EXHIBIT
PSC-3

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Brian Kalk	Chairman
Randy Christmann	Commissioner
Julie Fedorchak	Commissioner

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 & NECESSITY	CASE NO. PU-13-195

REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT

This Revised Second Amended Settlement Agreement ("Revised Second Amended Settlement") is entered into this 25th day of February 2014, by and between the North Dakota Public Service Commission Advocacy Staff ("Staff") and Northern States Power Company ("Xcel Energy" or the "Company") (collectively, the "Parties") and supersedes the Second Amended Settlement dated February 18th. This Revised Second Amended Settlement will (a) result in just and reasonable rates for the Company's retail electric operations in North Dakota for a four-year period beginning January 1, 2013 and ending December 31, 2016 and (b) implement a framework to reflect North Dakota's energy policy priorities as expressed by the Commission. The Second Amended Settlement reflected additional discussion and agreement of the Parties with respect to the annual percent increase in rates necessary to address increased costs of service during the term of the multi-year plan. This Revised Second Amended Settlement revises terms used in the Second Amended Settlement and corrects typographical errors. Through this Revised Second Amended Settlement the Parties have resolved all issues in the above captioned proceedings.

PRELIMINARY STATEMENT

The above captioned Cases address the Company's requested 9.25 percent retail revenue increases (Case No. PU-12-813; the Rate Case); the Company's request for advanced determinations of prudence (ADP) for 750 MW of additional wind resources and a certificate of public convenience and necessity (PC&N) for a 150 MW wind project (Case Nos. PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743; the Wind Cases); and the Company's request for ADP and PC&N for the construction of three gas combustion turbines to meet an identified capacity need in the 2017-2019 time frame (Case Nos. PU-13-194, PU-13-195; the Gas CT Cases). Attachment A contains a summary of the procedural history of the Rate Case, the Wind Cases, and the Gas CT Cases (collectively, the Proceedings).

The Proceedings have raised a number of rate and policy issues related to the Company's ongoing provision of service in North Dakota. In light of these issues, and in an effort to achieve mutually agreeable long-term solutions, the Parties have entered into this Revised Second Amended Settlement to develop a multi-year rate plan and address North Dakota energy policy goals. Specifically, this Revised Second Amended Settlement establishes:

- A four-year rate plan that results in just and reasonable rates to match the Company's current investment cycle while balancing our customers' need for predictable and competitive rates;

- A framework to ensure that the Company's North Dakota customers will be served by a resource mix consistent with North Dakota's energy policies. The framework provides hard deadlines and financial impacts to the Company if the framework is not sufficiently developed; and

- A path toward development of North Dakota based generation nearer to the Company's existing loads.

Just and Reasonable Rates

The rate plan agreed to in this Revised Second Amended Settlement reflects efforts to minimize the impacts on customer energy bills during the Company's current investment cycle while providing the Company a reasonable opportunity to recover its investments and operating costs and earn a fair rate of return. The rate plan agreed to in this Revised Second Amended Settlement also provides a base rate increase moratorium for Xcel Energy's North Dakota customers in the final year of the plan.

Recognizing that a long-term rate plan requires reliance on forecasted costs and sales, this Revised Second Amended Settlement establishes a mechanism to ensure that the rates set in the rate plan are just and reasonable. This mechanism provides for revenue sharing with our customers for weather-normalized earnings in excess of the authorized returns on equity (ROE) established in this Revised Second Amended Settlement. The Parties believe that this mechanism creates reasonable safeguards for Xcel Energy's customers.

Even with the rate increases contemplated in this Agreement, the Company's average rates in North Dakota are projected to remain among the lowest in the Midwest and approximately 15 percent lower than the national average through 2016. Moreover, in 2016 the Company's North Dakota rates will have increased, on average, only about 2.6 percent per year over the past twenty-five years. This is similar to the average annual rate of inflation expected during the same period.[1]

<u>Serving Customers Consistent With North Dakota Energy Policy</u>

In addition to the multi-year rate solution presented in this Revised Second Amended Settlement, the Parties are also proposing to undertake actions intended to address the long-term interest of the Commission in exerting more control over the energy resource mix serving the Company's North Dakota customers. This Revised Second Amended Settlement creates a negotiating framework through which the Parties will

[1] Source: U. S. Dept. of Labor (Consumer Price Index).

seek to adjust the resource mix to be more consistent with the North Dakota energy policy now and in the future.

That said, the Parties also recognize the immense complexity of implementing this plan. Therefore, our proposal implements a hard deadline by which such a mechanism must be developed and filed with this Commission for its approval. If the Parties are unable to meet this deadline, this Revised Second Amended Settlement will result in adverse financial impacts on the Company, as described in Section II.A.

The Parties believe that this policy-based framework is a novel and bold approach to provide a long-term solution to long-standing North Dakota concerns and is a significant benefit of this Revised Second Amended Settlement.

Development of North Dakota Generation

Consistent with the efforts of the Parties to provide solutions to the Commission's stated policy interests, as part of this Revised Second Amended Settlement, the Company is committing to develop North Dakota based generation consistent with prudent resource planning principles and the concepts of orderly development. The Company's commitment is consistent with the timing and parameters of Advocacy Staff's recommendations to the Commission in the Gas CT Cases and demonstrates the Company's commitment to provide a reasonable framework for meeting the energy policy goals of North Dakota.

In addition, this Revised Second Amended Settlement is intended to address other matters affecting the Company that are currently before the Commission. Through a negotiated process, the Parties are seeking to address the Commission's concerns and have documented the outcome of these negotiations in this Revised Second Amended Settlement.

REVISED SECOND AMENDED SETTLEMENT TERMS

The Parties agree to the provisions as defined below and supported by Attachment B, which is a summary of the Revised Second Amended Settlement Agreement adjustments and their revenue impact.

I. REVENUE MATTERS

A. Rate Plan

1. *Multi-Year Solution*

The Parties acknowledge that the Company's rate request is driven largely by its current investment cycle which includes efforts to extend the lives and increase the capacity of its nuclear fleet, significantly invest in its transmission system, and to refresh and automate its distribution system. These investments not only create a revenue deficiency in the 2013 test year, but are forecasted to drive revenue shortfalls in 2014 and 2015 as well.

The Rate Plan agreed to by the Parties in this Revised Second Amended Settlement allows the Company to implement annual electric base rate increases for three years in lieu of filing additional and separate rate cases to address the forecasted deficiencies in those years due to the Company's on-going investment cycle. The Rate Plan then imposes a rate moratorium for the final year to match with the close of the Company's investment cycle. As part of the Rate Plan, the Company would be precluded from filing another general rate application prior to November 1, 2016 (and increasing base rates before 2017). The agreed-to Rate Plan is derived from a consideration of the Company's longer-range financial forecasts and a common desire to lessen bill impacts.

The proposed retail revenue increase percentages and corresponding base revenue increase estimates are shown in Table 1 below:

Table 1

Plan Year	Retail Increase %	Est. Base Revenue Increase
2013	4.9 %	$7,378,000[2]
2014	4.9%	$9,368,000
2015	4.9%	$10,072,000
2016	0%	$0

The methodology for implementing the proposed increase percentages is provided in Attachment C.

2. *Ensuring Just and Reasonable Rates*

To ensure rates are appropriately set under the Rate Plan, the Parties agree to establish an earning sharing mechanism to share with customers any weather-normalized earnings above the ROE agreed to in this Revised Second Amended Settlement. The earnings sharing mechanism requires that in the event the Company's annual weather-normalized earnings exceed the agreed to ROE in this Revised Second Amended

[2] Reflects February 16, 2013 effective date of Revised Second Amended Settlement 2013 rate increase and corresponding 10.5 months of recovery for an estimated annualized increase of $8,953,000.

Settlement described in Section I.A.3, the Company will refund to customers 50 percent of any weather-normalized revenue earned in excess of its authorized ROE for a particular year of the Rate Plan.

The earnings sharing framework is asymmetrical; customers will not be charged for earnings below the authorized level. The Parties further agree that, in 2016, the calculation of weather-normalized earnings for the purposes of the revenue sharing mechanism shall account for the impact to the Company's overall earnings of the costs of any power purchase agreement for which the Company has agreed, or which the Commission has ordered, be excluded from the calculation of the Company's Fuel Cost Rider mechanism (FCR), either in whole or in part and such costs are not recovered in another jurisdiction.

3. *Return on Equity and Capital Structure*

To ensure a balance between rate affordability, system reliability, and the utility's financial health, the Parties agree for settlement purposes to an authorized ROE of 9.75 percent for 2013. The approved ROE will increase in 2014 and again in 2016 in acknowledgment of the longer-term nature of the Rate Plan as provided in Table 2 below:

Table 2

Plan Year	Authorized ROE
2013	9.75 %
2014	10.00 %
2015	10.00 %
2016	10.25 %

The Parties also agree that a 10.00 percent ROE will be used for purposes of determining interim rates in the Company's next electric rate application.

For future rate rider calculations, the capital structure and cost of debt listed in Attachment D would be used, specifically the test year amounts, and the ROE would be updated per this Revised Second Amended Settlement. For annual reporting, the actual capital structure and cost of debt would be used in addition to the specified ROE.

B. Rider Implementation and Reform

In addition to the Rate Plan agreed to in this Revised Second Amended Settlement, the Parties have agreed to implement transparency reforms to the Company's Fuel Cost Rider (FCR) and to implement a Transmission Cost Recovery Rider (TCR) and a North Dakota Renewable Energy Rider.

1. Fuel Cost Rider Reforms

In addition to the cost of fuel, the Company currently recovers the costs of its power purchase agreements (PPA) through the FCR, consistent with the Commission's rules. N.D. Admin. Code § 69-09-02-39. However, the Parties recognize that a stronger "gatekeeping" mechanism is necessary to ensure that the Commission has been fully notified of PPA costs to be recovered through the FCR to determine if they are prudent. To that end, the Parties have agreed to reform the procedures through which the Company may include the costs of PPAs in the FCR.

For projects less than 50 MW in size, the Company will make an annual filing providing notification of any new PPAs that have been included in the FCR in that year. Such annual filing will include a description of the project, a summary of the justification for the contract or investment, the expected annual costs over the life of the contract, and the initial estimated monthly bill impact to residential customers. Such notification will provide clear and transparent notice to the Commission of the new PPA(s) under 50 MW being included in the Company's FCR calculation and allow the Commission to decide if it wants to review the PPA(s) in more detail to determine its prudence, consistent with the Commission's current Automatic Adjustment Clause Rules. The Parties agree that in the event the Commission does not commence review of the PPA(s) identified in the annual FCR notice filing within six months of the filing, the PPA(s) identified in the annual FCR notification filing will be deemed prudent for ratemaking purposes for the life of the PPA(s). In addition to the annual FCR notification filing, the Company will also provide similar information for new PPA(s) in the Company's regular monthly FCR filing in which the costs and volumes of that PPA are being included in the FCR calculation for the first time. The Parties further agree that the foregoing FCR reform is not applicable to any of the Company's energy purchases from the MISO market.

The Parties agree that Commission granting an ADP of all future PPAs over 50 MW is required before such costs are included in the Company's FCR for recovery. The Parties further agree that the foregoing FCR reform is not applicable to any of the Company's energy purchases from the MISO market.

The Company will file compliance tariff sheets implementing the above-mentioned FCR reforms within 90 days of the date of an Order adopting this Revised Second Amended Settlement.

2. Transmission Cost Rider

A significant component of the Company's investment cycle is the substantial investment in transmission infrastructure to support the Company's integrated system. Key among these investments is the Company's development of the CapX2020 Group 1 Projects for which the Commission granted an ADP in Case No. PU-09-678. As part of the Rate Case, the Company requested that the Commission approve the Company's implementation of a Transmission Cost Rider (TCR) to allow for rider recovery of these investments. To that end, the Parties agree to implement the Company's request to establish a TCR, consistent with N.D.C.C. § 49-05-04.3. The Company will file compliance tariff sheets implementing the TCR within 90 days of the date of an Order adopting this Revised Second Amended Settlement.

Consistent with the Company's request in the Rate Case, and to ensure transparency to the Commission and our customers of the costs included in the TCR, this Revised Second Amended Settlement only establishes the TCR tariff. The Company must file with the Commission a request to include specific costs for recovery through the TCR in a separate proceeding.

3. North Dakota Based Renewable Energy Rider

North Dakota law encourages the development of renewable resources in the State. Specifically, N.D.C.C. § 49-05-16 provides a rebuttable presumption that generation resource to be developed in North Dakota are prudent. Further, N.D.C.C. Chs. 49-02, 49-05 and 49-06 and Commission precedent in Case No. PU-06-466 allows for the recovery of costs of renewable resources developed in North Dakota. To that end, the Parties agree to implement a North Dakota Renewable Energy Rider as part of the Company's rate structure. To ensure transparency of the costs to be recovered through this rider, the Company may only include the costs of renewable projects that are located in North Dakota and for which the Commission has granted an ADP. As of the date of this Revised Second Amended Settlement, the Parties contemplate that the Company will recover the costs of the Border Winds Project (the subject of Case No. PU-13-742) through the Renewable Energy Rider, consistent with the agreed to terms of this Revised Second Amended Settlement concerning the Company's requested ADP in that Case.

The Company will file compliance tariff sheets implementing its Renewable Energy Rider within 90 days of the Commission's Order adopting this Revised Second Amended Settlement.

II. IMPLEMENTATION OF NORTH DAKOTA ENERGY POLICY

The Parties recognize that it has been the interest of North Dakota to exert more control over its energy resource future for a number of years. The Company and Staff began substantially addressing this interest in the Settlement Agreement adopted by the Commission in Case No. PU-07-776. In that settlement, the Company and Staff agreed to implement processes to keep the Commission informed of the Company's resource planning efforts through the then relatively new ADP law (N.D.C.C. § 49-05-16) to provide the Commission an opportunity to provide early input into the Company's resource decisions. A clear outcome of the Proceedings is the realization by both the Company and Staff that, while they improved awareness and enhanced dialogue regarding the Company's resource decisions, the processes implemented in Case No. PU-07-776 have been insufficient to address the Commission's needs.

In light of this, the Parties agree to make a fundamental and unprecedented shift in the way the Company serves its North Dakota customers by proposing to adjust rates to effectively change the resource mix serving its North Dakota customers so that it is more consistent with North Dakota's energy policies. The Parties believe that a comprehensive framework may be a better way to address the Company's resource decisions than on a case-by-case basis.

The Parties also recognize that an undertaking of this nature is extremely complex. To allow for a timely settlement of the Proceedings, this Revised Second Amended Settlement is intended to provide a framework for the Parties to further develop and implement such a mechanism. Through this framework, the Parties intend to cooperatively develop a mechanism through which the Company will serve its North Dakota customers with a resource mix consistent with North Dakota energy policies. However, due to the complexity of the undertaking, the likely involvement of other state Commissions, and the potential that the Parties may not reach ultimate agreement on the appropriate mechanism to implement the proposal, the Parties have agreed to a deadline by which they will bring a negotiated agreement to implement such a mechanism (Negotiated Agreement) to the Commission for approval. Should the Negotiated Agreement not be filed with the Commission by that deadline, the Parties have agreed on a remedial action that will disallow certain renewable energy costs identified in the Rate Case and the Wind Cases on a prospective basis. The Parties believe that such a negotiating structure will induce both the Company and Staff to obtain a timely and successful outcome of negotiations as well as provide for a default result consistent with the Commission's current policies and authority should no agreement be reached.

As part of this Revised Second Amended Settlement, the Company and Staff have also settled the outstanding issues in the Wind Cases and the Gas CT Cases as well as other outstanding renewable energy related issues that arose in the Rate Case. Further, this Revised Second Amended Settlement includes a commitment by the Company to develop North Dakota based thermal generation consistent with prudent resource planning principles as described in detail below.

A. North Dakota Policy Based Generation Mix – Negotiating Framework

As described above, the Parties have agreed to negotiate in good faith to develop a mechanism whereby the Company will serve its North Dakota customers with resources (either real or proxy) consistent with North Dakota's energy policies. The Parties have entered into preliminary discussions to explore the feasibility of such mechanism and agree that such an outcome is feasible. To that end, the Parties have agreed to the following general principles as a framework to guide such good faith negotiations to result in a Negotiated Agreement.

1. All policy choices come with benefits and drawbacks and that the ultimate outcome of the Company's proposal is to allow its North Dakota customers to obtain the benefits and bear the burdens of North Dakota's energy policy choices. Benefits may include immediately lower pricing while burdens may include increased exposure to commodity and regulatory risk. Consistent with this principle, the Parties agree that any cost savings or cost increases, now and in the future, that result from any Negotiated Agreement shall be allocated to the Company's North Dakota jurisdiction.

2. North Dakota energy policies are considered to be those expressed by the legislature through the enactment of laws, including the Renewable Energy Objective (N.D.C.C. § 49-02-28), and the Commission as expressed in its rules and orders.

3. The North Dakota historically allocated share of the Company's existing thermal resources provides an appropriate base upon which to meet a significant percentage (likely over 75 percent) of the Company's North Dakota resource needs. The North Dakota Renewable Energy Objective represents a reasonable amount of renewable resources to be included in the ultimate resource mix.

4. Any resources (real or proxy) utilized to replace existing Company resources that are deemed inconsistent with North Dakota energy policies should be "like" replacements taking into account the nature of the existing Company resource to be replaced (*i.e.* baseload, intermediate, peaking, *etc.*) and the contribution of the replaced resource to the integrated system (*i.e.* capacity and energy).

5. Proxy pricing (for either energy or capacity) for any future resource addition should reflect marginal pricing for the type of resource for which the proxy price is being utilized as a replacement.

6. Resource choices should be guided by the concept of reasonableness so that the ultimate North Dakota resource mix would be a reasonable approximation of what would have occurred had the Company historically developed its overall resource mix consistent with North Dakota policy so as not to result in only the lowest cost resources available making up the total agreed to North Dakota resource mix.

7. The Parties will consider the financial impact to the Company of the agreed upon resource mix in developing the Negotiated Agreement which includes but is not limited to providing for reasonable and mutually agreeable implementation schedules and deadlines.

8. The Negotiated Agreement must address how future resource additions will be treated if the Commission does not approve such future resource addition. Such future scenarios must account for both the energy and capacity value of such resources.

9. To provide certainty, the Negotiated Agreement is intended to be final for the purposes of developing a baseline resource mix (real or proxy) to serve the Company's North Dakota customers.

10. The Negotiated Agreement shall be subject to approval by the Commission.

The Parties agree to use their best efforts to negotiate in good faith, obtain agreement, document such agreement in the Negotiated Agreement, and file the Negotiated Agreement for approval with the Commission no later than June 30, 2015, unless the Parties mutually agree to request an extension from the Commission.

In the event the Parties do not (a) file an agreement with the Commission by June 30, 2015, or (b) request from the Commission an extension of time to file an agreement by June 30, 2015, then beginning January 1, 2016 the Company shall (i) remove from its calculation of its FCR the costs and volumes of the 21 PPAs identified on Attachment E, page 1; (ii) remove the costs of the three PPAs listed in Attachment E, page 2 from its FCR calculation and replace those costs as part of its FCR calculation with proxy costs representing the capacity and energy from the Company's Allen S. King Plant; and (iii) the Pleasant Valley Wind Project shall be disallowed from recovery in base rates in North Dakota and the volumes representing the energy production of the Pleasant Valley Project will be removed from the Company's calculation of its FCR. The Parties agree that this provides a penalty to the Company to induce the Company to use its best efforts to reach agreement in accordance with the negotiating framework.

B. Development of North Dakota Based Generation

As part of the Gas CT Cases, the Company proposed to construct two gas combustion turbines (CT) near Hankinson, North Dakota known as Red River Valley Unit 1 and Red River Valley Unit 2 to meet an identified capacity resource need in the 2017-2019 time frame. The record in the Gas CT Cases also reflects the fact that the Company may choose some alternative resource to meet that need instead of one or both of the proposed North Dakota based CTs. In light of the record in the Gas Cases, the Parties acknowledge that the Gas Cases identified the interest of the Commission in ensuring that the Company develops generation closer to its loads in North Dakota. The Parties further acknowledge that the record in the Gas CT Cases reflects the fact that diversifying the location of the Company's generation mix and locating generation closer to the Company's North Dakota loads provides some benefits to the Company's North Dakota customers as well as all of the other customers served by the Company.

In recognition of the fact that the Company's proposal to construct and own North Dakota based generation to meet its 2017-2019 resource need may not be implemented, but to obtain the benefits of North Dakota based generation identified in the Gas CT Cases, the Company hereby commits to develop up to 400 MW of thermal generation resources in North Dakota no later than 2036, consistent with the principles of orderly development of resources, the principle of least-cost development as provided in N.D. Admin. Code § 69-09-02-33, and general concepts of prudent resource planning to meet incremental additional resource needs that may arise in that timeframe. In furtherance of the foregoing sentence, and not in limitation thereof, development of North Dakota based generation must be cost effective taking into account the benefits of locating generation nearer to North Dakota loads and the benefits of geographic diversity of generation when compared to other alternatives.

Additionally, the Company's North Dakota based generation must be developed to meet an identified resource need. The Company shall continue to inform the Commission of its resource needs through the filing of its Ten-Year Plan and Midwest Resource Plan consistent with North Dakota law and the Company's commitments. The Company and Advocacy Staff shall meet and confer with respect to resource needs as they deem appropriate. When performing its resource planning, the Company shall incorporate its commitment into its planning efforts. Further, the Company agrees to advocate for the development of North Dakota based generation in other affected jurisdictions to the extent such North Dakota based generation is both cost effective and needed, as discussed in this Section II.B.

C. Jurisdictional Demand Allocator

In light of the issues raised in the Rate Case related to the appropriate demand allocation methodology to be used for the purposes of setting the Company's North

Dakota rates, the Parties agree that a study shall be performed to analyze the contribution of the Company's North Dakota jurisdiction toward the Company's overall system-wide production and transmission costs, and the available demand allocation methodologies which may be implemented to reflect such cost causation (the Study).

The Parties intend the Study to be unbiased and thorough. To that end:

1. Scope. The Parties will determine, after consulting and seeking the input of the Commission, the appropriate scope of the Study, consistent with the terms of this Revised Second Amended Settlement. The scope of the Study will be to analyze a number of demand allocator methodologies and propose recommendations for the methodology or methodologies that most reasonably represent the cost causation of the North Dakota jurisdiction on the Company's overall system-wide production and transmission costs. Secondary consideration will be given to maintaining consistency among jurisdictions and administrative feasibility.

2. Independent Third-Party. The Parties will utilize the services of an independent third-party to assist in directing, monitoring, and evaluating the results of the Study. The Parties and the Commission must agree on the third-party to be used. Both Parties will fully cooperate with the third-party. Either Party may supplement the Study as appropriate to assure that the Commission has a full and complete record for its use.

3. Costs. The costs of using an independent third-party will be paid by the Company. The Parties agree to use deferred accounting to recover these costs as a rate case expense in the Company's next rate case

4. Submittal. In light of the intent of the Parties to provide an unbiased and thorough Study and allow for the Commission to review the results, the Parties will submit the Study to the Commission no later than one-year after the Commission issues an order adopting this Revised Second Amended Settlement. The Commission may direct that additional analysis be done regarding the Study after the initial submission. The Parties shall also consult and seek input from the Commission prior to initiating the Study as provided in Paragraph 1 above.

5. Use as Evidence. The results of the Study may be used by the Parties as evidence in the Company's next North Dakota rate case to support a particular demand allocation methodology.

6. Implementation of the Settlement. For purposes of this Revised Second Amended Settlement, the Parties agree to the continued use of the average 12-month Coincident Peak (12CP) demand methodology. Further, the jurisdictional allocations used in rate rider calculations during the term of the Revised Second Amended Settlement will be made using 12CP with the specific allocation factors updated to reflect the current circumstances and information.

D. Prairie Rose PPA

The Parties agree that, while the Company was not timely in filing its ADP application, (ultimately leading to Commission rejection of the ADP) the costs of the Company's Prairie Rose PPA are recoverable. In recognition of the Company's late-filed ADP and the Staff's concern that this resource exceeds what is needed to meet North Dakota's Renewable Energy Objective, the Parties agree that only the Prairie

Rose energy costs incurred on and after the date the Commission adopts this Revised Second Amended Settlement will be included in the FCR calculation and the Company will forego any unrecovered portion of the Prairie Rose PPA incurred prior to that time.

E. Settlement of the Gas CT Cases

The Parties agree that the Company's proposal to construct Black Dog Unit 6 and Red River Valley Units 1 and 2 under the flexible, phased in approach described in the Company's Application is a cost-effective and prudent approach to meet forecasted capacity needs of the Company in the 2017 to 2019 time-frame.

While acknowledging the prudence of the Company's proposal to construct and own Black Dog Unit 6 and Red River Valley Unit 1 and 2, this Revised Second Amended Settlement shall in no way be construed to foreclose upon the possibility and prudence of some other approach to meet the Company's proposed 2017-2019 capacity needs, such as any proposal that may be selected as part of the Minnesota Competitive Acquisition Process described in the record of the Gas CT Cases. In the event the Company chooses to move forward with a resource acquisition other than Black Dog Unit 6 or Red River Valley Unit 1 or Red River Valley Unit 2 to meet its 2017-2019 capacity need, it shall file an application for an Advanced Determination of Prudence for such other resource acquisition(s).

In the event that the Company constructs and owns Red River Valley Unit 1 or Red River Valley Unit 2 to meet its identified 2017-2019 resource needs, the Company's commitment in Section II.B of this Revised Second Amended Settlement shall be deemed to have been satisfied.

F. Settlement of the Wind Cases

The Parties agree that the Company's proposal to construct and own the Border Winds Project and to purchase the output of the Courtenay Project as described in the Wind Cases enjoy a rebuttable presumption of prudence as resource additions located within the State of North Dakota pursuant to N.D.C.C. § 49-05-16. The Parties further agree that the record in the Wind Cases does not support a rebuttal to the presumption of prudence. Therefore, the Parties agree that the Border Winds Project and the Courtenay Project are prudent resource additions to the Company's integrated system and meet the standards for advanced determinations of prudence from the Commission. The disposition of the Odell and Pleasant Valley Projects are intended by the Parties to be addressed in the Negotiated Agreement or as provided for in Section II.A of this Revised Second Amended Settlement.

III. RATE CASE ADJUSTMENTS

A. Pension Loss Amortization

The Parties agree to extend the Company's amortization period for unrecognized pension costs reflecting, among other things, costs associated with the 2008 market downturn.

The Company's pension costs are determined under the Aggregate Cost Method, a pension funding method based on guidelines provided by the Internal Revenue Service. The method does not comply with SFAS 87, but is allowed as a permitted exception under SFAS 71 since it has received regulatory approval. The Parties agree that the Company will move from the current "percent of compensation" based amortization period of approximately 10 years to a 20 year amortization period. The appropriate ratemaking treatment will include a return on the unamortized balance. The extension of the amortization period will delay recovery for the Company but will reduce test year revenue requirements by approximately $447,000.

B. Annual Incentive Plan

The Parties agree that for purposes of determining the overall test year revenue requirement and future regulatory reporting, Annual Incentive Plan costs above 15 percent of base pay will be excluded. This reduces the test year revenue requirement by $209,000.

C. Charitable Contributions and Economic Development Donations

The Parties agree that for purposes of determining the overall revenue requirement and annual regulatory reporting during the 2013-2016 term of the Agreement, donations to state and local economic development entities and charitable contributions will be excluded. This reduces the test year revenue requirement by $171,000 and $157,000, respectively.

D. Asset-based Margins on Wholesale Sales

In the Settlement Agreement resolving a previous rate application (Case No. PU-07-776), the Parties agreed that the Company would pass to customers 85 percent of the margins realized from wholesale electricity sales from Company-owned (asset-based) generation. The Company currently passes 100 percent of the jurisdictional allocation of these margins to its Minnesota and South Dakota customers.

The Parties agree that the Company will, beginning January 1, 2014, pass through 100 percent of wholesale asset-based margins to North Dakota customers as well. This change does not impact base rate revenue requirements, but it will benefit customers by reducing their fuel costs approximately $56,000 (asset-based margins are flowed to customers through the Fuel Cost Rider).

E. Amortized Expenses

The Parties agree to increase the amortization period for various non-recurring expense items from the Company's initially filed three year period to a four year period. This is consistent with the four-year term of the Rate Plan. The items included in this amortization treatment include rate case expenses from the previous and pending dockets, private fuel storage costs, deferred demand side management expenses, and SO_2 emission credits. The longer amortization period will result in a test year decrease in revenue requirements of approximately $92,000.

F. Department of Energy Nuclear Fuel Proceeds

In 2012, $4,668,000 in Department of Energy ("DOE") proceeds were credited to customer bills through a one-time bill credit as part of the interim rate refund in Case No. PU-10-657. These payments are a result of the Company's successful litigation against the DOE for its failure to take spent nuclear fuel during the period 1998 to 2013, net of legal costs. This Revised Second Amended Settlement Agreement provides for the disposition of an estimated $5,200,000 in additional payments received since then or yet to be received from the DOE.

The Parties agree that by having the Company retain the DOE payments received since the first payment and recording these proceeds as income in 2013 and 2014 allows a lower base rate increase to be implemented in these two years. The proceeds would be applied as follows under the Rate Plan:

2013: $3.9 million (from payments received in 2012 and 2013)
2014: $1.3 million (from payments received in 2013 and expected in 2014)

The Parties recognize that, while this approach provides only temporary revenue relief for 2013 and 2014, it helps to reduce revenue requirements and customer base rate impacts and provides for an efficient disposition of the DOE payments.

IV. RATE DESIGN

A. Class Apportionment

The Parties agree to a customer class revenue increase apportionment reflecting rate percentage changes (by customer class) that are consistent with the Company's originally proposed class revenue increases, as shown on Attachment F. This apportionment reflects rate percentage changes by customer class that are consistent with the Company's originally proposed class revenue allocation, as shown on the attachment.

The Parties agree to the miscellaneous tariff changes proposed in the Company's initial filing and not otherwise addressed in this Revised Second Amended Settlement. The Parties agree to use the Company's proposed rate design principles in developing final rates to implement the approved revenue requirement contained in this Revised Second Amended Settlement Agreement.

The Company shall file compliance tariff pages setting forth the revised electric rates and tariffs provided by this Revised Second Amended Settlement Agreement at least thirty (30) days after the date of approval of this Settlement.

B. Monthly Customer Charge

The Parties believe it would be prudent to make significant steps toward better matching of the fixed costs of providing electric service with fixed rates. Assigning fixed electric customer service costs (costs that are not driven by electric usage, such as metering and billing) to the fixed monthly Customer Charge is consistent with the bills that customers are familiar with when paying for other services. The Parties agree, therefore, to replace the four distinct Customer Charges for non-time of day residential electric service (regular overhead, overhead space heating, regular underground, and underground space heating) with a single, common Customer Charge of $14.00. The Small General Service Customer Charge will be set at $16.00. This will reduce the amounts of customer-related fixed costs recovered through the Energy Charge. The Energy Charges for the various residential and small general service rate codes will be reduced accordingly, such that the overall class increase is appropriately derived.

C. Account History Charge

The Parties agree to eliminate the $5 charge for responding to customer requests for account history.

D. Time of Day Rate

Currently, few of the Company's customers in North Dakota have opted for Time-of-Day (TOD) service. However, TOD offerings are becoming increasingly popular throughout the industry as customers seek ways to manage energy costs and utility companies implement smart metering technology and new billing systems. The Parties agree to investigate the feasibility of redesigning the Company's TOD rate in a manner that will provide accurate and clear pricing signals to customers, help reduce North Dakota's contribution to the Company's peak periods, and minimize the incremental costs to administrate the TOD rate. By December 31, 2014, the Company commits to submitting to the Commission either a pilot TOD tariff or a recommendation regarding an appropriate path for improving a residential TOD offering in North Dakota.

V. ADDITIONAL MATTERS

A. Renewable Energy Credit (REC) Sales

Currently, the Company passes to North Dakota customers 90 percent of the net proceeds from the sale of North Dakota-allocated RECs, as approved in Case No. PU-10-19. To date, North Dakota customers have been credited $1.1 million for their portion of REC sale proceeds. As a condition of this Revised Second Amended

Settlement, the Parties agree that the Company will pass 100 percent of North Dakota jurisdictional net REC proceeds to North Dakota customers for all sales on and after January 1, 2014.

Historically, the Commission's intentions have been for the Company to sell all North Dakota-allocated RECs not needed to meet the 2015 renewable objective of 10 percent. Given that the current market for hydro and biomass RECs is minimal since these types of RECs are not as viable for voluntary purchasers, the Company will investigate the potential for establishing a framework for transacting "inter-jurisdictional" REC sales whereby non-marketable RECs allocated to North Dakota could be transferred – or "sold" – to the Company's NSP REC portfolio for purposes of meeting the renewable energy standards or objectives of other jurisdictions served by the Company, subject to approval of the relevant jurisdictions. The proceeds from these transactions would be passed on to North Dakota customers like any other REC sale. The Company commits, as a condition of this Settlement, to file a report with the Commission no later than December 31, 2014 detailing its findings and recommendations for such a process.

VI. CUSTOMER REFUNDS

A. Interim Rates

Since the base rate increase for 2013 is lower than the current interim increase percent, this Revised Second Amended Settlement will result in a lower overall revenue increase for 2013 than the level currently being collected in interim rates. An estimated interim rate refund of approximately $3.45 million (plus interest) is expected to be issued to customers beginning approximately 1 month from the implementation of final rates.

The Parties agree the interim rates that went into effect on February 16, 2013 will remain in effect until final rates are implemented. An interim rate refund will be issued to customers within ninety (90) days of the implementation of final rates for the difference between total interim revenues collected since February 16, 2013 as reflected and calculated in Attachment G.

To determine the interim refund the Company will utilize the same practices it has used in the past and include monies for the St. Paul Cogeneration refund as agreed to by the Company in the Rate Case record.

At the time of this Revised Second Amended Settlement Agreement, the final amount of interim revenues collected is not available, so an estimate is made using a similar prorating of the annualized interim rate increase as described above resulting in a total customer refund of approximately $19.00 per residential customer, to be issued during the Revised Second quarter of 2014. Attachment G provides further information with respect to the interim rate refund.

VII. RELIABILITY AND REPORTING COMMITMENTS

A. Reliability Improvement Commitments

The Parties agree to expand the Company's current initiatives agreed to in its previous rate Settlement Agreement (Case No. PU-10-657) to improve reliability in North Dakota with the following actions:

1. Expansion of the Company's efforts to proactively locate and replace an older type of underground cable, referred to as 500 MCM cable, used in the Company's North Dakota electric distribution system. The original commitment was to incur $750,000 over three years (2012-2014) to find and remove this cable. Remaining funding from the Company's 2012 Intelliteam roll-out will be re-purposed to extend the 500 MCM removal project one additional year and expand the scope to approximately $400,000 per year from 2013-2015. No additional adjustment to test year revenue requirements is needed for this program expansion.

2. The current "Reliability Performance Plan" (RPP) in place for 2013, 2014, and 2015 will be extended through 2016 consistent with the general term of this Revised Second Amended Settlement. The RPP provides $50 credits to customers who experience more than 3 sustained outages in a given year, provides a financial incentive for the Company to achieve a 57 minute System Average Interruption Duration Index (SAIDI) threshold, and requires expanded outage reporting to the Commission. There is no additional adjustment to test year revenue requirements for the RPP term extension.

3. Suspension of the current practice of providing feeder outage notifications as they occur, and quarterly underground cable failure summary reports, until further Commission notice. The Company will continue to provide the Commission notice of major outages and other events as appropriate.

B. Removal Costs in Depreciation Rates

The Parties agree that the Company will footnote the North Dakota portion of its

Asset Retirement Obligation in its annual report of regulated earnings. It will also notify the Commission of any new depreciable life studies or revisions that have been completed and filed with the Minnesota Public Utilities Commission. The Parties agree that the depreciation lives and rates presented in the Rate Case will be the ones in effect upon approval of this Revised Second Amended Settlement.

C. Tariff Book Improvements

The Parties agree that the Company will submit to the Commission, no later than the date of its next general rate application, an updated and improved North Dakota Electric Rate Book. The new revision will include a thorough review of all tariffs and general rules of service and reflect language and/or format enhancements that will improve readability, remove unnecessary phrases or sections, and ensure the terminology is up-to-date and understandable. The Company will work with Staff throughout the project to ensure the revisions meet the needs of North Dakota customers, the Company, developers, and regulators.

D. Jurisdictional Financial and Budget Variance Reporting

During the Rate Case, Staff and the Commission expressed concerns about the Company's difficulty in producing North Dakota jurisdictional financial data on a monthly or year-to-date basis. The Parties recognize the need to be able to timely produce and review updates of actual expenses, test year expenses, rate base, and overall revenue requirements, particularly during discovery process. Thus, the Parties agree that, prior to the next general rate application, the Company will develop a jurisdictional financial system that can be used to update test year forecasts with actual data and/or revised revenue, expense, and capital expenditure forecasts. The tool will also be able to accommodate assumption changes for purposes of modeling different test year input scenarios.

VIII. OTHER TERMS AND CONDITIONS

A. Basis of Revised Second Amended Settlement

It is agreed that this Revised Second Amended Settlement is a negotiated settlement agreement subject to approval by the Commission. This Revised Second Amended Settlement does not establish any principle or precedent, or adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

B. Effect of the Settlement Negotiations

It is understood and agreed that all offers of settlement and discussions related to this Revised Second Amended Settlement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Revised Second Amended Settlement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

C. Applicability and Scope

This Revised Second Amended Settlement shall be binding on the Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Revised Second Amended Settlement does not set policy or overturn precedent. This Revised Second Amended Settlement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding.

D. Effective Date

This Revised Second Amended Settlement shall be effective on the date of the Commission Order approving the Revised Second Amended Settlement. The revised rates and tariff agreed to by this Revised Second Amended Settlement Agreement shall be effective on the dates specified herein.

E. Modification

If a Commission Order modifies or conditions approval of this Revised Second Amended Settlement, it shall be deemed terminated if either Party files a letter with the Commission within three (3) business days of the date of such Order stating that a condition or modification to the Revised Second Amended Settlement is unacceptable to such party.

F. Force Majeure

The Parties agree that certain material changes in the Company's forecasted expenses during the term of the Rate Plan that are beyond the Company's control and may require adjustment to the Company's rates then in effect or may be appropriate for deferral or recovery through a new rider, provided that the change is reasonably expected to increase or decrease the Company's North Dakota jurisdictional revenue requirement for its electric business by at least $1.5 million in that year.

The Parties agree that the Company may petition to the Commission to provide for a mechanism to address these additional costs as they arise during the effectiveness of the Rate Plan. The types of cost changes that would qualify for an adjustment pursuant to this section include changes in Generally Accepted Accounting Principles that are appropriately reflected in rate regulation; changes in tax laws (both federal and state in any jurisdiction that may affect the Company's cost of service in North Dakota); changes in the Company's obligations stemming from changes in federal or North Dakota state or municipal laws, or regulations issued or actions taken by federal or North Dakota state or local governmental bodies, including but not limited to the Environmental Protection Agency, the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Commission, and the Nuclear Regulatory Commission; and natural disasters or catastrophic events, net of any insurance proceeds.

CONCLUSION

The Parties have agreed to the forgoing terms to resolve all outstanding issues in the above-captioned proceeding. These terms are a result of negotiations between the Parties, are in the public interest, and will result in reasonable electric rates through 2016. For these reasons, the Parties urge the Commission to approve this Revised Second Amended Settlement.

[SIGNATURE PAGE FOLLOWS]

Dated this 25th day of February 2014.

Northern States Power Company,

A Minnesota corporation

By: ______________________

David M. Sparby

President and Chief Executive Officer

Dated this 25th day of February 2014.

Northern Dakota Public Service Commission Staff

By: ______________________

Ryan Norrell

Counsel to the Commission

[SIGNATURE PAGE TO REVISED SECOND AMENDED SETTLEMENT]

PROCEDURAL HISTORY
Case No. PU-12-813

On December 18, 2012, Northern States Power Company ("NSP" or "Xcel Energy") filed a Notice of Change in Rates for Electric Service ("Notice") with the North Dakota Public Service Commission (the "Commission") to increase its rates for electric utility service to provide additional 2013 test year annual revenue of $16,900,000 or a 9.25 percent increase over current rates effective for electric service on and after January 17, 2013. The Company filed testimony by eight witnesses in support of the Notice, along with revised tariffs, exhibits, and supporting statements.

Xcel Energy proposed to increase residential base rates by $6,312,000 or 8.95 percent and commercial service revenues by $10,380,000 or 9.47 percent. The 2013 proposed monthly increase for a residential customer using 750 kilowatt-hours in a winter month is $6.40 and in a summer month is $6.64. Rates for public authorities were proposed to increase by $92,000 or 8.29 percent.

Concurrent with the Notice, Xcel Energy submitted an Alternate Petition for Interim Rates. The proposed interim increase, which impacted only base rates, was for $14,704,000 or 8.05 percent, to be effective February 16, 2013 (60 days from filing) in the event the Commission suspended the proposed general increase. The proposed interim increase and rate design were submitted pursuant to the criteria set forth in N.D.C.C. 49-05-06.

On December 21, 2012, the Commission issued an order suspending Xcel Energy's general rate increase application and set the matter for investigation and hearing.

On January 30, 2013, the Commission issued an order authorizing Xcel Energy to implement an interim electric rate increase of $14,704,000 effective February 16, 2013 and subject to refund.

On February 4, 2013, Xcel Energy filed compliance tariffs reflecting the Commissions interim rate Order.

On February 13, 2013 the Commission issued a Notice of Hearing, Intervention Deadline, and Public Input Session. The Notice announced that a Public Hearing would be held beginning August 27-29, 2013 at 9:00 a.m. central time, setting forth the following issues to be considered in this case:

1. What is the value of NSP's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is NSP's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

3. What is a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are NSP's rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

The Notice of Hearing also announced Public Input Sessions to be held via interactive television on April 15, 2013, at 7:00 p.m. and April 16, 2013, at 12:00 p.m. central time at various locations in Fargo, Grand Forks, Minot, and Bismarck. Members of the public were invited to appear and participate in the informal discussion. Finally, the Notice set forth a deadline of May 1, 2013 for parties to indicate their interest in participating in the case. No parties intervened.

On April 3, 2013, Xcel Energy filed supplemental direct testimony in regards to cost recovery of the Prairie Rose wind power purchase agreement. In the Company's Prairie Rose ADP docket, the Commission had recently ordered that recovery of Prairie Rose costs be considered in a "separate proceeding".

On April 15 and 16, 2013, the Commission conducted two public input sessions. The sessions utilized interactive video-conferencing capabilities to include participants in Fargo, Grand Forks, Minot, and Bismarck. Outside of local media, only one person from the public attended.

On July 17, 2013, Advocacy Staff consultants Snavely, King, Majoros, and Associates, Inc. filed Direct Testimony. The testimony recommended a rate decrease in the amount of $2,088,000 based on an authorized ROE of 9.0 percent.

On July 22, 2013, Advocacy Staff analyst Sara Cardwell filed Direct Testimony.

On August 12, 2013 Xcel Energy filed rebuttal testimony and exhibits. The testimony reduced the amount of the rate increase request to $14,884,000 or 8.15 percent.

On August 22, 2013 Advocacy Staff filed supplemental testimony and exhibits. The testimony revised the recommended rate decrease to $10,018,000.

On August 26, 2013 the NDPSC held its initial Work Session in this proceeding.

On August 27, 28, and 29, 2013 Evidentiary Hearings were held in the Commission Hearing Room, 12th Floor, State Capitol Building.

During the months of September, October, and November, various settlement discussions were held between Staff and the Company to resolve the issues in the case.

On September 24, 2013, the NDPSC held its second Work Session in this proceeding.

On October 30, 2013, the NDPSC held its third Work Session in this proceeding.

On December 5, 2013 the Commission held its fourth Work Session in this proceeding.

On December 5, 2013, Advisory Staff issued a letter to NSP indicating that two late-filed exhibits remained outstanding, and that the Commission was interested in getting a status update on Settlement discussions in this case. The requested information was to be filed by December 11, 2013.

On December 6, 2013 NSP sent a letter to the Commission indicating that Settlement discussions were in progress but had been delayed by the Company's efforts to complete an updated five year forecast of its regulated earnings in North Dakota. The

Company informed the Commission that it and Advocacy staff would attempt to complete negotiations and file a Settlement Agreement by December 13, 2013.

On December 9, 2013 NSP filed the final late-filed exhibit requested during the Evidentiary Hearings with the Commission.

During the week of December 9 – 13, 2013, representatives met with Advocacy Staff to negotiate the final terms of a multi-year Settlement Agreement.

At a special meeting on December 10, 2013, the Commission took official notice in the rate case of the records of six other ADP filings and two Resource Plan dockets in North Dakota.

On December 13, 2013 this Settlement Agreement was entered into by Advocacy Staff and Xcel Energy, and filed with the Commission.

On December 20, 2013, Advocacy Staff filed testimony in support of the Settlement Agreement. Also on this day, NSP responded to the December 10, 2013 Notice recognizing the records of multiple open cases before the NDPSC to clarify certain statements made by a witness in the Gas CT cases (Case Nos. PU-13-194 and PU-13-195) should be evaluated in their entirety.

On January 7, 2014 the Commission held an Informal Hearing on the Settlement Agreement.

On January 15, 2014, NSP filed testimony supporting the Settlement Agreement.

On January 17, 2014, Advocacy Staff submitted additional testimony documenting

Staff's presentation of the Settlement Agreement to the Commission at its January 7th Informal Hearing.

On January 23, 2014, the Commission conducted a Formal Hearing on the Settlement Agreement.

On January 24, 2014, the Commission held its fifth Work Session in this proceeding.

On January 28, 2014, NSP filed the first of two hearing exhibits requested during the January 23rd Formal Hearing.

On February 3, 2014 the Amended Settlement Agreement and final hearing exhibit requested during the January 23rd Formal Hearing was filed.

On February 12, 2014, the Commission held its sixth Work Session in this proceeding.

On February 18, 2014, the Second Amended Settlement Agreement was filed.

On February 25, 2014, the Revised Second Amended Settlement Agreement was filed.

The administrative record in this proceeding supports the Revised Second Amended Settlement Agreement, and the Parties jointly recommend the Commission approve this Revised Second Amended Settlement Agreement without further modifications.

Case Nos. PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743

On July 26, 2013, Northern States Power Company (NSP or Company) filed an application with the North Dakota Public Service Commission (Commission) seeking an advance determination of prudence (ADP) under North Dakota Century Code Section 49-05-16 for NSP's undertaking of three wind projects:

- a proposed power purchase agreement (PPA) for the 200 megawatt (MW) Courtenay Wind Project (Courtenay) to be located in Stutsman County, North Dakota in Case No. PU-13-706;

- a proposed PPA for the 200 MW Odell Wind Project (Odell) to be located near Mountain Lake, Minnesota in Case No. PU-13-707; and

- a proposed purchase of the 200 MW Pleasant Valley Wind Project (Pleasant Valley) to be located near NSP's existing Grand Meadow Wind Farm in southeastern Minnesota in Case No. PU-13-708.

On August 13, 2013, NSP filed an application for an ADP for the proposed purchase of the 150 MW Border Winds Project (Border Winds and collectively with Courtenay, Pleasant Valley and Odell, the Resource Additions) to be located in Rolette County, North Dakota in Case No. PU-13-742. Also on August 13, 2013, NSP filed an application for a Certificate of Public Convenience and Necessity for Border Winds in Case No. PU-13-743.

On September 25, 2013, the Commission issued a Notice of Consolidated Hearing consolidating for hearing Case Nos. PU-13-706, PU-13-707, PU-13-708, PU-13-742, and PU-13- 743 and scheduling a hearing for October 31, 2013 in the Commission Hearing Room, Twelfth Floor, State Capitol, Bismarck, North Dakota. The Notice specified the issues to be considered were:

1. Are the PPAs reasonable and prudent and in the best interests of customers?
2. Is NSP's proposed investment in the Pleasant Valley Wind Project and the Border Winds Project prudent?
3. Whether the public convenience and necessity will be served by the purchase and operation of the facilities.
4. Whether the applicant is fit, willing, and able to provide service.

On October 2, 2013, NSP filed corrections to the ADP applications in the instant Cases.

On October 31, 2013, a public hearing was held as scheduled.

On November 5, 2013 the Commission held its first work session on these Cases.

On December 2, 2013 the Commission held its second work session on these Cases.

During the week of December 9 – 13, 2013, representatives met with Advocacy Staff to negotiate the final terms of a multi-year Settlement Agreement.

On December 13, 2013 this Settlement Agreement was entered into by Advocacy Staff and Xcel Energy, and filed with the Commission.

On December 20, 2013, Advocacy Staff filed testimony in support of the Settlement Agreement. Also on this day, NSP responded to the December 10, 2013 Notice recognizing the records of multiple open cases before the NDPSC to clarify certain statements made by a witness in the Gas CT cases (Case Nos. PU-13-194 and PU-13-195) should be evaluated in their entirety.

On January 7, 2014 the Commission held an Informal Hearing on the Settlement Agreement.

On January 15, 2014, NSP filed testimony supporting the Settlement Agreement.

On January 17, 2014, Advocacy Staff submitted additional testimony documenting Staff's presentation of the Settlement Agreement to the Commission at its January 7th Informal Hearing.

On January 23, 2014, the Commission conducted a Formal Hearing on the Settlement Agreement.

On January 24, 2014, the Commission held its fifth Work Session in this proceeding.

On January 28, 2014, NSP filed the first of two hearing exhibits requested during the January 23rd Formal Hearing.

On February 3, 2014 the Amended Settlement Agreement and final hearing exhibit requested during the January 23rd Formal Hearing was filed.

On February 12, 2014, the Commission held an additional Work Session in this proceeding.

On February 18, 2014, the Second Amended Settlement Agreement was filed.

On February 25, 2014, the Revised Second Amended Settlement Agreement was filed.

The administrative record in this proceeding supports the Revised Second Amended Settlement Agreement, and the Parties jointly recommend the Commission approve this Revised Second Amended Settlement Agreement without further modifications.

Case Nos. PU-13-194, PU-13-195

On April 26, 2013, Northern States Power Company (NSP or Company) filed an application with the North Dakota Public Service Commission (Commission) seeking an advance determination of prudence (ADP) under North Dakota Century Code Section 49-05-16 for its proposal to add three 215 MW natural-gas-fired, simple cycle, combustion turbine (CT) generators to its system (Case No. PU-13-194):

- The first CT will be constructed at Xcel Energy's Black Dog generation plant in Burnsville, Minnesota (Black Dog Unit 6) for service beginning in 2017;
- The second and third CTs will be constructed at a new plant site to be located in the Red River Valley near Hankinson, North Dakota (Red River Valley Units 1 and 2) for service beginning in 2018 and 2019.

The Company also requested the Commission grant a Certificate of Public Convenience and Necessity for Red River Valley Units 1 and 2, pursuant to North Dakota Century Code Chapter 49-03 (Case No. PU-13-195).

On October 9, 2013, the Commission issued a Notice of Consolidated Hearing consolidating for hearing Case Nos. PU-13-194 and PU-13-195, and scheduled a hearing for November 26, 2013, in the Commission Hearing Room, Twelfth Floor, State Capitol, Bismarck, North Dakota. The Notice specified the issues to be considered were:

1. Whether NSP's proposed investment in the three CTs is prudent;

2. Whether the public convenience and necessity will be served by the NSP's construction and operation of the three CTs; and

3. Whether NSP is fit, willing, and able to provide service.

On November 26, 2013, a public hearing was held as scheduled.

On December 2, 2013 the Commission held its first work session on these Cases.

During the week of December 9 – 13, 2013, representatives met with Advocacy Staff to negotiate the final terms of a multi-year Settlement Agreement.

On December 13, 2013 this Settlement Agreement was entered into by Advocacy Staff and Xcel Energy, and filed with the Commission.

On December 20, 2013, Advocacy Staff filed testimony in support of the Settlement Agreement. Also on this day, NSP responded to the December 10, 2013 Notice recognizing the records of multiple open cases before the NDPSC to clarify certain statements made by a witness in the Gas CT cases (Case Nos. PU-13-194 and PU-13-195) should be evaluated in their entirety.

On January 7, 2014 the Commission held an Informal Hearing on the Settlement Agreement.

On January 15, 2014, NSP filed testimony supporting the Settlement Agreement.

On January 17, 2014, Advocacy Staff submitted additional testimony documenting Staff's presentation of the Settlement Agreement to the Commission at its January 7th Informal Hearing.

On January 23, 2014, the Commission conducted a Formal Hearing on the Settlement Agreement.

On January 24, 2014, the Commission held its fifth Work Session in this proceeding.

On January 28, 2014, NSP filed the first of two hearing exhibits requested during the January 23rd Formal Hearing.

On February 3, 2014 the Amended Settlement Agreement and final hearing exhibit requested during the January 23rd Formal Hearing was filed.

On February 12, 2014, the Commission held an additional Work Session in this proceeding.

On February 18, 2014, the Second Amended Settlement Agreement was filed.

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The administrative record in this proceeding supports the Revised Second Amended Settlement Agreement, and the Parties jointly recommend the Commission approve this Revised Second Amended Settlement Agreement without further modifications.

Xcel Energy
Electric Utility - State of North Dakota
Second Amended Settlement Agreement - 2013 Test Year Revenue Requirement
Dollars in 000's

Item	**Amount**	**Notes**
2013 Test Year Deficiency as Filed (Dec. 18, 2012)	$16,900	
Rebuttal Testimony Corrections, Updates, and Adjustment	($2,016)	
Revised Test Year Deficiency	$14,884	8.1%
Settlement Adjustments		
Return on Equity (from 10.25% to 9.75%)	($1,690)	
Unrecognized Pension Costs - extend amortization	($447)	a
Incentive Plan/ Nuclear Restricted Stock adjustments	($209)	b
Economic Develop Contributions	($171)	
Charitable Contributions	($157)	
Extend 3 Yr amortization of non-recurring items by 1 Yr	($92)	c
Total Adjustments	($2,766)	
Settlement 2013 Test Year Deficiency	$12,118	
Reduce Deficiency by DOE Proceeds	($3,937)	
Adjusted 2013 Test Year Settlement Deficiency	$8,181	
4.9% Settlement Increase for 2013	$7,378	d

Notes:

a) Reflects replacement of the current "percent of compensation" based amortization period of approximately 10 years to a 20 year amortization.

b) Limits AIP costs to 15 percent of base pay; removes all nuclear restricted stock costs.

c) see Exh. AEH-1, Schedule 20 of Application for amortized items

d) reflects partial annual recovery, effective Feb. 16, 2013

Xcel Energy
Electric Utility – State of North Dakota
Revised Second Amended Settlement Agreement Rate Change Procedures

1. The overall annual rate increase percent for 2013, 2014, and 2015 is 4.9 percent.

2. The Company's budget or updated forecast of the upcoming test year base revenues and fuel cost rider revenues will be used as the baseline for applying the annual 4.9 percent increase. Any Transmission Cost Recovery and/or Renewable Cost Recovery Rider revenues forecasted for the corresponding year will not be included in the baseline amount.

3. The annual base rate increase amount is determined by multiplying the Company's total projected base and fuel revenues for the upcoming forecast (test) year by 4.9 percent. The result is the allowable base rate increase amount for that forecast year.

   Annual Base Revenue Increase = Sum of (Projected Base and Fuel Revenues) x .049

4. The 2013 increase will be apportioned to classes based on the Company's apportionment proposal in Case No. PU-12-813. The Company is authorized to implement an across-the-board 4.9 percent increase to all classes in 2014 and 2015.

5. The compliance tariffs to effectuate the qualifying revenue increases proposed for each customer class will be filed with the Commission at least 60 days prior to their effective date (generally January 1 of the test year). Staff will review the filings for completeness and accuracy. No additional Commission action will be required.

6. The tariffs supporting the proposed 2013 and 2014 increases will be filed within 10 days of Commission approval of this Revised Second Amended Settlement Agreement. The 2013 and 2014 increases will go into effect May 1, 2014, or within 60 days of the order approving the compliance tariffs. Because those increases will be less than the interim rates currently in effect, they will result in interim rate refunds. The interim refunds will be issued within 90 days of the effective date of the new rates. The 2015 increase will be filed October 31, 2014 for rates to be effective January 1, 2015.

Case No. PU-12-813
Attachment D

Xcel Energy
Electric Utility - State of North Dakota
Settlement Agreement - Capital Structure

	2013			2014			2015			2016		
	%	Cost	Wtg.%	%	Cost	Wtg.%	%	Cost	Wtg.%	%	Cost	Wtg.%
Long Term Debt	44.96%	5.14%	2.31%	44.96%	5.14%	2.31%	44.96%	5.14%	2.31%	44.96%	5.14%	2.31%
Short Term Debt	2.48%	0.75%	0.02%	2.48%	0.75%	0.02%	2.48%	0.75%	0.02%	2.48%	0.75%	0.02%
Shareholders' Equity	52.56%	9.75%	5.12%	52.56%	10.00%	5.26%	52.56%	10.00%	5.26%	52.56%	10.25%	5.39%
Total	100.00%		7.45%	100.00%		7.59%	100.00%		7.59%	100.00%		7.72%

Xcel Energy – State of North Dakota
Electric Rate Case Settlement

IDENTIFIED RENEWABLE PPAS

BioMass

1. KODA Energy LLC (12 MW)
2. WM Renewable Energy (MN Methane) (12 MW)
3. Pine Bend (4.7 MW)

Community Based Energy Development (CBED) Wind

1. Jeffers Wind 20, LLC (50 MW)
2. Big Blue (36 MW)
3. Community Wind South (Zephyr) (30 MW)
4. Ridgewind Power Partners LLC (25 MW)
5. Adams Wind Generations (20 MW)
6. Danielson Wind Farms (20 MW)
7. Ewington Energy Systems LLC (20 MW)
8. Grant County Wind, LLC (20 MW)
9. North Community Turbines (15 MW)
10. North Wind Turbines (15 MW)
11. Valley View Transmission (10 MW)
12. Uilk Wind Farm (4.5 MW)
13. Hilltop Power (2 MW)
14. Winona County Wind (1.5 MW)
15. Woodstock Municipal Wind, LLC (0.8 MW)

Other Wind

1. Odell (200 MW)

Solar Contracts

1. Outland Solar (2 MW)
2. Best Power (St. Johns) (0.4 MW)

IDENTIFIED BIOMASS PPAS

1. FibroMinn (55 MW)
2. Laurentian Energy Authority I (35 MW)
3. St. Paul Cogeneration (25 MW)

Northern States Power Company
Electric Utility - North Dakota Retail Jurisdiction
Test Year Ending December 31, 2013
Settlement Rate Revenue Apportionment
Dollars in 000's

	Residential	Non-Dmd	Demand	Lighting	Retail	Other[1]	Total
Original Application							
Present	$70,465	$11,575	$98,825	$1,860	$182,724	$0	$182,724
Proposed	$76,777	$12,537	$108,334	$1,948	$199,597	$27	$199,624
Increase	$6,312	$963	$9,509	$89	$16,873	$27	$16,900
Percent change	8.96%	8.32%	9.62%	4.77%	9.23%		9.25%
Class Allocation	38.47%	6.28%	54.28%	0.98%	100.00%		
Settlement Agreement							
Test Year 2013							
Present Revenue	$70,465	$11,575	$98,825	$1,860	$182,724	$0	$182,724
Increase	$3,344	$510	$5,038	$47	$8,939	$14	$8,953
Percent change	4.75%	4.41%	5.10%	2.52%	4.89%		4.90%
Total Revenue	$73,809	$12,085	$103,863	$1,907	$191,663	$14	$191,677
Class Allocation	38.51%	6.31%	54.19%	0.99%	100.00%		
Year 2014							
Present Revenue	$73,620	$12,054	$103,597	$1,902	$191,172	$14	$191,186
Increase	$3,602	$590	$5,068	$93	$9,353	$15	$9,368
Percent change	4.89%	4.89%	4.89%	4.89%	4.89%		4.90%
Total Revenue	$77,222	$12,643	$108,665	$1,995	$200,525	$29	$200,554
Class Allocation	38.51%	6.31%	54.19%	0.99%	100.00%		
Year 2015[2]							
Present Revenue	$79,144	$12,958	$111,369	$2,044	$205,515	$30	$205,545
Increase	$3,873	$634	$5,449	$100	$10,056	$16	$10,072
Percent change	4.89%	4.89%	4.89%	4.89%	4.89%		4.90%
Total Revenue	$83,016	$13,592	$116,819	$2,144	$215,571	$46	$215,617
Class Allocation	38.51%	6.31%	54.19%	0.99%	100.00%		

[1] Other: Increases in Non-Retail Operating Revenues: Late Payment Fees

[2] Year 2015 is an example based on current estimated revenue; updated 2015 figures will be filed with the Commission prior to the implementation of the 2015 increase.

Northern States Power Company
Electric Utility - State of North Dakota
Summary of Interim Refund
Second Amended Settlement

Case No. PU-12-813
Attachment G
Schedule 1

		2013 TY	2014 TY	Total
Interim Refund Factor Calculation				
1	Authorized Annual Interim Rate Increase	$14,704,000	$14,704,000	
2	Approved Annual Base Rate Increase	$8,953,000	$18,321,000	
3	Annualized Excess Interim Recovery (line 1- line 2)	$5,751,000	-$3,617,000	
4	% Refundable (line 3 / line 1)	39.1118%	-24.5987%	
5	Actual Interim Revenue Increase Collected[1]	$12,115,262	$5,256,467	$17,371,729
6	Interim Refund Excluding Interest (line 4 x line 5)	$4,738,497	-$1,293,022	$3,445,475
7	Interest on Interim Refund Balance (Schedule 3)	$63,804	$44,248	$108,051
8	Interim Refund Including Interest (line 6 + line 7)	$4,802,301	-$1,248,775	$3,553,526
9	St Paul Co-Gen PPA Refund			$89,000
10	Net Interim Refund Including Interest (line 8 + line 9)			**$3,642,526**
11	**Interim Refund Factor (line 10 / line 5)**			**20.9681%**
Est. Average Residential Customer Interim & DOE Settlement Refunds				
12	Interim Revenues for Residential Customers			$7,209,620
13	Average Residential Customers Feb. 2013 - Nov. 2013			78,909
14	Average Interim Revenues per Customer (line 12 / line 13)			$91
15	Est. Average **Interim Refund** per Residential Customer (line 11 x line 14)			**$19.16**

[1] 2013 interim revenues collected from Feb. 16, 2013 through Dec. 31, 2013. 2014 interim revenues collected from Jan. 1, 2014 through April 30, 2014. Revenues for February through April 2014 are estimates. See Schedule 2.

Northern States Power Company
Electric Utility - State of North Dakota
Interim Rate Refund by Month
Second Amended Settlement

Case No. PU-12-813
Attachment G
Schedule 2

	Interim Revenue Collected	% Refundable[1]	Interim Refund (excl. Interest)
Feb-13	$110,174	39.1118%	$43,091
Mar-13	$929,205	39.1118%	$363,429
Apr-13	$1,189,781	39.1118%	$465,345
May-13	$1,094,524	39.1118%	$428,088
Jun-13	$1,055,081	39.1118%	$412,661
Jul-13	$1,485,768	39.1118%	$581,111
Aug-13	$1,371,588	39.1118%	$536,453
Sep-13	$1,361,855	39.1118%	$532,646
Oct-13	$1,241,161	39.1118%	$485,440
Nov-13	$1,026,980	39.1118%	$401,670
Dec-13	$1,249,146	39.1118%	$488,563
2013 Total	$12,115,262		$4,738,497
Jan-14	$1,506,467	-24.5987%	-$370,571
Feb-14 Est.	$1,300,000	-24.5987%	-$319,783
Mar-14 Est.	$1,250,000	-24.5987%	-$307,484
Apr-14 Est.	$1,200,000	-24.5987%	-$295,184
2014 Total	$5,256,467		-$1,293,022
Grand Total	$17,371,729		$3,445,475

[1] Schedule 1, Line 4

Northern States Power Company
Electric Utility - State of North Dakota
Interim Refund Interest Calculation
Second Amended Settlement

Case No. PU-12-813
Attachment G
Schedule 3

Revenue Month	Beginning Balance	Curr Mo Int Rev Refund	Ending Balance	Average Balance	Days	Annual Interest[1]	Monthly Interest
Feb-13 [2]	$0	$43,091	$43,091	$21,545	13	3.25%	$25
Mar-13	$43,116	$363,429	$406,545	$224,830	31	3.25%	$621
Apr-13	$407,165	$465,345	$872,510	$639,838	30	3.25%	$1,709
May-13	$874,219	$428,088	$1,302,307	$1,088,263	30	3.25%	$2,907
Jun-13	$1,305,214	$412,661	$1,717,875	$1,511,545	30	3.25%	$4,038
Jul-13	$1,721,913	$581,111	$2,303,024	$2,012,468	31	3.25%	$5,555
Aug-13	$2,308,579	$536,453	$2,845,031	$2,576,805	31	3.25%	$7,113
Sep-13	$2,852,144	$532,646	$3,384,790	$3,118,467	30	3.25%	$8,330
Oct-13	$3,393,120	$485,440	$3,878,561	$3,635,840	31	3.25%	$10,036
Nov-13	$3,888,597	$401,670	$4,290,267	$4,089,432	30	3.25%	$10,924
Dec-14	$4,301,191	$488,563	$4,789,754	$4,545,472	31	3.25%	$12,547
2013 Total							$63,804
Jan-14	$4,802,301	($370,571)	$4,431,730	$4,617,015	31	3.25%	$12,744
Feb-14 Est.	$4,444,474	($319,783)	$4,124,691	$4,284,582	28	3.25%	$10,653
Mar-14 Est.	$4,135,344	($307,484)	$3,827,860	$3,981,602	31	3.25%	$10,990
Apr-14 Est.	$3,838,850	($295,184)	$3,543,666	$3,691,258	30	3.25%	$9,860
2014 Total							$44,248
Grand Total							$108,051

[1] Prime interest rates are from Federal Reserve Statistical Release H15 - Bank Prime Loan - Monthly
http://www.federalreserve.gov/releases/h15/data/Monthly/H15_PRIME_NA.txt

[2] Interim rates effective February 16, 2013 through April 30, 2014