and timely, opportunity for the
2 Commission to explore this important issue. The Settlement also
3 contemplates the use of this information to set the demand allocator in the
4 Company's next rate case.
5

6 **A. North Dakota Energy Resource Mix (The Restack)**

7 Q. WHAT IS THE RESTACK?

8 A. The Restack is a process by which we intend to customize or reassign the
9 costs of the types of energy resources on our system that are to be used for
10 serving our North Dakota customers. The process will ensure that the costs
11 assigned to North Dakota are based on a resource mix that is consistent with
12 North Dakota's energy priorities and is not impacted by the energy policies,
13 mandates, and requirements of other states we serve. It is our intention that
14 this will address long-standing Commission concerns related to the
15 Company's resource mix.
16

17 Q. HOW WILL THE RESTACK WORK?

18 A. The Settlement identifies 10 principles to guide the Company and Staff's
19 negotiation of an agreement implementing the restack. These principles are
20 intended to retain the advantages of our integrated system for our North
21 Dakota customers while shielding them from other states' policies and the
22 impacts to our cost structure.
23

24 The Restack will first adjust costs based on a current resource mix serving
25 our North Dakota customers as if it had been historically developed under
26 North Dakota energy policy. We expect that this will result in immediate
27 cost savings, at least in the immediate future, to customers through the

1 replacement of the costs of certain renewable energy resources with other
2 resource options more in line with North Dakota energy priorities.

3
4 The Restack will also set a framework to address future Company resource
5 decisions. Given new solar mandates in Minnesota and the likely continued
6 investment in renewable resources for the Company to meet its mandates in
7 other states, a key goal of the Restack will be to implement a framework to
8 address costs on a going forward basis.

9
10 While not foreclosing the many different ways that creative implementation
11 of the Restack could work, we envision utilizing the existing FCR
12 mechanism to replace certain generation costs with reasonable proxies to
13 achieve this goal. We believe this is well within and consistent with the
14 Commission's authority.

15
16 Q. WILL THE COMPANY AND STAFF SUBMIT THE NEGOTIATED OUTCOME OF
17 THE RESTACK WORK FOR COMMISSION APPROVAL?

18 A. Yes. A key provision of this portion of the Settlement is that the Restack is
19 only subject to this Commission's approval. This means that the Company
20 takes on all of the risk of non-recovery in its other jurisdictions. We are
21 unaware of any other instance where a multi-jurisdictional utility has agreed
22 to this kind of fundamental change to its rate structure without guarantees of
23 recovery in other states it serves. We view this as a significant concession
24 and a key opportunity to drive cost savings to our North Dakota customers.

25
26 Q. WHAT HAPPENS IF THE COMPANY AND STAFF ARE UNABLE TO REACH AN
27 AGREEMENT?

1 A. The Restacking provisions of the Settlement do require significant additional
2 work to be done and further negotiations between Staff and the Company.
3 In recognition of this, the Settlement sets a hard deadline by which a
4 negotiated Restack agreement is to be filed. If a Restack framework is not
5 filed by July 1, 2015, then beginning in 2016 the Settlement removes 21
6 renewable purchase power agreements (PPA) from our FCR, replaces three
7 biomass contracts with a proxy cost based on the all-in cost of our coal-fired
8 King plant, and reprices the energy from the Company-owned Minnesota
9 Pleasant Valley wind project with system average energy costs. These
10 changes will result in near-term rate reductions of between \$4 million to
11 \$7 million a year, and hence provide a significant incentive to the Company
12 to ensure successful completion of the negotiations. With these mechanisms
13 in place, we believe that the Restack process is likely to be productive.

14

15 **B. Commitment to Build Generation in North Dakota**

16 Q. PLEASE DESCRIBE THE COMPANY'S COMMITMENT TO CONSTRUCT NORTH
17 DAKOTA BASED GENERATION BY 2036.

18 A. The Natural Gas CT Advance Determination of Prudence (ADP) and
19 Certificate of Public Convenience and Necessity cases (PU-13-194 and PU-
20 13-195) raised the issue of the Company's construction of North Dakota
21 based generation. In recognition of the fact that the proposed Restack will
22 develop a resource mix consistent with North Dakota's energy priorities but
23 will not necessarily result in construction of a generating plant within North
24 Dakota's borders, the Company has committed to construct a dispatchable
25 plant near our North Dakota loads by 2036, subject to prudent resource
26 planning principles.

1 The Hankinson natural gas CT proposal indicates that North Dakota based
2 generation is feasible and can be cost effective. We also recognize that it
3 would not be prudent to construct a plant on our system that was either not
4 needed or non-economic. Consequently, our commitment to construct
5 North Dakota based generation provides a sufficiently long timeframe to
6 incorporate the goal of a North Dakota based plant into our resource
7 planning efforts, to allow a need for the plant to arise, and to allow for the
8 development of infrastructure in the state to ensure such plant is cost
9 effective.

10
11 Q. A 20-YEAR TIME FRAME TO MEET THIS COMMITMENT IS A LONG TIME. HOW
12 WILL THE COMMISSION KNOW THAT THE COMPANY INTENDS TO FOLLOW
13 THROUGH WITH THIS COMMITMENT?

14 A. In recognition of this long time frame, the Settlement requires the Company
15 to include this commitment in its resource planning efforts and to advocate
16 for a North Dakota based generator in its other jurisdictions. Therefore, the
17 Commission can hold the Company accountable for its implementation of
18 this commitment.

19
20 For example, the Company will be filing resource plans in North Dakota and
21 Minnesota in the summer of 2014. As part of the Settlement, we will be
22 required to include a North Dakota based generator as part of our resource
23 planning goals. Further, we will incorporate a North Dakota based
24 generator into our 2014 Resource Plan as our next likely capacity resource to
25 be added to the system.

1 Because the Settlement must be adopted by the Commission by order, the
2 Commission will be able to enforce this commitment through its
3 enforcement authority.

4
5 **C. Demand Allocator**

6 Q. SETTING THE DEMAND ALLOCATOR BECAME A SIGNIFICANT ISSUE IN THIS
7 CASE. HOW DOES THE SETTLEMENT ADDRESS THIS ISSUE?

8 A. We agree with the Commission and Staff that the demand allocator
9 methodology should reasonably ensure that our North Dakota customers
10 pay their fair share, and only their fair share, of overall system costs.
11 However to accomplish this, we believe a thorough review of inter-
12 jurisdictional demand allocation is necessary. Such review has not been done
13 yet and is not a part of the record in the current rate case.

14
15 Q. WHAT DO YOU ENVISION SUCH A STUDY WOULD ENCOMPASS?

16 A. We envision a collaborative process with the Commission and Staff and
17 potentially other state regulatory representatives to ensure that the scope and
18 contents of the study are appropriately set. During our investigation we
19 would likely profile various methods of allocation, analyze their impacts on
20 our North Dakota cost structure, and develop recommendations for the
21 Commission to consider. At this point, we would expect to study in depth a
22 number of demand allocation methodologies including the 12-month
23 coincident peak (CP) and 1 CP methodologies. Our study may extend into a
24 review of our system planning and operational processes, and assess the
25 impact our North Dakota loads have on the NSP system. We also anticipate
26 that the study will analyze other methodologies used by other utilities, how
27 such methodologies were selected, and the experience of others who have

1 engaged in such review and analysis.¹ After the study is performed, the
2 Commission and its Staff will have an opportunity to provide comments and
3 request revisions so that the study reflects a comprehensive review of this
4 issue. We believe this work can address the challenges of implementing a
5 multi-jurisdictional change to the demand allocator to ensure the financial
6 health of the Company

7
8 Q. WHAT CRITERIA WOULD BE USED TO ANALYZE THE VARIOUS METHODS?

9 A. Presumably the study will take a look at these approaches in the context of
10 Commission precedent to determine how each method meets the goals of:

- 11 • Fairness: Any demand allocator should fairly apportion cost based on
12 the cost causation principle – the key goal of setting the demand
13 allocator;
- 14 • Consistency: This is an important, but secondary, goal to allow the
15 Company to recover its prudent cost of service from all of the
16 jurisdictions in which we provide service; and
- 17 • Administrative factors: The demand allocation methodology should be
18 easy to administer and not produce large swings from year-to-year. The
19 study will analyze volatility of different methodologies and strategies to
20 mitigate them while ensuring reasonable accuracy of the demand
21 allocation.

¹ For example, the Wyoming Commission staff has conducted such reviews, and their process and findings may provide useful information for the study provided in the Settlement. Stephen N. Ellenbecker & David M. Mosier, *Splitting Merger Benefits and Costs*, PUBLIC UTILITIES FORTNIGHTLY, Dec. 6, 1990, at 39.

1 Q. WHY SHOULD THE COMMISSION ALLOW ADDITIONAL TIME FOR SUCH A
2 STUDY BEFORE MAKING A DECISION ON THIS MATTER?

3 A. Simply stated, the record does not contain sufficient evidence to support the
4 implementation of a different methodology at this time. In fact, the record
5 provides little guidance as to what an appropriate demand allocation
6 methodology should be if the Commission wishes to change the long-
7 standing 12 CP methodology and does not reflect the Commission's
8 precedential factors of fairness, consistency, and administrative impacts in
9 relation to other methodologies raised in this proceeding. Further,
10 Commission precedent and fundamental principles of ratemaking do not
11 support selecting a demand allocator based solely on what allocates the least
12 amount of costs to our North Dakota customers. Consequently, further
13 analysis is warranted and this issue should not be prejudged based on a
14 particular intended outcome.

15
16 Further, the record is clear that the NSP System has been developed to do
17 more than just meet the summer peak as evidenced by a mix of resources on
18 our system such as baseload, intermediate, and peaking facilities. As Mr.
19 Diller's Testimony in support of the Settlement points out, if the NSP
20 System was planned only to meet the system peak day requirements (which
21 does inform our capacity needs) then it is logical to assume we would have a
22 system of only peaking plants, which have low capital costs but which would
23 increase overall system energy costs for all of our customers. Clearly, this is
24 not how the NSP System is operated. In fact, the record contains much
25 evidence that the NSP System is designed and operated to reliably meet
26 demand peaks in all months of the year and minimize energy costs
27 throughout the year with base and intermediate load plants, resource

1 diversity exchanges, outage management, and other factors all which point to
2 the appropriateness of the 12 CP methodology.

3
4 Q. DOESN'T THE RECORD INCLUDE SUPPORT FOR 1CP?

5 A. While Advocacy Staff Witness Karl Pavlovic raised the 1CP methodology in
6 his written testimony, he changed his recommendation in his opening
7 statement on the stand after analyzing the Company's testimony as to its
8 management of the integrated system. In fact, Mr. Pavlovic stated that it
9 was highly unlikely that a 1CP allocator would be appropriate, and he was
10 the first to recommend further study of this issue. Mr. Diller also noted that
11 a 1CP methodology would be appropriate if the entire NSP System was
12 composed of peaking plants to meet summer demand but also noted that
13 this is not how the NSP System is structured. Mr. Diller recommended
14 against making significant changes that will have far-reaching effects based
15 on the record in this case. And, Commission precedent has rejected utilizing
16 a 1CP methodology for the Company after a thorough review based on a
17 very similar record to this Case. Mr. Diller identifies several other
18 methodologies that may be appropriate, but recommends that the study
19 provided for in the Settlement is the appropriate way to make a final
20 determination on this issue.

21
22 Q. WHY IS THE PROPOSED STUDY THE BEST WAY TO ADDRESS THE DEMAND
23 ALLOCATOR ISSUE?

24 A. I would suggest several reasons.

25 First, the demand allocator is one of the most impactful factors in the
26 jurisdictional cost of service study and it should not be adjusted without a
27 full and thorough review. The proposed study would provide an

1 opportunity to do this review outside of the adversarial process of a rate
2 case. This approach would motivate the Company and Staff to work
3 collaboratively to identify appropriate methods consistent with the
4 Commission's principles of fairness, consistency and administrative
5 efficiency instead of advocating for a particular position.

6
7 Second, although the Settlement sets a deadline for submittal of the study,
8 we envision a collaborative process with the Commission and Staff and
9 expect significant follow-up after its July 1, 2014 submittal to identify and
10 include additional information as may be appropriate. This process is likely
11 to last well past the submission of the study and will appropriately position
12 this issue as part of the Company's next rate case following the rate plan.

13
14 Third, doing this work between rate cases would allow the Company and
15 Staff to develop implementation strategies. There can be more than one way
16 to calculate even one type of demand allocator, so this process will help to
17 identify and assess various implementation details and options.

18
19 Finally, performing a comprehensive study will enable the Commission and
20 Staff to develop a clear understanding of the financial and other
21 consequences of improperly setting the demand allocator. For example, the
22 1CP methodology initially brought forward by Mr. Pavlovic utilized a three-
23 year historic averaging methodology to mitigate the volatility of a 1CP
24 methodology. However, by utilizing historic data, Mr. Pavlovic did not
25 account for the loss of certain wholesale customers from the system, which
26 shifted total system demand to our retail customers. Mr. Pavlovic's
27 recommendation would have resulted in an implementation of a 1CP

1 methodology that would not have accurately represented current conditions,
2 and it would have resulted in an under-allocation of costs to our North
3 Dakota customers by as much as 50 percent.

4
5 All this is to say that it takes time to do this right. Although the Settlement
6 requires submission of the study by July 1 we think it would likely take a
7 significant amount of time after the submission of the study for follow-up
8 such that we would likely need all of the time between submission of the
9 study and filing of our next rate case to fully flesh out and propose
10 implementation of an appropriate demand allocator. Further, the Settlement
11 contemplates that all of this analysis will be used to inform the record in a
12 subsequent rate case. Using the time between rate cases, we believe, is the
13 most prudent course of action.

14
15 Q. COULDN'T THE COMMISSION JUST DO THIS WORK AS PART OF THE CURRENT
16 RATE CASE?

17 A. Performing this analysis as part of the current case would further delay the
18 outcome of the case by several months. We cannot set final rates without a
19 demand allocator and therefore Customers would continue to pay interim
20 rates while we perform this analysis. This would delay the interim rate
21 refund and cause the Company to continue to accrue liabilities, leading to
22 ongoing uncertainty. Ultimately, performing the long-term analysis
23 contemplated by the Settlement as part of this proceeding could undermine
24 rate certainty for customers, a key component of the Settlement.

25
26 Q. WHY IS IT REASONABLE FOR THE COMMISSION TO SET RATES FOR THE TERM
27 OF THE RATE PLAN UTILIZING THE CURRENT DEMAND ALLOCATOR?

1 A. Keeping the long-term status quo in place until the next rate case is not
2 unreasonable. Both the record and almost twenty years of consistent
3 practice support doing so. And, the Settlement provides significant value to
4 customers that can be captured now. Given the significant tilt in favor of
5 our customers that the Settlement as a whole provides, the Company would
6 likely not be able to support the Settlement if the Commission were to order
7 a change in the demand allocator during the term of the rate plan.

8
9 That said, we do recognize the concern that the Commission has in setting
10 rates that may over-allocate costs to our North Dakota customers. We share
11 this concern and it is an issue we propose to analyze as part of the study.
12 On balance, we believe it is reasonable to utilize the 12CP demand allocator
13 during the rate plan given the other benefits to our customers during its
14 term.

15
16 **V. SETTLEMENT OF OTHER CASES**

17
18 Q. DOES THE SETTLEMENT IMPACT OTHER PROCEEDINGS?

19 A. Yes. The Settlement was developed as a package to address many issues in
20 eight open dockets. The terms included in the Settlement resolve the
21 Company's request for an ADP and Certificate of Public Convenience in
22 Case Nos. PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743, PU-
23 13-194 and PU-13-195.

24
25 Q. HOW DOES THE SETTLEMENT RESOLVE THE COMPANY'S REQUESTED ADPS
26 FOR NEW WIND RESOURCES?

1 A. The Settlement provides that the Company's proposal to construct and own
2 the Border Winds Project and to purchase the output of the Courtenay
3 Project, are prudent resource additions to the Company's system since they
4 are based in North Dakota and therefore meet the rebuttable presumption
5 of prudence for the granting of an advanced determination of prudence
6 from the Commission.

7
8 The Settlement also provides that disposition of the Odell and Pleasant
9 Valley Projects located in Minnesota will be addressed in the Company's
10 commitment to develop a Restack mechanism whereby the Company will
11 serve its North Dakota customers with resources consistent with North
12 Dakota's energy policies. If the Restack is unsuccessful, these projects are
13 automatically addressed by provisions for failing to achieve a Restack
14 agreement.

15
16 Q. HOW DOES THE SETTLEMENT RESOLVE THE COMPANY'S ADP AND CPCN
17 REQUESTS FOR THE BLACK DOG UNIT 6 AND RED RIVER VALLEY UNITS 1
18 AND 2?

19 A. The Settlement provides that the Company's proposal to construct Black
20 Dog Unit 6 and Red River Valley Units 1 and 2 under the flexible, phased-in
21 approach described in the Company's Application is a cost-effective and
22 prudent approach to meet forecasted capacity needs in the 2017 to 2019
23 timeframe.

24
25 The Settlement does not foreclose the possibility of prudence of another
26 approach to meet the proposed capacity needs in 2017 through 2019 and the
27 Parties recognize that a different proposal may be selected as part of the

1 Competitive Acquisition Process in the state of Minnesota. The Company
2 will file an application for an ADP in the event the Company chooses to
3 proceed with a resource acquisition other than Black Dog Unit 6 or Red
4 River Valley Units 1 or 2.

6 VI. OTHER PROVISIONS AND ADJUSTMENTS

7
8 Q. WHAT EXPENSE ADJUSTMENTS ARE ACCEPTED BY THE SETTLEMENT?

9 A. The settlement accepts all expense adjustments proposed by Staff in the rate
10 case. They include:

- 11 • Pension – The Company will extend the amortization period for
12 unrecognized pension costs, including the loss attributable to the 2008
13 market downturn, to a 20-year amortization period, reducing test year
14 revenue requirements by \$447,000;
- 15 • Annual Incentive Plan – Annual Incentive Plan costs are capped at 15
16 percent of base pay, reducing test year revenues by \$209,000;
- 17 • Charitable Contributions and Economic Development Donations –
18 Donations to state and local economic development entities and
19 charitable contributions will be excluded during the 2013-2016 term of
20 the Settlement, reducing test year revenue requirements by \$328,000;
- 21 • Asset-Based Margins on Wholesale Sales – Beginning January 1, 2014,
22 the Company will pass through 100 percent of wholesale asset-based
23 margins to North Dakota customers, which will reduce annual fuel costs
24 by approximately \$56,000;
- 25 • Amortized Expenses – The Company will increase the amortization
26 period for various non-recurring expense items (including rate case
27 expenses, private fuel storage costs, deferred demand side management

1 expenses, and SO2 emission credits) to a four-year period, which will
2 reduce test year revenue requirements by \$92,000; and

- 3 • Department of Energy (DOE) Nuclear Fuel Proceeds – The Company
4 will make additional dispositions of \$5.2 million in DOE proceeds (\$3.9
5 million in 2013 and \$1.3 million in 2014), which will reduce revenue
6 requirements and base rate impacts.

7
8 These adjustments reduce test year revenue requirements by more than \$1
9 million, exclusive of the DOE dispositions.

10 11 VII. RATE DESIGN

12
13 Q. DOES THE SETTLEMENT RESOLVE THE OPEN RATE DESIGN ISSUES?

14 A. Yes. The Settlement address all rate design issues raised during the rate case
15 as follows:

- 16 • Class Apportionment – Customer class revenue increases would be
17 apportioned consistent with the Company's originally proposed class
18 revenue increases and the Company will use its proposed rate design
19 principles to implement the approved revenue requirement contained in
20 the Settlement;
- 21 • Tariff Book Improvements – The Company will submit an updated and
22 improved North Dakota Electric Rate Book no later than the date of its
23 next general rate application to improve tariff readability, remove
24 unnecessary phrases or sections, and ensure the terminology is up-to-
25 date;
- 26 • Monthly Customer Charge – The Company will replace the four distinct
27 Customer Charges for non-time of day residential electric service with a

1 single, common Customer Charge of \$14.00, and the Small General
2 Service Customer Charge will be set at \$16.00;

- 3 • Account History Charge – We will eliminate the \$5 charge for
4 responding to customer requests for account history; and
- 5 • Time of Day (TOD) Rate – We will, in collaboration with Staff,
6 investigate the feasibility of redesigning the Company’s TOD rate and
7 the Company will submit to the Commission either a pilot TOD tariff or
8 a recommended path for improving the residential TOD offering by
9 December 31, 2014.

10
11 **VIII. RELIABILITY**

12
13 Q. DOES THE SETTLEMENT INCLUDE PARAMETERS TO GUIDE THE COMPANY’S
14 COMMITMENT TO OFFERING RELIABLE SERVICE IN NORTH DAKOTA?

15 A. Yes. We will expand our current initiatives to improve reliability in North
16 Dakota as follows:

- 17 • The Company will expand its efforts to proactively locate and replace the
18 500 MCM cable used in the distribution system; and
- 19 • The current “Reliability Performance Plan” in place through 2015 will be
20 extended through 2016.

21
22 Q. WHAT IS THE STATUS OF THE INTELLITEAM PROJECT IN NORTH DAKOTA?

23 A. We have completed installation of the Intelliteam rollout in Fargo, as
24 planned. As described in late-filed Exhibit D, our engineers conducted an
25 assessment of future expansion of the Intelliteam technology in North
26 Dakota. In anticipation of settlement, we discussed our findings with Staff.
27 We are willing to explore this further with the Commission if desired.

1 The Company is committed to providing reliable service in North Dakota,
2 and no additional adjustment to test year revenue requirements for the
3 Company's reliability commitments are included in the Settlement.
4

5 IX. CONCLUSION

6
7 Q. PLEASE SUMMARIZE YOUR TESTIMONY.

8 A. Using an innovative and creative approach, Advocacy Staff and the
9 Company have developed a reasonable Settlement Agreement comprised of
10 many features that work together on balance to provide significant overall
11 benefit to North Dakota stakeholders and the Company. The Settlement
12 represents a comprehensive resolution to this rate case and many other open
13 cases before the Commission, is well supported by the record, and offers
14 opportunity for further collaboration on several issues which have been of
15 key interest to the Commission. For these reasons, I recommend the
16 Settlement Agreement be adopted and approved.
17

18 Q. DOES THIS CONCLUDE YOUR PRE-FILED SUPPLEMENTAL TESTIMONY?

19 A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN NORTH DAKOTA

CASE No. PU-12-813

NORTHERN STATES POWER COMPANY
ADVANCED DETERMINATION OF PRUDENCE –
COURTENAY WIND PROJECT APPLICATION

CASE No. PU-13-706

NORTHERN STATES POWER COMPANY
ADVANCE DETERMINATION OF PRUDENCE –
ODELL WIND PROJECT APPLICATION

CASE No. PU-13-707

NORTHERN STATES POWER COMPANY
ADVANCE DETERMINATION OF PRUDENCE –
PLEASANT VALLEY WIND PROJECT
APPLICATION

CASE No. PU-13-708

NORTHERN STATE POWER COMPANY
ADVANCE DETERMINATION OF PRUDENCE –
BORDER WINDS PROJECT APPLICATION

CASE No. PU-13-742

NORTHERN STATE POWER COMPANY
150 MW BORDER WINDS PROJECT –
ROLETTE COUNTY PUBLIC CONVENIENCE
AND NECESSITY

CASE No. PU-13-743

NORTHERN STATES POWER COMPANY
ADVANCE DETERMINATION OF PRUDENCE –
NG GENERATOR APPLICATION

CASE No. PU-13-194
OAH FILE No. 20130458

NORTHERN STATES POWER COMPANY
RED RIVER VALLEY NG UNITS 1 & 2 –
HANKINSON, ND PUBLIC CONVENIENCE
AND NECESSITY

CASE No. PU-13-195
OAH FILE No. 20130459

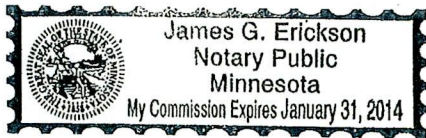
VERIFICATION


STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

David Sederquist, being first duly sworn on oath, deposes and says that he is Senior Regulatory Consultant with Northern States Power Company, d/b/a/ Xcel Energy, a Minnesota corporation, in the above captioned matters, that the supplemental testimony and schedules submitted in the above captioned matters under his name were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.


David Sederquist

Subscribed and sworn to before me this 14th day of January, 2014.




Notary Public
My Commission Expires: 1-31-14

David H. Sederquist
Senior Regulatory/Financial Consultant
Northern States Power Company, doing business as Xcel Energy
2302 Great Northern Drive, Fargo, North Dakota 58102

Current Responsibilities

Responsible for regulatory affairs within NSP's North Dakota jurisdiction, including communication of regulatory issues and events to ND management, assisting with preparation of ND filings, testifying at NDPSC hearings, participating in joint regulatory task forces, coordinating meetings/events involving NDPSC and Company personnel, acting as liaison with corporate Regulatory Services staff, and other special regulatory projects. Also responsible for analyzing ND financial reports, performing economic analysis, monitoring key performance indicators, and assisting with legislative initiatives.

Previous Employment

Senior Regulatory/Financial Consultant, ND	September 2000 -
Regulatory/Financial Analyst	May 1993 - Aug. 2000
Senior Financial Analyst	Mar. 1992 - Apr. 1993
Lead Financial Analyst, Financial Accting, Budgets, & Reports	Dec. 1990 - Feb. 1992
Senior Financial Analyst, NSP Electric Utility	May 1988 - Nov. 1990
Operations Analyst, Corporate Depreciation & Economics	Jun. 1984 - Apr. 1988

Education

University of Minnesota	2006
Minnesota Management Institute Program	
Minnesota State University Moorhead	1983
Bachelor of Science (Mathematics)	

Previous Testimony

Electric Rate Case - Reliability Performance Plan	Case Nos. PU-10-657, 11-55, 11-557
Performance Based Regulation Plan	Case No. PU-400-00-195
NSP/NCE Merger	Case No. PU-400-99-418
Natural Gas Rate Reduction	Case No. PU-400-96-559
DSM Accounting Change	Case No. PU-400-95-401
NSP/WEC Merger	Case No. PU-400-95-340
Electric Demand Allocation Correction	Case No. PU-400-94-514
Manitoba Hydro Cost Recovery	Case No. PU-400-93-731
Viking Acquisition Recovery	Case No. PU-400-93-534

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED

Northern States Power Company
 Electric Utility - State of North Dakota
 Settlement Financial Summary

Case No. PU-12-813
 Exhibit____(DHS-1), Schedule 2
 Page 1 of 1

	As Filed	Fcst							
	<u>2013 TY</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>				
Revenue Assumptions									
Operating Revenues (base + fuel)	\$228,226	\$228,226	\$232,952	\$242,016	\$250,300				
Settlement Base Rate Increases	\$0	\$7,948	\$18,705	\$29,001	\$29,001				
DOE Proceeds (Other Rev)	\$0	\$3,937	\$1,315	0	\$0				
TCR Rider Recovery (CapX2020 only) ¹	\$0	\$0	\$3,199	\$3,371	\$3,601				
ND Renewable Rider Recovery (Border Winds) ²	\$0	\$0	\$0	\$1,192	\$2,777				
Renewable PPA Restacking ³	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>-\$5,700</u>				
	\$228,226	\$240,111	\$256,170	\$275,580	\$279,979				
		[TRADE SECRET BEGINS							
Rate Base Assumptions									
Plant In Service	\$870,972								
<u>Depreciation Reserve</u>	<u>\$419,589</u>								
Net Plant	\$451,383								
CWIP	\$2,037								
Accum Deferred Taxes	\$92,784								
<u>Other Rate Base</u>	<u>\$17,012</u>								
<u>Total Rate Base</u>	<u>\$377,648</u>								
Cost Assumptions									
Fuel/Purchases	\$82,971								
O&M	\$86,753								
Depreciation	\$22,936								
Property Taxes	\$7,940								
Current & Deferred Inc Taxes	\$8,211								
Resulting Calculations									
Operating Income	\$19,415								
Debt Interest	\$8,799								
Earnings for Common	\$10,616								
Equity Rate Base	\$198,492								
		TRADE SECRET ENDS]							
ROE	5.35%	9.86%	9.68%	10.04%	8.40%				

Notes

- 1 Would include only PSC-approved projects; Currently reflects only CapX2020 projects based on Commission-issued ADP
- 2 Borders Wind assumed recovery as part of the Settlement. Additional revenue subject to Commission approval.
- 3 Initial calculation reflects penalty if restack is unsuccessful; Actual revenue reduction subject to outcome of restack.