

DIRECT TESTIMONY AND SCHEDULES
AAKASH H. CHANDARANA

**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-_____

Policy Testimony

Exhibit __ (AHC-1)

June 30, 2017

- 37 PU-17-322 Filed 02/02/2018 Pages: 24
Exhibit NSP-3 - Direct Testimony of Aakash Chandarana (Policy)
Northern States Power Company
- 43 PU-17-271 Filed 02/02/2018 Pages: 24
Exhibit NSP-3 - Direct Testimony of Aakash Chandarana (Policy)
Northern States Power Company
- 43 PU-17-270 Filed 02/02/2018 Pages: 24
Exhibit NSP-3 - Direct Testimony of Aakash Chandarana (Policy)
Northern States Power Company

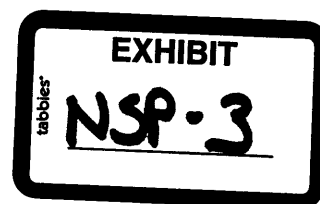


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Statement of Qualifications

Schedule 1

1 I. INTRODUCTION AND QUALIFICATIONS

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Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Aakash H. Chandarana. I am the Regional Vice President for Rates and Regulatory Affairs for Northern States Power Company-Minnesota (NSP or Xcel Energy or the Company). In this role, I am responsible for the Company’s regulatory filings with the utility commissions in Minnesota, North Dakota, and South Dakota, including proceedings related to rates, resource planning, and service quality filings.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. Prior to joining Xcel Energy, I was a partner at the Briggs and Morgan, P.A. law firm. My practice focused on the energy industry, primarily the state and federal regulation of utilities. I represented utilities in commercial transactions involving generation interconnection agreements, power purchase agreements, and other related types of transactions. I also assisted my clients in regulatory proceedings, including state electric rate cases, and transmission interconnection disputes at the Federal Energy Regulatory Commission.

In 2013, I joined Xcel Energy as its Lead Assistant General Counsel – Regulatory North. In that role, I was the lead regulatory attorney for the Company’s operations in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan. In January 2015, I assumed my current role. Exhibit ___ (AHC-1), Schedule 1 summarizes my qualifications.

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

2 A. The purpose of my testimony is to provide support for our request for an
3 Advance Determination of Prudence (ADP) for Xcel Energy's Biomass
4 power purchase agreement (PPA) cost-savings transactions. This consists of
5 three transactions that relate to our biomass portfolio and will reduce costs
6 for our customers: (1) the Benson Power (Fibrominn) PPA Termination and
7 Acquisition for Subsequent Shutdown; (2) the Pine Bend Biogas PPA Early
8 Termination; and (3) the Hennepin Energy Recovery Center (HERC) PPA
9 Extension and Restructuring (collectively, the Proposed Transactions). I
10 also provide support for our request for authorization for deferred
11 accounting for some the costs of our Proposed Transactions.

12

13 **II. THE BIOMASS PPA PROPOSED TRANSACTIONS**

14

15 Q. PLEASE DESCRIBE XCEL ENERGY'S BIOMASS PPA PROPOSED
16 TRANSACTIONS.

17 A. The Company is entering into a series of transactions that are intended to
18 help optimize our biomass portfolio and significantly drive down costs for
19 our customers. In total, we estimate that our Biomass PPA Proposed
20 Transactions will save customers over \$377 million net present value (NPV)
21 over the next eleven years.

22

23 Our initiative is composed of the following transactions:

24

25 (1) *Benson Power (f/ k/a Fibrominn)*: We are proposing to terminate
26 our existing PPA with Benson Power for the output of the 55 MW
27 Benson Power turkey litter fueled generating facility; acquire the

1 Benson Power facility; and shut it down. We estimate that this
2 transaction will provide net savings of approximately \$345 million
3 NPV.

4
5 (2) *Pine Bend Biogas*: We are proposing to terminate our existing
6 PPA for the output of the 12 MW Pine Bend biogas facility in
7 exchange for a margin earning agreement that sets the date of
8 termination. We estimate that this transaction will provide net savings
9 of \$5 million.

10
11 (3) *HERC*: We are proposing to restructure the PPA for the
12 output of the 33.7 MW HERC waste-to-energy facility, in recognition
13 of HERC's right to extend the PPA at fair market value. The PPA
14 restructuring provides certainty to the Company in lieu of potential
15 litigation over the existing PPA and is expected to provide overall
16 savings of approximately \$27 million when compared against
17 continuing under the existing PPA.

18
19 Company witness Mr. Greg Chamberlain provides additional information
20 regarding the key terms of these transactions. Company witness Mr. P.J.
21 Martin discusses the economic analyses that supports the proposed
22 transactions in his Direct Testimony.

23
24 Q. WHY IS NSP PURSUING THESE TRANSACTIONS?

25 A. To save our customers money. The PPAs at issue in this Application are
26 considerably above current market prices as well as the cost of most other
27 resources in the NSP System's generating portfolio. NSP initiated

1 negotiations with the purpose of eliminating these costly PPAs in order to
2 save money for customers and optimize NSP's portfolio.

3

4 Q. WHAT PROMPTED THE COMPANY TO EXAMINE ITS BIOMASS PORTFOLIO?

5 A. NSP was notified that the owners of the Benson Power facility were looking
6 to sell it. The Company decided to take the opportunity to analyze the
7 potential benefits of purchasing the plant and shutting it down rather than
8 continuing to purchase power under the existing PPA terms. The Company
9 determined that purchasing the plant, shutting it down, and replacing the
10 energy in the market would save NSP customers hundreds of millions of
11 dollars over the remaining term of the PPA.

12

13 Q. WHAT DROVE THE EXAMINATION OF THE PINE BEND AND HERC PPAs?

14 A. The significant cost savings that customers would realize if the Benson
15 Power facility was purchased and closed encouraged us to reevaluate the
16 remainder of our biomass portfolio to determine whether other PPAs could
17 be terminated or amended in order to provide more savings to ratepayers.
18 The Company determined that early termination of the Pine Bend PPA and
19 amendment of the terms of the HERC PPA could substantially reduce
20 energy costs.

21

22 Q. IS THE COMPANY PURSUING OTHER OPPORTUNITIES SIMILAR TO THE
23 PROPOSED TRANSACTIONS?

24 A. We believe that it is worthwhile to pursue opportunities as they may arise to
25 drive down costs for our customers. For example, we are currently
26 negotiating the potential termination of our biomass PPA with the
27 Laurentian Energy Authority. Should we reach agreement with Laurentian,

1 we will also bring that transaction to the North Dakota Public Service
2 Commission (Commission).

3

4 Q. ARE THE PROPOSED TRANSACTIONS CONSISTENT WITH THE CURRENT
5 REGULATORY AND STATUTORY FRAMEWORK FOR BIOMASS FACILITIES?

6 A. Yes. The Benson Power facility was built pursuant to Minnesota's statutory
7 Biomass Mandate, which I discuss in more detail later in my testimony. The
8 continued emergence of more economic and efficient sources of renewable
9 energy, such as wind and solar, as well as the low cost of natural gas has
10 prompted legislators and regulators to reexamine the practicality of biomass
11 energy production. These factors prompted the Company to work with the
12 Minnesota legislature to make practical, cost saving changes to the 1994
13 legislation that contains the Biomass Mandate. The Benson Power
14 transaction proposed in the Company's Application is consistent with those
15 recent amendments.

16

17 The Pine Bend and HERC facilities were built pursuant to the federal Public
18 Utilities Regulatory Policies Act (PURPA). PURPA does not restrict the
19 Company from buying out or amending the Pine Bend or HERC PPAs.

20

21 Q. WILL THE PROPOSED BIOMASS TRANSACTIONS REQUIRE REGULATORY
22 APPROVAL OUTSIDE OF NORTH DAKOTA?

23 A. Yes. All of the transactions are subject to the approval of the Minnesota
24 Public Utilities Commission (MPUC). We filed a Petition for Approval of
25 the biomass transactions with the MPUC on June 30, 2017—the same day
26 we filed our Application in this Case.

27

1 The Company will also be filing for approval of the Benson Power
2 transaction from the Federal Energy Regulatory Commission (FERC) under
3 Section 203 of the Federal Power Act. Upon taking ownership of the
4 Benson Power facility, the Company will file Attachment Y (Notification of
5 Generation Resource/SCU/Pseudo-tied Out Generator Change of Status)
6 with MISO regarding the proposed closure of the Benson Power facility.

7

8 Q. DO THE GOVERNING CONTRACTS ADDRESS APPROVAL BY THE COMMISSION
9 AS A CONDITION PRECEDENT TO CLOSING?

10 A. Yes. The agreements governing each transaction contemplate obtaining the
11 approval of the Commission prior to closing. Because the Pine Bend and
12 HERC agreements do not, by themselves, trigger the Company's ADP
13 obligation, the requirement to obtain Commission approval is not
14 absolute—as it is in the Benson Power contract. That said, the Company
15 chose to present the transactions as a package and, accordingly, have
16 brought them forward for Commission approval.

17

18 Q. WHAT ARE THE EXPECTED SAVINGS TO THE COMPANY'S NORTH DAKOTA
19 CUSTOMERS AS A RESULT OF THE PROPOSED TRANSACTIONS?

20 A. The following chart summarizes the expected savings for all NSP customers,
21 and, more specifically, for North Dakota customers.

22

1 **Table 1: Estimated Savings of Proposed Transactions**

Transaction	Nominal Dollars in Millions				NPV Dollars in Millions			
	System			ND	System			ND
	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

2
3
4 North Dakota customers should save a total of \$21 million NPV as a result
5 of NSP's proposed biomass transactions. The Direct Testimony of P.J.
6 Martin provides a detailed description of our cost savings analysis and
7 calculations.

8
9 **III. EVOLUTION OF THE COMPANY'S BIOMASS PORTFOLIO**

10
11 Q. HOW DID THE COMPANY'S BIOMASS PORTFOLIO DEVELOP?

12 A. For over thirty years, Xcel Energy has been developing its biomass portfolio.
13 As the service provider for five states with large agricultural and timber
14 product industries, development of biomass fueled generation has been an
15 interest of the Company and our stakeholders. To that end, the Company
16 has developed a portfolio of biomass projects totaling approximately 180
17 MW.

18
19 Different projects were acquired pursuant to different laws and programs.
20 We acquired our first several biomass projects under our obligation to
21 purchase the output from qualifying facilities as required by PURPA. We
22 then acquired three more biomass contracts under Minnesota's Biomass

1 Mandate. Finally, our last biomass contracts were acquired under the
2 auspices of the Minnesota Renewable Development Fund (RDF) program.

3

4 Q. WHAT ROLES DO THE BIOMASS PPAS PLAY IN THE NSP SYSTEM?

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

12

13 Q. PLEASE DESCRIBE THE PURPA PROJECTS.

14 A. Starting in the 1980s, the Company entered into a series of hydroelectric and
15 biomass PPAs that arose generally under PURPA and state implementing
16 statutes. PURPA allows a "qualifying facility" to require a utility such as
17 Xcel Energy to purchase the output of the facility at the utility's "avoided
18 cost." PURPA was designed, in part, to promote small power production
19 and the potential use of alternative fuels. Two of the PPAs that are part of
20 the current restructuring arose out of the Company's purchase requirements
21 under PURPA, namely the Pine Bend and HERC PPAs. Additionally, the
22 WM Renewables (MN Methane) PPA was also added to Xcel Energy's
23 biomass portfolio under PURPA.

24

25 While PURPA allows the owner of a qualifying facility to force utilities to
26 purchase power at the "avoided cost," it does not preclude the owner and a
27 utility from negotiating terms of or terminating a PPA. Accordingly, the

1 bilateral agreements between NSP and the biomass facilities covered by
2 PURPA are permitted under the statute.

3

4 Q. PLEASE DESCRIBE THE MINNESOTA BIOMASS MANDATE?

5 A. A significant amount of the Company's biomass power additions have been
6 driven by Minnesota legislative requirements arising out of the Company's
7 nuclear power program. In 1994, the Minnesota Legislature passed the
8 Prairie Island Cask Storage Authorization Act. Through the Act, the
9 Minnesota Legislature required the Company to acquire biomass resources
10 (the Biomass Mandate) in exchange for being allowed to continue the
11 operation of its nuclear power plants. This legislation was essential to the
12 Company's continued operation of its Prairie Island nuclear power station.
13 The Company was running out of space to store spent nuclear fuel and
14 needed authority to construct on-site spent nuclear fuel storage. Without
15 statutory authorization to construct on-site storage, Prairie Island would
16 have been forced to cease operations.

17

18 While the 1994 legislation authorized the necessary on-site spent nuclear fuel
19 storage, it also mandated that the Company construct and operate, or
20 contract to obtain, 125 MW of installed capacity generated by farm grown
21 closed-loop biomass. The legislation also included a wind-energy mandate
22 as well as other obligations on NSP in exchange for the right to keep the
23 Prairie Island nuclear power plant operational.

24

25 Q. HOW DID NSP COMPLY WITH THE BIOMASS MANDATE?

26 A. After the initial Biomass Mandate legislation was passed, the Company
27 sponsored a series of competitive processes to seek qualifying projects to

1 help satisfy the mandate. The Company encountered difficulties in finding
2 projects that were financially viable or cost-effective, given the state of
3 technology at the time. We encountered situations where projects were
4 proposed that, for one reason or another, were not able to advance to
5 commercial operation.

6
7 In an effort to facilitate compliance, the Minnesota legislature modified the
8 Biomass Mandate each legislative session for several years. This helped
9 vendors refine their proposals in an effort to advance projects capable of
10 achieving commercial operation. Since initial enactment of the Biomass
11 Mandate in 1994, the biomass statute (Minn. Stat. § 216B.2424) has been
12 amended fifteen times, including (1) a reduction of the total biomass capacity
13 requirement from 125 MW to 110 MW, and (2) amendment of the definition
14 of biomass to refine and expand the acceptable fuel sources. Many of the
15 statutory amendments over the years were driven by the challenges the
16 industry encountered in developing feasible projects given the state and cost
17 of the technology at the time.

18
19 The Company met its requirements under the Biomass Mandates by entering
20 into PPAs with Benson Power (Fibrominn's successor in interest), the
21 Laurentian Energy Authority, and St. Paul Cogeneration. These three
22 contracts meet the 110 MW Biomass Mandate. NSP's Proposed
23 Transactions include terminating the Benson Power PPA, purchasing the
24 facility, and shutting it down.

25

1 Q. ARE THE TRANSACTIONS INVOLVING PPAs SUBJECT TO THE BIOMASS
2 MANDATE ALLOWED BY THE STATUTE?

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

13
14 Q. WHAT BIOMASS PROJECTS WERE INITIATED UNDER THE MINNESOTA RDF?

15 A. The 1994 Minnesota Prairie Island Cask Storage Act also established the
16 Minnesota Renewable Development Fund (RDF). As part of the RDF, the
17 Company administers a grant program that is intended to help support the
18 development of renewable energy projects utilizing nascent stage
19 technologies. Two biomass PPAs – one with Rahr Malting for the KODA
20 Energy Facility and one with Diamond K Dairy for their biodigester project
21 – have become part of Xcel Energy’s biomass portfolio through the RDF
22 program.

23
24 Q. DO ANY OF THE PROPOSED TRANSACTIONS AFFECT FACILITIES CREATED
25 UNDER THE MINNESOTA RDF?

26 A. No. The Proposed Transactions do not implicate any RDF projects.

27

1 Q. FOR REFERENCE, PLEASE SUMMARIZE THE DIFFERENT ASPECTS OF THE
2 COMPANY'S BIOMASS PORTFOLIO.

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

7
8

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

9

10 Q. HOW HAS THE COMMISSION ADDRESSED THE COMPANY'S BIOMASS PPAs IN
11 THE PAST?

12 A. The Commission has allowed the Company to recover the costs of all of its
13 biomass contracts since their inception. In the Company's 2013 test year
14 rate case (Case No. PU-12-813), Commission Advocacy Staff raised issues

1 with six key biomass contracts: (1) KODA Energy LLC, (2) WM Renewable
2 Energy (MN Methane), (3) Pine Bend, (4) Benson (Fibrominn), (5)
3 Laurentian Energy Authority I, and (6) St. Paul Cogeneration. Pursuant to
4 the Negotiated Agreement approved by the Commission on March 29, 2016,
5 in Case Nos. PU-12-813. *et al.*, the Company is currently recovering the cost
6 of these six biomass PPAs subject to a potential fifty percent refund which is
7 triggered if the Company fails to construct a gas-fired power plant in eastern
8 North Dakota by the end of 2025. The remaining biomass PPAs have not
9 been singled out for scrutiny and are being recovered by the Company with
10 no conditions.

11

12 Q. ARE THERE SPECIFIC CONSIDERATIONS RELATING TO NORTH DAKOTA'S
13 TREATMENT OF THE COMPANY'S BIOMASS PPAS?

14 A. Yes. Pursuant to the Negotiated Agreement approved by the Commission
15 in Case No. PU-12-813, if Xcel Energy does not complete construction of a
16 gas-fired power plant in eastern North Dakota by 2025, it will have to refund
17 50 percent of the revenues collected from North Dakota customers that
18 exceed the revenues that would have been collected if North Dakota
19 customers had paid an adjusted system average cost for power instead of
20 purchasing the power from specific biomass facilities. If the transactions
21 move forward, both the price of power paid by North Dakota customers
22 and the amount of the potential refund will be affected.

23

24 Q. PLEASE PROVIDE A BRIEF DISCUSSION OF THE HISTORY OF THE REFUND
25 PROVISION OF THE NEGOTIATED AGREEMENT.

26 A. In 2016, the Company and Commission Advocacy Staff entered into a First
27 Revised Negotiated Agreement (Negotiated Agreement) that addressed the

1 biomass PPAs at issue in this Application, among others.¹ In the Negotiated
2 Agreement, we agreed to either (i) build or have located in eastern North
3 Dakota a natural gas-fired electric generation facility with the capacity of at
4 least 200 MW by the end of 2025, or if the facility is not in service by that
5 time (ii) refund to its North Dakota customers 50 percent of the revenues
6 collected from North Dakota customers that exceed the revenues that would
7 have been collected if North Dakota customers had paid an adjusted system
8 average cost for fuel, and energy, and associated capacity for the six biomass
9 PPAs identified in the Negotiated Agreement. The Benson Power and Pine
10 Bend PPAs were named in the agreement.

11

12 Q. WILL THE COMPANY COMPLETE THE NORTH DAKOTA FACILITY BY 2025?

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

16

17 Q. HOW WOULD THE PROPOSED TRANSACTIONS AFFECT THE REFUND?

18 A. Even if the refund required by the Negotiated Agreement is triggered in the
19 future, it would still be in North Dakota customers' best interest for the
20 Company to move forward with the Proposed Transactions. The cost to
21 North Dakota customers of continuing with the existing PPAs above the
22 system average cost of fuel has been estimated to be approximately \$53
23 million from 2016 through 2025, the period covered by the refund
24 provisions of the Negotiated Agreement. This would result in a potential
25 refund of \$26.5 million from NSP if the North Dakota electric generation

¹ 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).

1 facility is not completed by 2025. As a result, the net cost to North Dakota
2 ratepayers over that period would be \$26.5 million.

3
4 If the Company moves forward with the proposed biomass transactions, the
5 cost to North Dakota customers of the remaining biomass PPAs would
6 drop to \$38 million from 2016 to 2025. If the refund becomes applicable,
7 North Dakota customers would receive \$19 million from the Company and
8 the net cost to the ratepayers would drop to \$19 million net of the refund.

9
10 In sum, providing an ADP for our Proposed Transactions will benefit North
11 Dakota customers regardless of whether NSP meets the 2025 electric
12 generation facility deadline provided for in the Negotiated Agreement. If
13 NSP finishes construction by that date, the cost to customers associated with
14 the biomass PPAs will drop from \$53 million to \$38 million, a savings of \$15
15 million. If the facility is not completed by 2025, the biomass PPAs' cost to
16 customers, net of the refund from NSP, will drop from \$26.5 million to \$19
17 million, a savings of \$7.5 million. In either event, customers will realize
18 savings from our cost-saving initiative and these savings will be realized
19 sooner than 2025.

20

21 Q. HOW ARE THE PROPOSED TRANSACTIONS IMPLICATED IN THE COMPANY'S
22 RESOURCE TREATMENT FRAMEWORK (RTF) PROCEEDING?

23 A. As part of the RTF proceeding, the Company has proposed, as one option,
24 to allocate the costs, energy, capacity, and other benefits of all of the
25 biomass contracts to the remainder of the NSP System and not our North
26 Dakota customers. In the event this option became a reality, the HERC
27 restructuring would still impact our North Dakota customers while the

1 remaining Proposed Transactions would be moot with respect to our North
2 Dakota customers.

3
4
5

IV. REQUEST FOR DEFERRED ACCOUNTING

6 Q. HOW DOES THE COMPANY INTEND TO RECOVER THE COSTS ASSOCIATED
7 WITH THE PROPOSED TRANSACTIONS?

8 A. The costs of the proposed biomass transactions are reasonable and prudent
9 to achieve the resultant net cost savings. While the ADP statute, N.D.C.C. §
10 49-05-16, makes clear that the finding of prudence is binding for ratemaking
11 purposes, it does provide for timely rate recovery of the costs of the prudent
12 resource additions. The Company intends to seek to recover the North
13 Dakota share of these costs in future proceedings, most likely a rate case of a
14 fuel cost recovery rider filing.

15

16 Q. IS THE COMPANY MAKING ANY REQUEST WITH RESPECT TO THE COSTS OF
17 THE PROPOSED TRANSACTIONS AT THIS TIME?

18 A. Yes. So as not to delay our ability to execute on the Proposed Transactions,
19 the Company is requesting authority for deferred accounting so that the
20 Company can create a regulatory asset and defer recognizing the costs of the
21 Proposed Transaction when they occur so that they can be recovered in the
22 future.

23

24 Q. WHY DOES THE COMPANY PROPOSE DEFERRED ACCOUNTING FOR THE
25 COSTS THROUGH CREATION OF A REGULATORY ASSET?

26 A. The costs associated with purchasing and shutting down the Benson Power
27 facility and terminating the Pine Bend PPA are above and beyond both what

1 the Company has budgeted for normal utility operations and what was
2 reflected in the costs of service to set current rates. It would be
3 inappropriate to expense these costs as they occur due to the nature and
4 materiality of the expenses. These one-time extraordinary expenditures are
5 most appropriately accounted for through the creation of a regulatory asset.
6 Failure to obtain deferred accounting treatment would force the Company to
7 write off these costs in the year in which they occur, signaling no support for
8 the Proposed Transactions.

9

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

18

19 Q. FOR WHAT COSTS IS THE COMPANY SEEKING A DEFERRAL?

20 A. The Company is requesting that it be authorized to accumulate the costs
21 incurred with purchasing and shutting down the Benson Power facility and
22 terminating the Pine Bend PPA in a regulatory asset in Account 182.3. The
23 Company also requests that it be allowed to include a cost of capital return
24 on the asset. The costs to be deferred in the regulatory asset for Benson
25 Power relate to the North Dakota share of costs necessary to terminate the
26 PPA, acquire the plant, and shut it down, and also the North Dakota share
27 of the O&M costs necessary to run the plant as it is shut down in an orderly

1 fashion. The costs to be deferred in the regulatory asset for the Pine Bend
2 PPA relate to the North Dakota share of the termination payment of
3 \$1,050,000. The Company will propose mechanisms to recover these costs
4 sometime in the future.

5

6 Q. WHY IS THE COMPANY NOT SEEKING DEFERRED ACCOUNTING TREATMENT
7 FOR THE HERC TRANSACTION?

8 A. As a restructuring of a PPA, recovery of the costs of the HERC transaction
9 are authorized for recovery through our FCR Rider. Consequently, there is
10 already a real-time recovery mechanism available for this transaction. The
11 same is not true with respect to the costs of the other Proposed
12 Transactions.

13

14 **V. PRUDENCE OF THE CUSTOMER COST-SAVING INITIATIVE**

15

16 Q. ARE THE PROPOSED TRANSACTIONS PRUDENT?

17 A. Yes. The Company's Proposed Transactions are prudent. Our analysis,
18 with its conservative assumptions, shows that the Proposed Transactions
19 will result in significant cost savings to customers from both a long-term
20 perspective and a near-term rate impact perspective. We anticipate that
21 North Dakota customers will save, conservatively, approximately \$21
22 million. Based on our analyses, we believe that it is prudent, reasonable and
23 in our customers' best interests for the Commission to grant an ADP for the
24 Proposed Transactions.

25

1 **VI. PRESENTATION OF WITNESSES**

2

3 Q. WHO ARE THE WITNESSES FOR THE COMPANY IN THIS PROCEEDING?

4 A. In addition to my Direct Testimony, the Company sponsors the following
5 witnesses:

6

7 ● Mr. P.J. Martin discusses the economic analyses and expected cost
8 savings that we expect to achieve by undertaking our Proposed
9 Transactions.

10 ● Mr. Greg Chamberlain discusses the key terms of the Proposed
11 Transactions.

12

13 **VII. CONCLUSION**

14

15 Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

16 A. Yes, it does.

Northern States Power Company

Aakash H. Chandarana
Regional VP, Rates and Regulatory Affairs
NSP

Aakash Chandarana is Regional Vice President of Rates and Regulatory Affairs – Minnesota. He is responsible for Xcel Energy’s regulatory filings with the utility commissions in Minnesota, North Dakota, and South Dakota.

Chandarana joined Xcel Energy in 2013 as Lead Assistant General Counsel – Regulatory North where he was the lead regulatory attorney for Xcel Energy’s operations in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan. He represented Xcel Energy in regulatory proceedings and handled most issues related to rate cases, nuclear issues, fuel costs, depreciation, renewable energy, and resource planning. In January 2015, he was promoted to his current role. He has more than 10 years of experience in energy and regulation.

Chandarana serves on the Finance Board of the Boys and Girls Club. He also is a member of the Minnesota State Bar Association.

Prior to joining Xcel Energy, Chandarana was a partner at the law firm of Briggs and Morgan where his practice focused on the energy industry. He represented utilities in commercial transactions involving generation interconnection agreements, power purchase agreements, and regulatory proceedings.

Chandarana received his B.A. in biology and business management from Washington University in St. Louis and his law degree from Washington University in St. Louis School of Law.

