BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF NORTH DAKOTA

NORTHERN STATES POWER COMPANY ADVANCE PRUDENCE – BIOMASS PPAS APPLICATION	CASE NO. PU-17-____
NORTHERN STATES POWER COMPANY DEFERRED ACCOUNTING – BIOMASS PPAS APPLICATION	CASE NO. PU-17-____

APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE

AND

APPLICATION FOR AUTHORITY FOR DEFERRED ACCOUNTING

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (NSP or Xcel Energy or the Company), submits to the North Dakota Public Service Commission (Commission) this Application for an Advance Determination of Prudence (Application) for proposed transactions relating to the Company's power purchase agreements (PPAs) for the Benson Power, LLC (Benson Power) (f/k/a Fibrominn) biomass plant (Benson facility), the Pine Bend biogas plant (Pine Bend facility), and the Hennepin Energy Recovery Center (HERC). This Application is being made pursuant to N.D.C.C. § 49-05-16, the Settlement Agreement in Case No. PU-07-776, and the Company's commitments in Case Nos. PU-12-59 and PU-12-813, *et al.*

As part of this Application, Xcel Energy further submits to the Commission a request for authority for deferred accounting that would allow the Company to defer recognition for the transactional, plant closing, and other associated costs of the Benson Power and Pine Bend transactions. This request is being made pursuant to N.D.C.C. § 49-05-16, N.D. Admin. Code § 69-09-05.1-03, 18 U.S.C. § 101, and the March 9, 2016 Order in Case Nos. PU-12-813.

35 PU-17-322 Filed 02/02/2018 Pages: 37
Exhibit NSP-1 - Application for ADP and Application for Deferred Accounting

41 PU-17-271 Filed 02/02/2018 Pages: 37
Exhibit NSP-1 - Application for ADP and Application for Deferred Accounting

41 PU-17-270 Filed 02/02/2018 Pages: 37
Exhibit NSP-1 - Application for ADP and Application for Deferred Accounting

We entered into negotiations with Benson Power, Pine Bend, and HERC with the objective of saving customers money and optimizing NSP's overall portfolio. We believe that the proposed transactions achieve that result. Specifically, the Company is proposing to: (1) terminate the PPA with Benson Power (Benson PPA), acquire the Benson facility, and subsequently close the facility; (2) terminate the PPA with the Pine Bend facility (Pine Bend PPA) early through a series of negotiated terms; and (3) extend the terms of the HERC PPA on more favorable terms (collectively, the Proposed Transactions). As provided in Table 1, below, these Proposed Transactions together will achieve over $519.1 million in total nominal cost savings for our customers over the next 11 years, which results in a net present value (NPV) of $377.3 million. North Dakota customers should realize about 5.49 percent of these savings, or approximately $28.5 million nominal and $20.2 million NPV.

Table 1: Nominal and NPV Cost Savings of Proposed Transactions*

	Nominal Dollars in Millions				NPV Dollars in Millions			
	System			ND	System			ND
Transaction	Current	Proposed	Savings	Savings	Current	Proposed	Savings	Savings
Pine Bend	15.4	8.8	6.6	0.4	12.3	7.1	5.2	0.3
HERC	89.1	56.2	32.9	1.8	71.5	44.9	26.6	1.5
Fibrominn	771.6	292.0	479.6	26.3	561.2	215.6	345.6	19.0
Total	876.1	357.0	519.1	28.5	645.0	267.6	377.4	20.7

*The period for the early PPA termination depends on the timing of regulatory approvals. Our analysis assumes the proposed changes would take effect as of January 1, 2018.

The cost savings from the Proposed Transactions will benefit customers in all cases, even if the Company must make the refund for the Benson and Pine Bend PPAs as provided for in the Commission-approved First Revised Negotiated Agreement (Negotiated Agreement) in Case Nos. PU-12-813, *et. al.*[1] Consequently, the Proposed Transactions are prudent.

If all contingencies are met and the Proposed Transactions proceed, Xcel Energy will incur transactional, plant closing, PPA buyout, and other associated costs that are unusual and non-recurring and were not contemplated by the Commission when setting current rates. These costs are reasonable and prudent for the achievement of

[1] *See N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, *et al.*, ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT (N.D.P.S.C. Mar. 9, 2016) ("By the end of 2025, NSP will build or have located in eastern North Dakota a natural gas-fired electric generation facility with a capacity of at least 200 MW. . . . If the combustion turbine is not in-service by December 31, 2025, NSP will refund to its North Dakota customers 50 percent of the revenues collected from North Dakota customers that exceed the revenues that would have been collected if North Dakota customers had paid an adjusted system average cost for fuel, and energy and associated capacity, for the six biomass PPAs identified in the Negotiated Agreement.").

the net cost savings contemplated by the Proposed Transaction. So as not to delay our ability to execute on the Proposed Transactions, the Company is requesting that the Commission authorize the Company to treat these costs as a regulatory asset and defer accounting so that they can be recovered in the future. The Company will then propose mechanisms to recover these costs sometime in the future.

In sum, the Proposed Transactions present a significant opportunity to drive down overall system costs and reduce North Dakota customers' energy expenses. Xcel Energy respectfully requests that the Commission grant an Advanced Determination of Prudence of the transactions and grant our request for deferred accounting treatment for the transaction costs.

The remainder of this Application addresses the following:

- Compliance Matters;
- Xcel Energy's Biomass Portfolio;
- Background and Key Terms of the Proposed Transactions;
- Economic Analysis of the Proposed Transactions;
- Prudence of the Proposed Transactions;
- Request for Deferred Accounting Authority; and
- Request to Consolidate Cases for hearing.

In support of our Application, Xcel Energy provides the following Direct Testimony:

- Policy Testimony – Aakash Chandarana
- Transaction Testimony– Greg P. Chamberlain
- Economic Analysis Testimony – Philip Joseph "P.J." Martin

II. COMPLIANCE MATTERS

A. DESCRIPTION OF APPLICANT

Xcel Energy is a Minnesota corporation duly authorized to conduct business in the State of North Dakota as a foreign corporation. The Company conducts business in the State of North Dakota as a public utility subject to the jurisdiction and regulation of the Commission pursuant to Title 49 of the North Dakota Century Code. The name and address of Xcel Energy is:

Northern States Power Company, a Minnesota corporation
414 Nicollet Mall
Minneapolis, Minnesota 55401

Xcel Energy also operates in North Dakota from the following address:

Northern States Power Company
2302 Great Northern Drive
Fargo, North Dakota 58102

The Company's Certificate of Incorporation with amendments and Certificate of Authority were filed with the Commission on September 30, 2009, and October 12, 2009, respectively, in Case No. PU-09-664. Current Certificates of Good Standing issued by the North Dakota and Minnesota Secretaries of State were filed in the same case, and are incorporated herein by reference.

Xcel Energy has service territory in five upper Midwest states including North Dakota. We presently serve approximately 94,000 retail electric customers in and around Fargo, Grand Forks, and Minot, North Dakota. We own just over 250 miles of transmission lines and 14 substations in North Dakota.

B. Communication and Service

We respectfully request that the following persons be placed on the Commission's official service list for all official communications in this case:

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C. Standard of Review

North Dakota Century Code section 49-05-16(1)(d) authorizes the Commission to issue an ADP if it "determines that the resource addition is prudent."

This standard is similar to the "honestly and prudently invested" standard that the Commission uses for ratemaking.[2] The general prudence standard calls for

[2] *See* N.D.C.C. § 49-06-02.

determining whether the utility action was reasonable at the time it was taken under all relevant circumstances.[3] Under Section 49-05-16(1), the Commission may issue an order approving the prudence of a proposed project if four conditions are met:

> a. The public utility files with its application a projection of costs to the date of the anticipated commercial operation of the resource addition;
>
> b. The public utility files with its application a fee in the amount of one hundred seventy-five thousand dollars….;
>
> c. The commission provides notice and holds a hearing, if appropriate, in accordance with section 49-02-02; and
>
> d. The commission determines that the resource addition is prudent. For facilities located or to be located in this state the commission, in determining whether the resource addition is prudent, shall consider the benefits of having the resource addition located in this state.

D. Authority for Relief Requested

1. *Advanced Determination of Prudence*

North Dakota Century Code § 49-05-16 allows for a public utility to seek an ADP from the Commission for a resource addition at the utility's discretion. Pursuant to the Settlement Agreement in Case No. PU-07-776, the Company is obligated to file an Application for an ADP for its acquisition of generating resources above 50 MW. Consistent with the precedent in Case Nos. PU-15-181 and PU-15-183, which stand for the proposition that the Company must seek an ADP for the acquisition of a facility for which it already has a Commission-approved PPA, the Company is seeking an ADP for its purchase of the Benson facility.[4] Additionally, the Company believes that the contract extension with HERC qualifies as a resource addition pursuant to the statute and although the Company is not required to seek an ADP for a resource addition of this size pursuant to the Settlement Agreement in Case No. PU-07-776, N.D.C.C. § 49-05-16 authorizes the Company to do so.

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[3] *See* Charles F. Philips, Jr., *The Regulation of Public Utilities — Theory and Practice* at 292 (Public Utility Reports 1988); *see also* David. J. Muchow & William A. Mogel, *Energy Law and Transactions* at § 4.02[3] [b] (2009).

[4] Pursuant to the Jurisdictional Determination provided on May 14, 2015 in Case No. PU-15-173, the Company does not require Commission approval for the Benson Power transaction pursuant to N.D.C.C. § 49-04-06.

The Company has included the PPA termination transaction with Pine Bend as this transaction is part of the overall Proposed Transactions for which the Company seeks Commission approval and deferred accounting authority.

In sum, while some aspects of the Proposed Transactions do not fit neatly within the Company's commitment to seek ADPs, it is clear that elements of the transactions (e.g., the Benson PPA) merit advance Commission feedback. Further, the overall impact of the transactions, if considered in the aggregate, meets the threshold for ADP consideration. As a result, the Company is seeking ADPs for the Proposed Transactions.

Consistent with our Letter of Commitment in Case No. PU-12-59, the Company is filing this Application at the same time as it is seeking similar authority in Minnesota.

2. *Deferred Accounting*

The Commission may authorize deferred accounting and amortization of unusual and non-recurring expenses that were not contemplated when setting the current rates.[5] By doing so, the Commission allows a utility to designate unusual and infrequent expenses as "regulatory assets" that will be amortized over future accounting periods.[6] Additionally, some of the expenses at issue in this application are associated with resources that are implicated in a previously approved settlement agreement that permits Xcel Energy to petition the Commission for special accounting treatment.[7]

III. XCEL ENERGY'S BIOMASS PORTFOLIO

Xcel Energy has been developing its biomass portfolio for many years. As the service provider for five states with large agricultural and timber product industries, development of biomass-fueled generation has been an interest of the Company and our stakeholders. To that end, the Company has developed a portfolio of biomass projects totaling almost 180 MW.

Different projects were acquired pursuant to different laws and programs. We acquired our first several biomass projects under our obligation to purchase the output from qualifying facilities as required by the Public Utilities Regulatory Policies

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[5] N.D. Admin. Code § 69-09-05.1-03 (adopting the accounting practices set forth in the Uniform System of Accounts ("USOA") prescribed by the Federal Energy Regulatory Commission ("FERC"), as set forth in 18 U.S.C. § 101); see also N.D.C.C. § 49-05-16.

[6] USOA, Definitions No. 31, Balance Sheet Accounts No. 182.3.

[7] *N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, et al., ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT (Mar. 9, 2016).

Act (PURPA). We then acquired three more biomass contracts under Minnesota's Biomass Mandate. Finally, our last biomass contracts were acquired under the auspices of the Minnesota Renewable Development Fund (RDF) program.

We believe that fostering emerging technologies is in our customers' best interest. We are a leader in wind generation, in part, due to our early adoption of the technology. By being an early adopter in the past, we are now positioned to add additional wind generation to our system and materially drive down customer costs. Unlike wind, biomass-fueled generation has not emerged as an economic renewable generation alternative.

This section of our Application provides background on Xcel Energy's biomass portfolio.

A. PURPA PROJECTS

Starting in the 1980s, the Company entered into a series of hydroelectric and biomass PPAs that arose generally under PURPA and state implementing statutes. PURPA allows a "qualifying facility" to require a utility such as Xcel Energy to purchase the output of the facility at the utility's "avoided cost." PURPA was designed, in part, to promote small power production and the use of alternative fuels. Two of the PPAs that are part of the current restructuring arose out of the Company's purchase requirements under PURPA, namely the Pine Bend and HERC PPAs. Additionally, the WM Renewables (MN Methane) PPA—which is not a part of this application—was also added to Xcel Energy's biomass portfolio under PURPA.

B. MINNESOTA BIOMASS MANDATE PROJECTS

A significant amount of the Company's biomass resources have been driven by Minnesota legislative requirements arising out of the Company's nuclear power program. In 1994, the Minnesota legislature passed the Prairie Island Cask Storage Authorization Act. As part of this legislation, Xcel Energy was mandated to construct and operate, or contract to construct, 125 MW of installed capacity generated by farm grown closed-loop biomass (Biomass Mandate). This mandate was subsequently reduced to 110 MW by the Minnesota legislature in 2003.

This legislation was essential to the Company's continued operation of its Prairie Island nuclear power station. The Company was running out of space to store spent nuclear fuel and needed authority to construct on-site spent nuclear fuel storage. Without Minnesota authorization to construct on-site storage, Prairie Island would have been forced to close. The Minnesota legislation authorized the construction of on-site storage. As part of that legislative package, the Company was mandated to construct and operate, or contract to obtain, 125 MW of biomass resources. The legislation also included a wind-energy mandate as well as a requirement to implement and administer the RDF in exchange for the right to keep the Prairie Island nuclear power plant operational.

After the initial Biomass Mandate legislation was passed, the Company sponsored a series of competitive processes to seek qualifying projects to help us fill the mandate requirements. The Company encountered difficulties in finding projects that were financially viable or cost-effective, given the state of technology at the time. We encountered situations where projects were proposed that, for one reason or another, did not advance to commercial operation.

In an effort to facilitate compliance, the Minnesota legislature modified the Biomass Mandate each legislative session for several years. This helped vendors refine their proposals in an effort to achieve projects that would advance to commercial operation. Since initial enactment of the Biomass Mandate in 1994, the biomass statute (Minn. Stat. § 216B.2424) has been amended fifteen times, including (1) a reduction of the total biomass capacity requirement from 125 MW to 110 MW, and (2) amendment of the definition of biomass to refine and expand the acceptable fuel sources. Many of the statutory amendments over the years were driven by the challenges the industry encountered in developing feasible projects given the state and cost of the technology at the time.

The Company met its requirements under the Biomass Mandates by entering into PPAs with Benson Power (Fibrominn LLC's (Fibrominn) successor in interest), the Laurentian Energy Authority, and St. Paul Cogeneration. These three contracts met the 110 MW Biomass Mandate. The Benson PPA is implicated in this Application.

In the most recent legislative session, Minn. Stat. § 216B.2424 was amended to add subdivision 9. This section provides that the Minnesota Public Utilities Commission (MPUC) may approve an amended PPA, the early termination of a PPA, or the purchase and closure of a biomass facility if: (1) all contracting parties agree to the terms and conditions of the amended/terminated PPA/purchase and closure of a facility; and (2) the action is in the best interest of the customers. We supported this legislative change in Minnesota as we believed it would provide an opportunity for the Company to pursue cost savings that would positively impact customers in all of our states. A copy of these legislative changes is provided as Attachment A to this Application.

C. RENEWABLE DEVELOPMENT FUND PROJECTS

The 1994 Minnesota Prairie Island Cask Storage Act also established the Minnesota RDF. As part of the RDF, the Company administers a grant program that is intended to help support the development of renewable energy projects utilizing nascent stage technologies. Two biomass PPAs – one with Rahr Malting for the KODA Energy facility and one with Diamond K Dairy for their biodigester project – have become part of Xcel Energy's biomass portfolio through the RDF program. Neither of these projects is implicated in this Application.

D. NORTH DAKOTA TREATMENT OF THE BIOMASS PORTFOLIO

The Commission has allowed the Company to recover the costs of all of its biomass contracts since their inception. In the Company's 2013 test year rate case (Case No. PU-12-813), Commission Advocacy Staff raised issue with six key biomass contracts: (1) KODA Energy LLC, (2) WM Renewable Energy (MN Methane), (3) Pine Bend, (4) Benson (Fibrominn), (5) Laurentian Energy Authority I, and (6) St. Paul Cogeneration. Pursuant to the Negotiated Agreement approved by the Commission on March 9, 2016 in Case Nos. PU-12-813. *et. al.*, the Company is currently recovering the cost of these six biomass PPAs subject to a potential fifty percent refund. The refund would be triggered if the Company fails to construct a gas-fired power plant in eastern North Dakota by the end of 2025. The remaining biomass PPAs have not been singled out for scrutiny and are being recovered by the Company with no conditions.

E. THE PROPOSED TRANSACTIONS

While making a reasonable investment in biomass as an emerging technology was in our customers' best interest, over time the benefits that many thought could be achieved through biomass resources have lagged behind other emerging technologies, such as wind and solar. Additionally, our biomass contracts are some of the most expensive contracts on the NSP System. Consequently, when the Benson facility came on the market for sale, we began to explore opportunities to eliminate these costs for our customers. Additionally, when HERC proposed renegotiating its contracts, we sought ways to improve the terms of the contract for the benefit of our customers. This work led us to explore potential other ways we could reduce or eliminate above-market energy costs for our customers. Our Proposed Transactions, which represent over 50 percent of our biomass portfolio, are a product of that work. Further, we continue to explore similar opportunities and are negotiating with the Laurentian Energy Authority regarding the potential to terminate our PPA for the output of their biomass facilities. Should we reach agreement with Laurentian, we will also bring that transaction to the Commission.

Table 2, below, identifies the contracts making up the Company's biomass portfolio, their size, under which program they were acquired, their North Dakota recovery status, and if they are included in the current ADP Application's Proposed Transactions.

Table 2: Biomass Portfolio

Project	Size	Program Acquired	ND Recovery Status	Proposed Transaction?
Benson Power (Fibrominn)	55 MW	MN Biomass Mandate	Subject to Refund	Yes
KODA Energy	12 MW	RDF	Subject to Refund	No
WM Renewable Energy	4.7 MW	PURPA	Subject to Refund	No
HERC	33.7 MW	PURPA	No Restrictions	Yes
Laurentian Energy Authority	35 MW	MN Biomass Mandate	Subject to Refund	No
Pine Bend	12 MW	PURPA	Subject to Refund	Yes
Diamond K Dairy	0.35 MW	RDF	No Restrictions	No
St. Paul Cogeneration	25 MW	MN Biomass Mandate	Subject to Refund	No

IV. KEY TERMS OF THE PROPOSED TRANSACTIONS

This section discusses each of the three Proposed Transactions as well as the background of each PPA and key terms surrounding the contractual changes.

A. BENSON POWER

The Benson transaction involves three steps: (1) terminate the existing PPA; (2) purchase and take ownership of the facility and (3) shut down the facility.

1. Background

Xcel Energy and Benson Power (as successor in interest to Fibrominn) are parties to a biomass PPA dated as of August 31, 2000, and amended as of June 7, 2004, and

February 16, 2011, as assigned and modified by the Consent and Agreement dated as of August 20, 2015, by and between Benson Power and NSP for the sale and purchase of energy and capacity from the 55 MW electric generating facility fueled by poultry litter and other biomass fuels located in Benson, Minnesota. Xcel Energy entered into a PPA with Benson Power as part of the Company's efforts to comply with Minnesota's Biomass Mandate.

Benson Power, a Delaware limited liability company, owns the Benson facility. The Benson facility was previously owned by Fibrominn, and the land it occupies was previously owned by PowerMinn 9090, LLC. All workers at the facility are employed by the NAES Corporation which is an independent services company with deep experience in operations and maintenance of power plants throughout the United States. When it was originally built, it was the first power plant in the country designed to burn poultry litter as a source of fuel. The fuel stock currently consists of a mix of poultry litter and wood.

The original term for the Benson PPA was September 11, 2007 to September 10, 2028. The estimated contract price of ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** (in 2018) consists of an energy payment (with annual escalation), plus fuel transportation costs in excess of a baseline amount, property taxes, and any shortfall in sales of ash for fertilizer. This results in an estimated levelized cost to customers of ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** over the remaining PPA term.

2. *Transaction Key Terms*

The Company proposes to terminate the Benson PPA, acquire the Benson facility, and subsequently close the facility once we have approval from the Midcontinent Independent System Operator, Inc. (MISO). Below are the steps we will take to facilitate an orderly shutdown of the plant:

1. Obtain the necessary regulatory approvals and, within three days, close the transaction with Benson Power (which means we terminate the current PPA and take ownership of the plant).
2. Submit the MISO Attachment Y within days of closing transaction.
3. Operate the Benson facility for 6 months (assuming MISO approval of our Attachment Y) - these 6 months entails operating near normal levels until we eliminate inventory and honor fuel supply contracts and then offering the unit for emergency use only until closing post MISO approval.
4. Begin closure of the facility; remove all hazardous material etc., which will take about one month.

5. Facilitate demolition efforts, equipment salvage, and restoration which we estimate will take about 18 months.

If all goes as currently planned, we expect the plant shutdown and associated efforts will be complete by early 2020.

The Benson transaction is structured primarily as an asset sale. Early in the Company's discussions with the sellers,[8] it became evident that they wanted to sell the facility outright and had already taken steps in that direction. Because our analysis demonstrated that negotiating a near term PPA termination followed by an asset purchase would yield significant savings for our customers, we continued with negotiations—which were ultimately successful. An agreement to terminate the PPA and purchase the facility was reached.

The financial terms of the agreement provide that NSP will pay Benson Power $95 million in exchange for the facility and termination of the PPA. Separately, Minnesota legislation was also approved during the most recent legislative session that directs $20 million ($4 million in 2018, $6.5 million in 2019 and 2020, and $3 million in 2021) from the RDF to the City of Benson for economic development. As discussed in the economic analysis below, North Dakota ratepayers do not contribute to the RDF and we will not seek to include these costs in our deferral or request their recovery from our North Dakota customers in a future rate proceeding.

The Asset Purchase and Sale Agreement between Benson Power and the Company includes the following key terms:[9]

- The Company will purchase from Benson Power, substantially all of the assets of Benson Power and the PPA will be terminated for a transaction price of $95 million.
- The transaction will close on the third day after satisfaction or waiver of all the conditions to closing (which includes regulatory approvals), or as parties agree.
- At closing, the Company will place $12 million of the $95 million into escrow to be held by an escrow agent for two years as security for warranties and covenants.

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[8] In 2014 the facility entered receivership. When the facility exited the receivership process in August of 2015, the prior debt holders who had financed the facility became the new owners.

[9] The Benson transaction documents are extremely voluminous. For convenience, and consistent with past practice, we are not including them in this filing. We will make them available upon request.

- Certain costs related to the termination of the contract for the sale of ash to North American Fertilizer (NAF) may be deducted from the transaction price payable to the owners of Benson Power and paid directly to NAF. NSP will credit Benson Power for the value of the ash inventory as of the closing date to the extent it reduces the amount of costs payable to NAF.
- Prior to closing, Benson Power can only enter into contracts cancellable on 60 days' notice.
- Jenny-O poultry litter supply contract (in renegotiation at the time of the execution of the agreement), a key contract for Benson Power, will contain 180 day termination notice provision with take or pay terms with payments estimated to be approximately $1.1 – $1.7 million, depending on the length of notice provided.
- If closing has not occurred by March 31, 2018, either party may terminate.

To facilitate the transaction, the Company also agreed to certain terms with the City of Benson:

- NSP to provide a site specific public safety shut down plan.
- NSP to make two additional annual local property tax payments following the removal of the facility, each based on the payments made in the year prior to removal.
- NSP to reimburse the City of Benson any stranded investments related to water, waste water, and electric distribution assets.
- NSP to make a payment, up to $200,000, for a new water line and relocation of controls for the NAF plant. The fertilizer plant—which neighbors the Benson facility—currently obtains water from the plant.
- Upon closure the facility, NSP will remove all above-ground improvements to grade, remove all foundations to a depth of four feet below grade, and remediate environmental contamination, if any, in accordance with applicable law.
- NSP will provide the City of Benson the following written notices:
    - No later than 30 days prior to the shutdown of the facility, a shutdown notice notifying the City of Benson of the date the facility will be shut down; and

    - No later than 30 days after completion of all removal activities at the facility, a final removal notice notifying the City of Benson of the completion of removal.
- Upon closure of the facility, the City of Benson has an option to purchase the site per the following terms:
    - The City of Benson must exercise this option no later than six months following NSP's shutdown notice;
    - The City of Benson must close on the site no later than 30 days following the date of the removal notice; and
    - The purchase price shall be equal to the appraised value of the restored site (i.e., without the Benson facility) as determined by an appraisal obtained by NSP.
- Upon closure of facility, the Company will submit an Attachment Y to MISO.

3. Required Regulatory Approvals

The contract between Benson Power and the Company is subject to approval by the Commission consistent with the precedent set in Case No. PU-12-59. Additionally, the contract is also subject to approval by the MPUC. The Company will also be filing for approval of the Benson Power transaction from the Federal Energy Regulatory Commission (FERC) under Section 203 of the Federal Power Act.

In addition, upon receiving Commission approval and the Company taking ownership of the facility, the Company will file Attachment Y (Notification of Generation Resource/SCU/Pseudo-tied Out Generator Change of Status) with MISO regarding the proposed closure of the Benson facility. MISO's process requires the owner of a Generation Resource to submit an Attachment Y Notice at least twenty-six (26) weeks prior to retiring the plant.

As part of its review process, MISO will consider whether the Benson facility is a System Support Resource (SSR), a unit that is required to maintain the reliability of the transmission system. While possible, we understand the likelihood of the Benson facility being categorized as an SSR is remote. And, while we expect MISO will approve our request to shut down the Benson facility, there is a small chance that MISO could determine it is a SSR, a unit that is required to maintain the reliability of the transmission system. SSR Agreements are a last-resort measure and are only required once all potential alternatives have been examined. While this is unlikely for the Benson facility, it is a potential outcome that is out of our control and of which we want the Commission to be aware.

MISO will also consider how the closure of the Benson facility may impact its planning year—which runs from June 1 through May 31. If we submit the Attachment Y notification after December 1, we may be obligated to utilize the facility to meet our planning reserve requirements or offer the facility into the planning resource auction for the next planning year. Again, we understand that this scenario is unlikely due to the excess of capacity in MISO's Zone 1.

B. PINE BEND

We propose to terminate early the Pine Bend PPA.

1. Background

Gas Recovery Systems (GRS) owns and operates the 12 MW Pine Bend landfill gas facility in Dakota County, Minnesota. GRS entered into a PPA with the Company on September 20, 1994 for a term of 30 years, ending no later than December 31, 2025. Pursuant to the Pine Bend PPA, the Company agreed to purchase the output from the 12 MW waste-to-energy electric generating unit. The Pine Bend PPA was executed as a contract under PURPA. As a qualifying facility under PURPA, the PPA included both capacity and energy payments that were designed to be at or below the Company's levelized avoided costs based on three reference units: a peaking unit in service before May 1, 1996, an intermediate facility in service by 2001, and a base-load unit in service by 2005. Starting in May 2005, the energy prices have been based on actual costs for Sherco 3.

In 2010, the Company amended the PPA to establish a simplified "all in" structure to provide GRS a more reliable revenue stream, and help to avoid the need to purchase more expensive replacement energy if the facility was forced to shut down. The amendment was effective for the remaining 16 years of the PPA. Under the amendment, the purchase price for energy was about $2 million higher than the prior PPA payment structure, depending on future capacity and energy costs linked to Sherco 3. Amendment No. 2 had a net present value of about $9 million less than the estimated cost of replacement energy should the GRS project fail to maintain operations.

The Pine Bend PPA with GRS is scheduled to terminate on December 31, 2025. The current price of energy under the terms of the PPA is ***[TRADE SECRET BEGINS TRADE SECRET ENDS]***. This price is to increase by 1.5 percent annually through the last year of the PPA in 2025 when the price is scheduled to be ***[TRADE SECRET BEGINS TRADE SECRET ENDS]***.

2. *Transaction Key Terms*

Xcel Energy is proposing to terminate the Pine Bend PPA. If the PPA is terminated, we expect our customers will see a NPV savings of approximately $5.2 million over the life of the PPA ($6.6 million in nominal dollars). Key terms of the termination agreement[10] are as follows:

- The effective date of the termination agreement will be the first day of the month following all closing contingencies being met or waived.
- NSP will pay GRS monthly the difference between the current PPA price and the average monthly locational marginal price at the NSP.NSP node plus $10/MWh. If the difference is negative, no payment will be made to GRS by NSP that month.
- The Termination Agreement shall terminate the earlier of three years from the effective date or when GRS has received $1,050,000 through monthly payments from NSP.

The Company estimates that at current market prices, the $1,050,000 cap on consideration under the termination agreement will be met in approximately two years.

C. HERC

We propose to amend the terms of the HERC PPA.

1. *Background*

HERC is a waste-to-energy facility, where waste from Hennepin County is received and burned to generate steam. In 1985, HERC entered into an agreement with Hennepin County to design, construct, own, operate, and maintain a solid waste resource energy facility to process municipal solid waste to produce steam for heating and cooling and to generate electric power, subject to HERC negotiating and entering into an electric sales agreement with NSP. The HERC facility was proposed as a qualifying facility under PURPA.

The HERC PPA is for the output of 33.7 MW of capacity. The contract began in January of 1990 and contains a 28-year term with an end date of December 31, 2017.

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[10] The Pine Bend transaction documents are extremely voluminous. For convenience, and consistent with past practice, we are not including them in this filing. We will make them available upon request.

The HERC PPA includes a contractual right to a 7-year extension at Seller's option at "fair market value."

Formal negotiations began in January 2017 when HERC provided an initial extension offer to NSP. The parties were ultimately able to agree on the Proposed Transaction presented here.

2. *Transaction Key Terms*

The proposed contract amendment extends the current PPA seven years (to December 31, 2024) consistent with HERC's extension rights under the current PPA. The pricing under the proposed amended PPA has been substantially simplified. Under the current PPA, NSP is obligated to make separate energy and capacity payments, and the formulae used to calculate the payments are complex.

Under the proposed amended PPA, pricing has been simplified to a single $/MWh payment for energy delivered, which is designed to compensate HERC for both energy and capacity. The simplified "all in" energy pricing structure benefits all parties including customers. It will provide assurance to customers that they are paying a reasonable price for *delivered* energy.

The existing pricing for 2017 will be converted to an all-in $/MWh price of ***[TRADE SECRET BEGINS TRADE SECRET END]*** retroactive to January 1, 2017 (subject to applicable regulatory approvals). The ***[TRADE SECRET BEGINS TRADE SECRET END]*** price is based on current expectations of what the average $/MWh price will amount to at the end of the year per the current price structure. The current capacity payment of ***[TRADE SECRET BEGINS: TRADE SECRET ENDS]*** per the existing pricing structure allows HERC to get paid a significant amount of money (in excess of ***[TRADE SECRET BEGINS: TRADE SECRET ENDS]*** per year) regardless of actual MWh output at the facility. As a result, the Company wanted to immediately convert to the $/MWh structure to adopt a "pay for performance" approach in which HERC only gets paid for delivered energy.

Table 3 contains the estimated pricing for the current PPA and the pricing for the amended and extended PPA starting in 2018.

Table 3: HERC PPA Pricing

Year	Existing PPA Price	Proposed 7 Year Extension Pricing
	[TRADE SECRET BEGINS	
2018		
2019		
2020		
2021		
2022		
2023		
2024		
	TRADE SECRET ENDS]	

V. ECONOMIC ANALYSIS

The Company negotiated the Proposed Transactions in an effort to save customers money and optimize pricing for the overall NSP System portfolio.

To evaluate the economic impact of each of the Proposed Transactions, we compared the costs under the current PPAs to the costs of each Proposed Transaction and the projected cost of replacement energy. As required by North Dakota statute, no environmental externality costs are included in the analysis.[11]

We performed mark-to-market modeling in Microsoft Excel to calculate the cost savings to customers. We used this methodology instead of using Strategist for five main reasons. First, the total nameplate capacity of all the resources in question total 135.7 MW which is small relative to the total nameplate capacity on our system which is over 10,000 MW. Second, the contracts at issue all are "must take" contracts and therefore the volumes are generally predictable on an annual basis. Accordingly, because production levels stay relatively flat, the analysis did not require a full system model to simulate the dispatch of these resources relative to others. Third, the NSP System is currently projected to be long on capacity until the mid-2020s. As a result, eliminating these contracts has a limited impact on our capacity position and does not change our expansion plan. Fourth, because the Proposed Transactions only impact energy/fuel—as opposed to capacity—a simple comparison to the Minnesota Hub forward curve provides a good proxy alternative to a full Strategist run. Fifth and finally, for contracts that we are ending prematurely, our analysis assumes all avoided

[11] *See* N.D.C.C. § 49-02-23.

contract MWh are replaced with market energy purchases, which is likely a conservative assumption as there are many hours in which the system is long on energy and replacement may not be necessary.

Despite taking a conservative approach to developing base assumptions, our analysis shows that each of the Proposed Transactions will result in net savings for all of our customers under all contemplated scenarios.

We estimate that the Proposed Transactions will achieve over $519.1 million in total nominal cost savings ($377.4 million NPV) for customers over the next 11 years. North Dakota customers should realize approximately 5.49 percent of the overall savings ($28.5 million) during this period, which is equivalent to North Dakota customers' proportion of all affected customers. On an NPV basis, the savings equate to $377.3 million for the whole system and $21.1 million for North Dakota customers.

The Company recognizes that although it has filed a single application for the Proposed Transactions, the Commission may elect to assess the prudence of each of the projects individually as well as in the aggregate. For that reason, we have provided an individual analysis of each Proposed Transaction.

A. BENSON POWER

To analyze the economic impact of terminating the Benson PPA by purchasing the facility and shutting it down, NSP compared the projected the cost of the Benson PPA for the remainder of its term (through 2028) with the sum of (i) the cost of replacement market energy during that same period, plus (ii) the cost of the buyout and subsequent shutdown of the Benson facility.

1. *Cost of the Benson PPA*

The cost of the Benson PPA though its 2028 termination date was calculated by taking the assumed production from the Benson facility based on historical actual production and the obligations under the PPA and multiplying that by the expected cost of the PPA on a $/MWh basis. We also took into account the other payments required under the PPA such as $62.9 million for energy and fuel transportation charges, ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** for an ash revenue shortfall, and $949,000 for property taxes.[12] The present value of revenue requirements of that stream of payments equals $561 million through 2028.

2. Cost of Replacement Power

The cost of replacement power needed if the Benson facility is shut down was calculated using a mark-to-market analysis of projected combined energy and capacity prices through 2028. This allowed a comparison of the cost of power from the Benson facility against current market estimates. The estimates of market energy prices range from about $23/MWh to $34/MWh during the same timeframe that the PPA levelized cost is estimated to be ***[TRADE SECRET BEGINS***
TRADE SECRET ENDS].

NSP's analysis used a market pricing stream that excluded replacing capacity due primarily to the small size of the plant and the fact that the NSP System has sufficient capacity through most of the remainder of the contract. This resource provides 39.2 MW of accreditable capacity to the NSP System so it is not expected to have material impact on capacity needs through the mid-2020s.

Including the cost of replacement energy is a conservative assumption as there will be many hours during the year that market replacement energy is not needed because NSP System generation production is sufficient to meet load needs. Replacement costs for the energy provided by the Benson facility over the life of the PPA are expected to total $127.7 million. To the extent the Company does not need to buy replacement power, our customers will realize additional savings.

3. Cost of Buyout and Shutdown of Benson Facility

The cost of purchasing and shutting down the Benson facility contains several components.

First, there are $106.8 million in costs that are necessary to terminate the PPA and acquire and shut down the plant. These costs represent several contractual obligations including the PPA termination and asset purchase price, contract termination fees, stranded investment costs for the City of Benson, and payment to the fertilizer plant. In addition, this also includes demolition and remediation costs. Demolition costs were estimated by working with a third-party consultant. To be conservative, our cost estimate includes assumptions for complete foundation

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[12] Additional detail about these assumptions, as well as NSP's assumptions regarding the energy price escalation, pass through escalation, heat content and heat rate, and capacity factor, are included in the Direct Testimony of Company witness Mr. Martin.

removal. Our estimate also includes $400,000 in salvage credit that we expect to receive from the sale of equipment. This salvage credit assumes the sale of some motors, transformers, air compressors, the generator, and recycling of copper and steel. The Company will work to maximize the value of the materials and salvage value and to the extent we recognize more value than currently estimated, the recovery amounts would be reduced accordingly and the expected customer benefits from the transaction would increase.

Next, there are $14.5 million (nominal) in expenses necessary to wind down operations and shut down the facility, including operation and maintenance (O&M) costs, property taxes, fuel, and fuel transportation. The estimate includes anticipated costs to run the facility at full capacity for two months after the transaction closes and a small amount of expenses to operate the facility during the subsequent four month shutdown phase in the event the facility is called on to run, plus one more month to remove all hazardous material from the site prior to beginning demolition efforts. The seven-month timing estimate is based on the six-month Attachment Y filing process plus one additional month to physical demolish the facility.

The NPV of the costs to buy, shut down, and replace any necessary energy are approximately $215.6 million ($292.0 million nominal). Table 4 below summarizes the underlying cost assumptions for the plant purchase and closure, and there are additional details in the Direct Testimony of Company witness Mr. Martin.

Table 4: Assumptions Underlying Analysis for Purchase and Closure

$95M PPA termination and asset purchase price
$1.5M contract termination fees
$1.5M legal, miscellaneous fees and insurance
$8.8M demolition, remediation and other related costs
$128M replacement energy costs
$1M Fuel
$5M Transportation
$3K Landfill Expense
$4.9M Operating contracts, materials, & supplies
$3.5M property taxes

Costs are recovered and accounted for differently across the states of the NSP System. In order to estimate the economic effects of terminating the Benson PPA for customers across all states, NSP assumed that the $106.8 million of costs in the first four lines of Table 4 above will be treated as a regulatory asset subject to deferred accounting, and the remaining $14.5 million in expenses would be recovered from customers as they are incurred. In this Application, however, we are requesting that all costs of North Dakota's traditionally allocated share of the Benson transaction, including the $14.5 million of O&M costs be deferred. This may result in a slight impact to our economic analysis, though it should not be material to the millions of dollars in estimated savings for North Dakota customers.

4. *Results of the Benson Purchase and Shut Down Economic Analysis*

In sum, the NPV of the cost of continuing the existing Benson PPA is $561.2 million and the cost to terminate the PPA, buy and shut down the plant, and replace any necessary energy are approximately $215.6 million. Accordingly, our analysis shows significant customer savings of approximately $345.6 million on a NPV basis by purchasing and shutting down the facility and buying replacement energy as opposed to continuing the terms of the PPA. The nominal cost of continuing the existing Benson PPA is $771.6 million and the nominal cost of the proposed Benson transaction is $292.0 million, so the nominal savings of buying the Benson facility and terminating the PPA is approximately $479.6 million.

The North Dakota share of this savings is approximately $19.0 million NPV and $26.3 million nominal over the same period based on an approximately 5.49 percent share of the overall NSP System. As noted above, given our conservative assumptions, the projected savings represents a conservative estimate. If the Benson energy does not need to be replaced, the savings to ratepayers would increase.

B. PINE BEND

In order to assess potential savings to customers through an early termination of the Pine Bend PPA, NSP compared the cost of the PPA for the remainder of its term (through December 2025) with the cost of terminating the PPA early plus the market costs of energy that NSP will have to pay after termination is complete.

1. *Cost of Pine Bend PPA*

The Pine Bend PPA is scheduled to end in December of 2025. The current price of energy under the terms of the PPA is ***[TRADE SECRET BEGINS TRADE SECRET ENDS]***. This price increases by 1.5 percent annually through the last year of the PPA in 2025 when the price is scheduled to be ***[TRADE***

SECRET BEGINS ***TRADE SECRET ENDS]***. The pricing for 2017 through the end of the contract is provided in Table 5 below. Annual production at the facility is approximately 36,000 MWh.

Table 5: Pine Bend Existing PPA Pricing

Contract Period	PPA Price ($/MWH)
	[TRADE SECRET BEGINS
Oct 2016 to Sep 2017	
Oct 2017 to Sep 2018	
Oct 2018 to Sep 2019	
Oct 2019 to Sep 2020	
Oct 2020 to Sep 2021	
Oct 2021 to Sep 2022	
Oct 2022 to Sep 2023	
Oct 2023 to Sep 2024	
Oct 2024 to Sep 2025	
Oct 2025 to Dec 2025	
	TRADE SECRET ENDS].

The NPV of current Pine Bend PPA obligations is $12.3 million though 2025, assuming that the plant would produce 36,000 MWhs per year.

2. *Cost of Terminating Pine Bend PPA and Replacement Energy*

The proposed termination agreement with Pine Bend provides that in exchange for terminating the PPA, monthly payments will be made by NSP to GRS in the amount of the difference between the current PPA price and the average monthly locational marginal price at the NSP.NSP node plus $10/MWh until GRS has received a total of $1,050,000 or until the end of three years after monthly payments have begun, whichever is earlier. Based on the current MISO energy market price forecast, we estimate that we will make the full termination payment ($1,050,000) within about two years. Assuming the Commission approval takes place about 4 to 6 months after submission, it is estimated that monthly payments by NSP to GRS will conclude by late 2019.[13]

[13] To simplify this analysis, the minimal impact of deferred accounting for the termination payments was not taken into account. NSP is, however, seeking approval from the Commission to defer accounting for these costs, as discussed below.

In addition to the $1,050,000 termination payment , the cost of replacement energy post termination is forecast to be $6.1 million. The termination payment and the replacement energy has a NPV of $7.1 million.

3. Results of the Pine Bend PPA Termination Economic Analysis

Under the current contract, total contract costs are expected to amount to an NPV of $12.3 million for the remaining eight years. Replacement costs for market energy at Minnesota Hub based on pricing from spring 2017 are expected to only amount to a NPV of $6.1 million. After accounting for the monthly payments from NSP to GRS totaling $1,050,000, the proposed PPA termination results in an expected NPV customer savings of $5.2 million over the remaining life of the PPA. North Dakota customers will realize approximately $285,000 of that savings. To the extent the Company does not need to buy replacement power, our customers will realize additional savings.

C. HERC

The original HERC PPA includes both energy and capacity payments. The energy charge is based on actual production costs at Sherco 3 subject to a formula adjustment which assigns more value for volumes delivered during on-peak versus the off-peak hours. The capacity charge is currently ***[TRADE SECRET BEGINS*** *month* ***TRADE SECRET ENDS]*** and is adjusted annually in May. Annual production at the facility has averaged ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** over the past five years.

The amended PPA extends the contract seven years. The Company feels that seven years is a reasonable time frame for extension as it will allow the Company to compare HERC to other resource alternatives in 2025 when there is a capacity need.

In addition to reducing the going-forward pricing beginning in 2018 compared to what the pricing would have been under the existing PPA, the amendment also moves the contract pricing to an "all-in" $/MWh pricing framework. The ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** price is based on current expectations of what the average $/MWh price will amount to at the end of the year per the current price structure. The current capacity payment of ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** per the existing pricing structure allows HERC to get paid a significant amount of money ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** regardless of actual MWh output at the facility. As a result, the Company wanted to immediately convert to the $/MWh structure to adopt a "pay for performance" approach in which HERC only gets paid for delivered energy.

The change to a "pay for performance" model was a critical component to securing the Company's support because it shifts the risk of underperformance to HERC and away from our customers. Under the proposed amendment, if the facility experiences a significant outage or underperforms, our customers will benefit in that they avoid paying for capacity that is not providing any energy.

Assuming the five-year historical production average of about ***[TRADE SECRET BEGINS*** ***TRADE SECRET ENDS]*** per year, the proposed extension pricing (found in Table 6) is expected to provide NPV savings of $26.6 million compared to the existing pricing methodology over the life of the extension. Stated differently, if we continued the current contract, we estimate the costs would have totaled $72 million (NPV) over the remainder of the PPA, however, with the newly structured PPA, we estimate costs will total $45 million (NPV). While the proposed extension pricing is higher than current market estimates for energy and capacity, the Company feels the proposed extension pricing reflects best efforts to work with HERC to reach a solution that both parties could accept and also eliminates the risk of arbitration in which "fair market value" could have potentially been defined at a much higher level.

Table 6: HERC PPA Pricing

Year	Existing PPA Price	Proposed 7 Year Extension Pricing
	[TRADE SECRET BEGINS	
2018		
2019		
2020		
2021		
2022		
2023		
2024		
	TRADE SECRET ENDS]	

The proposed HERC PPA amendment is in the public interest because our analysis estimates that customers will realize NPV savings of approximately $26.6 million ($32.9 million nominal) over the life of the PPA. North Dakota's relative share of that savings is approximately $1.5 million NPV ($1.8 million nominal).

D. IMPACT ON REFUND PROVISIONS OF NEGOTIATED AGREEMENT

In 2016, the Company and Commission Advocacy Staff entered into the Negotiated Agreement that, among other things, addressed the biomass PPAs at issue in this Application.[14] In the Negotiated Agreement, we agreed to either (i) build or have located in eastern North Dakota a natural gas-fired electric generation facility with the capacity of at least 200 MW by the end of 2025, or if the facility is not in service by that time (ii) refund to our North Dakota customers 50 percent of the revenues collected from them in excess of the revenues that would have been collected if North Dakota customers had paid an adjusted system average cost for fuel, energy, and associated capacity for the six biomass PPAs identified in the Negotiated Agreement. The Benson and Pine Bend PPAs were specifically named.

The Company is in the process of developing its next Integrated Resource Plan, which it will file with the Commission in February 2019. Through this work, we hope to identify opportunities to meet our commitment.

Even if the refund required by the Negotiated Agreement is triggered in the future, it would still be in North Dakota customers' best interest for the Company to move forward with the Proposed Transactions. The cost to North Dakota customers of continuing with the existing PPAs above the system average cost of fuel has been estimated to be approximately $53 million from 2016 through 2025, the period covered by the refund provisions of the Negotiated Agreement. This would result in a potential refund of $26.5 million from NSP if the North Dakota electric generation facility is not completed by 2025. As a result, the net cost to North Dakota ratepayers over that period would be $26.5 million.

If the Company moves forward with the Proposed Transactions, the cost to North Dakota customers of the remaining biomass PPAs would drop to $38 million from 2016 to 2025. If the refund becomes applicable, North Dakota customers would receive $19 million from the Company and the net cost to the rate payers would drop to $19 million net of the refund.

In sum, providing an ADP for our Proposed Transactions will benefit North Dakota customers regardless of whether NSP meets the 2025 electric generation facility deadline provided for in the Negotiated Agreement. If NSP finishes construction by that date, the cost to customers associated with the biomass PPAs will drop from $53

[14] *See N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, *et al.*, ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT (Mar. 9, 2016).

million to $38 million, a savings of $15 million. If the facility is not completed by 2025, the biomass PPAs' cost to customers, net of the refund from NSP, will drop from $26.5 million to $19 million, a savings of $7.5 million. In either event, customers will realize savings from our cost-saving initiative and these savings will be realized sooner than 2025.

VI. PRUDENCE OF THE PROPOSED TRANSACTIONS

The Company's Proposed Transactions are prudent. Our analysis, with its conservative assumptions, shows that the Proposed Transactions will result in significant cost savings to customers from both a long-term perspective and a near-term rate impact perspective. We anticipate that North Dakota customers will save, conservatively, approximately $20.7 million. Based on our analyses, we believe that it is prudent, reasonable, and in our customers' best interests for the Commission to grant an ADP for these projects.

VII. REQUEST FOR DEFERRED ACCOUNTING AUTHORITY

The costs associated with purchasing and shutting down the Benson facility and terminating the Pine Bend PPA are above and beyond both what the Company has budgeted for normal utility operations and what was reflected in the costs of service to set current rates. It would be inappropriate to expense these costs as they occur due to the nature and materiality of the expenses. These one-time extraordinary expenditures are most appropriately accounted for through the creation of a regulatory asset. Failure to obtain deferred accounting treatment would force the Company to write off these costs in the year in which they occur, signaling no support for the Proposed Transactions.

The Company is specifically requesting that it be authorized to accumulate the costs incurred with purchasing and shutting down the Benson facility and terminating the Pine Bend PPA in a regulatory asset in Account 182.3. The Company also requests that it be allowed to include a cost of capital return on the asset. The costs to be deferred in the regulatory asset for the Benson facility relate to the North Dakota share of costs necessary to terminate the PPA, acquire the plant, and shut it down, and also the North Dakota share of the O&M costs necessary to run the plant as it is shut down in an orderly fashion. The costs to be deferred in the regulatory asset for the Pine Bend PPA relate to the North Dakota share of the termination payment of $1,050,000. The Company will propose mechanisms to recover these costs sometime in the future.

The size and magnitude of these transactions--the purchase of the Benson facility and the payments to Pine Bend--are sufficiently large that they could potentially require the Company to file a rate case and the Company does not have excess earnings to offset the higher costs. The Commission has previously allowed deferred accounting when the amounts are sufficiently large that they could accelerate the timing of a rate case, and when the utility does not have excess earnings that should first be used to offset the higher costs.[15]

In the alternative, the Company respectfully requests that the Commission order additional testimony be filed to address the ratemaking and recovery mechanisms to provide for recovery of these extraordinary costs.

VIII. REQUEST TO CONSOLIDATE CASES FOR HEARING

Pursuant to N.D. Admin. Code § 69-02-04-04, Xcel Energy respectfully requests that the Commission consolidate the Company's Application for Advanced Determination of Prudence and Application for Deferred Accounting for hearing. Both Applications contain similar issues of law and fact and the public interest will not be prejudiced by their consolidation.

IX. CONCLUSION

For all of the reasons set forth above, NSP respectfully requests the Commission make an advance determination of the prudence of the Company's purchase and closure of the Benson facility, early termination of the Pine Bend PPA, and renegotiation and extension of the HERC PPA. NSP further requests that the Commission authorize the Company to designate the specified transactional costs as regulatory assets.

Dated: June 30, 2017

Northern States Power Company

Respectfully submitted,

/s/ Aakash H. Chandarana

AAKASH H. CHANDARANA
REGIONAL VICE-PRESIDENT
RATES AND REGULATORY AFFAIRS

[15] *See Re Montana- Dakota Utils. Co., a Div. of MDU Res. Grp., Inc.* Case No. PU-399-92-564, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (Mar. 24, 1993); *Re Montana- Dakota Utils. Co., a Div. of MDU Res. Grp., Inc.* Case No. PU-399-92-564, ORDER ON RECONSIDERATION (Jan. 18, 1994).

ATTACHMENT A

Sec. 20. Minnesota Statutes 2016, section 216B.2424, is amended by adding a subdivision to read:

Subd. 9. **Adjustment of biomass fuel requirement.** (a) Notwithstanding any provision in this section, the public utility subject to this section may, with respect to a facility approved under this section, file a petition with the commission for approval of:

(1) a new or amended power purchase agreement;

(2) the early termination of a power purchase agreement; or

(3) the purchase and closure of the facility.

(b) The commission may approve a new or amended power purchase agreement under this subdivision, notwithstanding the fuel requirements of this section, if the commission determines that:

(1) all parties to the original power purchase agreement, or their successors or assigns, as applicable, agree to the terms and conditions of the new or amended power purchase agreement; and

(2) the new or amended power purchase agreement is in the best interest of the customers of the public utility subject to this section, taking into consideration any savings realized by customers in the new or amended power purchase agreement and any costs imposed on customers under paragraph (e). A new or amended power purchase agreement approved under this paragraph may be for any term agreed to by the parties and may govern the purchase of any amount of energy.

(c) The commission may approve the early termination of a power purchase agreement or the purchase and closure of a facility under this subdivision if it determines that:

(1) all parties to the power purchase agreement, or their successors or assigns, as applicable, agree to the early termination of the power purchase agreement or the purchase and closure of the facility; and

(2) the early termination of the power purchase agreement or the purchase and closure of the facility is in the best interest of the customers of the public utility subject to this section, taking into consideration any savings realized by customers as a result of the early termination of the power purchase agreement or the purchase and closure of the facility and any costs imposed on the customers under paragraph (e).

(d) The commission's approval of a new or amended power purchase agreement under paragraph (b) or of the termination of a power purchase agreement or the purchase and closure of a facility under paragraph (c), shall not require the public utility subject to this section to purchase replacement amounts of biomass energy to fulfill the requirements of this section.

(e) A utility may petition the commission to approve a rate schedule that provides for the automatic adjustment of charges to recover investments, expenses and costs, and earnings on the investments associated with a new or amended power purchase agreement, the early termination of a power purchase agreement, or the purchase and closure of a facility. The commission may approve the rate schedule upon a showing that the recovery of investments, expenses and costs, and earnings on the investments is less than the costs that would have been recovered from customers had the utility continued to purchase energy under the power purchase agreement in effect before any option available under this section is approved by the commission. If approved by the commission, cost recovery under this paragraph may include all cost recovery allowed for renewable facilities under section 216B.1645, subdivisions 2 and 2a.

(f) This subdivision does not apply to a St. Paul district heating and cooling system cogeneration facility, and nothing in this subdivision precludes a public utility that operates a nuclear-power electric generating plant from filing a petition with the commission for approval of a new or amended power purchase agreement with such a facility.

(g) For the purposes of this subdivision, "facility" means a biomass facility previously approved by the commission to satisfy a portion of the biomass mandate in this section.

EFFECTIVE DATE. This section is effective the day following final enactment.

Sec. 21. Minnesota Statutes 2016, section 216C.05, subdivision 2, is amended to read:

Subd. 2. **Energy policy goals.** It is the energy policy of the state of Minnesota that:

(1) annual energy savings equal to at least 1.5 percent of annual retail energy sales of electricity and natural gas be achieved through cost-effective energy efficiency;

(2) the per capita use of fossil fuel as an energy input be reduced by 15 percent by the year 2015, through increased reliance on energy efficiency and renewable energy alternatives; ~~and~~

(3) 25 percent of the total energy used in the state be derived from renewable energy resources by the year 2025~~.~~; and

(4) retail electricity rates for each customer class be at least five percent below the national average.

Sec. 3. Minnesota Statutes 2016, section 116C.779, subdivision 1, is amended to read:

Subdivision 1. **Renewable development account.** (a) The renewable development account is established as a separate account in the special revenue fund in the state treasury. Appropriations and transfers to the account shall be credited to the account. Earnings, such as interest, dividends, and any other earnings arising from assets of the account, shall be credited to the account. Funds remaining in the account at the end of a fiscal year are not canceled to the general fund but remain in the account until expended. The account shall be administered by the commissioner of management and budget as provided under this section.

(b) On July 1, 2017, the public utility that owns the Prairie Island nuclear generating plant must transfer all funds in the renewable development account previously established under this subdivision and managed by the public utility to the renewable development account established in paragraph (a). Funds awarded to grantees in previous grant cycles that have not yet been expended and unencumbered funds required to be paid in calendar year 2017 under paragraphs (f) and (g), and sections 116C.7792 and 216C.41, are not subject to transfer under this paragraph.

(c) Except as provided in subdivision 1a, beginning January 15, 2018, and continuing each January 15 thereafter, the public utility that owns the Prairie Island nuclear generating plant must transfer to ~~a renewable development~~ the renewable development account $500,000 each year for each dry cask containing spent fuel that is located at the Prairie Island power plant for each year the plant is in operation, and $7,500,000 each year the plant is not in operation if ordered by the commission pursuant to paragraph ~~(c)~~ (i). The fund transfer must be made if nuclear waste is stored in a dry cask at the independent spent-fuel storage facility at Prairie Island for any part of a year.

~~(b)~~ (d) Except as provided in subdivision 1a, beginning January 15, 2018, and continuing each January 15 thereafter, the public utility that owns the Monticello nuclear generating plant must transfer to the renewable development account $350,000 each year for each dry cask containing spent fuel that is located at the Monticello nuclear power plant for each year the plant is in operation, and $5,250,000 each year the plant is not in operation if ordered by the commission pursuant to paragraph ~~(c)~~ (i). The fund transfer must be made if nuclear waste is stored in a dry cask at the independent spent-fuel storage facility at Monticello for any part of a year.

(e) Each year, the public utility shall withhold from the funds transferred to the renewable development account under paragraphs (c) and (d) the amount necessary to pay its obligations under paragraphs (f) and (g), and sections 116C.7792 and 216C.41, for that calendar year.

(f) If the commission approves a new or amended power purchase agreement, the termination of a power purchase agreement, or the purchase and closure of a facility under section 216B.2424, subdivision 9, with an entity that uses poultry litter to generate electricity, the public utility subject to this section shall enter into a contract with the city in which the poultry litter plant is located to provide grants to the city for the purposes of economic development on the following schedule: $4,000,000 in fiscal year 2018; $6,500,000 each fiscal year in 2019 and 2020; and $3,000,000 in fiscal year 2021. The grants shall be paid by the public utility from funds withheld from the transfer to the renewable development account, as provided in paragraphs (b) and (e).

(g) If the commission approves a new or amended power purchase agreement, or the termination of a power purchase agreement under section 216B.2424, subdivision 9, with an entity owned or controlled, directly or indirectly, by two municipal utilities located north of Constitutional Route No. 8, that was previously used to meet the biomass mandate in section 216B.2424, the public utility that owns a nuclear generating plant shall enter into a grant contract with such entity to provide $6,800,000 per year for five years, commencing 30 days after the commission approves the new or amended power purchase agreement, or the termination of the power purchase agreement, and on each June 1 thereafter through 2021, to assist the transition required by the new, amended, or terminated power purchase agreement. The grant shall be paid by the public utility from funds withheld from the transfer to the renewable development account as provided in paragraphs (b) and (e).

(h) The collective amount paid under the grant contracts awarded under paragraphs (f) and (g) is limited to the amount deposited into the renewable development account, and its predecessor, the renewable development account, established under this section, that was not required to be deposited into the account under Laws 1994, chapter 641, article 1, section 10.

~~(c)~~ (i) After discontinuation of operation of the Prairie Island nuclear plant or the Monticello nuclear plant and each year spent nuclear fuel is stored in dry cask at the discontinued facility, the commission shall require the public utility to pay $7,500,000 for the discontinued Prairie Island facility and $5,250,000 for the discontinued Monticello facility for any year in which the commission finds, by the preponderance of the evidence, that the public utility did not make a good faith effort to remove the spent nuclear fuel stored at the facility to a permanent or interim storage site out of the state. This determination shall be made at least every two years.

~~(d)~~ (j) Funds in the account may be expended only for any of the following purposes:

(1) ~~to increase the market penetration within the state of renewable electric energy resources at reasonable costs;~~

~~(2) to promote the start-up, expansion, and attraction of renewable electric energy projects and companies within the state;~~

~~(3)~~ to stimulate research and development ~~within the state into~~ of renewable electric energy technologies; ~~and~~

~~(4) to develop near-commercial and demonstration scale renewable electric projects or near-commercial and demonstration scale electric infrastructure delivery projects if those delivery projects enhance the delivery of renewable electric energy~~

(2) to encourage grid modernization, including, but not limited to, projects that implement electricity storage, load control, and smart meter technology; and

(3) to stimulate other innovative energy projects that reduce demand and increase system efficiency and flexibility.

Expenditures from the fund must benefit Minnesota ratepayers receiving electric service from the utility that owns a nuclear-powered electric generating plant in this state or the Prairie Island Indian community or its members.

The utility that owns a nuclear generating plant is eligible to apply for ~~renewable development account~~ grants under this subdivision.

(k) For the purposes of paragraph (j), the following terms have the meanings given:

(1) "renewable" has the meaning given in section 216B.2422, subdivision 1, paragraph (c), clauses (1), (2), (4), and (5); and

(2) "grid modernization" means:

(i) enhancing the reliability of the electrical grid;

(ii) improving the security of the electrical grid against cyberthreats and physical threats; and

(iii) increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.

~~(e) Expenditures authorized by this subdivision from the account may be made only after approval by order of the Public Utilities Commission upon a petition by the public utility. The commission may approve proposed expenditures, may disapprove proposed expenditures that it finds to be not in compliance with this subdivision or otherwise not in the public interest, and may, if agreed to by the public utility, modify proposed expenditures. The commission may approve reasonable and necessary expenditures for administering the account in an amount not to exceed five percent of expenditures. Commission approval is not required for expenditures required under subdivisions 2 and 3, section 116C.7791, or other law.~~

~~(f) The account shall be managed by the public utility but the public utility must consult about account expenditures with an~~ (l) A renewable development account advisory group that includes, among others, representatives of the public utility and its ratepayers, and includes at least one representative of the Prairie Island Indian community appointed by that community's tribal council, shall develop recommendations on account expenditures. ~~The commission may require that other interests be represented on the advisory group.~~ The advisory group must ~~be consulted with respect to the general scope of expenditures in designing~~ design a request for proposal and ~~in evaluating~~ evaluate projects submitted in response to a request for proposals. ~~In addition to consulting with~~ The advisory group~~, the public utility~~ must utilize an independent third-party expert to evaluate proposals submitted in response to a request for proposal, including all proposals made by the public utility. A request for proposal for research and development under paragraph ~~(d)~~ (j), clause ~~(3)~~ (1), may be limited to or include a request to higher education institutions located in Minnesota for multiple projects authorized under paragraph ~~(d)~~ (j), clause ~~(3)~~ (1). The request for multiple projects may include a provision that exempts the projects from the third-party expert review and instead provides for project evaluation and selection by a merit peer review grant system. ~~The utility should attempt to reach agreement with the advisory group after consulting with it but the utility has full and sole authority to determine which expendituresshall be submitted to the commission for commission approval.~~ In the process of determining request for proposal scope and subject and in evaluating responses to request for proposals, the ~~public utility~~ advisory group must strongly consider, where reasonable, potential benefit to Minnesota citizens and businesses and the utility's ratepayers.

(m) The advisory group shall submit funding recommendations to the public utility, which has full and sole authority to determine which expenditures shall be submitted by the advisory group to the legislature. The commission may approve proposed expenditures, may disapprove proposed expenditures that it finds not to be in compliance with this subdivision or otherwise not in the public interest, and may, if agreed to by the public utility, modify proposed expenditures. The commission shall, by order, submit its funding recommendations to the legislature as provided under paragraph (n).

~~(g) Funds in~~ (n) The commission shall present its recommended appropriations from the account to the senate and house of representatives committees with jurisdiction over energy policy and finance annually by February 15. Expenditures from the account ~~may not~~ must be ~~directly~~ appropriated by ~~the legislature by a~~ law ~~enacted after January 1, 2012, and unless appropriated by a law enacted prior to that date may be expended only pursuant to an order of the commission according to this subdivision~~. In enacting appropriations from the account, the legislature:

(1) may approve or disapprove, but may not modify, the amount of an appropriation for a project recommended by the commission; and

(2) may not appropriate money for a project the commission has not recommended funding.

~~(h)~~ (n) A request for proposal for renewable energy generation projects must, when feasible and reasonable, give preference to projects that are most cost-effective for a particular energy source.

~~(i)~~ (o) The ~~public utility~~ advisory group must annually, by February 15, report to the chairs and ranking minority members of the legislative committees with jurisdiction over energy policy on projects funded by the account for the prior year and all previous years. The report must, to the extent possible and reasonable, itemize the actual and projected financial benefit to the public utility's ratepayers of each project.

(p) By February 1, 2018, and each February 1 thereafter, the commissioner of management and budget shall submit a written report regarding the availability of funds in and obligations of the account to the chairs and ranking minority members of the senate and house committees with jurisdiction over energy policy and finance, the public utility, and the advisory group.

~~(j)~~ (q) A project receiving funds from the account must produce a written final report that includes sufficient detail for technical readers and a clearly written summary for nontechnical readers. The report must include an evaluation of the project's financial, environmental, and other benefits to the state and the public utility's ratepayers.

~~(k)~~ (r) Final reports, any mid-project status reports, and renewable development account financial reports must be posted online on a public Web site designated by the ~~commission~~ commissioner of commerce.

~~(l)~~ (s) All final reports must acknowledge that the project was made possible in whole or part by the Minnesota renewable development ~~fund~~ account, noting that the ~~fund~~ account is financed by the public utility's ratepayers.

(t) Of the amount in the renewable development account, priority must be given to making the payments required under section 216C.417.

EFFECTIVE DATE. This section is effective the day following final enactment.

Sec. 4. Minnesota Statutes 2016, section 116C.7792, is amended to read:

116C.7792 SOLAR ENERGY INCENTIVE PROGRAM.

The utility subject to section 116C.779 shall operate a program to provide solar energy production incentives for solar energy systems of no more than a total nameplate capacity of 20 kilowatts direct current. The program shall be operated for ~~five~~ eight consecutive calendar years commencing in 2014. $5,000,000 shall be allocated ~~for~~ in each of the ~~five~~ first four years, $15,000,000 in the fifth year, $10,000,000 in each of the sixth and seventh years, and $5,000,000 in the eighth year from funds withheld from transfer to the renewable development account ~~established in section 116C.779 to a separate~~ under section 116C.779, subdivision 1, paragraphs (b) and (e), and placed in a separate account for the purpose of the solar production incentive program. The solar system must be sized to less than 120 percent of the customer's on-site annual energy consumption. The production incentive must be paid for ten years commencing with the commissioning of the system. The utility must file a plan to operate the program with the commissioner of commerce. The utility may not operate the program until it is approved by the commissioner.

EFFECTIVE DATE. This section is effective the day following final enactment.

Sec. 5. Minnesota Statutes 2016, section 216B.164, subdivision 2, is amended to read:

Subd. 2. **Applicability; rights maintained.** (a) This section as well as any rules promulgated by the commission to implement this section or the Public Utility Regulatory Policies Act of 1978, Public Law 95-617, Statutes at Large, volume 92, page 3117, as amended, and the Federal Energy Regulatory Commission regulations thereunder, Code of Federal Regulations, title 18, part 292, as amended, shall, unless otherwise provided in this