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December 28, 2010

-VIA E-MAIL & FEDERAL EXPRESS-

Darrell Nitschke, Executive Director
North Dakota Public Service Commission
State Capitol Building, Dept 408
600 East Boulevard
Bismarck, ND 59505-0480

**Re: APPLICATION OF NORTHERN STATES POWER COMPANY, A
MINNESOTA CORPORATION, FOR AN ADVANCED DETERMINATION
OF PRUDENCE FOR THE 150 MW MERRICOURT WIND PROJECT
CASE NO. PU-08-908**

**APPLICATION OF NORTHERN STATES POWER COMPANY, A
MINNESOTA CORPORATION, FOR AN ADVANCED DETERMINATION
OF PRUDENCE FOR THE 201 MW NOBLES WIND PROJECT
CASE NO. PU-08-907**

Dear Mr. Nitschke:

Section 49-05-16 of the North Dakota Century Code, which contains the Advanced Determination of Prudence ("ADP") statute, includes an annual progress reporting provision for any resource addition that has received an ADP.

On December 20, 2010, Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), submitted a General Rate Case filing, Case No. PU-10-657. Attached is a copy of the Supply Operations testimony we presented in that case as our 2010 annual progress report for the Merricourt and Nobles Wind projects, which were issued ADPs on August 12, 2009. Please refer to Pages 8 and 9, 14 through 17 and 27 through 37 of that testimony for our ADP update. Note that the Nobles Wind Project went in-service and achieved commercial operating status on December 21, 2010.

57 PU-08-908 Filed 12/29/2010 Pages: 46
ADP - Annual Progress Report - Merricourt Wind and Nobles Wind
Northern States Power Company
Sara Cardwell

50 PU-08-907 Filed 12/29/2010 Pages: 46
ADP - Annual Progress Report - Merricourt Wind and Nobles Wind
Northern States Power Company
Sara Cardwell

Darrell Nitschke, Executive Director
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December 28, 2010

Please contact Dave Sederquist at 701-241-8632 or dave.sederquist@xcelenergy.com or me at 612-330-7975 or sara.j.cardewll@xcelenergy.com if you have any questions regarding this information.

Sincerely,

/s/

Sara J. Cardwell
Manager, Regulatory Administration

Direct Testimony and Schedule
Pamela K. Graika

Before the North Dakota Public Service Commission
State of North Dakota

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

Docket No. PU-10-____
Exhibit____(PKG-1)

Supply Operations

December 20, 2010

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Schedules

Resume of Pamela K. Graika

Schedule 1

1 I. INTRODUCTION AND QUALIFICATIONS

2
3 Q. PLEASE STATE YOUR NAME AND OCCUPATION.

4 A. My name is Pamela K. Graika. I am the General Manager of Power
5 Generation for Xcel Energy Services Inc. (“XES”).
6

7 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

8 A. I have a Bachelor’s Degree in Chemical Engineering and have worked for
9 Xcel Energy in various management positions since 1979. Prior positions I
10 have held within the Company include Production Engineer, Plant Manager,
11 and Director of Environmental and Regulatory Affairs. My resume is
12 attached as Exhibit___(PKG-1), Schedule 1.
13

14 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

15 A. I am testifying on behalf of Northern States Power Company, a Minnesota
16 corporation (“Xcel Energy,” the “Company,” or “NSPM”). I present Xcel
17 Energy’s 2011 Operating and Maintenance (“O&M”) and capital budgets for
18 the Energy Supply organization and demonstrate that these costs are
19 reasonable to recover from ratepayers.
20

21 Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

22 A. First, I address Energy Supply’s O&M costs. I present information in the
23 following sections:

- 24 • *Overview*, including a summary of the Energy Supply organization and costs
25 included in the 2011 budget;

- 1 • *Changes in the NSPM Generating System*, discussing system impacts and
2 resulting costs related to our Metro Emissions Reduction Project, the
3 Sherburne County Power Plant, and various wind projects; and
4 • *Cost Deviations*, presenting details related to major cost changes from 2008
5 O&M spending to our 2011 O&M budget, and then provide details on five
6 components of the 2011 O&M Budget.

7
8 Second, I address Energy Supply's capital costs, including discussion of:

- 9 • *Capital Investments for 2011*; and
10 • *Capital Costs of Nobles and Merricourt Wind Projects*.

11 12 **II. ENERGY SUPPLY O&M COSTS**

13 14 **A. Overview**

15 Q. PLEASE DESCRIBE THE ENERGY SUPPLY ORGANIZATION'S ROLES AND
16 RESPONSIBILITIES.

17 A. Energy Supply's principal role is to operate and maintain NSPM electric
18 generating facilities in a safe, reliable, cost-effective, and environmentally
19 sound manner. We are also responsible for managing major construction
20 projects, dispatching electric generation resources, overseeing environmental
21 compliance, and the coordination of generating unit dispatch with the
22 Midwest Independent System Operator ("MISO").

23
24 Q. PLEASE DESCRIBE THE TYPES OF COSTS YOUR ORGANIZATION MANAGES.

25 A. Energy Supply manages all O&M, fuel, fuel-handling, and capital costs
26 associated with the operation, maintenance, and improvement of our
27 generating facilities. These costs range from daily operating and maintenance

1 expenses to multi-year, multi-million-dollar capital projects. Key cost
2 categories include labor, materials, chemicals, external contractors, suppliers
3 and vendors.
4

5 Q. PLEASE PROVIDE AN OVERVIEW OF YOUR 2011 ENERGY SUPPLY O&M
6 BUDGET.

7 A. Our total company 2011 Energy Supply O&M budget is \$167 million. This
8 amount reflects a downward adjustment related to mercury sorbent at
9 Sherburne County Power Plant (“Sherco”) based upon recent performance
10 data. Company witness Mr. John M. Felling incorporates this adjustment into
11 the Company’s overall revenue requirement as a part of his Direct Testimony.
12 With this adjustment, our 2011 O&M budget represents an approximate \$7.5
13 million, or 4.7 percent increase over our forecast O&M spending for 2010.
14

15 Q. WHAT ARE THE MAIN CAUSES FOR THE INCREASE IN O&M EXPENSE FROM
16 2010 TO 2011?

17 A. Overall, we are seeing a steady increase in O&M costs primarily due to:
18 • the installation of new wind resources on our system;
19 • the increased maintenance and project costs of combined cycle natural gas
20 facilities at our High Bridge, Riverside and Black Dog generating facilities;
21 and
22 • environmental improvements at our plants.
23

24 **B. Changes in the NSPM Generating System**

25 *1. Metro Emissions Reduction Project (“MERP”)*

26 *a. Background Regarding MERP in Last Rate Case*

1 Q. WERE THE MERP PROJECTS ADDRESSED IN THE COMPANY'S LAST ELECTRIC
2 RATE CASE?

3 A. Yes, as noted by Company witness Ms. Laura McCarten, the Company's
4 MERP initiative was discussed in detail as a part of the Company's last electric
5 rate case and was addressed as a part of the settlement agreement approved in
6 that proceeding ("2008 Rate Case Settlement"). As a part of the 2008 Rate
7 Case Settlement, contested issues related to the rehabilitation of the Allen S.
8 King Plant ("King") and the High Bridge projects were resolved. As a result,
9 costs related to King were authorized for recovery; the Commission also
10 approved 8 months of recovery of our High Bridge project. As noted by Ms.
11 McCarten, in this application we request to pick up the remaining four months
12 to annualize the investment in rates.

13

14 Q. WHAT BENEFITS OF MERP WERE ADDRESSED BY THE COMPANY IN THE LAST
15 ELECTRIC RATE CASE?

16 A. As a part of her Rebuttal Testimony in our last electric rate case, Company
17 witness Ms. Elizabeth M. Engelking provided a comprehensive overview of
18 the three related projects. As a part of that testimony, the following benefits
19 of King and High Bridge were illustrated:

- 20 • Life extensions of both King and High Bridge;
- 21 • Efficiency improvements at both plants;
- 22 • Capacity reclamation and/or additions at both plants;
- 23 • Increased system reliability and operational flexibility;
- 24 • Cost savings relative to other alternatives; and
- 25 • Significant reductions in emissions.

26

1 Q. WAS THE ISSUE OF WHETHER THE MERP PROJECTS WERE REQUIRED BY
2 MINNESOTA LAW ADDRESSED IN THE PRIOR ELECTRIC RATE CASE?

3 A. Yes. Ms. Engelking's testimony clarified that these projects were not
4 mandated under Minnesota law. Furthermore, the 2008 Rate Case Settlement
5 clarified the parties' agreement that the refurbishment and repowering of the
6 two MERP projects were prudent and economic investments.

7

8 *b. Riverside*

9 Q. IS THE COMPANY SEEKING RECOVERY OF COSTS RELATED TO THE THIRD
10 MERP PROJECT IN THIS PROCEEDING?

11 A. Yes. Costs related to our Riverside repowering project ("Riverside") are
12 included in this rate case.

13

14 The Riverside project involved the replacement of Unit 7 with two natural gas
15 combustion turbines operating in a combined cycle. The project also included
16 the retirement of Unit 8. The Riverside project provides 439 MW of
17 accredited capacity (a net increase in URGE capacity of about 52 MW).
18 Riverside began commercial operation in May of 2009.

19

20 Q. PLEASE FURTHER DISCUSS THE DECISION TO PURSUE THE RIVERSIDE PROJECT.

21 A. Riverside was originally built in 1911. While some of the original units have
22 been retired, Units 7 and 8 have undergone several maintenance activities to
23 improve operating efficiency and reduce air emissions. As of January 1, 2002:
24 (1) Unit 7, which had a capacity of 150 MW, had a remaining life of 12.8 years;
25 and (2) Unit 8, which had a capacity of 236.5 MW, had a remaining life of 6.9
26 years. Thus, both units would have needed significant investments in order to
27 maintain reliability (or would have been retired in the case of Unit 8) by the
28 time of the proposed 2009 conversion of Riverside, or shortly thereafter.

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Q. WHAT WOULD THE COMPANY HAVE DONE IF RIVERSIDE WAS NOT REHABILITATED?

A. The alternative to the Riverside project was to install a new, comprehensive Air Quality Control System (“AQCS”) at the Riverside site. The cost of a new AQCS was estimated to be \$98 million. However, this estimate neither included investments needed to address aging plant components nor the costs of obtaining 52 MW of additional capacity and energy from an alternative source.

Q. WHAT WAS THE COST ESTIMATE FOR REPLACING RIVERSIDE AT THE TIME IT WAS PROPOSED?

A. When it was proposed, Riverside was projected to cost \$240 million. The cost for converting Riverside to natural gas translated to a per kW-installed value of \$483, including transmission. The per kW-installed value of Riverside compared very favorably to costs for new natural gas plants, which ranged from \$711 to \$827 per kW-installed, including transmission.

Q. WHAT OTHER ALTERNATIVES WERE CONSIDERED IN ADDITION TO RIVERSIDE? HOW DID THEY COMPARE IN TERMS OF COST?

A. As noted above, the Company compared the cost of the Riverside project to the cost of a new gas combined cycle generating facility, which at the time MERP was proposed would have cost between \$711/kW to \$827/kW.

Q. WHAT ARE THE BENEFITS OF THE RIVERSIDE CONVERSION?

A. The Riverside conversion allowed us to both extend the life of a plant that was nearing retirement and increase the output of the facility by 52 MW to help

1 meet Xcel Energy's customers' future demand for electricity. The availability
2 of the existing brownfield site and existing transmission and facility
3 infrastructure resulted in costs for Riverside that were far lower than the cost
4 of constructing a new plant elsewhere to replace Riverside and add capacity.
5 The combined cycle characteristics increased the efficiency of fuel conversion
6 from approximately 33 percent to approximately 49 percent. In addition, the
7 facility conversion avoided the cost of substantial new air quality controls that
8 would have been required to meet minimum federal standards in the 2009
9 time frame.

10
11 In addition to cost savings related to the construction of other generation
12 alternatives, the ratepayer savings provided by Riverside resulting from
13 avoided capacity and energy costs was estimated to reduce revenue
14 requirements by \$15 million in 2009, and rose to an average of \$20-21 million
15 per year in 2010 and thereafter.

16
17 *c. Impact of the MERP Projects on the System*

18 Q. HOW HAVE THE THREE PROJECTS AFFECTED THE SYSTEM IN RECENT YEARS?

19 A. All three of our MERP projects have now achieved commercial operation.
20 The operational performance of King has improved significantly since the
21 retrofit of the facility. As noted above, while the three projects provide
22 benefits, some increased labor is required to operate and maintain the new
23 emissions control equipment. In addition, more chemicals are needed for
24 NOx and mercury reduction at King.

25
26 Furthermore, as noted above, High Bridge and Riverside were replaced or
27 converted to combined cycle plants. Combined cycle facilities require

1 significantly higher maintenance costs than traditional gas fired plants as I will
2 discuss below. In addition, as High Bridge and Riverside move beyond their
3 first years of operation, certain maintenance activities will no longer be
4 covered by warranties, resulting in additional O&M costs.

5
6 *2. Impact of Natural Gas Combined Cycle Units*

7 Q. YOU MENTIONED THAT NATURAL GAS COMBINED CYCLE UNITS HAVE HIGHER
8 ASSOCIATED O&M COSTS. CAN YOU PLEASE ELABORATE?

9 A. Yes. Combined cycle facilities (at High Bridge, Riverside and Black Dog) are
10 designed to be more efficient than our older natural gas fired combustion
11 turbines. However, the increase in efficiency results from operations at
12 extreme high temperatures. As a result, the combined cycle facilities require
13 significantly higher maintenance costs than a traditional peaking plant. As
14 these facilities move beyond their first years of operation, certain elements will
15 no longer be covered by warranties. Therefore, we expect increases in O&M
16 expenses at these units to address wear and tear issues. An example of these
17 higher maintenance costs is the hot gas path parts refurbishments at High
18 Bridge and Black Dog Unit 5, which will take place in 2012 in order to be
19 prepared for their next outages at a cost of \$3.3 million.

20
21 *3. Wind Generation*

22 Q. WHAT WIND PROJECTS ARE AT ISSUE IN THIS RATE CASE?

23 A. There are three wind projects for which we seek cost recovery as a part of the
24 Energy Supply 2011 test-year budget: (1) Grand Meadow; (2) Nobles; and (3)
25 Merricourt. The Merricourt project is expected to achieve commercial
26 operation in November of 2011. Accordingly, we are seeking partial cost

1 recovery related to Merricourt in both our 2011 test-year budget and as part of
2 the Company's request for a step-in rate increase for the 2012.

3

4 Q. HAS GRAND MEADOW BEEN REVIEWED BY THE COMMISSION PREVIOUSLY?

5 A. Yes. The procurement decision related to Grand Meadow was addressed in
6 the 2008 Rate Case Settlement. In particular: (1) the Commission authorized
7 recovery of costs associated with Grand Meadow; and (2) the Commission
8 found that Grand Meadow was able to take advantage of existing production
9 tax credits to produce low and stable-priced energy that will contribute to Xcel
10 Energy's efforts to meet North Dakota's renewable energy objective.

11

12 Q. HAVE NOBLES AND MERRICOURT BEEN ADDRESSED BY THE COMMISSION
13 PREVIOUSLY?

14 A. Yes. Both Nobles and Merricourt received Advance Determination of
15 Prudence ("ADP") findings from the Commission in Case Nos. PU-08-907
16 and PU-08-908 respectively. Additionally, Merricourt received a Certificate of
17 Public Convenience and Necessity ("CPCN") in Docket No. PU-08-910. As I
18 discuss more fully below, I will provide an update to the capital costs related
19 to those projects.

20

21 Q. WHEN WILL NOBLES AND MERRICOURT ACHIEVE COMMERCIAL OPERATION?

22 A. Nobles is expected to achieve commercial operation in late 2010 and, as noted
23 above, Merricourt in November 2011.

24

25 **C. O&M Cost**

26 Q. AS PART OF THE PREPARATION FOR THIS CASE, HAVE YOU CONSIDERED HOW
27 YOUR 2011 O&M BUDGET COMPARES TO PAST SPENDING?

1 A. Yes. We believe the most appropriate and useful comparison was between
2 our O&M spending and forecasted spending levels for 2010 and the 2011
3 budget. The 2010 forecast includes six months of actual spending, plus six
4 months of forecasted spending.

5

6 Q. WHY DID YOU COMPARE THE 2011 BUDGET TO 2010 FORECAST COSTS RATHER
7 THAN TO 2008 ACTUAL COSTS?

8 A. 2010 forecast O&M costs are more appropriate for comparison to our 2011
9 O&M than prior years' actual costs because our 2010 O&M forecast, unlike
10 prior years' actual costs, reflects costs related to the operation of all three of
11 the MERP projects, usage of mercury sorbent for mercury emission control,
12 and our Nobles wind project. Accordingly, the 2010 forecast is a more
13 representative year in terms of the types of costs we expect to see in future
14 years, i.e., 2011 and beyond.

15

16 Q. WHAT COST SAVING MEASURES HAS THE COMPANY IMPLEMENTED IN ORDER
17 TO MITIGATE INCREASING O&M COSTS?

18 A. As discussed more fully by Ms. McCarten, in response to recessionary
19 conditions in 2009, the Company searched for additional measures to reduce
20 costs while ensuring we maintain reliability in both the near and longer term.
21 The Energy Supply organization undertook several cost saving initiatives,
22 some of which continue to provide cost savings in our 2011 test year O&M
23 budget. For example:

24 • In 2009, we reduced employee expenses and found ways to manage
25 reductions to fleet costs, the savings of which continue into our 2011 test-
26 year O&M budget; and

- 1 • In early 2009, we installed a lime slaker water heating system at King,
2 which allowed us to reduce our usage of lime. The reduced usage, as well
3 as resulting chemical costs savings for lime, are fully reflected in our 2010
4 forecast and our 2011 test-year O&M budget.

5

6 Q. PLEASE PROVIDE AN OVERVIEW OF THE MAJOR DIFFERENCES BETWEEN 2010
7 FORECAST SPENDING FOR O&M AND 2011 BUDGET FOR O&M.

8 A. Table 1 below (“2011 O&M Budget Chart”) shows the cost categories for
9 which there are significant differences between the 2010 forecast and the 2011
10 budget. It should be noted that the individual increases and decreases are
11 intended to provide descriptions of the primary drivers of differences.

1

Table 1

2011 O&M Budget Chart		
2010 Year-End Forecast for O&M		\$159,533,306
Base Labor		\$542,243
Regular time labor increase primarily due to wage increases for GM MN plants	\$1,005,000	
Overtime reduction primarily due to nuclear plant support budgeted in nuclear (\$200k) and miscellaneous minor outages in 2010.	(\$500,000)	
Base Non-Labor		\$3,852,961
Contract Labor increase due to Nobles and Merricourt Wind facilities	\$2,511,000	
Contract Labor increase due to FERC/NERC requirements	\$700,000	
Increase due to land lease payments for Nobles and Merricourt Wind facilities	\$1,226,000	
Decrease due to increase in credits budgeted due to activities on Sherco Unit 3	(\$582,000)	
Base Commodities		\$3,218,500
Increase due to activated carbon at King plant for mercury control	\$2,956,500	
Increase due to lime usage at the Wilmarth plant and commodity price increase	\$244,000	
Increase in sulfuric acid and other chemicals due to usage at the Riverside plant and commodity price increase	\$470,000	
Increase due to activated carbon at Sherco plant for mercury control	\$618,000	
Adjustment for activated carbon at Sherco plant	(\$1,070,000)	
Overhauls		(\$3,206,140)
Decrease primarily due to a Sherco Unit 3 overhaul budgeted in 2011 resulting in additional payment from partner (SMMPA) (\$5.5M), offset by an increase for the Black Dog Unit 3 and Unit 4 overhaul and Riverside Unit 9 warranty inspection in 2011.	(\$3,200,000)	
Projects		\$3,031,588
Increase primarily due to the Sherco stacker/reclaimer refurbishment (\$1.2M); inspection of the new High Bridge combined cycle turbine (\$430k); Riverside plant site remediation and intake closure following the MERP conversion (\$550k); and gearbox and generator bearing repairs at the Grand Meadow Wind facility (\$1.0M). This increase is offset by a \$180k decrease in the 2011 budget for boiler cleaning projects at the RDF plants.		
2011 Adjusted O&M Budget		\$166,972,458

2

3

1. *Components of the 2011 Test Year O&M Budget*

4

a. *Base Labor Costs*

5 Q.

PLEASE FURTHER DEFINE "BASE LABOR COSTS."

6 A.

Base labor costs relate to labor of Energy Supply employees in a department or station and overtime for recurring activities required to operate stations or departments on a daily basis. Base labor is primarily native station employees

8

1 performing native station work or a supplemental workforce performing
2 station work of a routine and recurring nature. These costs recur annually.
3

4 Q. IN THE 2011 O&M BUDGET CHART, YOU NOTED AN INCREASE IN WAGE
5 INCREASES. UPON WHAT DID YOU BASE THE WAGE INCREASES FOR ENERGY
6 SUPPLY EMPLOYEES?

7 A. We assumed wage increases of 2.5 percent for non-bargaining employees and
8 a slightly different value for our bargaining employees. Wage increases are
9 addressed by Company witness Ms. Jill H. Reed. As noted in the 2011 O&M
10 Budget Chart, the increase in wages accounts for a \$1,005,000 difference from
11 the 2010 forecast.
12

13 Q. PLEASE ELABORATE ON THE DECREASE IN BASE LABOR COSTS ATTRIBUTABLE
14 TO THE OVERTIME REDUCTION.

15 A. Our maintenance employees support the nuclear plants from time to time,
16 primarily for their overhauls. The actual labor and overtime is posted to our
17 generating plants. We have budgeted for a reduction in this area of
18 approximately \$500,000 in 2011.
19

20 Q. CAN YOU PROVIDE AN UPDATE ON THE LEVEL OF STAFFING NECESSARY TO
21 OPERATE AND MAINTAIN THE COMPANY'S GENERATION UNITS?

22 A. We are currently using 2004 as our high water mark and have decreased the
23 number of staff since that time. Our goal is to keep overall staffing levels
24 consistent with 2007 levels. We have needed to make small increases in staff
25 related to increased operating and maintenance expenses for emissions control
26 activities. For example, the new emissions control equipment at King requires
27 more labor to operate and maintain. The conversion of High Bridge from

1 coal to natural gas provided for a reduction in labor to operate, as did the new
2 Riverside combined cycle plant. However, the reduction in labor associated
3 with High Bridge and Riverside has been partially offset by the hiring of
4 additional employees at other plants, for example, the required additional
5 labor needed to operate and maintain the new emissions control equipment at
6 King. In addition, wage increases have offset the reduction in labor at High
7 Bridge and Riverside. Despite these factors, however, our base labor costs
8 have remained relatively flat with a net increase of \$542,243 in 2011.

9
10 *b. Base Non-Labor Costs*

11 Q. PLEASE FURTHER DEFINE "BASE NON-LABOR COSTS."

12 A. Base non-labor costs are materials, contractor expenses, permits, dues, fleet
13 vehicles, employee expenses and other miscellaneous costs required to operate
14 stations or departments on a daily basis, excluding base commodity costs
15 detailed below. These costs recur annually.

16
17 Q. DESCRIBE THE INCREASE IN BASE NON-LABOR COSTS RELATED TO THE WIND
18 PROJECTS.

19 A. Operating and maintenance of our wind projects are performed by
20 contractors. As noted in the 2011 O&M Budget Chart, a large portion of the
21 increase in base non-labor costs relate to these maintenance contracts being
22 implemented for Nobles and Merricourt. As I noted at the outset, Merricourt
23 O&M costs are part of the 2011 budget.

24
25 Q. PROVIDE A SUMMARY OF THE TOTAL O&M COSTS RELATED TO THE
26 COMPANY'S WIND PROJECTS.

1 A. Table 2 below provides an overview of the O&M costs related to Grand
2 Meadow, Nobles and Merricourt:

3
4 **Table 2**
5 **Wind O&M Costs**

Project	2009 Actual	2010 Forecast Spending*	2011 Budget
Grand Meadow	\$2,610,417	\$2,534,327	\$3,648,025
Nobles	\$0	\$1,657,430	\$4,025,922
Merricourt	\$0	\$0	\$1,629,060

6 *September 2010 forecast, 8 months actual and 4 month forecast.

7

8 Q. WHAT PORTION OF THESE O&M COSTS ARE ALLOCATED TO NORTH DAKOTA
9 CUSTOMERS?

10 A. Mr. Felling discusses the North Dakota jurisdictional portion of the O&M
11 costs for our wind projects.

12

13 Q. HOW DO THE O&M COSTS FOR NOBLES AND GRAND MEADOW COMPARE TO
14 FORECAST SPENDING IN 2010?

15 A. The 2011 O&M increase for Grand Meadow reflects a combination of two
16 related factors. First, the two-year manufacturer's warranty on parts expires at
17 the end of 2010. When this occurs, the Company will experience a permanent
18 cost increase in our O&M budget, as we continue to order, stock and install
19 replacement parts. Second, there is an associated need to incur higher
20 maintenance costs, reflecting the start of a new and routine maintenance cycle.
21 After two to three years of operation, generator bearing replacements and
22 gearbox rebuilds can be expected to occur on an ongoing basis.

23

1 For Nobles, the difference between 2010 forecast spending reflects an
2 increase in O&M for routine maintenance related to the project's construction
3 completion and commercial operation. However, similar to Grand Meadow,
4 it is reasonable to expect cost increases in the future for Nobles when the
5 project manufacturers' parts warranties expire and associated increased routine
6 maintenance expenses are necessary.

7
8 Q. WHAT DO THE 2011 O&M COSTS FOR MERRICOURT REFLECT?

9 A. While Merricourt is not expected to achieve commercial operation until
10 November of 2011, it is still necessary to incur some O&M costs prior to the
11 in-service date. For example, staffing at the site must begin months before the
12 project commences commercial operation. This allows the turbines to be
13 operated and maintained as they are constructed. The budgeted amount for
14 Merricourt in 2011 is based upon our experience with Grand Meadow.

15
16 Q. WHAT IS THE COMPANY DOING TO MANAGE O&M COSTS FOR WIND
17 PROJECTS?

18 A. The O&M service contract for the wind facilities is competitively bid to assure
19 we receive competitive pricing. The maintenance necessary at the wind project
20 sites will not change based on who provides the service, but the cost of
21 providing the maintenance can change. In summary, using competitive
22 bidding ensures the fairest costs but does not mean that costs will not
23 increase.

24
25 Q. CAN YOU DESCRIBE THE INCREASE IN BASE NON-LABOR ASSOCIATED WITH
26 THE LAND LEASE PAYMENTS FOR NOBLES AND MERRICOURT?

1 A. When approaching landowners for the property rights necessary to construct
2 and operate the wind projects, two payment options were offered.
3 Landowners were given the choice between an up-front lump sum payment
4 and annual payments over the life of the project. The two options are
5 designed to give land owners approximately equivalent alternatives on a
6 present value basis. The two options, however, are treated differently by the
7 Company for accounting purposes. The single lump sum payment is treated
8 as a capital expenditure, while the annual payments are an O&M expense.
9 Ultimately, more landowners chose annual payments than expected, which
10 resulted in a reduction in capital expense and a commensurate increase in
11 O&M over the term of the annual payments. These changes represent a cost
12 shift between capital and O&M costs, but do not increase or decrease the cost
13 of energy from the facility over its expected life.

14

15 Q. CAN YOU DESCRIBE THE DECREASE IN BASE NON-LABOR ASSOCIATED CREDITS
16 FOR ACTIVITIES AT SHERCO UNIT 3?

17 A. Yes. Sherco Unit 3 is a jointly-owned unit between the Company and
18 Southern Minnesota Municipal Power Agency (“SMMPA”). The Company
19 operates and maintains Sherco Unit 3. Therefore, we incur all of the expenses
20 and then bill SMMPA for their share. The payments from SMMPA are credits
21 that offset Energy Supply’s actual budget. These credits are reflected in our
22 2011 budget.

23

24 *c. Base Commodity Costs*

25 Q. PLEASE FURTHER DEFINE “BASE COMMODITY COSTS.”

1 A. Base commodity costs are chemical and water costs used in the generation
2 process, and for the control of emissions. Chemicals include lime, activated
3 carbon, sulfuric acid and others. These costs recur annually.
4

5 Q. CAN YOU DESCRIBE THE INCREASE IN ACTIVATED CARBON AT THE KING AND
6 SHERCO PLANTS FOR MERCURY CONTROL?

7 A. Yes. Pursuant to the Minnesota Mercury Emissions Reduction Act of 2006
8 (the "Act"), the Company was required to employ the available technology for
9 mercury removal at Sherco and King to remove at least 90 percent of the
10 mercury emitted from the units. The Act required the controls be
11 implemented by December 31, 2010. Both plans involved the use of
12 chemically reactive material, such as activated carbon ("mercury sorbent"),
13 which is injected into the flue gas upstream of a particulate control device.
14 The usage and associated commodity cost for mercury sorbent at King and
15 Sherco Unit 3 accounts for the increase from 2010 forecast spending and the
16 2011 budget.
17

18 Q. WERE THE COSTS RELATED TO MERCURY EMISSIONS CONTROL ADDRESSED AS
19 A PART OF THE 2008 RATE CASE SETTLEMENT?

20 A. Yes. As a part of the 2008 Rate Case Settlement the parties agreed to reduce
21 the revenue requirement by \$12,335. In particular, Section L of the 2008 Rate
22 Case Settlement reflects a reduction in costs "related to monitoring mercury
23 emissions reduction efforts at its King and Sherco generating plants to meet
24 Minnesota mercury emissions requirements."
25

26 Q. IS THE REQUEST TO RECOVER COSTS FOR MERCURY EMISSIONS CONTROL
27 INCONSISTENT WITH THE SETTLEMENT IN THE LAST RATE CASE?

1 A. No. There was a dispute in the last rate case related to the recovery of costs
2 for monitoring mercury emission that was settled by removing those costs as
3 part of an overall settlement. My understanding is that the settlement was tied
4 to the Staff's argument that the cost of the mercury monitoring equipment
5 was incurred in response to monitoring requirements enacted by the
6 Minnesota legislature rather than any requirement established by federal law.
7 The Staff initially believed \$438,427 had been included in the proposed
8 revenue requirement related to the mercury emissions reduction; however, the
9 amount was subsequently clarified to be \$12,335.

10

11 As argued by the Company in our last electric rate case, we continue to believe
12 that it is appropriate to allow recovery of the cost of complying with state law
13 where facilities are located. Further, since the time of our last electric rate
14 case, the Act has been approved by the Environmental Protection Agency
15 ("EPA") as an appropriate response to the federally-mandated requirement to
16 reduce mercury levels in water bodies. Accordingly, the costs incurred by the
17 Company to reduce mercury emissions are now needed to comply with federal
18 environmental regulation.

19

20 Q. CAN YOU PROVIDE MORE BACKGROUND OF THE FEDERAL MANDATE TO
21 REDUCE MERCURY LEVELS IN WATER BODIES?

22 A. The Federal Clean Water Act requires each state to evaluate its water bodies
23 and determine whether they meet water-quality standards. For mercury, these
24 standards define how much mercury can be in the water and in fish. Water
25 bodies that do not meet water-quality standards are added to a list of water
26 bodies referred to as the Impaired Waters List. Minnesota's 2008 Impaired

1 Waters List included 1,475 lakes and river segments that were considered
2 impaired for mercury, usually due to fish contamination.

3
4 To address impaired waters, states are required to evaluate the sources of
5 pollution, the reduction in the pollutant needed to meet water-quality
6 standards, and allowable levels of future pollution. This evaluation, typically
7 done for each water body or watershed, is called a Total Maximum Daily Load
8 (“TMDL”). Because the source of essentially all mercury to Minnesota waters
9 is the atmosphere, the Minnesota Pollution Control Agency (“MPCA”) prepared a state wide mercury TMDL. This TMDL was approved by the U.S.
10 EPA in March 2007.

11
12
13 To meet water-quality standards, the TMDL determined that human-caused,
14 air-deposited mercury would need to be reduced by 93 percent from 1990
15 levels. Applying this to air emission sources in the state established a 789-
16 pounds-per-year air emission goal. Once a TMDL is approved by the EPA,
17 states are responsible for implementing measures to achieve the goals
18 established in the TMDL. The MPCA, along with other stakeholders,
19 developed a Mercury TMDL Implementation Plan for the State of Minnesota.
20 The Mercury TMDL Implementation Plan incorporated the Act.

21
22 Because the Mercury TMDL Implementation Plan was mandated under the
23 Federal Clean Water Act and approved by the EPA, the mercury emissions
24 control and related costs are necessary to implement Federal requirements.
25 Accordingly, it is appropriate to seek recovery of a portion of these costs from
26 North Dakota ratepayers.

27

1 *d. Overhauls*

2 Q. PLEASE FURTHER DEFINE “OVERHAUL COSTS.”

3 A. Overhaul costs relate to the overhaul outages that are scheduled and planned
4 in advance. Budgeted overhaul costs include all costs incurred for overhauls
5 scheduled to be performed (incremental costs). Fixed or “base” costs are
6 budgeted as “Base” (e.g., regular time labor for native station employees) and
7 are *not* included in overhaul costs. Overtime, contract work, materials and
8 other expenses used for overhauls are included, as well as activities performed
9 only during the overhaul and are overhaul dependent, are included in this
10 category.

11
12 Q. CAN YOU DESCRIBE THE DECREASE IN OVERHAUL COSTS RELATED TO SHERCO
13 UNIT 3?

14 A. Yes. An overhaul at Sherco Unit 3 occurs once every three years. As noted
15 above, SMMPA is a co-owner of Sherco Unit 3. The overhaul at Sherco Unit
16 3 requires an additional payment from SMMPA, as a co-owner. The payment
17 from SMMPA results in the decrease for Overhaul costs. Primarily as a result
18 of this credit, our overhaul costs in 2011 are down \$3.2 million from 2010
19 levels.

20
21 Q. ARE THERE ANY OTHER OVERHAUL COSTS IN 2011?

22 A. Yes, there are. In order to maintain efficient operations, a turbine overhaul is
23 needed at Black Dog Unit 3 and a boiler overhaul is needed at Black Dog Unit
24 4. An overhaul warranty inspection of the new Riverside Unit 9 is also
25 necessary to determine if there are any necessary repairs that would be covered
26 under the warranty.

27

1 Q. ARE THE OVERHAUL COSTS BUDGETED FOR 2011 REPRESENTATIVE OF WHAT
2 CAN BE EXPECTED IN FUTURE YEARS?

3 A. Yes. It is useful to consider how our 2011 budget for Overhaul costs compare
4 to prior years overhaul spending and our forecast for 2012, which is as
5 follows:

6 **Table 3**

2007 Actuals	2008 Actuals	2009 Actuals	2010 Forecast	2011 Budget	2012 Budget
\$24,343,781	\$17,974,255	\$13,305,552	\$19,720,019	\$16,513,879	\$22,314,950

7
8 An average of the six years above is \$19,028,739. Thus, our 2011 budget for
9 Overhaul costs is reasonable and, in fact, is lower than what can be expected
10 for 2012.

11
12 *e. Project Costs*

13 Q. PLEASE FURTHER DEFINE "PROJECT COSTS."

14 A. Project costs are related to work that is separate and independent of overhaul
15 costs. Items in this cost category are not overhaul dependent, even though
16 they may be performed during the overhaul. Projects are typically larger
17 expenses. The projects typically do not occur every year and could cross over
18 from year to year. Overtime, contract work, materials and other expenses
19 used for projects are included in this cost category. Examples of project costs
20 are:

- 21 • Major coal mill overhauls;
- 22 • Major pump rebuild performed outside of an overhaul;
- 23 • Partial baghouse bag replacement; and
- 24 • Conveyor belt replacement.

25

1 Q. CAN YOU DESCRIBE THE \$3,031,588 INCREASE IN PROJECT COSTS FROM 2010
2 TO THE 2011 BUDGET?

3 A. The most significant one-time projects in 2011 are:

- 4 • The refurbishment of the coal Stacker/Reclaimer at Sherco, which is \$1.2
5 million;
- 6 • Gearbox and generator bearing projects at the Grand Meadow Wind
7 facility, which is \$1 million;
- 8 • Riverside plant site remediation and intake closure following the MERP
9 conversion, which is \$550,000;
- 10 • The first inspection of the new High Bridge combined cycle steam turbine,
11 which is \$430,000; and
- 12 • Decrease for boiler cleaning at the Refuse Derived Fuel (“RDF”) plants,
13 which is \$180,000.

14

15 Q. WHY DOES THE SHERCO COAL STACKER/RECLAIMER REFURBISHMENT
16 REQUIRE REFURBISHMENT IN 2011?

17 A. The coal Stacker/Reclaimer at the Sherco Plant is original plant equipment
18 and has reached the end of its projected life. The coal Stacker/Reclaimer is a
19 critical component as it delivers coal to the Sherco generating units, and as
20 such, must be maintained in a reliable condition. We considered capital
21 project alternatives to replace the Stacker/Reclaimer, but it was estimated to
22 cost between \$17 million and \$40 million. We elected to perform an O&M
23 project in 2011 that involves refurbishment of the rail track upon which the
24 Stacker/Reclaimer travels and some parts of the travel assembly. The 2011
25 project is intended to ensure reliable Stacker/reclaimer operation and defer
26 the revenue requirements associated with a major capital project as we
27 continue to research a more cost-effective long-term alternative.

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Q. DO YOU EXPECT TO HAVE PROJECTS LIKE THE STACKER/RECLAIMER EVERY YEAR?

A. While our 2011 Stacker/Reclaimer project is somewhat unique in that it has allowed us to avoid a capital project, we have other unique projects in 2012 that will cause increases in Project costs. Specifically, we will perform a Sherco Unit 3 Mill Overhaul and two Hot Gas Path parts refurbishments at Black Dog and High Bridge in 2012, which I will discuss more fully below. In addition, we expect to have additional wind-related project work in 2012 and beyond with Nobles and then Merricourt achieving commercial operation. Because we expect to continue to have additional one-time *projects* in future years, and that the level of these projects will increase, the 2011 *budget* for project costs represents a reasonable basis upon which to set prospective rates.

Q. PLEASE FURTHER DESCRIBE HOT GAS PATH PARTS REFURBISHMENTS THAT WILL OCCUR AT BLACK DOG AND HIGH BRIDGE.

A. Typical Hot Gas Path parts refurbishments are done on a prescribed frequency of 16,000 to 24,000 operating hours or 500-600 starts, whichever comes first. This frequency is established to ensure safe reliable unit operations during the life of the machine. Going much beyond these intervals can put the units at risk and drive costs higher for both repair and replacement not to mention potential collateral damage within the combustion turbine. During a Hot Gas Path inspection all components associated with a combustion inspection are pulled, repaired, and/or replaced if at end of life, plus we inspect and repair the first two rows of combustion turbine blades, vanes, ring segments, etc. associated with the hottest portion of the

1 combustion turbine. Similar to the combustion inspection parts, these are also
2 inspected and refurbished or replaced once they reach the end of useful life.
3 As I discussed earlier, the Hot Gas Path parts refurbishments in 2012 for both
4 High Bridge and Black Dog Unit 5 have a combined cost of \$3.3 million.

6 III. CAPITAL INVESTMENTS

8 A. Capital Investments for 2011

9 Q. WHAT ARE YOUR PLANT ADDITIONS FOR NSPM IN 2011?

10 A. Our plant additions are \$493 million, \$399.8 million of which relates to
11 Merricourt.

13 Q. WHAT KINDS OF CAPITAL INVESTMENTS ARE BEING MADE AT THE
14 GENERATING PLANTS?

15 A. Most capital expenditures are for equipment and materials that have worn out
16 through normal use or operation. These include: generator rewinds; boiler
17 tubing replacements; computerized control system replacements; and turbine
18 replacements. Also included are environmental compliance projects such as
19 landfill management, mercury control, SCR catalyst replacement and land
20 remediation.

22 Q. WHAT TYPE OF CAPITAL INVESTMENTS ARE BEING MADE AT SHERCO IN 2011?

23 A. Sherco has capital expenditures for:

- 24 • Replacement of: (1) computerized control system in the Sherco coal yard;
- 25 (2) distributed controls; and (3) plant programmable logic controllers at
- 26 Sherco Units 1 and 2. The existing systems are 10-20 years old. Thus,

1 replacements are needed due to parts becoming obsolete and to meet new
2 load swing requirements to better integrate wind.

- 3 • Equipment replacement at the Sherco coal yard, such as yard rails and coal
4 chutes, which become degraded due to everyday use.
- 5 • Ongoing landfill, pond and capping projects.

6

7 Q. ARE THERE CAPITAL INVESTMENTS IN 2011 FOR SHERCO UNIT 3
8 SPECIFICALLY?

9 A. Yes. The High Pressure and Intermediate Pressure turbines and the generator
10 step-up transformer at Sherco Unit 3 will be replaced during the overhaul
11 outage in the Fall of 2011. This project will increase generation by 21 MW
12 without increasing emissions. Also, a portion of the baghouse bags will be
13 replaced and a new boiler cleaning system will be installed. These capital
14 investments are estimated to cost approximately \$17 million in 2011.

15

16 Q. ARE THERE COST SAVING CAPITAL PROJECTS FOR 2011?

17 A. Yes. At Sherco we will replace the demineralizer and implement slaking water
18 heating projects, both of which will offset some of the increase in chemical
19 costs.

20

21 Q. ARE THERE EXAMPLES OF EQUIPMENT EFFICIENCY IMPROVEMENTS?

22 A. Yes, as noted above, the replacement of turbines at Sherco Unit 3 will increase
23 generation by 21 MW. In addition, new turbines will be installed at our St.
24 Anthony Falls Hydro Plant that are more efficient and will increase generation
25 by about 20 percent.

1 **B. Capital Costs of Nobles and Merricourt**

2 Q. WHAT IS THE PURPOSE OF THIS PORTION OF YOUR TESTIMONY?

3 A. This portion of my testimony addresses capital costs related to the Nobles and
4 Merricourt that are incremental to costs provided as a part of the ADP
5 proceedings.

6

7 Q. PLEASE BRIEFLY DESCRIBE HOW THE NOBLES AND MERRICOURT PROJECTS
8 ARE BEING CONSTRUCTED.

9 A. As we indicated in our ADP applications, Xcel Energy entered into
10 build/transfer agreements (also referred to as engineering and procurement or
11 “EPC” agreements) with enXco Development Corporation to develop and
12 construct both the Nobles and Merricourt wind projects. Under this
13 approach, the Company obtains ownership of the projects in a progressive
14 manner. Under our agreement with enXco, Xcel Energy was to obtain the
15 CPCN (for Merricourt) and ADP while enXco would apply for the Certificate
16 of Site Compatibility required pursuant to NDCC Chapter 49-22.

17

18 The cost estimates filed with our ADP accounted for the payments directly to
19 enXco, but did not include all costs incurred by Xcel Energy during the
20 construction management phase. As discussed more fully below, these are
21 necessary and direct costs in order for Nobles and Merricourt to be
22 constructed and achieve operation. It is also important to note that the
23 additional capital costs discussed below do not materially alter the
24 reasonableness of the selection of the two projects.

25

26 Q. WHAT ARE THE CONSTRUCTION MANAGEMENT PHASE COSTS RELATED TO
27 NOBLES AND MERRICOURT?

1 A. The costs are the internal Xcel Energy costs and are not payable directly to
2 enXco as part of the EPC agreement. The costs can be broken into three
3 main categories: (1) labor; (2) non-labor; and (3) contingency costs. Table 5
4 provides the costs for each category.

5
6 **Table 4**

Nobles Project Costs	
Labor	\$3.270 M
Non-Labor	\$4.170 M
Contingency	\$6.250 M
Totals	\$13.703 M

7
8 **Table 5**

Merricourt Project Costs	
Labor	\$2.26 M
Non-Labor	\$3.26 M
Contingency	\$8.78 M
Totals	\$14.30 M

9
10 I will discuss each category in greater detail below.

11
12 Q. ARE THESE COSTS ORDINARY AND NECESSARY TO MANAGE LARGE
13 CONSTRUCTION PROJECTS?

14 A. Yes. Internal project management costs are incurred for any major
15 construction project. While enXco has original responsibility for managing
16 the projects and their subcontractors, the Company continues to have overall
17 oversight responsibilities. Those responsibilities should not be delegated.

18
19 *a. Labor Costs*

20 Q. WHAT DO THE LABOR COSTS CONSIST OF?

21 A. The labor costs consist of: (1) internal labor costs for engineering and
22 construction oversight (“E&C”); (2) consultant costs; and (3) legal costs.

1

2 Q. PLEASE PROVIDE SOME BACKGROUND ON THE “E&C” COMPONENT OF THE
3 LABOR COSTS.

4 A. During the period enXco develops and constructs the Nobles project, the
5 Company performs an oversight role to help ensure they are adhering to the
6 contractual requirements and maintaining a level of quality that is consistent
7 with the Company’s expectations. Eight Company employees perform this
8 oversight role (the “project team”). Among other tasks, the project team at
9 Nobles: (1) is on site at the project five to six days per week; (2) works with
10 landowners to locate access roads and minimize road issues in a manner that
11 will minimize future O&M costs and potential issues with landowners; (3)
12 attends daily enXco morning meetings to discuss a wide array of issues,
13 including safety and the daily construction schedule; (4) observes construction
14 practices; (5) serves as the Company contact for site inspections/audits,
15 including quality assessment and quality control, as well as adherence to design
16 documents and contract specifications; and (6) coordinates the Company’s
17 substation work with enXco.

18

19 For the Merricourt project, we will use a similar project team who will
20 perform the same types of tasks. We currently expect the project team at
21 Merricourt to begin work in April or May 2011.

22

23 Q. HAS THE COMPANY INCURRED E&C OVERSIGHT LABOR-RELATED COSTS FOR
24 OTHER MAJOR CONSTRUCTION PROJECTS?

25 A. Yes. E&C oversight labor costs are not unique to the Nobles and Merricourt
26 projects. For example, the Company incurred and was allowed to recover
27 these costs for Grand Meadow and our MERP projects.

1

2 Q. ARE THE E&C OVERSIGHT LABOR COSTS ASSOCIATED WITH NOBLES AND
3 MERRICOURT COMPARABLE TO THE E&C OVERSIGHT LABOR COSTS
4 ASSOCIATED WITH GRAND MEADOW?

5 A. Yes. The E&C oversight costs for these projects are summarized below in
6 Table 6:

7

Table 6

E&C Oversight Costs		
Grand Meadow	\$23/kW	1.15% of total project cost
Nobles	\$23/kW	0.9% of total project cost
Merricourt	\$23/kW	0.9% of total project cost

8

9 These costs are comparable on a total project cost basis. As explained, the
10 E&C oversight labor costs provide significant value and represent about one
11 percent of the total project costs for both wind projects.

12

13 Q. HAS THE COMPANY'S E&C OVERSIGHT PROVIDED BENEFITS TO THE NOBLES
14 AND MERRICOURT PROJECTS?

15 A. Yes. Through the E&C process for Nobles, adjustments were made during
16 construction which will provide improved performance and lower operating
17 costs. For example, we are conscious of access road placement. Landowners
18 will more readily grant easement access to areas of their property that are
19 lower lying areas because they are less valuable agricultural production areas.
20 However, these areas are also prone to being wetter in spring and fall and
21 experience more drifting in winter. Thus, while enXco is responsible for
22 obtaining all easements, we involved our E&C team during the discussions
23 with landowners for Nobles in order to identify types of issues that could
24 affect our access and costs from a long-term perspective. For the Merricourt

1 project, we intend to use our E&C project team in a similar manner and,
2 accordingly, we anticipate similar benefits.

3
4 Q. PLEASE DESCRIBE THE CONSULTANTS' ROLES AND THE LEGAL COSTS.

5 A. During site development and construction of the Nobles project, the
6 Company hired a consulting firm ("URS") as an Owners-Engineer to provide
7 technical oversight and review of certain contract deliverables. The original
8 scope of work under the contract included items such as: review of permit
9 applications, site studies, foundation designs, and electrical designs. All work
10 under the contract is performed on an "as-requested" basis, with a not-to-
11 exceed value. Under the contract, URS has reviewed the Certificate of Need
12 and Large Wind Energy Conversion System ("LWECS") Site Permit
13 application, project permit application schedules, wetland and avian studies
14 and permitting requirements, and the terms and conditions of the project
15 agreements. URS was chosen to perform these services due in part to its
16 capability and experience in providing similar assessment and oversight of
17 prior wind projects. The Company also used outside legal services to perform
18 land title reviews, support contractual interpretation and compliance, and
19 assist with contract closing activities.

20
21 The Company plans to hire URS to perform the same functions for the
22 construction of the Merricourt project.

23
24 Q. WHAT DID THE COMPANY DO TO MAKE SURE THE CONSULTANT AND LEGAL
25 COSTS WERE REASONABLE?

26 A. For the costs related to the consultant, the Company selected URS as a result
27 of a request for proposal ("RFP") process. The Company chose the

1 consultant based upon the competitiveness of its bid, both from a monetary
2 standpoint and from an experience/expertise standpoint.

3

4 With regard to amount of costs related to the legal services, the Company
5 selected the outside law firms pursuant to responses received to a law
6 department RFP and based on our experience with these firms being able to
7 provide cost-effective service for these types of transactions.

8

9 *b. Non-Labor Costs*

10 Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF THE NON-LABOR COSTS
11 RELATED TO NOBLES.

12 A. Similar to the labor cost discussion, even though the bulk of the costs related
13 to Nobles and Merricourt stem from our EPC agreement with enXco,
14 additional non-labor cost incurrence is necessary in order to allow the projects
15 to be constructed and become operational. The non-labor components
16 include: (1) landowner payments for easements; (2) compensation for crop
17 damage caused by construction crews; (3) sales taxes related to road materials
18 and building materials; (4) insurance premiums related to “builder’s risk”
19 property insurance, which covers property owners and builders for projects
20 under construction; and (5) Xcel Energy’s portion of the transmission
21 interconnection costs.

22

23 Q. WHY ARE THESE COSTS NOT COVERED BY THE EPC AGREEMENT?

24 A. The costs are related to project development activities that remain the
25 responsibility of Xcel Energy. Easements and other land acquisitions are
26 required from affected landowners for the turbine footprints and access roads
27 as well as for the substation in order to construct and operate the project. The

1 easements also require us to pay for damage to crops during the construction
2 period. However, the final easement amount is subject to individual
3 negotiations with landowners. Additionally, while some generation production
4 equipment is exempt from sales tax, Minnesota law requires sales tax to be
5 paid on other portions of the Nobles project, such as non-generation
6 materials. Our EPC contract with enXco requires us to pay the sales tax, and
7 we have chosen to provide the builder's risk insurance during construction.

8
9 *c. Contingency Costs*

10 Q. PLEASE DESCRIBE WHAT IS INCLUDED IN THE LAST CATEGORY OF COSTS
11 REFERRED TO AS "CONTINGENCY COSTS."

12 A. We are requesting \$6.25 million in contingency costs for Nobles and \$8.78
13 million for Merricourt. It is normal business practice to include contingencies
14 in capital project estimates. Contingency costs are intended to account for
15 unplanned or uncertain costs that arise during the construction process.
16 While the build transfer approach under which enXco builds the wind project
17 significantly reduces contingency costs to the Company by placing more of
18 the burden on enXco, it does not completely eliminate them.

19
20 At this point during the construction of Nobles, we have identified costs of
21 approximately \$2.55 million for which Xcel Energy could be responsible that
22 fall under the contingency category of costs. I believe the \$6.25 million is a
23 reasonable estimate of final costs, but will be able to provide an update
24 regarding the total amount actually spent in early 2011.

25
26 Because construction has not yet begun on the Merricourt project and the in-
27 service date is not until November 2011, we have not yet incurred any

1 contingency costs for this project. Since the Nobles and Merricourt EPC
2 agreements are similar, and because we have encountered contingency costs
3 for Nobles, we anticipate we will incur contingency costs for Merricourt as
4 well. Furthermore, we have identified additional challenges for the
5 construction of Merricourt in comparison to Nobles, including a more hilly
6 terrain that could result in greater costs related to the establishment of roads.
7 In light of the likelihood of incurring contingency costs and the additional
8 challenges related to Merricourt, I believe the \$8.78 million budget for
9 contingency costs for the Merricourt project is reasonable.

10
11 Q. PLEASE PROVIDE AN EXAMPLE OF CONTINGENCY COSTS THAT HAS BEEN
12 IDENTIFIED FOR THE NOBLES PROJECT.

13 A. We are in the final stages of approving a \$2.3 million change in the greasing
14 mechanism that would result in reduced O&M and operational risks at
15 Nobles. This change would require a vendor to modify the GE wind turbines
16 at the project site. It is possible that the Merricourt project could require a
17 modification to the wind turbine lube oil system, similar to what is being done
18 now at Nobles.

19
20 Q. WHY ARE THE MERRICOURT CONTINGENCY COSTS ESTIMATED TO BE
21 GREATER THAN THOSE ESTIMATED FOR NOBLES?

22 A. The contingency cost estimate for Nobles versus Merricourt reflects the fact
23 that Nobles is much farther along in its construction than Merricourt. At this
24 time, our estimate for Merricourt is relatively higher due to several additional
25 uncertainties. For example, we currently do not have design plans from
26 MISO or design plans from enXco for the operations and maintenance
27 building. Another uncertainty regards payments to landowners. It is not

1 known how many will take a one-time payment or an annuity. Also, the terrain
2 of the land may bring unique challenges for construction or start-up. These
3 uncertainties make it more difficult to predict what type of contingency costs
4 to expect.

5
6 Q. WHAT IS THE PROCESS TO REVIEW AND APPROVE COSTS THAT FALL UNDER
7 THE CONTINGENCY CATEGORY?

8 A. All contingency costs are reviewed by project management and must receive
9 the necessary approvals. The approval process varies depending upon use,
10 dollar amount and priority. Depending upon the dollar amount, a
11 cost/benefit or case study may be required to justify approval. Such was the
12 case with the greasing mechanism previously mentioned, where a case study
13 was performed. That case study assessed the benefits of installing an
14 improved automatic greasing system, which would provide long-term cost and
15 reliability benefits.

16
17 Q. OVERALL, WHAT HAS THE COMPANY DONE TO MINIMIZE THE ADDITIONAL
18 NOBLES AND MERRICOURT PROJECT COSTS?

19 A. As noted above, these are necessary and ordinary expenses, many of which are
20 not within the Company's control (e.g. payments to landowners, taxes). Where
21 the ability exists to exercise some cost control, we have taken steps to manage
22 those costs.

23
24 First, using a build/transfer approach of an EPC puts much of the project risk
25 on the contractor versus the owner. Thus, the build/transfer arrangement
26 minimizes the need for contingencies to a level that is substantially less than
27 the contingencies would have been if we self-built the projects.

1

2 Second, our active involvement in the E&C oversight process helps minimize
3 costs by working with the contractor throughout the construction process.
4 For example, we were able to obtain insurance cost savings by replacing
5 enXco's builder's insurance with our own. Our involvement also leads to a
6 better quality project. For example, it is expected that the higher up-front
7 costs for the change in automatic greasing described above will result in long-
8 term savings and increased reliability.

9

10 Third, we also try to minimize costs by using RFPs where appropriate for
11 services such as the hiring of the engineering consultant and outside legal
12 resources. Finally as I described above, we closely review change orders and
13 contingency costs, such as the greasing mechanism change, and require
14 approvals before they can be incurred.

15

16 Q. IS THE COMPANY REQUIRED TO PROVIDE ANNUAL FILINGS AS A PART OF THE
17 ADPS ISSUED FOR NOBLES AND MERRICOURT?

18 A. Yes. North Dakota Century Code 49-05-16(3) states, "a resource addition
19 approved by the Commission is subject to annual reporting requirements until
20 commercial operation of the resource addition." I request that my testimony
21 serve as the update to the Commission with respect to both ADPs.

22

23 Q. DO THE ADDITIONAL COSTS AFFECT THE COMPANY'S OPINION REGARDING
24 THE REASONABLENESS OF NOBLES AND MERRICOURT?

25 A. No. At the time we submitted our ADP applications for Nobles and
26 Merricourt, the projects were estimated to increase the total Company present
27 value revenue requirements ("PVRR") by approximately 0.11 and 0.12 percent

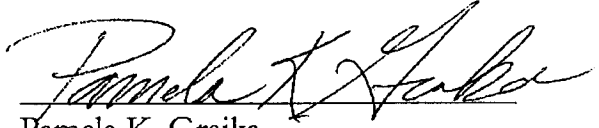
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STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern)
States Power Company, a Minnesota corporation)
For Authority to Increase Rates for Electric Service) Case No. PU-10-____
in North Dakota)

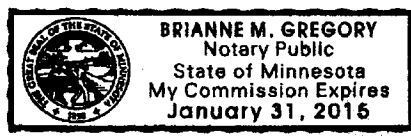
**AFFIDAVIT OF
Pamela K. Graika**

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


Pamela K. Graika

Subscribed and sworn to before me, this 16 day of December, 2010.


Notary Public



Statement of Qualifications
Pamela K. Graika
Manager, Power Generation
Xcel Energy
250 Marquette Plaza, Minneapolis MN 55102

Current Responsibilities

Manage 5 large coal and gas fired power plants and 3 smaller RDF plants, for a total of 4,500 MW's.

Previous Positions

Xcel Energy and Northern States Power Company Minnesota

General Manager, North Region Energy Supply	2002–Present
General Manager, Peaking and Renewables	2000–2002
Director, Environmental Affairs	1994–2002
Plant Manager, High Bridge Generating Plant	1990–1994
Plant Superintendent, Combustion Turbines and Hydro	1988–1990
Senior Production Engineer, Combustion and Hydro	1986–1988
Administrator Plant Permits and Compliance, Environmental Services	1982–1986
Assistant Environmental Engineer, Power Production	1980-1982
Asst. Production Engineer, High Bridge Plant	1979 - 1980

Education

Bachelor of Science, Chemical Engineering, University of Minnesota 1978

CERTIFICATE OF SERVICE

I, Lindsey L. Didion, hereby certify that I have this day served copies of the foregoing document on the attached lists of persons:

- Darrell Nitschke, Executive Director c/o Michael R. Diller with the North Dakota Public Service Commission by e-mail and by Federal Express; and
- by depositing a true and correct copy, properly enveloped with postage paid, in the United States Mail at Minneapolis, Minnesota to those persons listed on the attached service list for the following dockets:

CASE NO. PU-08-907 AND PU-08-908
Progress Report

Dated this 28th day of December 2010

/s/

Lindsey L. Didion

Xcel Energy ADP Applications for Merricourt &
Nobles Wind Projects
Progress Report – Service List.
Docket Nos: PU-08-907 and PU-08-908
12-28-2010

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North Dakota Public Service Commission
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