June 17, 2015

Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission
600 E Blvd Ave
Bismarck, ND 58505

Re: Direct Testimony

Northern States Power Company
Geronimo Solar PPA
Case No. PU-15-95

Dear Mr. Nitschke:

Enclosed for filing is an original copy of Advocacy Staff's direct testimony recommending that Northern States Power Company's request for an Advance Determination of Prudence for various solar units located in Minnesota be denied.

The attached testimony is essentially the same testimony filed in NSP's 187 MW Solar Portfolio (Case No. 14-810) application for ADP which the commission denied earlier today. The issues are essentially the same and staff seeks a similar outcome in this proceeding.

Sincerely,

Mike Diller

Mike Diller
Director of Economic Regulation

Enclosure

13 PU-15-95 Filed 06/17/2015 Pages: 20
Advocacy Staff's pre-filed testimony
Public Service Commission Advocacy Staff
Mike Diller, PSC Advocacy Staff

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of Northern States Power Company's

Advance Determination of Prudence

For its 100 MW Aurora Distributed Solar Power Purchase Agreement

Case No. PU-15-95

DIRECT TESTIMONY

OF

MIKE DILLER

ON BEHALF OF THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

ADVOCACY STAFF

June 17, 2015

Table of Contents

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

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

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

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

A: The commission has appointed me to advocacy staff (staff) in this proceeding. As such, I will provide the commission with an analysis of Northern States Power Company's (NSP) application for Advance Determination of Prudence (ADP) for its proposed 100 MW 20-year Power Purchase Agreement with Aurora Distributed Solar, LLC, an affiliate of Geronimo Energy, LLC (Geronimo Solar PPA). The proposal is for distributed solar generation facilities to be located at up to 24 sites in Minnesota that interconnect to various NSP distribution substations.[1]

Q: Please summarize your testimony.

A: NSP's North Dakota ratepayers do not need the proposed generation capacity or the energy that these units would provide. The proposal does not represent least cost planning. Instead, the Geronimo Solar PPA is being

[1] NSP Application, Page 1.

proposed to satisfy Minnesota's Solar Energy Standard (SES). Staff recommends that the commission deny the requested ADP.

Q: How did you determine that the Geronimo Solar PPA is not needed?

A: Staff compared NSP's most recent load forecasts to the capacity of its existing generation resources noting that NSP is able to meet its load obligations without any additional generation facilities until 2024.[2]

NSP's load forecasts have not changed since the commission held its Advance Determination of Prudence (ADP) hearing on NSP's proposed Solar Portfolio on May 6, 2015, followed by an order denying ADP on June 17, 2015.[3] The additional costs of this proposal are much greater than the Solar Portfolio. The Solar Portfolio added $14 million to NSP's system costs whereas this filing adds $62 million.[4]

For the few years between now and 2024 when resource adequacy is projected to be tight, NSP provided low cost alternatives to the Minnesota Public Utilities Commission (MPUC) including increasing its diversity exchange agreement with Manitoba Hydro by 75 MW and extending the lives of its oil-fired peaking units at Blue Lake.[5]

In its Reply Comments to the Comments filed by other parties to the Competitive Resource Acquisition Process (CAP) before the MPUC, NSP indicates that generation surplus exists through 2023.[6]

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[2] NSP's Application, Page 36.
[3] Commission Order dated June 17, 2015, Case No. PU-14-810.
[4] Solar Portfolio Application Case No. PU-14-810 Pg. 10; NSP's Application, Pg. 31.
[5] NSP's MN Compliance Filing dated October 2, 2014, Docket No. E002/M-14-789, Pgs. 9-11.
[6] NSP's MN Reply Comments dated November 3, 2014, Docket No. E002/M-14-789, Page 6.

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

- 71 MW Geronimo Solar PPA (2018);
- 278 MW Calpine Mankato combined cycle PPA (2019);
- 207 MW Black Dog unit #6 combustion turbine (2020);
- 73 MW Manitoba Hydro diversity exchange agreement (2016);
- 98 MW from the Solar Portfolio (2018).[7]

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

A: NSP already carries excess generation via its planning reserve margin to account for catastrophic events and unforeseen outages. Still, there can be instances where adding generation beyond an adequate reserve margin is reasonable and efficient. Making such a determination is part of the Integrated Resource Plan (IRP). Generally, it is more advantageous to manage generation resources as closely as possible to load requirements because it is expensive to carry more generation than required or needed.

Q: How has resource adequacy changed in recent years?

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

MISO requires a system wide planning reserve margin (PRM) of 7.1%.[8] Said another way, NSP must carry excess generation of 7.1% above its peak

[7] NSP's Application, Table 6, Page 36.
[8] MISO 2015-2016 Loss of Load Expectation Study Report, Page 4.

demand coincident with the MISO system less its load management capabilities. Historically, MISO's required PRM has continued to decline.[9] MISO expects its future PRM to continue shrinking.[10] As a result, capacity needs will likely diminish relative to overall needs.

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

A: Yes. The installed capacity (ICAP) or nameplate ratings of generators on MISO's system are adjusted to reflect only generation that is available and deliverable; also known as unforced capacity (UCAP) rating. The UCAP rating accounts for the robustness of generator interconnections and transmission availability, derates for intermittent resources, thermal derates, planned maintenance, units that are inoperable, poor historical performance and estimated forced outages.[11] The PRM is based on a UCAP basis. As a result, the 7.1% UCAP planning reserve margin is a true margin above and beyond expected peak load requirements.

Q: How is the planning reserve margin calculated?

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

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

A: Yes. MISO coordinates transmission and generation services across 15 different states. Accordingly, the locational diversity within the large region in

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[9] MISO 2015-2016 Loss of Load Expectation Study Report, Page 32.
[10] Ibid, Page 33.
[11] MISO Business Practice Manual No. 011, Resource Adequacy, Appendix H, Pages 121-126.
[12] MISO 2015-2016 Loss of Load Expectation Study Report, Page 4.
[13] MISO Business Practice Manual No. 011, Resource Adequacy, Page 25.

terms of weather, temperatures, sunlight, peak-hour usage etc. is significant and permits the use of lower system wide reserve margins than otherwise would be required for a stand-alone company. For example, it may be cool and raining in Bismarck yet hot and humid in Minneapolis allowing for more efficient utilization of generation resources across the electric grid.

Q: Provide context for the size of MISO.

A: NSP is one of the larger load serving entities in MISO with about 10,000 MW of peak capacity needs.[14] MISO manages over 200,000 MW of generation capacity allowing for vast amounts of shared resources.[15] The administrative cost of MISO exceeds $.25 billion a year.[16] Ignoring the sharing aspect and economy of scale offered through MISO's operation, when additional generation is not needed, erodes the value of membership in MISO.

Q: Is there a cost to carry excess generation?

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

Similarly, excess generation diminishes the value of capacity. Because the MISO system has been in an excess capacity position, the market value for excess capacity has been minimal. For instance, the clearing price for capacity sold at the annual auction in 2013 was $1.05 per MW – Day.[17] In 2014, capacity at the annual auction garnered $3.29 per MW – Day for

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[14] Paul Johnson Prefiled Testimony, Table 1, Page 6.
[15] MISO Website, Corporate Information, Reliability Coordination Area (includes Manitoba).
[16] MISO Website, 2015-2017 Budget.
[17] 2013/2014 MISO Planning Resource Auction Results.

MISO's Zone 1 (NSP's zone).[18] Recently, MISO conducted its 3rd annual auction and the clearing price for NSP's zone was $3.48 per MW – Day.[19] Therefore, the auction price in 2015 for 1 MW of capacity for one year would be about $1,270 ($3.48 times 365 days). By contrast, MISO estimates the cost of new entry to be $98,810 for 1 MW of capacity for one year.[20] As you can see, there can be a significant cost to ratepayers associated with excess generation; both in terms of energy and capacity prices.

Q: Who benefits if NSP adds excess generation?

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

Q: When should excess generation resources be deployed?

A: It is sometimes possible for new generation to displace existing generation and still save consumers money. For instance, if the variable cost of a legacy plant is 5 cents per kWh and wind energy can be procured at 3 cents per kWh, it may make sense to carry the extra generation even if it is not needed to serve existing load. In this case, the Geronimo Solar PPA will add cost to the total system cost.

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

A: Yes, but it should not occur. NSP must provide MISO with its projected annual peak demand and monthly peaks and energy requirements by

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[18] 2014/2015 MISO Planning Resource Auction Results.
[19] 2015/2016 MISO Planning Resource Auction Results.
[20] MISO Business Practice Manual No. 011, Resource Adequacy, Page 90.

November 1 for the following planning year.[21] After the forecasts are reviewed and affirmed by MISO, NSP must submit a plan to meet its native load requirements. In the event available resources are not adequate to meet PRM requirements, MISO conducts an annual auction to allow entities short on capacity to buy capacity from those long on capacity. If NSP fails to procure adequate resources or buy capacity at auction, it can choose to subject itself to a MISO Capacity Deficiency Charge.[22]

Doing so would result in a charge of 2.748 times the Cost of New Entry (CONE).[23] CONE is the estimated annual capital, operating, and other costs that would be incurred to develop a new capacity resource.[24] The CONE value for NSP's Zone 1 is $98,810 per MW – Year.[25] The failure to plan for projected load requirements and/or buy capacity when needed could result in a penalty of $271,530 per MW – Year (2.748 times $98,810); but this should not occur.

Q: Does MISO assess penalties for forced outages?

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

Q: Should North Dakota rely entirely on MISO's annual capacity auction?

A: No. It is just one of many resources available to NSP for meeting its capacity needs. Generally speaking, the auction price information is included in my

[21] MISO Business Practice Manual No. 011, Resource Adequacy, Page 18.
[22] Ibid, Page 14.
[23] Ibid, Pages 14 and 90.
[24] FERC Order on Annual Cost of New Entry, Docket No. ER10-2090-000, Page 1.
[25] MISO Business Practice Manual No. 011, Resource Adequacy, Page 90.

testimony to show that there is in fact excess capacity and that it can be had for a reasonable price. It is not an end-all-be-all proposition but provides a one-year solution for those who would avail themselves of the market.

MISO's third annual capacity auction was recently held and Montana-Dakota Utilities Co. purchased one year's worth of capacity of 16.6 MW's for $21,085.32 or a cost of about $1,270 per MW – year. By comparison, MISO estimates the cost of new capacity to be $98,810 per MW – year.[26] MISO's annual auction is a real market; it is used by real utilities as a bridge from capacity deficiency to capacity sufficiency. Based on MISO's capacity cost of new entry, MDU saved its customers $1.6 million through the capacity auction by deferring the building of additional capacity by one year.

The forecasting of capacity and energy needs is done on a regular basis by NSP. Management is tasked with the responsibility of monitoring sales and trends in sales and planning for them accordingly. Forecasted needs generally do not change overnight. Resources are being planned well ahead of needs to accommodate the building time for generation assets. It is a primary reason for doing resource planning.

Q: Can you guarantee that NSP has enough capacity?

A: The electric system is a complex and dynamic system. No amount of duplication or planning can ensure the deliverability of electricity when it is needed. However, the electric industry has done a fabulous job of keeping the lights on. There is no reason to think that the disallowance of ADP for excess generation will change that tradition.

Despite being unable to guarantee uninterrupted service, here are some of the safeguards in place to ensure the robustness of available capacity:

[26] MISO Business Practice Manual No. 011, Resource Adequacy, Page 90.

- MISO manages the generation resources in the region to a mathematical probability of less than one-day loss of load event in 10 years or .1 day per year.
- NSP is required by MISO to carry a planning reserve margin of 7.1% above its peak load which occurs in the summer; not the winter.
- MISO's Zone 1 (NSP's zone) has the capability of importing more than 3,700 MW's of capacity from its other zones in the event additional support is needed.[27]
- ND produces much more electricity than it uses and it is limited in its export capabilities.
- The commission can cause generation to be built locally through its decisions, orders and legislative work.

Q: How does NSP justify the need for the Geronimo Solar PPA?

A: In its application and testimony NSP admits that the Geronimo Solar PPA is not a least cost plan but puts forward several qualitative reasons for adding the Geronimo Solar PPA. The following encapsulates the primary arguments advanced by NSP:

1. Effectively meets MN's Solar Energy Standard (SES)
2. Takes advantage of the Federal 30% Investment Tax Credit
3. Provides a hedge against future environmental regulation
4. Provides a hedge against natural gas prices
5. The impact to customers' bills are really small

1.

Q: Should the commission consider the MN Solar Energy Standard?

A: Yes. Minnesota (MN) borders our state. We trade with each other. We share MISO's Zone 1 to ensure resource adequacy in our region. NSP

[27]MISO 2015-2016 Loss of Load Expectation Study Report, Page 4.

provides service in both states. We should seek to mutually and beneficially coexist whenever possible so long as doing so is not detrimental to our own citizenry. In this instance, the Geronimo Solar PPA provides an opportunity where both MN and ND can benefit.

Before I get to that, please note that the voters of MN have chosen their representatives who in turn have determined that having solar energy is important to MN by mandating that 1.5% of its energy needs come from solar by 2020 and a goal of 10% by 2030.[28] Mandates, by nature, lead to ineffective allocation of resources but clearly MN has determined that the benefits of solar and the additional diversity of resources are worth the extra cost. There is nothing inherently wrong with different state policies; especially when both energy policies can be accommodated.

From a technical and fairness standpoint, basic cost allocation and rate design principles require that costs be assigned to the cost causers whether allocating costs between states or to various customer classes. Attempting to allocate MN costs to ND ratepayers to meet a MN mandate is comparable to taxation without representation and works against basic cost allocation principles and rate design techniques familiar to the commission.
The problem with allocating some of the costs and associated renewable energy credits (REC's) to ND is that it frustrates NSP's ability to achieve its MN SES. MN is the only state served by NSP that requires a solar energy standard. For this reason, it is in the best interest of MN to pay for its own specialized generation and reap all the benefits it perceives from investing in solar energy. Similarly, it is in the best interest of ND to adhere to its least cost planning objectives; a win-win scenario for both states. Both states' energy policies are met in the most efficient manner possible.

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[28] NSP's Solar Portfolio Application, Page 2, Case No. PU-14-810.

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

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

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

Q: Should North Dakota remain part of NSP's integrated system?

A: NSP operates an integrated system in the technical sense that the Eastern Grid is an interconnected system; including NSP's territory. It isn't so integrated from an energy policy perspective. In that regard, NSP's system is more of a MN system. For instance, the latest Integrated Resource Plan is more of a MN environmental plan rather than a least cost resource plan.

I don't believe the commission should worry too much about the threat of alienation from NSP's integrated system when denying this ADP. The commission should continue to expect that least cost planning will occur whether that occurs through total system generation additions or ND specific generation additions.

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

A: MN's Renewable Portfolio Standard (RPS) for Xcel Energy is 31.5% by 2020, including an SES of 1.5%. By comparison, the other states served by NSP have renewable standards and objectives of 10%; except for Wisconsin with a standard of 12.89%.[29]

2.

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

A: No, adding the proposed Geronimo Solar PPA results in additional costs of $62 million.[30]

Q: Will better opportunities occur for deploying solar?

A: Yes, solar is just coming into vogue. It is in the early development stage and therefore has a lot of upside potential in terms of efficiency improvements and technology advancements. According to IHS Energy's 2014 Market Brief entitled "Outlook for US Solar Photovoltaic Capital Costs and Prices, 2014-2030, IHS expects solar Photovoltaic capital costs to fall approximately 45% by 2030. Further, IHS expects efficiency gains in collecting solar power of 11% to 24% between 2009 and 2030.[31]

There is no reason to rush to market to take advantage of the ITC credit differential between 30% through 2016 and 10% thereafter except to satisfy the MN SES. There is no need for additional capacity. The cost of the energy from Geronimo Solar PPA is extremely high in comparison to expected energy market prices and available wind generation prices for the same time period. Solar efficiencies, in terms of capital costs and collecting the sun's rays, will continue to improve as the solar industry matures much like it has for wind generation, flat screen televisions, cell phones and so on.

[29] NSP's Integrated Resource Plan, Case No. PU-15-19, Page 56.
[30] NSP's ADP Application, Page 39.
[31] NSP Data Response No. 3, Case No. PU-14-810 (Solar Portfolio).

For these reasons there is no need to make an opportunity buy of solar generation.

3.

Q: Should the commission consider the value of solar energy as a hedge against future environmental regulation?

A: According to ND law:

> The commission may not use, require the use of, or allow electric utilities to use environmental externality values in the planning, selection, or acquisition of electric resources or the setting of rates for providing electric service. Environmental externality values are numerical costs or quantified values that are assigned to represent either:
> 1. Environmental costs that are not internalized in the cost of production or the market price of electricity from a particular electric resource; or
> 2. The alleged costs of complying with future environmental laws or regulations that have not yet been enacted.[32]

Also, according to ND law:

> The commission may not increase electric rates as a result of actions taken by other states requiring higher cost resources to be built, purchased, or otherwise acquired as a result of the application of quantified environmental externality values, as defined in section 49-02-23, as part of any resource selection process.[33]

To my knowledge, NSP has not included any numerical costs of complying with future environmental laws in its econometric modeling when developing its IRP and various sensitivity tests. While it has been the practice of the commission to consider qualitative reasons for considering potential environmental laws and regulations, it is at least useful to consider the spirit of these laws.[34]

The commission should also take note of its comments filed with the Environmental Protection Agency (EPA) arguing that the EPA's proposed Carbon Pollution Emission Guidelines for Existing Sources are not authorized

[32] N.D.C.C. § 49-02-23.
[33] N.D.C.C. § 49-06-24.
[34] Commission Big Stone 2 Order, Case No. PU-06-481, Finding 88, Page 16.

by Federal Law and that it circumvents the commission's resource planning authority.[35] Staff believes that granting deference in this proceeding for a proposed carbon dioxide ($CO^{2)}$ rule that may or may not stand up in court runs counter to the commission's legal position.

Nevertheless, if the commission wants to consider the qualitative value of solar as it pertains to the environment, note again that there is a huge price discount for wind PPA's compared to solar PPA's; and wind generation provides similar environmental attributes. If a hedge against CO^2 emissions is desired, wind energy is much cheaper.

Lastly, environmental hedges are like any other hedge which carries both risks and rewards. Too often, the benefits of limiting exposure to higher cost outcomes are trumpeted without equally considering the downside of a hedge.

For example, what if the White House falls into the hands of Republicans in 2016 and EPA extremism is reigned in? What if the courts find that the EPA has run amuck and does not have the authority to foist CO^2 rules upon the states? What if CO^2 concerns turn out to be the greatest hoax perpetrated on mankind but instead solar flaring from the world's largest heat source is determined to be the primary instigator of climate change?

Hedging against future environmental laws or regulations that have not yet been enacted can result in incurring large costs to comply with something that may or may not happen. There are both risks and rewards associated with hedges. Early compliance may or may not be beneficial. Early compliance to rules that may someday be enforceable may not be counted towards compliance of an eventual rule or law.

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[35] Commission's comments to EPA filed November 25, 2014, Case No. PU-14-736.

4.

Q: Does Geronimo Solar PPA provide a hedge against natural gas prices?

A: Yes, but not very well. In its application, NSP shows in its "high gas cost" scenario that the additional cost of adding the Geronimo Solar PPA increases the overall system cost by $44 million.[36]

5.

Q: Should the commission consider the smallness of the rate impact?

A: The decision to grant or deny ADP should be determined on the merits of the case and our best estimates whether or not the impact is great or small to ratepayers.

Q: Do you have any qualitative reasons for the commission to consider?

A: Yes. If the commission ever wants to see natural gas turbines built on the eastern side of the state by 2036 as agreed to by NSP in its last rate case, then it must resist taking on generation that is not needed. The Settlement Agreement approved by the commission in NSP's last rate case states that 400 MW of thermal generation resources will be developed in North Dakota no later than 2036 (listen carefully to the next part) "consistent with the principles of orderly development" and "prudent resource planning."[37] Orderly development and prudent resource planning cannot occur so long as Minnesota trumps that process by ordering more generation than is needed. As long as that continues and ND accepts it, Red River Valley Units 1 & 2 will not be built.

Secondly, it is worth considering Minnesota's end game in the realm of qualitative considerations. You may choose to believe that the MN PUC has lost its collective mind and cares nothing about the price of electricity when ordering excess generation capacity. I personally don't believe that. My

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[36] NSP's ADP Application, Page 39.
[37] Commission Order Adopting Settlement, Case No. PU-12-813, Page 18.

belief is that they are building excess generation to allow flexibility to run coal plants less (which is part of NSP's proposal in its most recent IRP) or perhaps movement towards eliminating coal plants in MN altogether. If I am right, the remaining coal plants will be run less or prematurely closed down; plants that ND has a 5% interest in. Paying for excess capacity we don't need helps facilitate the wrong direction of MN and hastens the ruin of MN coal plants that provide low cost energy to ND consumers.

Third and closely related to the first two, the commission should consider the matter of command and control. As long as the generating assets of NSP are located in MN, this commission and the state as a whole will have little or no control over whether the generating plants are used efficiently or ran until the end of the assets useful life. Today, the state of MN is at war with coal plants. When all the coal plants in MN are gone, it isn't too difficult to imagine that gas plants will be targeted next. If ND wants some say over its energy policy in the future, do not approve excess generation built in MN but instead sit tight and require that generation be built in ND to the extent possible.

Q: Do you consider Geronimo Solar PPA a used and useful resource?

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

Q: Does this conclude your testimony?

A: Yes, it does.

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
MW	Megawatt
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)