



**BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

***In the Matter of Northern States Power Company's
Advance Determination of Prudence
For its Solar Portfolio
Case No. PU-14-810***

**DIRECT TESTIMONY
OF
MIKE DILLER**

**ON BEHALF OF THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION
ADVOCACY STAFF**

February 20, 2015

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1 Q: **Provide your name and qualifications.**

2 A: My name is Mike Diller. I am the Director of Economic Regulation for the
3 North Dakota Public Service Commission (NDPSC). I am a utility analyst and
4 provide direction to a small staff. I have 30 years of utility regulatory
5 experience including service to both the Oklahoma Corporation Commission
6 and the NDPSC.

7 I received a Bachelor of Science Degree in Accounting from Oklahoma
8 Christian College in Edmond, Oklahoma in 1981. I am a Certified Public
9 Accountant and member of the American Institute of Certified Public
10 Accountants. I have testified before the NDPSC on numerous occasions
11 including acquisition and merger proposals, rate cases, settlements, advance
12 determination of prudence requests and rule changes.

13
14 Q: **What is the purpose of your testimony?**

15 A: The NDPSC has appointed me to advocacy staff (staff) in this proceeding. As
16 such, I will provide the NDPSC with an analysis of Northern States Power
17 Company's (NSP) application for Advance Determination of Prudence (ADP)
18 for its proposed Solar Portfolio (SP).

19
20 Q: **Please summarize your testimony.**

21 A: NSP's North Dakota ratepayers do not need the proposed SP for generation
22 capacity or the energy that these units would provide. The proposal does not
23 represent least cost planning. Instead, the SP is being proposed to satisfy
24 Minnesota's Solar Energy Standard (SES). Staff recommends that the
25 NDPSC deny the requested ADP and also deny any replacement costs for
26 the denied capacity.

27

1 **Q: How did you determine that the solar portfolio is not needed?**

2 A: Staff compared NSP's most recent load forecasts to the capacity of its
3 existing generation resources noting that NSP is able to meet its load
4 obligations without any additional generation facilities until 2024.¹

5

6 For the few years between now and 2024 when resource adequacy is
7 projected to be tight, NSP provided low cost alternatives to the Minnesota
8 Public Utilities Commission (MPUC) including increasing its diversity
9 exchange agreement with Manitoba Hydro by 75 MW and extending the lives
10 of its oil-fired peaking units at Blue Lake.²

11

12 In its Reply Comments to the Comments filed by other parties to the
13 Competitive Resource Acquisition Process (CAP) before the MPUC, NSP
14 indicates that a generation surplus is projected to continue through 2023,
15 even when excluding the proposed utility-scale solar generation.³

16

17 Despite NSP's comments, the MPUC approved or is expected to approve the
18 construction of the following generation resources (UCAP ratings):

19

- 72 MW Geronimo Aurora solar PPA (2018 in-service date);
- 20 • 308 MW Calpine Mankato combined cycle PPA (2019);
- 21 • 207 MW Black Dog unit #6 combustion turbine (2020);
- 22 • 73 MW Manitoba Hydro diversity exchange agreement (June, 2016);
- 23 • 98 MW from the Solar Portfolio (End of 2016).⁴

24

25 **Q: Isn't it better to have excess generation?**

26 A: NSP already carries excess generation via its planning reserve margin to
27 account for catastrophic events and unforeseen outages. Still, there can be

¹ Data Requests and Responses, Page 200.

² NSP's MN Compliance Filing dated October 2, 2014, Docket No. E002/M-14-789, Pgs. 9-11.

³ NSP's MN Reply Comments dated November 3, 2014, Docket No. E002/M-14-789, Page 6.

⁴ Data Requests and Responses, Page 200.

1 instances where adding generation beyond an adequate reserve margin is
2 reasonable and efficient. Making such a determination is part of the
3 Integrated Resource Plan (IRP). Generally, it is more advantageous to
4 manage generation resources as closely as possible to load requirements
5 because it is expensive to carry more generation than required or needed.
6

7 **Q: How has resource adequacy changed in recent years?**

8 A: The structure of generation resource adequacy has changed under regional
9 grid operators like the one NSP belongs to; Midcontinent Independent System
10 Operator (MISO). One of the primary values of operating the electric system
11 on a regional basis is to share generation assets to enable companies to
12 carry a smaller reserve margin and improve reliability at the same time. It is
13 no longer necessary or desirable for every utility to carry large amounts of
14 excess generation as though they are still operated on a stand-alone basis.
15

16 MISO requires a system wide planning reserve margin (PRM) of 7.1%.⁵ Said
17 another way, NSP is required to carry excess generation of 7.1% above its
18 peak demand coincident with the MISO system less its load management
19 capabilities.⁶ Historically, MISO's required PRM has continued to decline.⁷
20 MISO expects its future PRM to continue shrinking.⁸ As a result, capacity
21 needs will likely diminish relative to overall needs.
22

23 **Q: Does the PRM account for outages and undeliverable power?**

24 A: Yes. The installed or nameplate capacity (ICAP) ratings of generators on
25 MISO's system are adjusted downward to reflect only generation that is
26 available and deliverable; also known as unforced capacity (UCAP) rating.
27 The UCAP ratings account for the robustness of generator interconnections

⁵ MISO 2015-2016 Loss of Load Expectation Study Report, Page 4.

⁶ Data Requests and Responses, Page 200.

⁷ MISO 2015-2016 Loss of Load Expectation Study Report, Page 32.

⁸ Ibid, Page 33.

1 and transmission availability, availability or non-availability of intermittent
2 resources, thermal derates, planned maintenance, units that are inoperable,
3 poor historical performance and estimated forced outages.⁹ As a result, the
4 7.1% planning reserve margin is a true margin above and beyond expected
5 load requirements.

6
7 **Q: How is the planning reserve margin calculated?**

8 A: MISO uses a mathematical analysis to determine what level of PRM is
9 necessary to achieve the probability of less than one-day loss of load event
10 every 10 years (or .1 day per year) in accordance with its Federal Energy
11 Regulatory Commission Tariff.¹⁰ Accordingly, the minimum PRM requirement
12 is determined by either adding Coincident Peak Demand or removing
13 Planning Resources until a 0.1 day per year solution is reached.¹¹

14
15 **Q: Does the diversity of MISO minimize the need for capacity?**

16 A: Yes. MISO coordinates transmission and generation services across 15
17 different states. Accordingly, the locational diversity within the large region in
18 terms of weather, temperatures, sunlight, peak-hour usage etc. is significant
19 and permits the use of lower system wide reserve margins than otherwise
20 would be required for a stand-alone company. For example, it may be cool
21 and raining in Bismarck yet hot and humid in Minneapolis allowing for more
22 efficient utilization of generation resources across the electric grid.

23
24 **Q: Provide context for the size of MISO.**

25 A: NSP is one of the larger load serving entities in MISO with less than 10,000
26 MW of peak capacity needs.¹² MISO manages over 200,000 MW of

⁹ MISO Business Practice Manual No. 011, Resource Adequacy, Appendix H, Pages 136-137.

¹⁰ MISO 2015-2016 Loss of Load Expectation Study Report, Page 4.

¹¹ MISO Business Practice Manual No. 011, Resource Adequacy, Page 25.

¹² Data Requests and Responses, Page 200.

1 generation capacity allowing for vast amounts of shared resources.¹³ The
2 administrative cost of MISO exceeds \$.25 billion a year.¹⁴ Ignoring the
3 sharing aspect and economy of scale offered through MISO's operation,
4 when additional generation is not needed, erodes the value of membership in
5 MISO.

6
7 **Q: Is there a cost to carry excess generation?**

8 **A:** Yes. The recovery of generator costs in the MISO market comes primarily
9 from running the generators. Excess generation drives down the overall price
10 of the energy market and diminishes the run time of existing generators. As a
11 result, ratepayers will pay for the full carrying costs of generators only to get a
12 smaller price for less generation in return.

13
14 Similarly, excess generation diminishes the value of capacity. Because the
15 MISO system has been in an excess capacity position, the market value for
16 excess capacity has been minimal. For instance, the clearing price for
17 capacity sold at the annual auction in 2013 was \$1.05 per MW – Day.¹⁵ In
18 2014, capacity at the annual auction garnered \$3.29 per MW – Day for
19 MISO's Zone 1 (NSP's zone).¹⁶ Therefore, the auction price in 2014 for 1
20 MW of capacity for one year would be about \$1,200 (\$3.29 times 365 days).
21 By contrast, MISO estimates the cost of new entry to be \$89,500 for 1 MW of
22 capacity for one year. As you can see, there can be a significant cost to
23 ratepayers associated with excess generation; both in terms of energy and
24 capacity prices.¹⁷

25

¹³ MISO Website, Corporate Information, Reliability Coordination Area (includes Manitoba).

¹⁴ MISO Website, 2015-2017 Budget.

¹⁵ 2013/2014 MISO Planning Resource Auction Results.

¹⁶ 2014/2015 MISO Planning Resource Auction Results.

¹⁷ MISO Business Practice Manual No. 011, Resource Adequacy, Page 106.

1 **Q: Who benefits if NSP adds excess generation?**

2 A: The MISO pool of energy is one large integrated system. Therefore, adding
3 extra generation provides another option for energizing the regional grid and
4 therefore strengthens the overall grid. As a result, pouring more resources
5 into the pool than required by MISO enriches all the members of the grid at a
6 disproportional cost to local ratepayers. The goal of NSP should be to
7 manage its generation resources to the nearest possible level required by
8 MISO.

9

10 **Q: When should excess generation resources be deployed?**

11 A: It is sometimes possible for new generation to displace existing generation
12 and still save consumers money. For instance, if the average avoided cost of
13 legacy plants' fueled by fossil fuel is 5 cents per kWh and wind energy can be
14 procured at 3 cents per kWh, it may make sense to carry the extra wind
15 generation even if it is not needed to serve existing load. In this case, the SP
16 is projected to add cost to the total system revenue requirements rather than
17 lessen the overall cost.

18

19 **Q: Can NSP incur a penalty for failing to plan for enough generation?**

20 A: Yes, but it should not occur. NSP must provide MISO with its projected
21 annual peak demand and monthly peaks and energy requirements by
22 November 1 for the following planning year.¹⁸ After the forecasts are
23 reviewed and affirmed by MISO, NSP must submit a plan to meet its native
24 load requirements. In the event available resources are not adequate to meet
25 PRM requirements, MISO conducts an annual auction to allow entities short
26 on capacity to buy capacity from those long on capacity. If NSP fails to
27 procure adequate resources or buy capacity at auction, it can choose to
28 subject itself to a MISO Capacity Deficiency Charge.¹⁹

¹⁸ MISO Business Practice Manual No. 011, Resource Adequacy, Page 18.

¹⁹ Ibid, Page 14.

1 Doing so would result in a charge of 2.748 times the Cost of New Entry
2 (CONE).²⁰ CONE is the estimated annual capital, operating, and other costs
3 that would be incurred to develop a new capacity resource.²¹ The CONE
4 value for NSP's Zone 1 is \$89,500 per MW – Year.²² The failure to plan for
5 projected load requirements and/or buy capacity when needed could result in
6 a penalty of \$245,946 per MW – Year (2.748 times \$89,500); but this should
7 not occur.

8
9 **Q: Does MISO assess penalties for forced outages?**

10 **A:** No. In the event of an unforeseen outage (such as the recent fire at Coyote
11 Station near Beulah, ND), the MISO reserve margin is designed to cover any
12 shortfalls that may occur and there are no penalties assessed by MISO.
13 Further, it is not necessary for NSP to contract for capacity that was lost due
14 to a forced outage; negating any need to over-build or over-purchase
15 generation for forced outages. This is part of the value proposition of
16 belonging to MISO and its large economies of scale.

17
18 **Q: If there is no financial or operational need for the Solar Portfolio, how**
19 **does NSP justify its proposal?**

20 **A:** In its application and testimony, NSP puts forward several qualitative reasons
21 for adding the SP. The following encapsulates the primary arguments
22 advanced by NSP for adding the proposed SP:

- 23
24 1. Cost effectively meets MN's Solar Energy Standard (SES)²³
25 2. Takes advantage of the Federal 30% Investment Tax Credit²⁴
26 3. Provides a hedge against future environmental regulation²⁵

²⁰ MISO Business Practice Manual No. 011, Resource Adequacy, Page 103.

²¹ FERC Order on Annual Cost of New Entry, Docket No. ER10-2090-000, Page 1.

²² MISO Business Practice Manual No. 011, Resource Adequacy, Page 106.

²³ NSP's Application, Page 1.

²⁴ Ibid, Page 9.

²⁵ Ibid, Page 11.

1 4. Provides a hedge against natural gas prices²⁶

2 5. The impact to customers' bills are really small²⁷

3 1.

4 **Q: Should the NDPSC consider the MN Solar Energy Standard?**

5 **A:** Yes. Minnesota (MN) borders our state. We trade with each other. We
6 share MISO's Zone 1 to ensure resource adequacy in our region. NSP
7 provides service in both states. We should seek to mutually and beneficially
8 coexist whenever possible so long as doing so is not detrimental to our own
9 citizenry. In this instance, I think the SP projects provide a unique opportunity
10 where both MN and ND can benefit.

11
12 Before I get to that, please note that the voters of MN have chosen their
13 representatives who in turn have determined that having solar energy is
14 important to MN by mandating that 1.5% of its energy needs come from solar
15 by 2020 and a goal of 10% by 2030.²⁸ Mandates, by nature, lead to
16 ineffective allocation of resources but clearly MN has determined that the
17 benefits of solar and the additional diversity of resources are worth the extra
18 cost. There is nothing inherently wrong with different state policies, especially
19 when both energy policies can be accommodated.

20
21 From a technical and fairness standpoint, basic cost allocation and rate
22 design principles require that costs be assigned to the cost causers whether
23 allocating costs between states or to various customer classes. Attempting to
24 allocate MN costs to ND ratepayers to meet a MN mandate is comparable to
25 taxation without representation and works against basic cost allocation
26 principles and rate design techniques familiar to the NDPSC.

27

²⁶ Ibid, Page 13.

²⁷ Ibid, Page 14.

²⁸ NSP's Application, Page 2.

1 The problem with allocating some of the costs and associated renewable
2 energy credits (REC's) to ND is that it frustrates NSP's ability to achieve its
3 MN SES. MN is the only state served by NSP that requires a solar energy
4 standard. For this reason, it is in the best interest of MN to pay for its own
5 specialized generation and reap all the benefits it perceives from investing in
6 solar energy. Similarly, it is in the best interest of ND to adhere to its least
7 cost planning objectives; a win-win scenario for both states. Both states'
8 energy policies are met in the most efficient manner possible.

9
10 **Q: How does denying an ADP benefit NSP and MN?**

11 A: Let's assume that MN's SES requires NSP to acquire 75 MW of solar
12 generation. NSP would have to secure 100 MW of solar generation because
13 of the regulatory jurisdictional allocation of generation assets and purchased
14 power agreements among the various states. Because NSP is allocated
15 approximately 75% of these costs, it is necessary to add 100 MW of solar to
16 receive an allocated share of 75 MW for MN.

17
18 Instead, NSP should direct assign these projects to MN. In this way, the SES
19 is achieved more directly and prudently. Doing so avoids unnecessary rancor
20 between other states when adding these projects that are not cost effective.
21 It reduces the regulatory burden of seeking cost recovery in multiple
22 jurisdictions. It enhances NSP's chances of full cost recovery. It is a
23 friendlier and better way of considering needs of other stakeholders outside
24 MN.

25
26 **Q: How does the MN RPS compare to other states?**

27 A: MN's Renewable Portfolio Standard (RPS) for Xcel Energy is 31.5% by 2020,
28 including an SES of 1.5%. By comparison, the other states served by NSP

1 have renewable standards and objectives of 10%; except for Wisconsin with a
2 standard of 12.89%.²⁹

3

4 In conclusion, the NDPSC should consider NSP's need to meet its MN
5 mandates for SES and deny this ADP and any associated cost recovery to
6 help NSP comply with its MN obligations.

7

8

2.

9 **Q: Should NSP invest now to take advantage of the 30% ITC?**

10 A: No. Like sole source mandates for generation, subsidies from the federal
11 government distort the true economics of resource allocation. However, while
12 it pains me to say this from a pragmatic, taxpayer and free market ideology, it
13 would be foolish for NSP to ignore the "free money" offered by the Federal
14 Government to deploy solar generation. However, even with the 30% ITC,
15 NSP's reference case indicates that adding the proposed solar portfolio
16 results in additional costs of \$14 million.³⁰

17

18 **Q: Is the SP price comparable to the market price of energy?**

19 A: No, the cost of SP energy is never less than NSP's projected average cost of
20 available market energy for on-peak prices. The comparison of the SP
21 energy to off-peak prices is worse. This is true for the entire contract period.³¹

22

23 **Q: How does the SP compare to current wind energy prices?**

24 A: The SP contract prices are more than double the available wind prices for
25 similar contract periods as evidenced by Montana-Dakota Utilities Company's
26 recent ADP filing for its Thunder Spirit Wind Project.³²

27

²⁹ NSP's Integrated Resource Plan, Case No. PU-15-19, Page 56.

³⁰ NSP's ADP Application, Page 10.

³¹ Data Requests and Responses, Page 196.

³² MDU's ADP filing for Thunder Spirit Wind Project, Case No. PU-14-843.

1 **Q: Will better opportunities occur for deploying solar?**

2 A: Yes, solar is just coming into vogue. It is in the early development stage and
3 therefore has a lot of upside potential in terms of efficiency improvements and
4 technology advancements. According to IHS Energy's 2014 Market Brief
5 entitled "Outlook for US Solar Photovoltaic Capital Costs and Prices, 2014-
6 2030, IHS expects solar Photovoltaic capital costs to fall approximately 45%
7 by 2030. Further, IHS expects efficiency gains in collecting solar power of
8 11% to 24% between 2009 and 2030.³³

9
10 There seems to be little reason to rush to market to take advantage of the ITC
11 credit differential between 30% through 2016 and 10% thereafter except to
12 satisfy the MN SES. There is no need for additional capacity. The cost of the
13 energy from the SP is extremely high in comparison to expected energy
14 market prices and available wind generation prices for the same time period.
15 Solar efficiencies in terms of capital costs and collecting the sun's rays will
16 continue to decline as the solar industry matures much like it has for wind
17 generation, flat screen televisions, cell phones and so on. For these reasons
18 there is no need to make an opportunity buy of solar generation at this time.

19
20 3.

21 **Q: Should the NDPSC consider the value of solar energy as a hedge**
22 **against future environmental regulation.**

23 A: According to ND law:

24 The NDPSC may not use, require the use of, or allow electric utilities to use
25 environmental externality values in the planning, selection, or acquisition of
26 electric resources or the setting of rates for providing electric service.
27 Environmental externality values are numerical costs or quantified values that
28 are assigned to represent either:

- 29 1. Environmental costs that are not internalized in the cost of production
30 or the market price of electricity from a particular electric resource; or
31 2. The alleged costs of complying with future environmental laws or
32 regulations that have not yet been enacted.³⁴
33

³³ Data Requests and Responses, Page No. 13.

³⁴ N.D.C.C. § 49-02-23.

1
2 Also, according to ND law:

3 The commission may not increase electric rates as a result of actions taken
4 by other states requiring higher cost resources to be built, purchased, or
5 otherwise acquired as a result of the application of quantified environmental
6 externality values, as defined in section 49-02-23, as part of any resource
7 selection process.³⁵
8

9 To my knowledge, NSP has not included any numerical costs of complying
10 with future environmental laws in its econometric model when developing its
11 Reference Case and various sensitivity tests. While it has been the practice
12 of the NDPSC to consider qualitative reasons for considering potential
13 environmental laws and regulations, it is at least useful to consider the spirit
14 of these laws.³⁶
15

16 The NDPSC should also take note of its comments filed with the
17 Environmental Protection Agency (EPA) arguing that the EPA's proposed
18 Carbon Pollution Emission Guidelines for Existing Sources are not authorized
19 by Federal Law and that it circumvents the NDPSC's resource planning
20 authority.³⁷ Staff believes that granting deference in this proceeding for a
21 proposed CO² rule that may or may not stand up in court runs counter to the
22 NDPSC's position.
23

24 Nevertheless, if the NDPSC wants to consider the qualitative value of solar as
25 it pertains to the environment, note again that there is a huge price discount
26 for wind PPA's compared to solar PPA's; and wind generation essentially
27 provides the same environmental attributes as solar generation. If a hedge
28 against carbon dioxide (CO²) emissions is desired, wind energy is much
29 cheaper.
30

³⁵ N.D.C.C. § 49-06-24.

³⁶ NDPSC Big Stone 2 Order, Case No. PU-06-481, Finding 88.

³⁷ NDPSC's comments to EPA filed November 25, 2014, Case No. PU-14-736.

1 5.

2 **Q: Should the NDPSC consider the smallness of the SP's rate impact?**

3 A: Should NSP's lawyers and witnesses each give me \$100? It is a small and
4 insignificant amount to each of them in comparison to their annual salaries.
5 In relative terms, \$100 would be a smaller percentage of their salaries
6 compared to the rate impact projected by NSP of approximately .02 cents per
7 kWh.³⁹

8

9 The decision to grant or deny ADP should be determined on the merits of the
10 case and our best estimates whether the impact is great or small to
11 ratepayers. This is just the first of several MN ordered generation resources
12 that have or will be filed for ADP before the NDPSC. This case will likely
13 establish a framework for going forward.

14

15 **Q: Should the NDPSC deny recovery of replacement capacity?**

16 A: Yes, the Settlement Agreement adopted by the NDPSC in NSP's last rate
17 increase application included a Negotiating Framework for developing a
18 mechanism whereby the Company will serve its ND customers with resources
19 (real or proxy) consistent with ND's energy policies.⁴⁰ The resulting
20 negotiated mechanism is to be provided to the NDPSC for approval by June
21 30, 2015.⁴¹

22

23 In principle, ND ratepayers will be required to purchase capacity or accept a
24 proxy price for capacity when the NDPSC finds MN ordered generation does
25 not agree with ND's energy policies. However, in this instance, additional
26 capacity is not needed and therefore charging ND ratepayers a proxy price for
27 what would be its share of the SP capacity is unreasonable.

28

³⁹ NSP's ADP Application, Page 14.

⁴⁰ Order Adopting Settlement, Case No. PU-12-813, Attached Settlement Agreement, Page 14.

⁴¹ Ibid, Page 16.

1 The Settlement Agreement calling for a capacity proxy price was based on an
2 assumption that capacity would be needed. Accordingly, when capacity is
3 needed and NSP adds generation to meet a MN renewable standard that is
4 not least cost oriented, ND may substitute a proxy price for the needed
5 capacity based on its own energy policy of least cost planning.

6
7 I don't believe either party to the case imagined a situation where one state
8 would be ordering the construction of generating units beyond its native load
9 requirements; beyond the requirements of MISO at a net cost to consumers.
10 There is simply no justification for assigning additional capacity costs to ND
11 for generation capacity not needed or cost effective. To do otherwise would
12 allow one state to enrich itself based on its own perceived value of solar
13 generation and its desire for excess generation, at the expense of other
14 states.

15
16 A full denial is advantageous to NSP as it seeks cost recovery for the SP in
17 MN. The clearer the Order, the better equipped NSP will be for arguing for
18 full recovery from its Minnesota ratepayers as it seeks to meet the Minnesota
19 SES.

20
21 Finally, issuing an order denying a capacity proxy price in this instance
22 removes one of the obstacles that remains in the restack and cost allocation
23 filings to be made later in 2015 as required in the Settlement Agreement.

24
25 **Q: Does this conclude your testimony?**

26 **A: Yes, it does.**

27
28
29
30

1 Appendix – Acronyms Used in Testimony

ADP	Advance Determination of Prudence
CAP	Competitive Resource Acquisition Process
CO ²	Carbon Dioxide
CONE	Cost of New Entry
EPA	Environmental Protection Agency
ICAP	Installed Capacity Rating (MW)
IRP	Integrated Resource Plan
MDU	Montana-Dakota Utilities Co.
MISO	Midcontinent Independent System Operator
MPUC	Minnesota Public Utilities Commission
NDCC	North Dakota Century Code
NDPSC	North Dakota Public Service Commission
NSP	Northern States Power Company
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
SES	Solar Energy Standard
SP	Solar Portfolio
UCAP	Unforced Capacity Rating (MW)

2

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Q: What are your thoughts on whether NSP’s North Dakota ratepayers should be part of the integrated system?	1
Q: NSP argues for proxy pricing of the solar capacity and energy in order to maintain an integrated system in the short- to mid-term. Isn’t that reasonable?	2
Q: Are you really suggesting in your testimony that North Dakota rely on MISO’s annual auction for its capacity requirements?	2
Q: Mr. Haeger agrees that the Solar Portfolio is not the least cost resource but offers a lot of qualitative reasons for approving the ADP application nonetheless. Do you have any qualitative reasons of your own for the commission to consider?	4
Q: Mr. Haeger argues that determining a proxy price for capacity will result in North Dakota customers paying for used and useful resources serving them. Do you agree?	6
Q: Energy policy differences between MN and ND began showing up over the last 10 years because of differences in renewable objectives. NSP advocates that we continue to use proxy pricing until a more permanent solution can be determined. Why is a permanent solution taking so long?	6
Q: Do you have a recommendation for a permanent solution to the allocation of generation resources between the states of MN and ND?	8
Q: NSP provided a Supplement to its most recent IRP to reflect the MNPUC orders to build generation. Can you provide a condensed summary of Table 1: Updated Load and Resources for the commission and provide comments?	9
Q: Can you give the commission some assurances that enough capacity will be available for NSP’s ND ratepayers?.....	10
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1 **Q: Provide your name and qualifications.**

2 A: My name is Mike Diller. I am the Director of Economic Regulation for the
3 North Dakota Public Service Commission (NDPSC).

4
5 **Q: Have you provided other testimony in this case?**

6 A: I submitted Direct Testimony on February 20, 2015.

7
8 **Q: What is purpose of your Surrebuttal Testimony?**

9 A: NSP's witness, Mr. Haeger, provided 27 pages of Direct Testimony which I
10 followed up with 16 pages of Direct Testimony. Mr. Haeger has responded to
11 my testimony with 36 pages of Rebuttal Testimony plus 21 pages of attached
12 testimony related to the Advanced Determination of Prudence (ADP) for a
13 Purchase Power Agreement (PPA) with Aurora Distributed Solar, LLC not yet
14 heard by the commission. Advocacy Staff cannot respond to all the testimony
15 due to time limitations. However, we will address the more critical matters
16 and reaffirm our position.

17
18 **Q: What is your overall impression of Mr. Haeger's testimony?**

19 A: Generally, each round of testimony tends to narrow the scope and refine the
20 issues. In this case, Mr. Haeger raises a lot of questions and complexity for a
21 case that I believe is quite straight forward.

22
23 **Q: What are your thoughts on whether NSP's North Dakota ratepayers
24 should be part of the integrated system?**

25 A: Northern States Power Company (NSP) apparently expects its North Dakota
26 (ND) ratepayers to pay for the additional costs put upon it by the State of
27 Minnesota in order to be a part of its integrated system. In a sense, North
28 Dakota must pay to play. If North Dakota desires to enjoy NSP's large
29 economies of scale, then it must pay for generation it does not need.

30

1 NSP operates an integrated system in the technical sense that the Eastern
2 Grid is an interconnected system; including NSP's territory. It isn't so
3 integrated from an energy policy perspective. In that regard, NSP's system is
4 a MN system. Similarly, the latest Integrated Resource Plan is more of a MN
5 plan rather than least cost resource planning.

6
7 Quite frankly, I don't believe the commission should worry too much about
8 this threat of being alienated from NSP's integrated system. The commission
9 should just continue to expect that least cost planning will occur whether that
10 occurs through total system generation additions or ND specific generation
11 additions.

12
13 **Q: NSP argues for proxy pricing of the solar capacity and energy in order**
14 **to maintain an integrated system in the short- to mid-term. Isn't that**
15 **reasonable?**

16 A: No. NSP does not need capacity until 2024. It is one thing to adjust the
17 energy price of these solar projects to reflect a more reasonable price but
18 quite another to expect ND ratepayers to pay for capacity not needed, proxy
19 price or otherwise.

20
21 **Q: Are you really suggesting in your testimony that North Dakota rely on**
22 **MISO's annual auction for its capacity requirements?**

23 A: Of course not. It is just one of many resources available to NSP for meeting
24 its capacity needs. Generally speaking, the auction price information is
25 included in my testimony to show that there is in fact excess capacity and that
26 it can be had for a reasonable price. It is not an end-all-be-all proposition but
27 provides a one-year solution for those who would avail themselves of the
28 market.

29

1 MISO's third annual capacity auction was recently held and Montana-Dakota
2 Utilities Co. purchased a year's worth of capacity of 16.6 MW's for \$21,085.32
3 or a cost of about \$1,270 per MW – year. By comparison, MISO estimates
4 the cost of new capacity to be \$89,500 per MW – year. MISO's annual
5 auction is a real market; it is used by real utilities as a bridge from capacity
6 deficiency to capacity sufficiency. Based on MISO's capacity cost of new
7 entry, MDU saved its customers \$1.5 million through the capacity auction by
8 deferring the building of additional capacity by one year.

9
10 NSP submits its forecasted needs to MISO November 1 for its needs
11 beginning June 1 of the following year. MISO reviews the forecasts for
12 reasonableness and affirms the amount of needed resources. NSP then
13 must show how it will meet those needs. In the event NSP has not fully
14 anticipated its needs when submitting its resource needs, it must then acquire
15 capacity resources in one fashion or another with the capacity auction being
16 one of the available resources.

17
18 The forecasting of capacity and energy needs is done on a regular basis by
19 NSP. Management is tasked with the responsibility of monitoring sales and
20 trends in sales and planning for them accordingly. Forecasted needs
21 generally do not change overnight. Resources are being planned well ahead
22 of needs to accommodate the building time for generation assets that Mr.
23 Haeger talks about. It is a primary reason for doing resource planning. NSP
24 should not wake up November 1 and go OMG, our forecasted need is much
25 higher than we thought and we only have a few months to enter into bilateral
26 agreements, rely on the MISO auction or submit ourselves to MISO's CONE
27 penalty.

28

1 **Q: Mr. Haeger agrees that the Solar Portfolio is not the least cost resource**
2 **but offers a lot of qualitative reasons for approving the ADP application**
3 **nonetheless. Do you have any qualitative reasons of your own for the**
4 **commission to consider?**

5 A: Yes, I do. If the commission ever wants to see those natural gas turbines
6 built on the eastern side of the state by 2036 as agreed to by NSP in its last
7 rate case Settlement, then it must resist paying for capacity that is not
8 needed. The Agreement states that 400 MW of thermal generation resources
9 will be developed in North Dakota no later than 2036 (listen carefully to the
10 next part) “consistent with the principles of orderly development” and “prudent
11 resource planning.” Orderly development and prudent resource planning
12 cannot occur so long as Minnesota trumps the process by ordering more
13 generation than is needed. As long as that continues, Red River Units 1 & 2
14 will not be built.

15
16 Secondly, it is worth considering Minnesota’s end game in the realm of
17 qualitative considerations. You may choose to believe that the MN PUC has
18 lost its collective mind and cares nothing about the price of electricity when
19 ordering excess generation capacity. I personally don’t believe that. My
20 belief is that they are building excess generation to allow flexibility to run coal
21 plants less (which is part of NSP’s most recent IRP) or perhaps movement
22 towards eliminating coal plants in MN altogether. If that is right, our
23 ratepayers have a 5% stake in the remaining coal plants that will be run less
24 or prematurely closed down. Paying for excess capacity we don’t need helps
25 facilitate the wrong direction of MN and hastens the ruin of MN coal plants
26 that provide low cost energy to ND consumers.

27
28 Third and closely related to the first two, the commission should consider the
29 matter of command and control. As long as the generating assets of NSP are
30 located in MN, this commission and the state as a whole will have little or no

1 control over whether the generating plants are used efficiently or ran until the
2 end of the assets useful life. Today, the state of MN is at war with coal plants.
3 When all the coal plants in MN are gone, it isn't too difficult to imagine that
4 gas plants will be targeted next. If ND wants some say over energy policy in
5 the future, do not approve excess generation built in MN but instead hold tight
6 and require that generation be built in ND to the extent possible.
7

8 Fourth, the commission should inform NSP through its decision in this case
9 that a permanent solution is required. According to NSP, the proxy pricing for
10 generating units not acceptable to ND is just a temporary solution to buy more
11 time for a permanent solution. Demand a permanent solution and resist
12 paying a capacity proxy price to kick this can down the road. To the extent
13 ND pays for generation it does not need lessens the impetus for NSP to
14 instruct its cost causing state to pony up for its own costs. I cannot say this
15 any better than NSP's customer Larry Lampl of West Fargo wrote and
16 adopted here as my testimony:
17

18 I do not have a voice in the MN State Legislature on
19 mandated alternative energy source requirements that they
20 place on their energy companies. Therefore, I do not believe
21 that I or any other ND customer should be required to pay
22 increased electrical rates for their mandatory energy
23 sources. That cost should be borne by MN customers only
24 as it was their state legislators who passed the MN Solar
25 Energy Standard that impacts NSP.
26

1 **Q: Mr. Haeger argues that determining a proxy price for capacity will result**
2 **in North Dakota customers paying for used and useful resources**
3 **serving them. Do you agree?**

4 A: No. Could you argue that once these solar farms are built and providing
5 support and energy to the grid that they are indeed used? You could.
6 However, the phrase contains a conjunction “used AND useful” not merely
7 used. If being “used” was the only prerequisite, NSP could build a thousand
8 solar farms and a million wind farms and as long as they were connected to
9 the grid in some fashion then the added additions could be deemed used and
10 therefore reasonable and prudent. Thankfully, the full phrase of “used AND
11 useful” brings common sense into the legal realm. This legal metric requires
12 that these units also be “useful.” I contend that the lack of need for capacity
13 and the associated high priced energy these solar farms produce do not meet
14 the useful criteria. These solar farms are not useful to ND ratepayers.
15 Accordingly, these solar farms are not “used AND useful” for NSP’s ND
16 ratepayers.

17

18 **Q: Energy policy differences between MN and ND began showing up over**
19 **the last 10 years because of differences in renewable objectives. NSP**
20 **advocates that we continue to use proxy pricing until a more permanent**
21 **solution can be determined. Why is a permanent solution taking so**
22 **long?**

23 A: I think there are a number of reasons for this. The commission staff has been
24 working hard to better understand the Integrated Resource Planning process
25 and that takes time.

26

27 As you know, the Restacking Agreement came about through Settlement in
28 NSP’s last rate increase application because many of the generation
29 resources in MN were simply too expensive and built primarily for MN
30 purposes. We agreed in principle to finding an appropriate proxy for the re-

1 pricing of energy and capacity associated with those units as a stop gap
2 measure to minimize ND's exposure to costly energy and capacity. Of course
3 the Agreement was predicated on needing energy and capacity.
4

5 We have not come to terms yet on a restack agreement but some insight into
6 that process will help answer the question of why it is taking so long. When
7 we first started negotiating the terms for restacking generation, NSP
8 suggested that MISO's Cost of New Entry (CONE) should be used as a proxy
9 price for capacity that did not comport with ND energy policies. It seemed
10 reasonable until we asked more questions and discovered that MISO's CONE
11 price is inflated and not representative of what it would cost to bring new
12 capacity online. Staff realized that if we had not kept asking questions that
13 ND might have been saddled with an over-inflated price for capacity which
14 would have been embarrassing to us and the commission. Learning and
15 discovery take time.
16

17 Secondly, the commission should remember that NSP has a fiduciary
18 responsibility to its stockholders. As such, the Company is in the business of
19 limiting and eliminating risks to earnings to the degree possible. And so if you
20 think about it from a risk perspective, the least amount of risk for NSP is to
21 convince ND to pay full freight for each generation facility brought online,
22 whether it is needed or not. The next level of risk is to limit the risk to only the
23 "premium cost" being paid for such generation which is the general idea
24 behind the Restack Agreement.
25

26 The problem here is that the rules of the game have changed and in this
27 instance capacity is not needed at all so the proxy price for capacity should
28 be zero; not CONE or some semblance of CONE. Not paying for capacity
29 adds additional risk to NSP because then it would have to go to the cost

1 causers and recover the cost from them. The problem here is that MN is
2 good at ordering things and not so good at paying for them.

3
4 The commission should not make the management of risk in this regard easy
5 for NSP. They have a fiduciary responsibility to manage their own risk. North
6 Dakota ratepayers should not be expected to lift the risk for happenings in
7 MN. While the task before NSP may be difficult in MN, the Company needs
8 to get over the idea of seeking risk abatement from ND for the policy
9 decisions made in MN.

10
11 **Q: Do you have a recommendation for a permanent solution to the**
12 **allocation of generation resources between the states of MN and ND?**

13 **A:** I think Mr. Haeger has it right on his last page of Attached Testimony to his
14 Rebuttal Testimony when he concludes that it is incumbent upon the
15 Company to propose solutions to the impact that divergent state energy
16 policies have on NSP.

17
18 I agree that the Company is in the best position to develop a long-term
19 solution. That said, I have not been bashful with the Company in advocating
20 for simple straight-forward long-term solutions. Some of my suggestions
21 include agreeing this day forward to a fixed share of generation plants that
22 conform to ND's energy policy of least cost planning. Fixing the share will
23 eliminate any confusion as to what is owned and acceptable to ND. Fixing
24 the share will eliminate any noise from the jurisdictional allocation process so
25 that ND would know at any given time how much capacity it has; it would not
26 fluctuate based on 12CP. Knowing exactly what capacity is assigned to ND
27 will allow NSP to better manage its ND's capacity requirements and provide
28 the kind of deference we desire.

29

1 If and when ND needs capacity, NSP should be required to meet capacity
2 needs with the least cost resource addition and with much forethought and
3 timeliness of planning. NSP should be required to work with other utilities in
4 ND to partner on larger economical projects should that be available and I
5 believe those opportunities exist. NSP could partner at the company level or
6 partner at the ND level depending on the Company's needs and North
7 Dakota's needs at the time. If the rest of NSP's operations found itself awash
8 in capacity it could even sell ND capacity at the market rate so long as it was
9 the least cost option for ND. NSP is a large company always building
10 generation or replacing generation which provides plenty of opportunities to
11 secure capacity for ND and it does not necessarily need to be in direct
12 proportion to 12CP as has been the custom in the past. Montana-Dakota is
13 deploying smaller reciprocating engines on its system because they are least
14 cost capacity additions and perhaps the same could be done in Fargo, Grand
15 Forks or Minot where no generating facilities currently exist. NSP could enter
16 into short-term or long-term capacity agreements should that be least cost.
17 NSP could bridge the gap between deficient capacity and sufficient capacity
18 by making use of MISO's annual capacity auction just as MDU did last month.
19 ND could participate in the Calpine Mankato Energy Center II natural gas
20 combined cycle project that has also been filed for ADP before the
21 commission should that proposal result in least cost planning. The solutions
22 for ensuring adequate capacity for ND are quite extensive and very
23 manageable. Developing a long-term solution for generation cost allocation
24 should be achievable.

25
26 **Q: NSP provided a Supplement to its most recent IRP to reflect the MNPUC**
27 **orders to build generation. Can you provide a condensed summary of**
28 **Table 1: Updated Load and Resources for the commission and provide**
29 **comments?**

30 **A: Yes. Following are some of the more important lines for this proceeding:**

<u>MW's of:</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>
Obligation	9,607	9,691	9,764	9,818	9,843	9,863	9,924	9,919
Existing Resources	9,846	9,907	9,902	9,873	9,816	10,067	10,079	10,053
Existing Capacity Surplus	239	216	138	55	(27)	204	155	134
Additional Resources:								
Solar Portfolio (187*52%)	-	97	97	97	97	97	97	97
Black Dog 6 Natural Gas				208	208	208	208	208
Calpine Mankato Natural Gas				278	278	278	278	278
Geronimo Aurora Solar			70	69	69	69	68	68
Community Solar Gardens etc.	19	35	53	73	97	107	107	106
Projected Capacity Surplus	258	348	358	780	722	963	913	891
Capacity Surplus without Solar	239	216	138	541	459	690	641	620
Capacity Surplus Black Dog Only	239	216	138	263	181	412	363	342

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As can be noted, NSP projects a capacity deficit in 2020 but that is easily remedied from a ND basis because the commission has already granted an advance determination for Black Dog 6 natural gas combustion turbine expected to come online in 2019. The final line in the table above shows the amount of surplus capacity with none of the additional resources ordered by the MNPUC except for Black Dog 6 showing excess capacity for the next 9 years through 2023. Of course, the projections will change, the assumptions will change, the technologies will change, the policies will change and on and on but this schedule reflects NSP's best guess for its needs and resources to meet those needs.

Q: Can you give the commission some assurances that enough capacity will be available for NSP's ND ratepayers?

A: There are very few guarantees in life outside of death and taxes. However, the electric industry has done a fabulous job of keeping the lights on. There is no reason to think that a disallowance of ADP for these solar farms will change that tradition but here are some things to think about in that regard.

1 MISO manages the generation resources in the region to a mathematical
2 probability of less than one-day loss of load event in 10 years or .1 day per
3 year. Secondly, NSP is required by MISO to carry a planning reserve margin
4 of 7.1% above its peak load which occurs in the summer; not the winter.
5 Third, MISO's Zone 1 (NSP's zone) has the capability of importing more than
6 3,700 MW's of capacity from its other zones in the event additional support is
7 needed. Fourth, ND produces much more electricity than it uses and it is
8 limited in its export capabilities. Fifth, the commission can cause generation
9 to be built locally through its decisions, orders and legislative work. Sixth,
10 NSP will manage its operation to ensure capacity is available for its North
11 Dakota ratepayers. The electric grid is an essential service and is already
12 managed conservatively without the need for extra solar power generation.

13

14 **Q: Does this conclude your Surrebuttal Testimony?**

15 **A: Yes, it does.**

16