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DIRECT TESTIMONY AND SCHEDULES

JAMES A HEIDELL

STATE OF NORTH DAKOTA

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF NORTHERN STATES POWER COMPANY,	CASE NOS. PU-12-813,
A MINNESOTA CORPORATION AT D/B/A XCEL ENERGY	PU-13-706, PU-13-707.
JURISDICTIONAL COST ALLOCATION MATTERS	PU-13-708, PU-13-742,
	PU-13-743, PU-13-194,
	PU-13-195

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I. Introduction and Qualifications

Q. Would you please state your name, affiliation, and address?

A. My name is James A. Heidell. I am a Director at PA Consulting Group (PA). My business address is 1700 Lincoln Street, Suite 1550, Denver, CO 80203.

Q. On whose behalf are you filing this testimony?

A. I am filing this testimony on behalf of the Advocacy Staff of the North Dakota Public Service Commission (Commission or NDPSC).

Q. Please summarize your qualifications and experience.

A. I have worked in the energy industry for the past 35 years, primarily specializing in electricity and utilities. I have worked on issues related to resource planning, rates, analysis of electricity markets, and analysis of the economics of financial transactions for utilities and wholesale generation owners. My academic background includes a BSE in civil engineering from Tufts University, a MS in engineering economics from Stanford University, and a MBA in finance from the University of Washington. I am a Chartered Financial Analyst. My CV is provided in Exhibit JAH-1.

Q. Have you testified before the North Dakota Public Service Commission previously?

A. Yes. I testified on behalf of Montana-Dakota Utilities Co. in the matter of Big Stone II Generating Station, Case Nos. PU-06-481 and PU-06-482. I have submitted pre-filed direct testimony on behalf of Advocacy Staff in Northern States Power Company's request for an Advanced Determination of Prudence (ADP) for 1,550 MW of Wind, Case Number PU-17-120. I have submitted pre-filed direct testimony on behalf of Advocacy Staff in Otter Tail Power Company's request for an ADP for the Astoria CT and Merricourt Wind Project, Case Numbers PU-17-140, PU-17-141, and PU-17-143.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with an assessment of the Northern States Power Company – Minnesota (NSP or the Company) request for Legal Separation of the NSP North Dakota service territory (NSPD) from the rest of NSP and establish a separate operating company. I have reviewed the Application, supporting direct testimony, and responses to interrogatories in order to develop recommendations regarding whether:

- Legal Separation and creation of a separate operating company for NSP's North Dakota customers is in the best interest of North Dakota's rate payers;
- Legal Separation is necessary for resolving past disputes related to the procurement of resources and recovery of those associated costs;
- Legal Separation is necessary or helpful for resolving potential but unknown disputes related to legacy resources;
- Legal Separation is necessary or helpful for resolving potential but unknown disputes related to acquisition of future resources;
- Legal Separation will increase regulatory costs for North Dakota; and
- There is a better option for addressing procurement and cost recovery for new resources going forward.

Q. Would you please summarize the organization of your testimony?

A. Yes. I start with presenting my findings and recommendations and then I discuss in detail the basis for my findings and recommendations. My testimony is separated into five major topics with multiple sub-sections:

1. **Recommendations & findings**
2. **Overview of NSP's request for Legal Separation**
   - Introduction to Pseudo and Legal Separation (Section IV); and
   - An overview of the NSP proposal for Legal Separation (Section V).
3. **Evaluation of the NSP request for Legal Separation**

- Whether North Dakota rate payers will benefit from Legal Separation (Section VI);
- An evaluation of the power cost savings that NSP attributes to North Dakota as a result of Legal Separation (Section VII);
- Whether North Dakota customers are being subsidized under the current power cost allocation and cost recovery structure (Section VIII);
- A review of the status of the disputed resources (Section IX);
- Consideration of whether Legal Separation is necessary to address the disputed resources (Section X);
- Consideration of whether Legal Separation is necessary to address potential but undefined disputes related to the acquisition of new resources in the future (Section XI); and
- Consideration of whether Legal Separation is necessary to address potential but undefined disputes related to legacy resources (Section XII).

4. Alternative Approaches for the Commission to Consider

- Consideration of alternative approaches to Legal Separation to address future resource procurement (Section XIII); and
- A review of proxy pricing, the approach currently used by the NDPSC and its potential application going forward (Section XIV).

5. Recommendations

- Recommendations for an alternative solution to Legal Separation (Section XV);
- Other considerations (Section XVI); and
- A summary of my findings (Section XVII).

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit JAH-1: CV of James Heidell
- Exhibit JAH-2: NSP North Dakota Demand and Load Forecast (Confidential)

- Exhibit JAH-3: IOU's With Less than 100,000 Customers
- Exhibit JAH-4: Resource Expansion Plan Forecasts for NSPD
- Exhibit JAH-5: Regulatory Disallowances
- Exhibit JAH-6: Resources Acquired, Disputed Resources, & Production

II. Summary of Recommendations

Q. What is your recommendation in regards to the Company's request for Legal Separation of its North Dakota service territory into a separate operating company?

A. I recommend the Commission deny NSP's request to implement Legal Separation. Based upon the Application, corresponding exhibits and information provided through discovery, there are no long-term benefits for the service and convenience of the public in North Dakota and there is substantial likelihood of increased costs associated with administrative costs, transmission costs, potential loss of resource diversity and increased capacity and energy costs due to the small system size of the proposed NSP North Dakota utility operating company.

Q. What is your recommendation in regards to the treatment of disputed resources?

A. My recommendation is that the Commission continue with the current decisions and agreements until such time as NSP presents further evidence for the Commission's consideration regarding the cost and policy basis for an alternative cost recovery resolution.

Q. What is your recommendation in regards to the procurement of future resources?

A. My recommendation consists of three parts:

- First, any out-of-market costs for resources that are procured by a utility to conform with one state's policy or laws that also are not needed or are not least-cost should be borne by the state requiring the procurement. In these cases, proxy

pricing is an appropriate tool to apply to identify incremental costs. This is a practice that NSP already uses.

- Second, it may be appropriate to procure separate resources for different states and those costs should be separately accounted for. NSP has stated that it has the capability to separately track those costs.
- Third, in order to reduce potential future conflicts NSP should continue to use the ADP process so that it has a better indication of what costs will be recoverable in North Dakota. In addition, the NDPSC should implement an active review process for future NSP Integrated Resource Plans so that the Company has more certainty in treatment of future resources.

III. Findings

Q. Would you please provide a summary of the findings in your testimony that support your recommendation for the Commission to deny NSP's request for Legal Separation?

A. Based upon my review and analysis of the testimony filed in the Application, the exhibits contained within the Application, and the information produced in discovery, I conclude the following:

- The General and Administrative Expense (G&A) benefits are uncertain due to only high-level estimates of sharing of Xcel Energy Services (XES) costs, unknown allocation of XES costs shifted to power cost recovery, and increased administrative costs for running a separate operating company.
- There are no expected incremental benefits or incremental costs associated with distribution services.
- There are no potential transmission benefits, but there are potential transmission cost increases due to the uncertainty of the costs and agreements required to serve North Dakota as a separate operating company which would not have ownership of any transmission assets.

- The Commission has addressed or provided guidance on how the costs should be recovered for the current disputed resources. The Resource Treatment Framework (RTF) and recommendation for Legal Separation provides no further benefits to North Dakota customers with regards to addressing legacy disputes.
- There are simpler approaches than Legal Separation for procuring dedicated resources for North Dakota in the future should that be necessary.
- These simpler approaches allow NSP to recover the full costs of new resources procured for the benefit of North Dakota.
- While NSP may perceive a shareholder benefit for shifting power cost and transmission cost recovery from NDPSC to FERC jurisdiction, NSP has not identified any benefits to North Dakota rate payers for changing jurisdictional oversight of power costs.
- The NSP proposal to move jurisdiction over recovery of power costs to the FERC could have adverse impacts on the ability of North Dakota to oversee power costs consistent with North Dakota state policy and could also add increased regulatory expense associated with representing the interests of NSP's North Dakota rate payers at the FERC.

IV. Brief Overview of Legal and Pseudo Separation Frameworks

Q. What were the options that NSP proposed in its application for a Resource Treatment Framework (RTF)?

A. NSP in their application focused on two frameworks for resolution of past disputes with the NDPSC regarding cost allocation and addressing potential future resource procurement and cost recovery issues. These frameworks are referred to as Pseudo Separation and Legal Separation. Both frameworks include elements that address the allocation of costs and shares of energy and capacity from existing resources and structures for separately procuring all new resources for North Dakota on a going forward

basis. Pseudo Separation would attempt to accomplish this through accounting protocols and regulatory agreements that would be subject to ongoing state jurisdiction. Legal Separation would involve establishing a separate operating company for North Dakota, and once the NDPSC approves the agreement on the treatment of power costs, future management of those agreements will be under the jurisdiction of the FERC. NSP states:

> "Each of these structures can ultimately result in the same resource outcomes envisioned by our proposed RTF and each structure has benefits and drawbacks" [RTF Application p 6]

Q. Has NSP indicated whether it has a preference for either Pseudo, or Legal Separation?

A. Yes. In NSP's direct testimony filed on July 15, 2017 the Company is requesting and recommending Legal Separation and establishing a North Dakota distribution only operating company.[1] The Company stated that Pseudo Separation "does not provide sufficient certainty for the Company going forward".[2]

Q. What is the difference in how the allocation and cost recovery of existing resources is treated under the two frameworks?

A. I will discuss the treatment of existing resources under Legal Separation in detail in the next sections of my testimony. A critical difference is that under Legal Separation the agreement between NSP and NSPD would become a contract under the jurisdiction of the FERC. Under Pseudo Separation, the treatment of the resources would be subject to the ongoing jurisdiction of the NDPSC. Under Pseudo Separation there would be no change to the current treatment of costs other than generation related costs.

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[1] Chandarana Direct p 5 lines 13 -16, p 6 lines 11 - 13
[2] Chandarana Direct p 8 lines 20 – 23.

Q. How would NSPD contract for generation under Legal Separation?

A. NSP appears to present two different structures. Under one structure NSPD owns assets and enters into a FERC approved and regulated interchange agreement similar to the relationship between NSP and NSPW. This appears to create an integrated system with sharing of assets under a contractual arrangement under the jurisdiction of the FERC. Since North Dakota is already part of the NSP integrated system there appears to be little difference from the current arrangement except for creating a contractual arrangement between NSP and NSPD that is under the jurisdiction of the FERC versus under the jurisdiction of the state regulatory commissions.

NSP also outlines an alternative structure where NSPD has no assets but contracts for power from NSP and future needs are met with a separate acquisition of resources that are purchased by NSP and then their output is sold to NSPD under PPAs. This structure would also be under the jurisdiction of the FERC.

Q. What is the difference in how the allocation and recovery of the cost of new resources is treated under the two frameworks?

A. The differences are the same as previously discussed above regarding the treatment of existing resources under the two frameworks and they will be discussed in detail in the Legal Separation sections of my testimony.

Q. What is the difference in how the allocation and cost recovery of transmission costs is treated under the two frameworks?

A. Under Pseudo Separation there will be no change from the current approach of allocating transmission costs and MISO revenues based upon a load share ratio. Under Legal Separation the treatment of transmission costs will be significantly more complex arising from the fact that the North Dakota load is not directly tied to the NSP transmission system and North Dakota is not directly served by NSP transmission assets.

Q. Are there different rate implications for North Dakota customers between Legal and Pseudo Separation?

A. Yes. Both options will have rate implications for NSP's North Dakota customers. The long-term rate implications are ultimately unknown due to uncertainty regarding the acquisition of future resources, cost of the resources, and market energy prices. There will be rate implications if the Commission revisits past decisions regarding cost recovery for existing resources. There will be rate implications associated with implementation costs of either of the two separation proposals and Commission determinations of how costs are recovered. There are unknown rate implications associated with potential differences in how the FERC and the NDPSC will resolve issues.

Q. Has NSP provided estimates of the one-time cost to implement Pseudo and Legal Separation?

A. Yes. NSP estimates the cost to implement Pseudo Separation is $600,000 to address accounting and information technology changes necessary to track the costs.[3] The costs for Legal Separation are estimated to be $8M - $15M.[4]

Q. Do you have any recommendations for the criteria with which the Commission should review NSP's request for Legal Separation?

A. My recommendation is that the Commission consider three high level criteria.

1. Similar to a corporate transaction to purchase a utility, the Commission should consider if approval is in public interest.
2. The Commission should evaluate whether Legal Separation is an efficient way to solve potential future conflicts regarding resource acquisitions and retirements.

[3] NSP Supplemental Comments NSP 07.31.17 (pdf page 11)
[4] Docket No. E0002/M-16-223, Supplemental Comments and Information Schedule 10, Page 1 of 1.

3. The Commission should consider the regulatory and cost policy implications of shifting jurisdiction over power costs to the FERC and removal from North Dakota jurisdiction.

My evaluation of NSP's request for Legal Separation focuses on the first two criteria. As for the third criteria, I believe that the NDPSC is well situated to understand the policy implications of shifting jurisdiction to the FERC.

V. Overview of NSP's Request for Legal Separation

Q. Would you please summarize your understanding of NSP's request for Legal Separation?

A. Yes, NSP is requesting Legal Separation of North Dakota operations from the rest of the NSP system.[5] Under Legal Separation a new operating company referred to as NSPD would be created in the 2020 time frame and have the following attributes:

- NSPD would be a distribution-only utility i.e. owning no transmission or generation assets;
- Energy and capacity from the "Legacy System" generation resources would be purchased under contracts with NSP;
- A resolution of disputed resources would be contractually determined once and not re-visited;
- NSP would separately procure new resources for NSPD;
- All power contracts with NSP would be under the jurisdiction of the FERC;
- All transmission would most likely be purchased under the MISO tariff and there would be no NSP transmission costs and offsetting MISO revenues;
- NSPD would purchase shared services under a contract with XES. The portion of XES services related to power costs would be included in power costs and

[5] Direct Testimony of Chandarana, p 5 lines 13 - 15

under FERC jurisdiction. The costs related to G&A and distribution would be addressed in a service agreement that would be approved by the NDPSC;

- Distribution assets in North Dakota and NSP employees working on the distribution system in North Dakota would be transferred to NSPD; and
- NSP would establish an office in Bismarck and create a new position for President of the North Dakota utility.

Q. What is your understanding of the term "Legacy System"?

A. The Legacy System refers to existing NSP generation resources that NSP's North Dakota customers have shared and paid for in the past. These resources include the Prairie Island nuclear power plant, the Sherco coal plant (until all three of its units are retired), and various Company-owned and PPAs for both thermal and renewable resources. NSP ran different scenarios that included different combinations of assets remaining in the shared Legacy System post-2024.

Q. How would NSPD share the Legacy System?

A. My understanding is that NSPD would not own a share of the legacy assets but would enter into a contract for specific resources with NSP for a share, presumably based on current load shares. The price paid for energy and capacity, as well as the terms and conditions would be established in the contracts. These contracts would then be under the jurisdiction of the FERC.

Q. What is your understanding of the term "Disputed Resources"?

A. Disputed Resources are resources for which the NDPSC has determined to either not allow cost recovery of, or only allow partial cost recovery of. I discuss these further in Section IX of my testimony.

Q. What is NSP's proposal for contractually resolving issues related to disputed resources?

A. My understanding is that:

- All disputed resources with the exception of MEC II (Mankato Energy Center Unit II) would not be assigned to NSPD;
- NSPD would not be assigned any cost recovery responsibility associated with the accelerated depreciation created by the early retirement of Sherco Units 1 & 2;
- None of the 1,550 MW of wind would be allocated to NSPD; and
- NSPD would participate in a share of the MEC II PPA.[6]

Q. What are your primary concerns regarding NSP's proposal for Legal Separation?

A. I have a number of specific concerns regarding NSP's proposal. However, at a high level my assessment is:

- There are no cost savings to North Dakota rate payers;
- The Commission has already ruled on most of the disputed resources identified by NSP and review of those decisions does not require Legal Separation (or for that matter Pseudo Separation);
- This may not be the appropriate docket to review past decisions regarding disputed resources;
- The process of resolving future disputes about legacy or new resources through Legal Separation would be very complex and involve difficult negotiations to address hypothetical issues as opposed to addressing those potential conflicts when they are more defined;
- Legal Separation is not required for NSP to procure separate resources on behalf of North Dakota in the event that NSP has identified resources that meet the needs of Minnesota but not North Dakota or vice versa;

[6] Chandarana Direct p 29 – 30 lines 23-27 & 1 – 5.

- Legal Separation could introduce complexities and higher generation, transmission, and administrative costs for North Dakota with no benefits.

I discuss these concerns in detail in the next sections of my testimony.

Q. Given the recent history of disputes between NSP and the NDPSC regarding recovering the cost of resources, does it make sense to move the regulatory oversight to the FERC's jurisdiction?

A. No. I understand that NSP does not want to be in the position where it is not recovering its costs primarily due to different policies of the states that it serves. While NSP may receive more cost recovery under FERC jurisdiction, it would depend on the terms of the power cost contract. However, I have not made that assessment because both the terms for the contract for the legacy resources and the specifics of any future disputes are undefined.

Based on my review of the resource disputes, my assessment is that the NDPSC has been consistent in its evaluation of what new resources are appropriate for North Dakota and that NSP has the ability to avoid purchasing resources on behalf of North Dakota customers that do not meet NDPSC's criteria. Furthermore, an ADP filing can be used to identify whether a resource acquisition meets the NDSPC's criteria. There is no reason why NSP cannot have a reasonable amount of certainty regarding the acquisition of new resources under the NDPSC's jurisdiction. Regardless of the jurisdiction, if NSP wants to be a vertically integrated utility serving North Dakota and is willing to meet the needs of North Dakota then Legal Separation is not necessary.

VI. Assessment of Potential NSPD Cost Savings from Legal Separation

Q. Have you evaluated whether North Dakota customers will save money under NSP's Legal Separation Proposal?

A. Yes, I have reviewed and evaluated the analysis prepared by NSP. However, it should be recognized that both my review and NSP's analysis is based upon a large number of projections and uncertainties, so there is no definitive estimate. While NSP has forecast savings, my expectation is that in the long run, Legal Separation will result in higher rates for NSPD with limited control by the Commission to create rate savings.

Q. What are the major uncertainties concerning whether North Dakota rate payers will save money under Legal Separation?

A. There are a large number of uncertainties regarding the cost estimates including:

- What resources will be acquired for NSPD in the future including the type of resources and the cost of those resources;
- The terms of the contracts for legacy resources and what legacy resources will be shared;
- The terms associated with disputed resources;
- The transmission costs paid by NSPD;
- The cost of services provided to NSPD by XES;
- Increased administrative costs for NSPD;
- The cost of capital for NSPD; and
- One-time costs associated with Legal Separation.

NSP does not anticipate any changes in distribution and customer service costs under Legal Separation.[7] I discuss the costs associated with new resources in the next section of my testimony.

[7] NSP response to NDPSC 3-2.

Q. Why is there uncertainty regarding the terms for contracts associated with legacy resources?

A. It is my understanding that each legacy resource will need to be addressed individually in a separate power sales contract. However, the details of the pricing under those contracts and the escalation of charges over time have not been specified. The terms of the contracts are unknown and it is not clear what the rights and allocation of costs would be in the event that NSP decides to retire a resource before the contract end date. It is my expectation that under those contracts, NSPD would have little or no input on retirement, life extension, or even cost recovery issues. For example, North Dakota currently pays its load rated share of the full cost of a number of biomass projects located in Minnesota, and NSP is currently seeking to buy out some of those purchase contracts. The Commission has the opportunity to review the proposed buyout provisions under current regulation, but would not have that oversight if those purchase contracts are treated as legacy contracts under Legal separation.

Q. Is there uncertainty regarding the contracts associated with disputed resources?

A. Yes, there may be uncertainty regarding the MEC II contract depending on the terms of the contract with NSP as well as the terms of the contract between NSP and NSPD. The APD for MEC II was dismissed without prejudice. However, NSP is currently proposing to treat MEC II as a resource that North Dakota will participate in without a demonstration of need for the resource or establishing it is least cost. Moreover, there may not be agreement regarding the assignment of disputed resources. For example, the Commission may determine that it is appropriate for NSPD to share in the 1,550 MW of wind currently under review by the Commission.

Q. Do you have other concerns regarding NSP's proposal to create a FERC approved contract governing recovery of legacy system power costs?

A. Yes. My concerns are based on my understanding of how the contract will be developed and approved but I want to emphasize that the legal complexities are not within the scope

of my testimony. Based upon the information provided, NSP will essentially represent both parties to the contract, NSP & NSPD, and will develop a contract based upon what it perceives as reasonable and not "[to the] disadvantage a particular jurisdiction [or] to the advantage of another."[8] The inherent conflict is that if there were no disagreements about what costs each jurisdiction should bear with regards to legacy resources and the retirement of resources, then it is unlikely that NSP would be requesting Legal Separation in this proceeding.

NSP also suggests that the FERC would have jurisdiction over those contracts and that the NDPSC could intervene at the FERC if it disagrees with any of the terms of the contracts.[9] Litigating the terms of the contract at the FERC could be a substantial expense for the tax payers of North Dakota and the Commission needs to carefully evaluate the policy implications of surrendering its jurisdictional authority to the FERC.

Q. Has NSP committed to not seeking FERC approval of an initial power contract as part of Legal Separation without NDPSC agreement to the terms?

A. Not to my knowledge. Absent an NSP commitment not to pursue an initial power contract without agreement by the NDPSC, there is a risk that the initial contract could be unsatisfactory and unacceptable for North Dakota.

Q. Why is there uncertainty regarding transmission costs for NSPD?

A. Currently North Dakota is allocated a fractional share of the transmission costs and MISO revenues.[10] NSP Witness Beuning states that separating out NSPD would be complex. He notes:

[8] See NSP response to NDPSC 4-24.
[9] Ibid.
[10] Based upon a load ratio share of approximately 5.3% of the costs and revenues [Beuning Direct p 2.]

> "Redesigning the rate structure to accommodate separation of North Dakota from the remainder of the NSP System will be a complex endeavor that requires multiple changes …It will certainly require renegotiation of legacy grandfathered agreements ..." [Beuning Direct pp 3-4]

Mr. Beuning notes a number of complexities including that the NSP territory in North Dakota is served by transmission facilities owned by MISO, SPP, and the Minnkota Power Cooperative. Service to North Dakota is structured under legacy agreements that could be open to renegotiation if a new Operating Company (OpCo) is created.

Q. What estimate has NSP provided for increased transmission costs for NSPD?

A. NSP estimates an incremental cost of $1.3M. However, NSP indicates that it cannot commit to any estimate at this preliminary stage.[11]

Q. What is XES?

A. Xcel Energy Services is an Xcel Energy (Xcel) subsidiary that provides corporate services to Xcel's operating companies and other subsidiaries. These services are billed to the operating companies under a combination of direct assignment and cost allocation rules.

Q. How will XES costs increase under Legal Separation and is there uncertainty regarding administrative costs for NSPD?

A. NSP witness Ms. Everson calculates an $8.9M reduction in XES costs (5.5 M reduction after taxes) if NSPD were a separate operating company.[12] However, this is not the absolute savings since additional XES costs would be recovered through production costs

[11] NSP response to NDPSC 3-1
[12] Everson Direct p 16 lines 25 – 26 & CRB-1 Schedule 4 p 2 of 5.

charged to NSPD. The amount of XES costs allocated back under the production cost formula is opaque. For example, the production cost formula allocates over $11M of A&G expenses but it is not clear how much, or if any of that amount is from XES.[13]

Q. Why is there uncertainty regarding administrative costs for NSPD?

A. NSP's initial estimate is that additional G&A will be $1.4M/year.[14] This cost is primarily associated with a separate corporate officer and administrative assistant who would be located in Bismarck, and external professional services including auditing.[15] Ms. Everson notes that this estimate is subject to revision depending on accounting and IT costs necessary under Legal Separation.[16] These costs are currently not in the $1.4M estimate.

Q. Why is there uncertainty regarding the cost of debt for NSPD?

A. NSPD would have its own debt without any type of parental guarantee from Xcel.[17] While NSP does not have any parental guarantee of its debt, the rate base for NSP absent Legal Separation would be over $10B in 2020. Under Legal Separation, NSPD as a distribution-only utility would have a rate base of approximately $205M.[18] Assuming short and long term debt totaling 47.5%, NSPD would be in the market to finance less than $100M excluding working capital. Furthermore, individual issuances of debt are likely to be a fraction of the $100M. I anticipate that both the cost of debt would be higher and the financing costs would be higher than under the current allocated rate base.

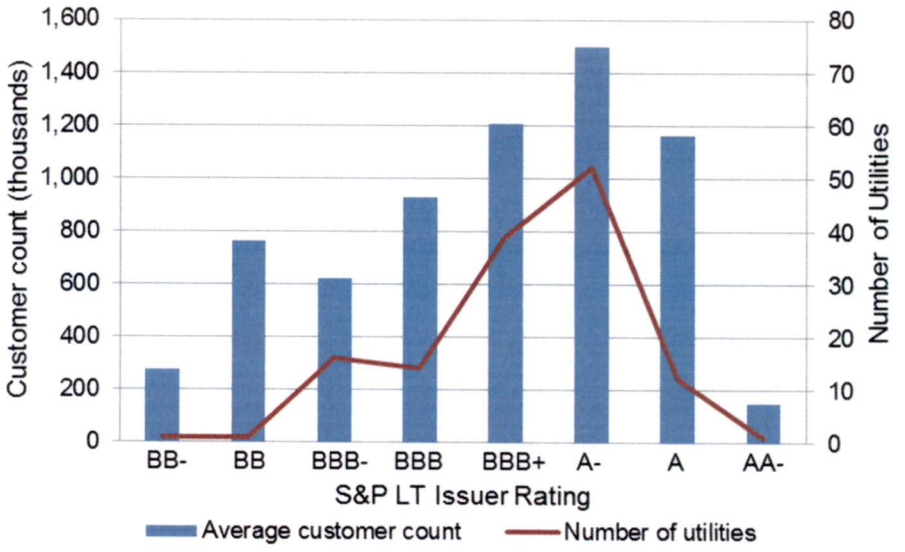
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[13] NSP Response to NDPSC 7-001 RTF Att C Live Prod Formula
[14] Everson Direct, Table 1 p 13.
[15] Everson Direct p 11 l 20 – 24.
[16] Everson Direct P 13 lines 22-24, page 12 line 1, and page 12 lines 12-20.
[17] None of the current Xcel operating companies have debt secured by Xcel. (NSP response to NDPSC 4-21.)
[18] Burdick Direct, Schedule 4 p 1.

Q. Why do you anticipate higher debt costs for the NSPD entity?

A. NSP Witness Starkweather noted that the NSPD utility would be relatively small and debt costs would likely be higher due to the small size of the debt issuance and the lack of diversity in the revenue sources.[19] In addition, NSP estimated that the NSPD long-term debt would increase by 128 basis points.[20] I looked for additional evidence that a NSPD utility would likely have higher debt costs. One indicator is the bond ratings of different sized utilities. As show in Figure 1, the larger size utilities tend to have higher bond ratings, which should translate into a lower cost of debt.

Figure 1: Long-term Issuer Credit Rating by Customer Count of Regulated Electric Utilities in the U.S., 2015[21]



Q. Why do you anticipate higher debt financing costs for the NSPD entity?

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[19] Direct testimony of Starkweather p 40 lines 13- 24.

[20] NSP response to NDPSC 7-001 RTF Att A Live Model NON-PUBLIC Exhibit_(CRB-1), Schedule 4, Page 2 of 5.

[21] Source: PA Consulting Group, SNL Financial.

A. As noted by NSP, NSPD would have to pay separate fees for bond ratings, credit facility commitments, and trustee fees.[22] In addition, debt issuance costs would need to be a larger percentage of the debt given the relatively small amounts of debt.

Q. Why is there uncertainty regarding the one-time costs for Legal Separation?

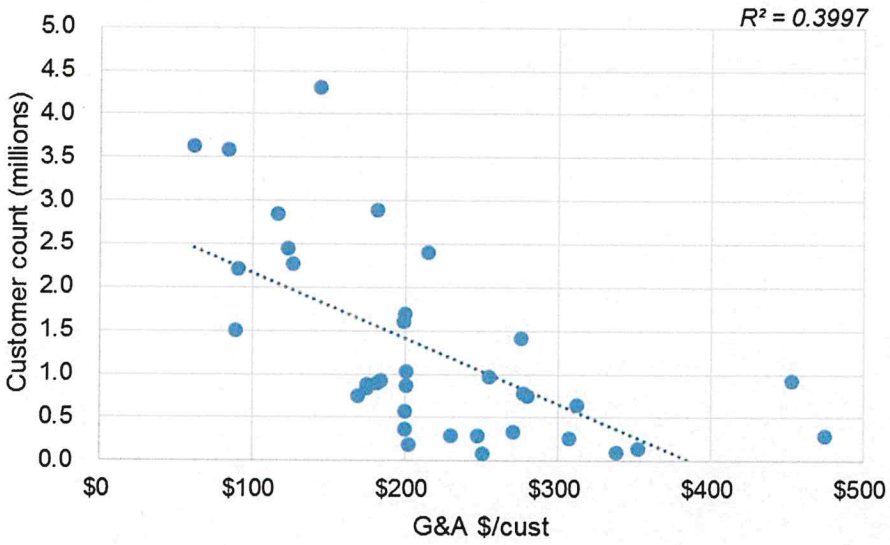
A. NSP estimates one-time separation costs of $8M - $15M with half the costs assigned to NSPD.[23] This is a significant cost range and it is not clear whether this includes the costs that both NSP rate payers and North Dakota tax payers would have to incur to negotiate the contract for the legacy resources and to include legal costs associated with obtaining FERC approval of the contract.

Q. Do you have other concerns about the economics of creating the NSPD OpCo?

A. Yes, separating out North Dakota to create a small utility is contrary to the consolidation trends in the utility industry that are partially justified on the basis of economies of scale. I recognize that the XES structure can provide some of the economies of scale to NSPD but those arrangements and terms can change over time. I looked at G&A cost per customer based upon utility size and there is a clear trend that costs are higher for small utilities. This trend is shown in Figure 2.

[22] NPS response to NSPD 3-004
[23] Refiled Direct testimony of Burdick, Exhibit (CRB-1), Schedule 10

Figure 2: G&A Cost vs Customer Count of Regulated Electric Utilities in selected U.S. markets, 2015[24]



Q. What are the savings estimates to NSPD calculated by NSP?

A. NSP Witness Burdick calculates an annual savings estimate of approximately $1M / in 2020, less than a 0.4% reduction than NSP's estimate of the Legacy System Benchmark revenue requirement.[25]

Q. Do you expect there to be savings to NSPD under Legal Separation?

A. No, excluding the issue of power costs for new resources that I discuss in the next section, I do not expect there to be savings. The NSP proposal has not demonstrated any reduction in power costs for legacy resources or any reduction in costs for disputed assets beyond the current resolution determined by the NDPSC. It calculates higher transmission costs, a potential for increased G&A costs, and includes one-time separation costs. NSP's claim of a reduction in XES costs may not be accurate, since it does not include XES costs that NSP would recover through power cost charges and does not

[24] Includes all 37 utilities in MISO, Northwest Power Pool, Southwest Power Pool, and Rocky Mountain Power Area for which 2015 G&A data was available. Source: PA Consulting Group, ABB's Energy Velocity Suite.
[25] NSP Response to NDPSC 7-001 RTF Att A Live Model NON-PUBLIC

include any accounting or IT changes. NSPD will likely have a higher cost of debt and higher associated debt issuance and administrative costs. Finally, while there are no anticipated changes in distribution costs, there are no assurances that those costs will not increase.

VII. Estimation of Power Costs Under Legal Separation

Q. Would you please summarize your understanding of how NSPD would acquire electricity under Legal Separation?

A. Yes, my understanding is that NSPD as a distribution-only utility would acquire its electricity and meet its capacity requirements through purchases from NSP. NSP is proposing to create a separate power portfolio for NSPD and not treat NSPD as part of its integrated system. The separate portfolio will initially consist of a share of non-disputed legacy resources and a share of the disputed resources based upon a resolution of the allocation of disputed resources. NSP will separately acquire new resources on behalf of NSPD as the utility needs more resources due to load growth, expiration of legacy contracts, or retirement of legacy resources. The terms and costs of acquiring electricity from these resources will be contractually determined by the administration of those contracts, which, along with the resolution of any disputes, will fall under FERC jurisdiction and not the NDPSC.

Q. Do you anticipate any change in reliability as a result of NSP's proposal?

A. No. I disagree with NSP Witness Everson that reliability is one of the benefits of the NSP integrated system.[26] On a daily operational basis, the MISO integrated system and associated rules will continue to be the source of short-term reliability with regards to generation. With regards to long-term reliability, the necessary capacity associated with North Dakota load would still be procured under the status quo or under Legal

[26] Everson Direct p 3-4 lines 26 -2.

Separation. In addition, the reliability of the transmission grid used to serve North Dakota is based on facilities owned by other utilities that NSP has access to through MISO network service and legacy transmission agreements.[27]

Q. What will NSPD's need for additional resources be?

A. NSPD's need will be driven by three factors: load growth, what legacy resources are shared with NSPD, and the remaining economic life of those resources or PPAs.

The NSPD load growth is not expected to be significant. As shown in Exhibit JAH__2 and in

Table *1*, the average annual load growth for the North Dakota service territory is less than 0.35% per year.

[CONFIDENTIAL DATA BEGINS]

Table 1: NSP North Dakota Load Growth Rates

[CONFIDENTIAL DATA ENDS]

The issue of what legacy resources would be shared with North Dakota is not as definitive as NSP suggests. According to the Application, NSPD could share in all but the disputed resources, it may get no legacy resources after 2025, or only it may only get a share of the nuclear and biomass resources.

[27] See Beuning Direct Testimony p 5 lines 6 – 14.

Q. Do you anticipate any change in benefits of economies of scale for not participating in the NSP integrated system?

A. Yes. I am concerned that there is the potential for higher costs associated with future resource procurement as a result of separate procurement of resources for NSPD. The NSPD system would be relatively small with a peak demand of less than 500 MW. As legacy resources retire and PPAs expire, NSPD could be in the market for relatively small amounts of energy and capacity, and may not have either the need or the financial resources to purchase larger projects with their associated economies of scale. Conceptually, NSP could identify partners for joint purchases, but I am concerned that NSP will not have the appropriate incentives, or that there may be institutional barriers to joint ownership of resources with potential competitors.

Q. How do utilities that are comparable in size to the proposed NSPD procure power?

A. There are a number of strategies. For example, public power entities are often members of joint action agencies and they procure some or all of their electricity under partial or full requirements service. I also reviewed Investor Owned Utilities (IOU) of comparable size to see if there were any with arrangements similar to what NSP is proposing.

Q. What IOUs did you review to evaluate how they secure power?

A. I started with an initial list of investor-owned operating companies with less than 100,000 customers, and identified 31 utilities out of 139 operating companies that have less than 100,000 customers. As a point of reference these 31 small utilities serve less than 1.4% of the total customers and loads served by investor-owned operating companies. I filtered this list to remove small remote utilities and utilities that cross-subsidize service across operating companies, and utilities with retail choice. The resulting list was 17 utilities. These utilities serve less than 0.8% of the customers and loads of investor owned operating companies. I then looked at utilities with over 60,000 customers to identify utilities more comparable to the proposed NSPD and identified nine companies. The summary of the operating companies that I reviewed are shown in Exhibit__JAH-3.

Q. Would you please summarize how the remaining 9 small utilities with between 60,000 and 100,000 customers secure power?

A. There is a mix of strategies but there appears to be a high reliance on purchasing power from the market or owning small parts of multiple generation units. Eight of the nine utilities I reviewed secure over two-thirds of their power through purchases versus owned assets.

Q. Is the separation of Entergy Gulf States Utilities, as discussed in Witness Starkweather's testimony, a good example of what NSP is proposing for the treatment of power costs and transmission costs for a utility dividing into two operating companies?

A. I do not believe it is a good example of what is being proposed by NSP for a number of reasons:

- Both Entergy Louisiana and Entergy Texas have their own transmission assets (Entergy Texas owns all of the transmission assets which it uses in Texas);
- Both Entergy Louisiana and Entergy Texas have their own generation assets (Entergy Texas owns all of the gas-fired generation plants in Texas which serve its customers);
- Entergy Texas has undivided ownership shares in some plants located in Louisiana as opposed to a power purchase contract;
- There are a limited number of unit-specific PPAs [28], and
- The two utilities are larger.

Q. Did NSP model potential power portfolios for NSPD?

A. NSP modeled a number of scenarios in Strategist and estimated the potential net present value of the alternative portfolios compared to its Preferred Case, which consists of the

[28] Entergy 10K 2017

current integrated system from which North Dakota takes a load share, at full cost, for all existing resources and forecast additions. The Present Value of Revenue Requirements (PVRR) of these scenarios, shown in Table 2, indicate that separation of the portfolios is a lower cost option for North Dakota. However, for reasons that I detail below, I do not believe these are reliable indicators of savings to North Dakota rate payers.

Table 2. NSPD PVRR of Selected Scenarios[29]

Scenario ID	Scenario Name	PVRR through 2040 ($M)	Delta to Preferred Case
2	NSP Preferred Case	2,256	
3_B	ND Shares Legacy but no Disputed Resources	2,162	(95)
3_C	ND Shares All Legacy and Disputed + 1,550 Wind	2,160	(96)
5_A	Separation in 2025, CT Replacement w Nuclear	2,027	(230)
5_B	Separation in 2025, CT Replacement w Nuclear	2,165	(91)
5_C	Separation in 2025, CT Replacement, No Nuclear	1,972	(284)
5_D	Separation in 2025, CT Replacement, No Nuclear	2,066	(190)

Q. What scenarios did NSP analyze in its modeling of power costs for NSPD with regards to acquiring future resources?

A. NSP modeled a set of scenarios which assumed North Dakota exits the NSP system with regard to legacy resources in 2025, with the exception of nuclear and biomass resources. However, I believe that the more relevant scenarios are those which were based upon the 2017 IRP plan and the most recent assumptions and also assumes that NSPD retains a share of the legacy resources, and assumes the ability to purchase and sell energy into the MISO market. This subset of scenarios includes a limited number of resource expansion plans. One scenario assumes that NSP purchases CTs and energy from MISO on behalf of NSPD, and the other scenario assumes NSP purchases CCs on behalf of NSPD.

[29] NSP Response to DR 6-004, Strat Data for Appendix 070617.xlsx

Q. Do you consider those scenarios as adequate for evaluation of how future resources would be procured on behalf of NSPD and the appropriate cost?

A. No. First, NSP did not include additional renewable resources in any of the resource expansion plan. My perspective is that the North Dakota Commission is not opposed to renewable resources, only non-economic purchases of renewable resources. The NDPSC has approved recovery of renewable resources and is currently considering a settlement regarding NSP's request for an ADP to acquire 1,550 MW of wind. I do not consider the scenarios related to either North Dakota continuing to share legacy resources, or not sharing legacy resources (except for nuclear and biomass) as reliable estimates of future power costs for North Dakota.

Specifically, NSP analyzed only three scenarios that included NSPD continuing to share the legacy thermal, nuclear and renewable resources. Those three scenarios are named Scenarios 3A, 3B, and 3C. Of those three, I believe the more relevant scenario is 3A. Scenario 3C includes NSPD sharing in the 1,550 MW of new wind resources; however, it also has NSPD sharing in the cost of disputed resources that the Commission has rejected. Alternatively, Scenario 3B does not assume NSPD sharing in disputed resources, and also does not allocate any of the 1,550 of wind to NSPD. Neither of these scenarios is consistent with current NDPSC Advocacy Staff positions on these resources so neither scenario is an appropriate starting position. Furthermore, both scenarios include MEC II and that is an acquisition that has yet to be evaluated.

Q. Would you please summarize the NSP Strategist scenarios built around NSPD continuing to share legacy resources after 2025?

A. These scenarios are based upon North Dakota continuing to share in legacy resources, incorporating a resolution of disputed resources. In these scenarios NSPD participates in MEC II and meets all future energy and capacity needs through the purchase of combustion turbines and purchasing market energy. Scenarios were also developed with

different gas prices and without North Dakota participating in the existing nuclear resources.

Q. Would you please summarize the results of these scenarios?

A. Yes, the annual results of these scenarios including the amount and type of energy and capacity acquired from legacy resources, NSPD dedicated resources, and market purchases are shown in Exhibit JAH__4. The fuel mix for two years is shown below in Table 3. In the NSP modeling the shortfall in energy as a result of Legal Separation is made up with increased market purchases. Consequentially there is a high reliance on market purchases over time. The shortfall of capacity is made up with the construction of a CT.

Table 3: Fuel Mix for Scenarios including Shared Legacy Resources

Scenario ID	Scenario Name	Year	Coal	Nuclear	Bio	Gas	Hydro	Wind /Solar	Market
2	Preferred Case	2025	25%	31%	2%	7%	3%	37%	-5%
3_B	ND Shares Legacy but no Disputed Resources	2025	25%	31%	1%	7%	3%	15%	18%
3_C	ND Shares All Legacy and Disputed + 1,550 Wind	2025	25%	31%	2%	7%	3%	33%	-1%
2	Preferred Case	2035	15%	0%	0%	34%	2%	32%	16%
3_B	ND Shares Legacy but no Disputed Resources	2035	15%	0%	0%	13%	2%	8%	62%
3_C	ND Shares All Legacy and Disputed + 1,550 Wind	2035	15%	0%	0%	13%	2%	24%	47%

Q. Would you please summarize the NSP Strategist scenarios which assume NSPD no longer shares legacy resources after 2025?

A. Two sets of scenarios were developed with these assumptions. One set assumes North Dakota continues to share the legacy nuclear and biomass resources, and the other set assumes North Dakota does not share in any legacy resources. These scenarios were modelled under different gas prices. The CC scenarios assume that NSPD meets future

energy and capacity needs with the purchase of a 389 MW CC in 2025. The CC would provide all of NSPD's required energy except for what is provided by the nuclear and biomass plants.

The CT scenarios assume that NSPD meets most of its energy needs from market purchases, except for what is provided by the legacy nuclear and biomass plants. These scenarios assume the construction of CTs primarily to meet capacity requirements.

Q. Would you please summarize the results of these scenarios?

A. Yes, The fuel mix for two years is shown below in Table 4 below. The NSPD system would be highly reliant on a single CC plant in the CC scenario, and in the CT scenario, the utility would be highly reliant on market purchases.

Table 4. Fuel Mix for Scenarios including Shared Legacy Resources

Scenario ID	Year	Coal	Nuclear	Bio	Gas	Hydro	Wind/Solar	Market
2	2025	25%	31%	2%	7%	3%	37%	-5%
5_A	2025	0%	33%	2%	8%	0%	0%	58%
5_B	2025	0%	33%	2%	66%	0%	0%	0%
5_C	2025	0%	0%	0%	12%	0%	0%	88%
5_D	2025	0%	0%	0%	100%	0%	0%	0%
2	2035	15%	0%	0%	34%	2%	32%	16%
5_A	2035	0%	0%	0%	12%	0%	0%	88%
5_B	2035	0%	0%	0%	100%	0%	0%	0%
5_C	2035	0%	0%	0%	12%	0%	0%	88%
5_D	2035	0%	0%	0%	100%	0%	0%	0%

Q. Have you prepared a summary of the NSP modeling of the North Dakota system under legal separation?

A. Yes, The resource expansion plans resulting from that modeling are summarized in Exhibit JAH__4.

Q. Based upon your review of the available information on how NSP proposes to procure future resources for NSPD, do you conclude that NSP has put forth a plan that is in the interest of North Dakota rate payers?

A. No. I do not think it is reasonable to evaluate whether North Dakota will have lower power costs under Legal Separation based upon the portfolios modeled. My concern is that there is not a diversity of resources in either the CT or CC scenarios. Furthermore, the CC scenario incorporates an additional element of risk where the utility would rely on a single resource for most of its generation. In order to evaluate whether any of the proposed resource plans are appropriate there would need to be a separate resource planning process in which the NDPSC could articulate its preferences and vision for the appropriate resources to serve NSP's North Dakota load. Finally, NSP has not demonstrated that it could cost effectively secure a diverse set of resources to serve the relatively small North Dakota load.

VIII. Review of NSP Claims of Cross Subsidization of North Dakota Customers

Q. Are North Dakota customers being subsidized by other NSP customers as a result of North Dakota disallowance of full cost recovery of the disputed resources?

A. No. The reality is that North Dakota, through its treatment of many of the disputed resources, is preventing North Dakota from cross subsidizing NSP's Minnesota customers. The genesis for many of the disputed resources is that NSP acquired assets that are not needed to meet energy and demand but were acquired at above market energy costs to comply with Minnesota's policy objectives and requirements, including requirements that NSP procure electricity from solar energy and Community-Based Energy Development (C-BED) projects. These legislative requirements of Minnesota are not shared by North Dakota. NSP's requests to recover a share of those costs from North Dakota customers is essentially asking for North Dakota customers to subsidize Minnesota's energy policies.

Q. Are North Dakota customers being subsidized by other NSP customers as a result of paying a proxy price in lieu of paying the full cost of the disputed resources?

A. No. The total cost of the disputed resources includes the value of the energy and other attributes including Minnesota community development benefits, supporting Minnesota RPS targets, and Minnesota carbon reduction goals. These attributes are not priced separately in the power purchase agreements and these are attributes that are purchased on behalf of Minnesota customers. Proxy pricing represents a reasonable approach for valuing the energy component provided in these contracts.

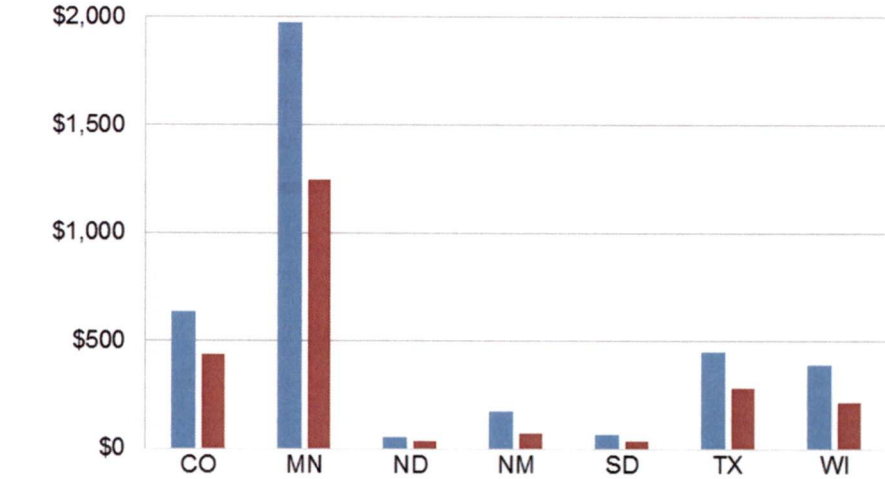
Q. Is the NDPSC asking to retain any of the value associated with the renewable energy credits and greenhouse gas reduction under proxy pricing?

A. No. The Commission has not requested that any monetized value of those credits be included in the Fuel Cost Rider (FCR).

Q. Are North Dakota customers being subsidized by NSP shareholders if the NDPSC disallows costs of NSP power purchases that are not based upon least cost and need?

A. No. NSP is a regulated monopoly and is subject to the jurisdiction of the states where it has franchises as well as the jurisdiction of the FERC. Disallowances are the result of regulators exercising their duties and complying with their state laws and policies. In addition, it is the responsibility of regulators to protect customers from a monopolist when they do not have the choice about who they buy their power from, and what sources of power they want to buy from. As shown in Figure 3 and Exhibit JAH-5, Xcel has been subject to disallowances in multiple jurisdictions. Disallowances are part of the regulatory compact and do not represent subsidies.

Figure 3: Regulatory Requests and Allowances by State for Xcel Energy Utilities, 2012 to 2016 ($millions)[30]



	CO	MN	ND	NM	SD	TX	WI
Request	$634.8	$1,976.9	$55.8	$173.4	$68.2	$448.0	$392.0
Allowance	$436.8	$1,248.4	$39.5	$71.6	$38.3	$280.5	$215.1

Q. Do the multiple disallowances related to the disputed resources imply that the Commission has not been acting reasonably?

A. No. As I noted disallowances, for better or worse, are part of the regulatory compact and Commission review takes the place of the discipline of the market for a utility monopoly. I also note that Regulatory Resource Associates, Inc. (RRA) ranks North Dakota utility regulation as "Average/1", or above the average in its normal distribution ranking. This ranking is based upon "the energy regulatory environment is somewhat more constructive than average from an investor perspective".[31] The ranking for North Dakota is also slightly above the ranking of the MPUC.

[30] While Xcel also operates in MI, it is excluded from this chart as there were no regulatory disallowances in that state in the period covered. Source: Xcel Energy Data Request No. 4-2.

[31] State Regulatory Evaluations Assessments of regulatory climates for energy utilities, RRA Regulatory Focus, August 21, 2017.

IX. Review of Disputed Resources

Q. Would you please briefly describe what the "Disputed Resources" are?

A. Yes, NSP defined "disputed resources" as resources that NSP is either not receiving full cost recovery for in North Dakota, or recovering the costs subject to refund.[32] My understanding is that these resources include the Minnesota C-BED projects, Minnesota solar projects, and some solar and biomass PPAs. In addition, the MEC II PPA is identified as a disputed resource. A list of 26 disputed resources identified by NSP was provided in Exhibit (AHC-1), Schedule 3, page 71, and I have included that list in Exhibit JAH_6, along with the Zephyr Wind C-BED project which I added.

Q. Have the treatment of the Disputed Resources been resolved by this Commission?

A. Yes, the treatment of the Disputed Resources has been resolved with the exception of MEC II where the Commission dismissed the application for an ADP without prejudice. I also note that all of the biomass resources that NSP has identified as disputed resources are currently recovered in full in North Dakota, and that NSP has filed an Application for an ADP in North Dakota to seek recovery of costs to buy out three PPAs and reduce the pricing on a fourth, since NSP has determined that it is lower cost to buy out these PPAs and buy replacement power in the market.

I have listed NDPSC's treatment of each of these resources in Exhibit JAH__6. In addition I prepared the following collective summary of the 27 disputed resources identified by NSP[33], shown in Table 5 below.

[32] Chandarana Direct p 28 lines 19 – 27.
[33] My list contains 27 projects versus 26 since I added the Zephyr Wind C-BED project.

Table 5: Summary of Disputed Resources

Type of PPA	# of PPAs	UCAP (MW)	NDPSC Treatment
C-BED Wind	15	38	ND pays proxy price
Biomass	6	128	Recovered in full
Solar[34]	3	1.4	ND pays proxy price
Solar[35]	3	81	Do not pay for - ADP denied
CC Gas	1		Unresolved - ADP dismissed without prejudice

Q. Were any of the 18 resources for which North Dakota pays a proxy price in lieu of the full PPA price identified as least cost resources of need for capacity and / or energy?

A. No, these all of these resources were purchased as result of Minnesota requirements and not purchased on the basis of least cost energy / capacity or for system resource needs.

Q. Is the Aurora Solar project a Disputed Resource?

A. No, NSP indicates that it is not disputed. While North Dakota does not pay the full price, NSP is recovering its costs based upon its PPA with Geronimo Wind Energy where by Geronimo agreed to reimburse Xcel for unrecovered costs associated with non-recovery of the ND portion of the PPA costs..[34] NSP states that it does not believe that it will be able to do this in the future.

Q. How is proxy pricing calculated for the disputed PPA costs?

A. The proxy price is calculated in the FCR. The calculation is based upon calculating the average cost per MWh of fuel, purchased power, and MISO costs excluding the costs and MWh associated with resources recovered under proxy pricing. That average calculated cost is the proxy price for those resources. The proxy price is then multiplied by the

[34] NSP Response to NDPSC 1-3 & MPUC Decision in Docket No. E-002/M-15-330, April 13, 2016.

MWhs associated with the resources recovered under proxy pricing in order to calculate the total replacement costs for the disputed resources.

Q. What percent of the North Dakota energy use falls under the proxy calculation in the FCR?

A. In July of 2017 it was approximately 2.7%.[35]

X. Legal Separation is Unnecessary to Resolve Disputed Resources

Q. Is NSP proposing an alternative resolution of Disputed Resources in conjunction with Legal Separation?

A. Yes. Although the Commission has resolved the disputed resources identified by NSP with the exception of MEC II, the Company is proposing a new resolution that includes:

- The Commission accepting MEC II;
- Not including the 1,550 MW of wind in North Dakota power costs;
- Not recovering accelerated depreciation associated with the early retirement of Sherco I & II from North Dakota customers; and
- Not recovering the disputed C-BED or small solar projects from North Dakota customers.

Q. Is developing an alternative resolution to the current resolution of Disputed Resources necessary to implement Legal Separation?

A. No, based upon my review of NSP's proposal there are no technical reasons why an alternative to the current resolution of disputed resources is required in order to implement Legal Separation. However, if one of the goals is to re-evaluate issues with known resources, then if the Commission decides to approve Legal Separation, then it is

[35] September 2017 Fuel Cost Rider Rates, Attachment D, Case No. PU-17-12,

logical for the Commission to determine whether NSPD will participate in the 1,550 MW of wind and MEC II in this proceeding.

Q. Is it necessary to have a resolution to Disputed Resources that all the state jurisdictions agree to?

A. I do not think that is strictly necessary. However, from an economic perspective Xcel may want full regulatory alignment and cost recovery to maximize earnings for its shareholders. Regulatory alignment with Minnesota with regard to which customers should bear the burden of incremental costs associated with incorporation of Minnesota mandates regarding renewable resources and incorporation of externality costs would help resolve NSP's issue with unrecovered costs.

Q. Do you recommend that the Commission review and modify its decisions regarding disputed resources as part of Legal Separation?

A. I do not recommend revisiting the decisions regarding disputed resources. While the Commission may agree to review past decisions as part of settlement negotiations, my presumption is that the Commission made its decisions based upon the technical details, projections about costs, and other facts as they were known at the time of the decision. It is certainly the Commission's prerogative to review those decisions, especially if NSP presents new evidence for the Commission to consider. However, the application for Legal Separation does not present any new evidence about the need for, or economics of, the Disputed Resources.

If the Commission chooses to reevaluate the Disputed Resources as a result of agreeing to Legal Separation, then my recommendation is that the Commission does not need to limit that evaluation to the list of Disputed Resources identified by NSP.

My understanding is that NSP is seeking a contract with NSPD for legacy resources that will no longer be subject to this Commission's approval. Under that arrangement it

makes sense for the Commission to re-evaluate all the legacy resources and decide which ones it should contract for. For example, the hypothetical early retirement of the Prairie Island plant could have substantial cost implications for North Dakota that would be removed from NSPSC jurisdiction.

XI. Future Disputed Resources

Q. Would you please describe what Future Disputed Resources are?

A. Yes. Future Disputed Resources are an unknown set of issues associated with unknown resources. NSP Witness Chandarana's direct testimony refers to anticipated future disagreements about resources acquired by NSP based upon "a vison for the future that focuses on renewable energy and decarbonizing our generation fleet".[36] NSP is concerned that there will be future disputes but has not identified any specific resource decision or what the economic consequences of those anticipated future disputes may be.

Q. Are the seven projects that compose the 1,550 MW of wind considered to be Disputed Resources?

A. NSP currently has an ADP filed with the Commission and a hearing on a settlement was completed at the end of September 2017. While the NDPSC Advocacy Staff is recommending approval of the ADP, it is not known whether any of these projects will be disputed resources until after the Commission has made a determination. NSP has indicated that the 1,550 of wind may not be a Disputed Resource.[37]

Q. Has NSP identified areas where it is anticipating disputes on future resources?

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[36] Chandarana Direct p 9 lines 24 – 25.
[37] NSP response to NDPSC 5-2.

A. I interpreted Witness Chandarana's testimony to imply that NSP may be interested in acquiring significant amounts of solar energy before the investment tax credit (ITC) begins to decrease starting in 2020.[38] In addition, in NSP's response to NDPSC 5-2 the Company indicated a number of potential disputes. I have summarized these potential resource conflicts in

Table *6*.

Table 6: Potential Future Disputed Resources Identified by NSP

Resource	Concerns Regarding ND Approval
MEC II (345 MW CC-PPA)	NDPSC has not ruled on this resource yet, although the Commission rejected the ADP without prejudice
MPUC approved an additional 650 MW of solar from solar gardens programs or other programs over the 2016 – 2021 time frame	The NDPSC has not approved past solar projects that were either not needed, or not least cost additions.
Sherco I & II replacement following early retirement in 2023/2026; 750 MW of intermediate capacity replacement and 750 MW of replacement generation	NDPSC has questioned the economics of early retirement of Sherco I & II. It is not known how the Commission will treat the proposed replacement resources.
Location of new combustion turbine targeted for North Dakota following NDPSC settlement. MPUC has directed NSP to consider it as a generic location.	Not locating the CT in North Dakota would be inconsistent with the 2016 rate case settlement
Minnesota directive to acquire an additional 400 MW of demand response resources by 2023	NDPSC may object if resources are not needed or cost effective
Buy out of biomass projects	These cases are pending at the NDPSC

Q. Do you anticipate that there will be a dispute between NSP and the NDPSC regarding potential purchases of additional solar in advance of the phase out of the ITC?

A. I do not have sufficient information to make that determination. However, I note that one of the drivers for NSP acquiring the 1,550 MW of wind in advance of a need for the resources was the phase out of the production tax (PTC) credit. However, in the case of

[38] Chandarana Direct p 10 lines 4 – 9. The 30% ITC will step down to 26% for projects starting construction in 2020 and 22% for projects started in 2021.

the 1,550 MW of wind it appears that the resources will be acquired at a price that lowers costs for North Dakota customers. The same pattern might be repeated for any solar purchases accelerated to take advantage of the 30% ITC. That could result in lower costs for North Dakota customers.

Q. Do you anticipate that there will be a dispute between NSP and the NDPSC regarding potential purchases of an additional 650 MW of solar for the Minnesota solar gardens program?

A. I do not have sufficient information to make that determination. I foresee an issue if the purchase price is above the cost of alternative resources (including renewable resources such as the 1,550 MW of wind). My understanding is that the mandate for solar gardens is in relation to Minnesota policy to promote renewable resources, and is not based on system least cost or a need for new resources. To the extent that a solar resource acquired for the solar gardens program is neither needed nor least cost, for North Dakota that resource would be neither a benefit of economies of scale, nor a benefit of an integrated system. Rather, it would be an incremental cost created by a state policy mandate not shared by North Dakota. This type of resource addition is not a justification for Legal Separation but should be resolved under regulatory alignment where Minnesota should not expect other states to subsidize its policies.

Q. Do you anticipate that there will be a dispute between NSP and the NDPSC regarding potential acquisition of an additional 400 MW of demand response resources from Minnesota customers?

A. Again, I do not have enough information. I foresee an issue if the purchase price of the demand responses were above the market value of the capacity, especially if the utility is not capacity short. To the extent that the purchase of the resource is driven by Minnesota policy and is not based on system least cost or a need for new resources, there may be a potential dispute. As with the previous discussion related to solar gardens, this type of

resource addition is not a justification for Legal Separation but should be resolved under regulatory alignment where Minnesota should bear the costs of its policy choices.

Q. Do you anticipate that there will be a dispute between NSP and the NDPSC if the Company decides to build the CT in a location outside of North Dakota?

A. Again, I do not have enough information. I foresee an issue if NSP does not have a valid cost savings argument for wanting to modify a commitment that it made in the settlement of case PU-12-813.[39] However, at this point a dispute about this issue is purely hypothetical since no specific project has been proposed and the MPUC has not rejected construction of a CT in North Dakota.[40]

Q. Do you anticipate that there will be a dispute between NSP and the NDPSC regarding the replacement energy and capacity for Sherco Units I & II?

A. Again, I do not have enough information. My understanding is that NSP justified the early retirement of Sherco Units I & II based upon economics. If the replacement resources are more expensive than what the costs would have been absent the early retirement, then there may be an issue, but that also raises potential questions regarding the prudence of NSP's decision to proceed with early retirement. I do not see that as a basis to proceed with Legal Separation. Furthermore, to the extent that Legal Separation removes the ability of the Commission to evaluate the prudence of an NSP action, I would recommend that the Commission not proceed with Legal Separation. However, I want to emphasize that I have not determined that early retirement of Sherco Units I & II is imprudent, and I have not evaluated the alterative cost projections of the resource(s) that NSP proposes to replace Sherco with.

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[39] In the settlement NSP agreed to build a gas fired resource (combustion turbine) of at least 200 MW in eastern North Dakota that will be in service by the end of 2025. If the CT is not build, NSP will refund 50% of the excess revenues collected from six biomass plants where excess revenues is the difference between the contract costs and adjusted system cost. Settlement Northern States Power Company 2013 Rate Increase Application Case No. PU-12-813, p 4. Of 17.

[40] My assumption is that NSP will not construct a system resource in North Dakota without the MPUC's approval.

XII. Future Disputes Regarding Legacy Resources

Q. What are future disputes regarding legacy resources?

A. Similar to Future Disputed resources, this refers to undefined disputes related to legacy resources. An example of what is conceptually being referred to is the current dispute related to NSP's decision to proceed with the early retirement of Sherco Units I & II along with the treatment of accelerated depreciation associated with the early retirement.

Q. Have any other disputes been identified regarding legacy resources?

A. No. As another example, NSP is currently evaluating, at the request of MPUC, the early retirement of the Prairie Island nuclear power plant.[41] At this point there is no decision to pursue early retirement and there is no presumption that North Dakota will disagree with the study conclusions, regardless of what they may be.

Q. If there are no known future disputes regarding legacy resources why are they an important consideration should Legal Separation occur?

A. It is important to acknowledge the potential for future disputes regarding legacy resources. These disputes could be regarding early retirement decisions, life extension investments, contract renegotiations such as the ones recently completed regarding four biomass projects, fuel contracts or any number of issues. If there are disputes, the terms of a potential Legal Separation contract between NSP and NSPD may provide some guidance, but if purchase contracts are under FERC jurisdiction, the Commission will not have any authority to authorize an adjustment or disallowance. The Commission would be effectively ceding its current authority to evaluate whether potentially significant future actions regarding legacy NSP owned resources and legacy contracts are prudent and in the interest of North Dakota customers.

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[41] See NSP responses to NDPSC 2-9 and NDPSC 4-6.

Q. Could the terms for retirement of resources be established contractually at the time of Legal Separation?

A. Yes. NSP indicated that those terms could be established in the contract.[42] However, this is an example of how establishing Legal Separation will be complex including the need for the Commission to determine if those terms are in the interest of North Dakota customers since the Commission will only have one opportunity for a review of complex issues where the specific issues leading to a retirement decision are not known. NSP notes that retirement decisions are dynamic and depend on market conditions and alternative supply options.[43]

Q. Is it your understanding that NSP is specifically seeking to remove the Commission from being able to rule on cost recovery regarding legacy resources subsequent to Legal Separation?

A. Yes. NSP refers to the FERC as being "a neutral third party to resolve disputes rather than relying on states…"[44]

XIII. Alternative Approaches

Q. If Legal Separation is unnecessary to address the Disputed Resources and future resource acquisition, then what are the options to reduce conflict and allow NSP to have a reasonable opportunity to earn a return on its investments in its North Dakota operations?

A. There are a number of options, not all of which are mutually exclusive, including:

- Regulatory alignment;
- Sale of the North Dakota portion of the utility;

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[42] NSP response to NDPSC 4-22 (d)
[43] NSP response to NDPSC 4-22 (d)
[44] NSP response to NDPSC 4-24 (d).

- Implementing a partial requirements approach to future resource acquisition;
- Separate procurement of new resources without Legal Separation;
- Proxy pricing; and
- Enhancing the approval process to provide NSP with more certainty regarding what new resource costs will be recoverable in North Dakota.

I will discuss these options in the next part of my testimony including NSP's apparent rejection of both regulatory alignment and proxy pricing.

Q. What do you mean by regulatory alignment?

A. NSP does not appear to have an issue of procuring resources that meet the needs of North Dakota customers, but has an issue with not getting full recovery of the cost of resources due to different state commissions operating under different laws regarding what resources are prudent to acquire. Bluntly stated, the MPUC may find a resource acquisition appropriate and prudent since it meets Minnesota statutes and/or passes a Present Value of Societal Costs (PVSC) test, versus North Dakota that uses a needs test and Present Value of Revenue Requirements (PVRR) test. In many cases NSP has acquired resources that meet the MPUC's criteria for being prudent investments for recovery, but failed the North Dakota criteria, and thus resulted in not receiving full cost recovery in ND. These are instances of a lack of regulatory alignment - two different jurisdictions have different perspectives and it leads to the utility not recovering its full costs.

Q. How can regulatory alignment be improved?

A. NSP can work with its multiple state jurisdictions to develop mutually acceptable agreements. I have not been involved in any of NSP efforts to date so I cannot address the specific challenge. However, given the different laws and mandates related to the acquisition of renewable energy, including targets for specific types of resources, as well as the treatment of externalities (CO_2 emissions, for example), I suspect that the different

commissions may be operating under constraints that make it difficult to agree on all resource acquisitions. However, there are potential solutions for alleviating those constraints.

Q. What solutions options exist if the Minnesota and North Dakota jurisdictions cannot agree on a resource purchase or acquisition?

A. In the instances where Minnesota's energy policies are driving acquisition of resources that are not least cost, but consistent with Minnesota's renewable energy requirements, legislative requirements, or treatment of externalities, Minnesota can take ownership of all the RECs and / or CO_2 reduction credits at the price premium over the least cost alternative. Alternatively, NSP can separately procure the resource for Minnesota customers.

Q. If regulatory alignment did not work in the past why should it work now?

A. Under NSP's proposal for either Legal or Pseudo Separation, the Company assumes that the MPUC is effectively agreeing to pay the full costs of the disputed resources acquired to meet MN policy mandates as well as potential future disputed resources. That same outcome can be achieved through regulatory alignment.

Q. If a resource is only acquired for MN customers, doesn't that mean it is no longer an integrated system?

A. I disagree with the presumption that to have benefits the system has to be integrated such that each utility has to buy into every resource. MISO is ultimately responsible for short term reliability (regulation and reserves), so from a power supply perspective the "benefits" from an integrated system are really the benefits of economies of scale in acquiring or constructing new generation resources to cost effectively meet energy needs and to meet capacity requirements for grid reliability. Some joint action agencies were developed to provide economies of scale for public power, and a number of joint action agencies support partial requirements utilities. The point of an integrated system is to

create economic benefits through economies of scale. The pursuit of 1,550 MW of wind is a potential example of economies of scale. On the other hand, purchase of power from fifteen C-BED projects that provide less than 2% of NSP's total electricity is not an example of economies of scale.

Q. Would you please explain what you mean by a "partial requirements" utility?

A. Yes, I am referring to a wholesale power purchases by a utility where the utility is not securing all of its electricity from a single provider.

Q. How is the model of joint action agencies and partial requirements utilities relevant to resolving NSP's power procurement challenges?

A. There are a few relevant parallels:

- In order for a member utility to benefit from economies of scale it is not necessary for a utility to participate in every project;
- Member utilities can select projects and participation levels to meet their unique needs; and
- The joint action agency can operate and procure power contracts and resources based upon differentiated needs of its members.

This model of the joint action agency and partial requirements utilities highlights an implementable path forward to address potential future resource needs of the different jurisdictions that NSP serves while addressing economies of scale for utilities with small resource procurement needs, as well as potential desires for a diversified generation portfolio.

Q. What are some examples of partial requirements utilities?

A. The agencies listed below are examples of agencies that purchase participation in power generation projects based upon their members' individual participation in those projects:

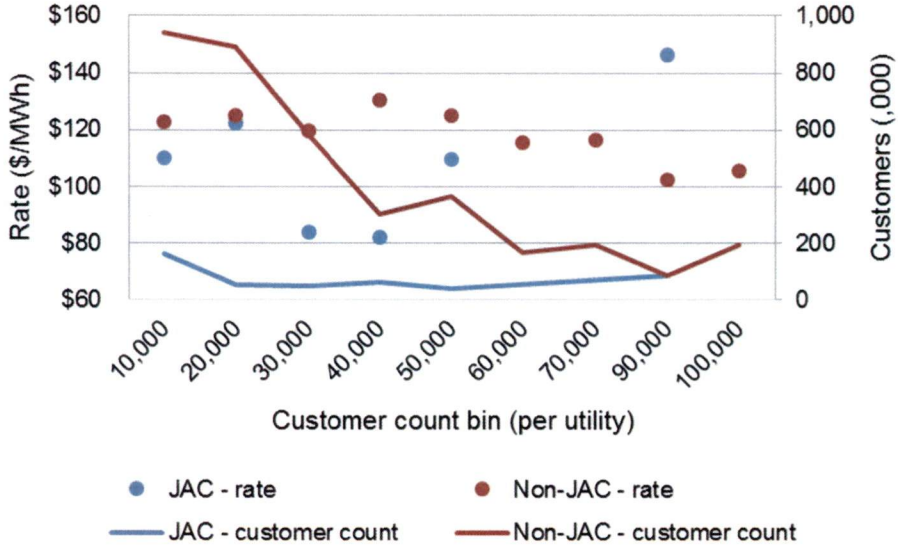
- Central Municipal Power Agency / Services (CMPAS) is a joint action agency with 12 members and two affiliates in Minnesota, and additional affiliates in Iowa and Wisconsin. CMPAS is a "project joint action agency," where member utilities have the option to join as either full or partial requirements members, select which projects they want to participate in, and develop their own rate structures according to their local resources and which projects they subscribe to.
- The Municipal Energy Agency of Nebraska (MEAN) is a joint action agency with 66 member utilities in the states of Nebraska, Colorado, Iowa, and Wyoming. It is a subsidiary of NMPP Energy, along with the Nebraska Municipal Power Pool (NMPP). While most members are considered "total requirements participants," two members are accepted, and allowed to procure power from non-agency owned generation within their municipalities.
- Heartland Consumers Power District (HCPD) is a joint action agency with members operating in South Dakota, Minnesota, and Iowa. While specific details on membership terms are not readily available, HCPD's most recent annual report, in 2016, states "Heartland provides supplemental, partial or full-requirements energy, depending on the needs of each of our customers."
- The Michigan Public Power Agency (MPPA) is "project-based agency," meaning that each member chooses to join or not join each of MPPA's projects, as well as their level of participation in each project. MPPA owns all or part of two coal plants, two combustion turbine plants, a landfill gas plant, a transmission network, and an energy services division (all in the state of Michigan). Over half of MPPA's 20 members are full or partial subscribers to four or more of these projects.
- American Municipal Power (AMP) is a joint action agency with 135 member utilities in nine states: Ohio, Pennsylvania, Michigan, Kentucky, Virginia, West Virginia, Indiana, and Maryland. Additionally, one joint action agency in Delaware (the Delaware Municipal Electric Corporation) is also a member. AMP operates six Joint Ventures (JV) totaling nearly 200 MW of capacity, including a

wind farm, hydroelectric plant, and several small distributed diesel and natural gas generation assets. Members are given the option to participate or not in each JV – presently each has between four and 42 participating members.

Q. Are utilities which are members of a joint action agency typically able to offer lower rates to their customers than non-members?

A. Yes, as shown in Figure 4, utilities which are members of a joint action agency or committee (JAA" or "JAC) are able to share resources, which tends[45] to result in lower rates for their residential customers. This is likely due to economies of scale.

Figure 4: Residential rates and customer counts for joint action and non-joint action utilities in MISO, 2016[46]



[45] Note that for utilities in the 90,000 to 100,000 customer range, only one JAC member is shown on the figure (Lansing Board of Water and Light), and should not be considered representative.

[46] Source: American Public Power Association Directory of Joint Action Agencies, ABB's Energy Velocity Suite, PA Consulting Group.

Q. If ND is receiving benefits of the NSP integrated system that it is not paying for?

A. No. However it is important to be more specific on what NSP is referring to as the benefits of an integrated system. NSP Witness Starkweather refers to these benefits as: economies of scale, load diversity, and generation resource diversity and states that those benefits are realized through lower fuel prices and lower price volatility.[47]

Q. Does NSP's purchase of the disputed resources to meet MN renewable requirements provide economies of scale and lower prices to North Dakota rate payers?

A. My opinion is that purchasing expensive C-Bed wind and small and expensive solar projects to meet Minnesota renewable energy standards is not a benefit of being in an integrated system. It provides no benefits that North Dakota considers to have value, only incremental costs, and a cost shifting to North Dakota. NSP has not identified any examples of resources purchased for North Dakota that don't have benefits for Minnesota. NSP's view of "benefits" does not appear to be reciprocal.

Q. If a resource is not acquired on behalf of North Dakota's customers, aren't you suggesting Pseudo Separation?

A. I am suggesting that resources can be purchased separately, and NSP Witness Everson points out that the accounting can be done. I do not refer to this as Pseudo Separation since NSP appears to want to develop completely different portfolios for North Dakota. My suggestion is that separate resources need only be purchased when states do not agree on whether a proposed resource is needed or in the public interest.

Q. Is this unique issue to North Dakota?

A. It appears that this may be a potential issue for some large multi-state utilities with divergent state polices. For example, the Wyoming Public Service Commission has issued a notice to amend its IRP review procedures following concerns raised by

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[47] NSP Response to NDPSC 4-16.

Wyoming Industrial Energy Customers regarding PacifiCorp shifting from resource acquisition based upon need / least cost versus pursuing compliance with renewable energy standards of other states. In addition, the Montana Legislature has been considering laws / policies regarding compensation if participating utilities force the early retirement of Colstrip Power Plant's Units 3 & 4.

Q. Why should sale of the North Dakota operations be an option?

A. NSP has expressed its concern with North Dakota regulation and is proposing solutions to move power and transmission costs from the regulatory oversight of the NDPSC. At the same time NSP Witness Chandarana says "The State of North Dakota allows us to operate in a strong business and regulatory environment".[48] This statement appears to be in conflict with the Company's arguments for Legal Separation. Even if the Company is not contemplating a sale at this time, the Company has indicated that it has had formal discussions in the past five years for sale of the North Dakota jurisdiction.[49] Consequentially, this is clearly an alternative to consider further.

The sale of a small jurisdiction is not uncommon in the utility industry. Examples include[50]:

- The 2009 sale Sierra Pacific's CA service territory, including 49,000 customers, to a subsidiary of Liberty Energy Utilities Co.;
- The 2005 sale of Monongahela Power Company's 29,000 Ohio customers to AEP;
- The 2015 sale of Alliant Energy Corp's 43,000 electric distribution customers to Southern Minnesota Energy Coop, a group of 12 neighboring electric utilities;
- The 2011 sale of the Vermont Marble Power Division of Omya Inc, including four hydroelectric plants and 890 customers, to Central Vermont Public Service Corporation;

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[48] Chandarana Direct p 39 lines 2 – 3.
[49] NSP response to NDPSC 4-13.
[50] Source: SNL Financial.

- The 2010 sale of Shenandoah Valley Electric Cooperative's distribution assets and rights, and 2,500 customers in West Virginia, to Potomac Edison Co, a subsidiary of Allegheny Energy, Inc.;
- The 2010 sale of Edison Sault Electric Company by Wisconsin Energy Co to Cloverland Electric Cooperative. The sale included two power plants totaling 34.6 MW, and 22,000 customers in Michigan's Upper Peninsula; and
- The 2008 sale of Cirro Energy's 52,600 customers to Dominion Retail, Inc.

Q. Are you recommending sale as the solution?

A. No. I only identify it as an option. I have suggested a number of viable options to Legal Separation that would allow for NSP to continue to profitably serve North Dakota and continue its relationship with North Dakota which has existed for longer than a century.

XIV. Proxy Pricing

Q. Did NSP investigate proxy pricing as a solution?

A. NSP in its Application for the RTF identified proxy pricing as one of the four options, and rejected it as infeasible.[51] However, NSP indicates that proxy pricing is appropriate when resources are mandated by a state policy that is not shared by another state.

> "A Proxy Pricing structure can be most successful when utilized to level difference between jurisdictions regarding a mandated resource selections, such as renewable energy mandates. In those instances, if one state's law requires the addition of a particular type of resource and other state does not, utilizing a Proxy Pricing regime can mitigate the cost shift of the mandated resource to the non-mandating states while still have all states contribute to the energy and capacity of a particular resource."
> (Chandarana Direct Schedule 2 p 24 of 31.)

[51] Chandarana Direct P 34 lines 1 – 3.

Q. Does NSP identify where it is more problematic to use Proxy Pricing?

A. Yes, NSP suggests that Proxy Pricing is more difficult when there are issues regarding the timing of a resource acquisition or the type of acquisition.

Q. How would you characterize the recent resource disputes with the NDPSC with regards to those resources being related to a mandate versus an issue of timing or type?

A. I have characterized the resources in Table 7. My opinion is that most of the disputes regarding recent acquisitions fall into the category of resources required by Minnesota's energy policies, and hence Proxy Pricing is appropriate to "mitigate the cost shift of the mandated resource".[52] I note that in the case of some of the resources, there is a difference in perspective as to why the resource was acquired or retired.

Table 7: Proxy Pricing and Disputed Resources

Resource	Acquisition / Retirement Reason	Comment
Biomass	MN state mandate	Benson, Laurentian, St. Paul subject to refund if NSP does not build gas fired plant in ND
Biomass	PURPA	Some subject to refund
C-Bed	MN legislative requirement	
Aurora solar	MN solar mandate	
187 MW Solar	MN solar mandate	competitive bid procurement
Sherco I & II	Difference in opinion on economics	Some differences in opinion have origins in MN externality pricing
MEC II	Difference in opinion on need	Resource has not been disallowed by NDPSC

Q. Do these resources represent a majority or minority of the NSP system resources?

[52] Chandarana Rebuttal, PUC of South Dakota Docket No. EL15-037 p 9 lines 19-20.

A. With the exception of Sherco I & II and MEC II, cases in which cost recovery has not yet been determined by the NPSC, these represent a minority of the resources. As shown in Exhibit JAH__6, the C-BED wind projects and solar purchase contracts that are currently treated with proxy pricing represent a very small part of the NSP resource portfolio.[53] It is important to keep this in mind due to NSP's statement that "In such circumstances, larger system integration is feasible and a minority of resources can be addressed through proxy pricing".[54]

Q. Does Xcel use proxy pricing currently?

A. Yes, it is currently used in three jurisdictions where there are disputes:

- The current use in North Dakota,
- The recent settlement between NSP and South Dakota related to the fuel cost rider,
- In allocation of costs for renewable resource costs between Texas and New Mexico where Texas does not pay for the cost of complying with New Mexico renewable energy mandates.

Q. Which resources use proxy pricing in North Dakota?

A. The MN C-BED projects and some of the disputed solar PPAs.

Q. Will proxy pricing be used in South Dakota based upon the recent settlement?

A. Yes, NSP Witness Chandarana has indicated that proxy pricing is acceptable for a number of resources:

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[53] Based upon 2016 FERC Form 1 data.
[54] Chandarana Exhibit___(AHC-1), Schedule 2, page 24 of 331.

"North Star and Marshall PPAS, the C-BED PPAs and the RDF PPAs, we believe a proxy pricing framework is a reasonable way to reach resolution on these resources." [Chandarana, Rebuttal Testimony, Docket No. EL16-037 Exhibit___(AHC-2), p. 6].

Based upon a proposed settlement it appears that NSP has recognized that proxy pricing is an appropriate way to address resources required as a result of Minnesota's energy policies, even though they be neither least cost nor needed.

Q. How is proxy pricing used in New Mexico and Texas?

A. NSP describes five solar PPA's purchased for New Mexico to meet RPS requirements that use proxy pricing in Texas. My understanding is that the New Mexico Public Regulation Commission determined that Southwestern Public Service Company (SPS) could recover all the costs associated with the projects that are above system avoided costs, established an approach to quantifying the value of the RECs from the projects, determined that the value of the RECS may be recovered in current rates, and created a regulatory asset to recover the costs above the system average costs and value of the RECs.[55]

Q. How did the New Mexico Commission determine the proxy price?

A. The proxy price is based upon the system avoided energy costs for serving Texas and FERC jurisdiction customers. My understanding is that SPS uses a production cost model to calculate the avoided costs based upon removing the renewable PPAs from the model.

Q. Is proxy pricing consistent with utility cost allocation principles?

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[55] Final Order Approving Recommended Decision Docket No. 1000015-UT, New Mexico Public Regulation Commission.

A. Yes, A fundamental principle for the allocation of costs and subsequent recovery of the allocated revenue requirement is that cost allocation should follow cost causation.

Q. What are the issues with proxy pricing?

A. NSP alludes to the 1,550 MW of wind as an example of a dispute that proxy pricing is not appropriate to address since NSP views the acquisition as a least cost solution. However, as of filing this testimony the NDPSC has not ruled on the 1,550 MW of wind and the NDPSC Advocacy Staff has recommended approval of the ADP. Hence, this appears to be an example of NSP rejecting proxy pricing based upon conjecture and not facts.

Q. Are there different approaches to establishing proxy pricing?

A. Yes. I have mentioned two approaches to establishing proxy prices in my discussion of how North Dakota uses proxy pricing with NSP and how New Mexico uses proxy pricing with SPP. I will briefly review those approaches as well as other approaches for proxy pricing of energy as well as capacity.

Q. What are some of the approaches for developing a proxy price for energy?

A. The potential approaches include:

- The utility's average fuel and purchased power costs excluding disputed resources (the current North Dakota approach);
- Short term models of the utilities avoided energy cost excluding the disputed resources (the approach used in New Mexico);
- The market cost of energy based upon a published index;
- Prices based upon a recent non-contested competitive procurement; and
- Long-term administratively determined marginal energy costs such as a PURPA rate filing.

Each of these approaches has its own advantages and disadvantages with regard to

reflecting an accurate proxy price and different administrative burdens to implement.

Q. Is there one specific approach to developing a proxy cost for energy that is the most accurate?

A. I do not think there is a "most accurate" approach. Developing such an approach also depends on what is being measured. For example, the index price of energy is presumably a good measure of the cost of purchasing an incremental kWh assuming that the index is robust and at a relevant delivery point. However, it may not accurately reflect the marginal cost of the utility, because the marginal kWh could potentially be procured from a utility owned generation asset rather than an incremental market purchase.

Q. What are some of the approaches for developing a proxy price for capacity?

A. The potential approaches include:

- Identification of the capacity cost associated with the last generation unit added or the next planned unit,
- The cost of a peaking unit (typically a combustion turbine),
- MISO capacity prices,
- Prices based upon a recent non-contested competitive procurement; and
- Long-term administratively determined marginal capacity costs such as a PURPA rate filing.

Q. What are some of the challenges associated with establishing a proxy price for capacity?

A. There may be disagreements about how to calculate the capacity value of a peaking plant or the last unit added due to differences in opinions regarding which costs should be included and what energy margins should be subtracted from the costs. It may also be difficult to identify current capacity prices if there are no recent competitive procurements.

Q. Given that there are different approaches and potential issues regarding the developing of proxy energy and capacity prices, is it realistic to establish proxy prices?

A. Yes. These issues can be worked out in a regulatory proceeding, just as commissions have a history of establishing QF rates or identification of capacity versus energy components of generation for cost of service studies.

Q. Do you believe that Proxy Pricing is a feasible solution?

A. Yes, I agree that it is one of the strategies that should continue to be used. As previously noted, it is an appropriate strategy to avoid shifting costs of a state's policies to a different state that does not share those policies. However, I also believe that at times it may be appropriate to secure separate resources.

XV. Proposed Solution

Q. What are the elements of your proposed solution to manage potential future disputes?

A. I recommend the following be implemented without Legal Separation:

- NSP continue with the settlement of the 2008 rate case and continue using the ADP process for generation resources;
- Review of resource plans by the NDPSC;
- Proxy pricing to avoid cost shifting as a result of resources that are not needed / not least cost but acquired to meet other state mandates that are not shared by North Dakota; and
- Separate resource acquisition for North Dakota in certain instances where appropriate and cost effective.

Q. Will use of the ADP process resolve conflicts regarding selection of resources

appropriate for North Dakota?

A. No, it does not resolve conflicts, but it will provide NSP with a clearer path of what will be awarded full cost recovery in North Dakota. If a resource does not get an ADP then NSP can determine whether it is appropriate to proceed knowing that depending on the type of resource it may need to rely on proxy pricing or not procure any of the resource on behalf of the North Dakota utility.

Q. What are you recommending with regard to the NDPSC review process of the NSP IRP?

A. The NDPSC can develop an informational proceeding to collect public comments and testimony. Based upon that information the NDPSC can provide guidance to NSP regarding what resource expansion plans appear to be in the public interest.

Q. Will use of an informal IRP review process resolve conflicts regarding selection of resources appropriate for North Dakota?

A. No, it does not resolve conflicts, but as with the ADP process it will provide NSP with a clearer path of what will be awarded full cost recovery in North Dakota.

Q. Why is proxy pricing a solution if NSP has already rejected this option?

A. Although NSP has rejected this option for North Dakota in this proceeding, the utility recognizes in its recent South Dakota settlement on the fuel clause that proxy pricing is in fact a reasonable solution to address not requiring the customers of one state to pay for the regulatory mandates imposed by another state.[56]

Q. When would separate resource acquisition for North Dakota be used?

A. Resource acquisition could be used instead of, or to replace, those resources serving NSP's North Dakota load under proxy pricing. The previously discussed resource

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[56] South Dakota Docket No. EL16-037.

planning and ADP approach would be used to first identify any appropriate resources and then to get advanced approval for the recovery of cost of those resources.

Q. Is this different than the Pseudo Separation being proposed by NSP?

A. The difference is that NSP is proposing a default separation of resource portfolios with separate procurement regardless of whether continued common procurement is done on the basis of least cost and / or need. If NSP procures resources on a least cost basis or when needed then there is no reason to have separate procurement for the North Dakota load.

Q. How would separate resource acquisition be implemented?

A. NSP Witness Ms. Everson discusses the accounting process for implementation of Pseudo Separation in her direct testimony. Should it be necessary to procure any separate resources to serve North Dakota load the same processes can be used. Specifically:

- The accounting can be accommodated using NSP's current accounting system;
- Procedures would have to be established to define how indirect costs are allocated;
- Procedures would need to be established for how costs would be recovered through the Fuel Cost Rider; and
- MISO revenues and expenses directly attributed to resources not shared can be directly assigned to the appropriate justifications.[57]

Q. Would separate acquisition of any resources under your proposed solution require any changes in the treatment of transmission?

A. No. As discussed by NSP Witness Beuning, no changes would be required to how transmission service would be provided to North Dakota.[58]

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[57] Direct Testimony of Everson pp 20 -24.
[58] Direct Testimony of Beuning p 24 lines 12 – 18.

XVI. Other Considerations

Q. Are their costs to North Dakota tax payers for shifting jurisdiction to the FERC?

A. Yes, there is likely to be additional costs since the NDPSC will need to represent its interests in front of the FERC for issues that are now addressed in North Dakota. In addition, the NDPSC will likely need to do more active monitoring of FERC cases to make sure it is aware of, and potentially participates in matters that could impact power costs under its FERC administered contracts.

Q. Has NSP identified whether Legal Separation is in the public interest?

A. That will depend on how the NDPSC defines "public interest". However, if the standard is that it provides net benefits then I do not conclude that it is in the public interest. NSP has indicated potential savings in 2020 but those savings are based upon estimates with a large number of unknowns, and at the same time NSP highlights that there are benefits from an integrated system that I interpret as economies of scale. NSP has not indicated that NSPD will have any benefits or economies of scale. To the contrary, NSP has not demonstrated how the future resource needs of NSPD, which are in small increments, will achieve any economies of scale.

If the NDPSC defines "public interest" as not doing any harm, then my concern is that North Dakota rate payers may actually experience harm as a result of being a small utility in an industry where IOUs are seeking consolidation to achieve economies of scale.

Q. If NSP were to proceed with Legal Separation should NSP be able to recover the one-time costs of establishing Legal Separation from North Dakota rate payers?

A. No. My perspective this would be a transaction that Xcel perceives as beneficial to shareholders and as I noted, there do not appear to be any benefits to its North Dakota customers.

XVII. Summary

Q. Is either Legal or Pseudo Separation necessary for resolving past disputes related to the procurement of resources and recovery of the associated costs?

A. No. The Commission had addressed past disputes in settlement orders and has indicated that recovery of MEC II costs is yet to be resolved.

Q. Is either Legal or Pseudo Separation necessary for resolving potential but unknown disputes related to legacy resources?

A. No. Presumably the FERC jurisdiction contract would address rights and obligations regarding potential disputes regarding legacy resources. Contract terms written by NSP that govern the relationship between NSP and a NSPD entity would require extensive scrutiny by the NDPSC since those terms would likely be established to provide full recovery of all costs with a pro-rata share based upon the North Dakota load share. Based upon the disagreement regarding the potential early retirement of Sherco I & II, those terms may not be acceptable to the NDPSC. Therefore, the establishment of the contract that is acceptable to be the NDPSC is like to be contentious and difficult given that it has to address cost recovery under a range of undefined eventualities and potentially litigated at the FERC. In the case of Pseudo Separation, any new disputes regarding legacy resources would still need to be addressed regardless of whether Pseudo Separation is implemented.

Q. Is either Legal or Pseudo Separation useful for avoiding potential but unknown disputes related to acquisition of future resources?

A. Yes. If new resources are procured separately for North Dakota then that should avoid disputes about cost recovery that are related to NSP not procuring resources that the NDPSC views as appropriate for serving North Dakota customers.

Q. Do you recommend Legal Separation as the preferred approach avoiding potential but unknown disputes related to acquisition of future resources?

A. No. Legal Separation may be preferred by NSP, however, based upon the information presented by NSP I have concluded that it is unlikely to be in the interest of North Dakota public. Legal Separation appears to present a number of risks without associated benefits. These risks include:

- Uncertainty regarding transmission costs for a North Dakota distribution only utility;
- Potential dis-economies of scale regarding procurement of a balanced resource portfolio; and
- Potential higher regulatory costs for North Dakota.

Q. If there are potential dis-economies of scale for a small utility, should North Dakota be willing to pay for all the resources that NSP procures?

A. No. Many of the past disputes are associated with the evaluation criteria that NSP is using to procure resources. Procurement of resources that are not least cost with regards to revenue requirements is not an example of resource procurement based upon economies of scale. The incremental cost of resources that are not procured on the basis of least cost revenue requirements but on the basis of meeting another state's mandates should be assigned on the basis of cost causation.

Q. Is there an alternative to either NSP's proposal for Legal or Pseudo Separation?

A. Yes. NSP already has agreed to proxy pricing in North Dakota and South Dakota to address the incremental costs of procurement associated with Minnesota mandates and Xcel / Southwestern Public Service Company has accepted proxy pricing in Texas to address the incremental cost of renewable resource procurement mandated by New Mexico. Furthermore, there may be instances where it does make sense to procure resources dedicated to specific states. Should the need arise, NSP has indicated that it is

feasible to implement the accounting and procedures to track separate resource procurement.

Q. Is it possible that Legal Separation may be appropriate in the future?

A. Yes, it is possible that at some point legal separation may be appropriate to revisit based upon the future needs of North Dakota. However, at this time I conclude that there is not a need, there are issues and costs associated with NSP's proposal, and there are better alternatives.

Q. Does this conclude your pre-filed testimony?

A. Yes.

PA

Jim Heidell



Jim Heidell specializes in electric and gas utility regulation, utility finance, wholesale electricity markets, evaluation of renewable energy technologies and financial analysis of complex investments. Mr Heidell assists clients with due diligence associated with acquisition of natural gas and electric utilities and wholesale energy market transactions. Mr Heidell has prepared and submitted testimony in both regulatory proceedings and civil contract damages cases. Mr Heidell also specializes in strategic analysis and evaluation of opportunities associated with renewable / alternative energy technologies. .

Primary expertise

- Electric and natural gas utility regulation and finance
- Analysis of wholesale electric markets
- Renewable Energy Technologies
- Asset valuation / M&A Advisor
- Damages estimation for civil litigation

Related experience

- Strategic planning
- Financial modelling of complex investments
- Financial planning

Qualifications

- 30-years' experience with electric & gas utilities and electricity markets
- MBA University of Washington
- MSE Engineering Economics, Stanford University
- BSE, Civil Engineering, Tufts University
- CFA

Primary expertise

Utility Regulatory Support - Prepare expert testimony in regulatory hearings related to resource acquisition, QF issues, rate impacts, marginal and embedded cost of service, and rate design. Developing marginal and embedded cost studies for regulated utilities.

Renewable Energy Technologies - Develop business plans, market positioning strategies, and financial analysis of renewable technologies including PV cell manufacturing, flywheels, and fuel cells along with renewable generation technologies including solar thermal, geothermal, wind, battery storage, and IGCC projects.

Analysis of Electric Markets - Develop energy and capacity forecasts for U.S. power markets to support: strategic investments by utilities and major energy companies, development of utility risk management strategies, and corporate strategies for generation asset acquisition and disposition.

Asset Valuation / M&A Advisor - Provide valuation advice for acquisition of electric generation portfolios, single power plants, transmission projects, electric utilities, and gas distribution companies. Work also included review of wholesale and retail regulatory pricing mechanisms and analysis of associated risk.

Damages Estimation for Civil Litigation Testimony - Prepare expert witness testimony to support power contract litigation, property tax cases, power plant development agreements, and quantification of economic damages.

Financial Analysis - Long-term modelling of utility finance. Analysis of major capital investments using a variety of tools to incorporate uncertainty and risk.

Key client achievements

UTILITY REGULATORY SUPPORT

Analysis and testimony on behalf of Constellation Energy Group related to typical merger and acquisition conditions required by regulators in utility and non-utility transactions. Testimony related to the EDF / Constellation joint venture.

Testimony related the use and design of ratchet rates on behalf of Northern Indiana Public Service Company. Testimony related to the application of ratchets to the client's unique position and appropriate recovery of costs.

Analysis of the economics of an electric utility's interruptible rates including the value of interruptions versus the payments received by customers. Developed recommendations for pricing interruptible rate programs that were consistent with the utility's avoided costs and ISO markets.

Developed electric cost-of-service studies, rate design, and testimony to support Puget Sound Energy in multiple general rate cases in Washington. The engagements included addressing issues such as special rates for strategic customers with competitive options, line extension policies, and rates to address revenue attrition.

Developed natural gas cost-of-service studies, rate design, and testimony to support Puget Sound Energy in a general rate case in Washington.

Prepared marginal cost of service studies and testimony to support Montana-Dakota utilities in multiple Montana rate cases.

Assist Montana-Dakota Utilities in development of its integrated resource plan through analysis of options using the Strategist planning model.

Supported Montana-Dakota Utilities in answering a complaint in front of the South Dakota Public Utilities Commission regarding a wind generator requesting a contract under the provisions of PURPA.

Provided expert testimony related to Montana Dakota's proposed participation in the Big Stone II power plant. Prepared and delivered testimony provided in multiple hearings in North Dakota and Minnesota.

Prepared testimony on behalf of Hydro One Networks regarding rate shock and how to address necessary rate changes associated with the restructuring of the electric utility business in Ontario.

Developed an analysis or weather risk associated with the retail power sales of IPALCO. Effort was conducted as part of a comprehensive risk assessment conducted by AES. Models of the weather / load relationship were developed and then integrated with the rate structures and cost adjustment mechanisms to assess the utility's overall exposure to weather risk.

Advised Old Dominion Electric Cooperative on options for acquiring new generation in a depressed power market and incorporation of the analysis in their long-term resource planning.

MEXICO ENERGY MARKET REFORM

Developed rate proposals for PEMEX SDC tariffs for transportation, conditioning and storage of oil and natural gas. The rate proposals were the final stage of a project that started with benchmarking tariff structures in key markets worldwide, development of business considerations, development of appropriate cost of service and rate design principles, preparation of a revenue requirement, development of a cost of service model and study, and development of proposed rates for the PEMEX services.

Developed long-run electricity price forecasts multi-national energy companies reflecting the rules of the reformed market. Price forecast based upon an hourly chronological dispatch model.

Delivery of a workshop for rate design for CFE transmission. Review of distribution and transmission revenue requirements for CFE and analysis of financial implications of energy reform on CFE.

ELECTRIC MARKETS RISK MODELING

Advised major European trading company on entering the U.S. electricity trading business. Project included selection of target markets, characterization of types of trading opportunities, characterization of market volumes, identification of target customers, review of key licensing requirements, and development of a high level business strategy.

Provided support to a bond insurance company to prepare an assessment of the distribution of income from a fleet of peaking power plants in the South-East. Analysis used to review the provision for loss reserves.

Supported a bond insurance agency in determining the probability that a fleet of Mid-West generation assets would generate insufficient cash to meet debt payments and reserve requirements.

Developed an Excel based model for a mid-west public utility to assist in developing annual targets for the amount of surplus generation capacity to be sold as merchant and in contracts of varying tenor. The model was integrated into the corporate financial model to assist in identifying the appropriate risk profile to support building the reserve fund and to delay future rate increases.

M&A and BANKRUPTCY ADVISOR

Advised creditors of the Puerto Rico Power Authority (PREPA) with regards to restructuring over eight billion dollars of debt. Multiple analyses were developed to support the restructuring negotiations including the development of a financial model to forecast the revenue requirement under different scenarios of fuel costs, types of generation resources, and cost savings initiatives.

Prepared an analysis of New Mexico Gas Company to support a prospective buyer. We assisted multiple clients with due diligence related to the acquisition of gas LDCs. Assisted the client with a review of the deal model including: assumptions about rate cases, assumptions regarding ROE, sales growth by rate class, and revenue by rate class. The engagement also included an assessment of the regulatory climate and potential conditions and costs associated with obtaining regulatory approval of the transaction.

Prepared a valuation of the Mountaineer Gas Company including the analysis of regulatory issues to support the debt financing associated with the purchase of the energy company.

Assisted an infrastructure fund in valuing power contracts and reviewed the regulatory model used in conjunction with establishing the price to bid for the acquisition of Northwestern Utility.

Prepared an analysis of Duquense Light to support an infrastructure fund's bid for the utility. The analysis included projections of growth opportunities through distribution & transmission investment, analysis of the POLR load obligation, and a review of key regulatory issues.

Developed a valuation model of Mirant including analysis of debt carrying capacity to assist a strategic player in the U.S. Power Industry determine whether to make an unsolicited offer to purchase Mirant.

Assisted an international oil company in development of modelling processes and assumptions to support a corporate effort to acquire a fleet of U.S. merchant generating assets.

Support a strategic player in valuing the Lake Road Generation Plant as part of their bid to acquire the asset in a competitive auction. Effort involved projection of future gross margins of the plant, analysis of the ISO-NE Forward Capacity Market, and analysis of transmission constraints.

Directed the valuation of the entire NRG portfolio on behalf of the bank creditors in the NRG bankruptcy hearings. The valuation work included advising on a range of types of generation assets in the U.S. as well as in Europe, South America, and the Asia-Pacific region. Mr Advised on the fairness of offers for assets being disposed of by NRG.

Assisted creditors in the valuation of assets in the NEG bankruptcy including the options for completing unfinished gas-fired generation assets. Served as the interim finance manager for the Lake Road Generation facility.

Member of team that advised Calpine as part of the company's restructuring and plan of reorganization. Assignment included analysis of the Canadian portfolio, advising on the sale of generation assets, modelling of long-term turbine maintenance costs, and the valuation of complex power contract.

Assisted the lenders on valuation and strategy related to AES' turn-back of the Granite Ridge Power Plant to the lender group.

Advised the bank and lender group on valuation and strategy related to the bankruptcy of the Kendall Power Plant.

ELECTRIC GENERATION FINANCE SUPPORT:

Market expert report for the Landfill Energy Systems, a national 66 MW portfolio of fourteen landfill gas power plants. The market expert report included a discussion of the key attributes of each of the power markets that the portfolio encompasses, long-term forecasts of wholesale electricity prices, and forecasts of gross margins.

Independent Market Expert Report to support the financing of the repowering and development of a fleet of combined cycle and simple cycle power plants in the ERCOT market. The independent market expert report was used to support the syndication of loans and obtaining debt ratings associated with investing over $1 billion in the Barney Davis, Nueces Bay, and Laredo Energy Center facilities.

Independent Market Expert Report to support the financing of Sequent Power's purchase of the Wolf Hollow 730 MW combined cycle power plant located in ERCOT. The report was used to support the

syndication and rating of over $400M of primary and mezzanine debt. The report incorporated forecast of gross margins for both the contracted and non-contracted portions of the facility as well as providing a detailed description of the ERCOT market conditions and key assumptions to the financial analysis.

Independent Market Expert Report to support the financing of Invenergy's purchase of the partially completed Grays Harbor 620 MW combined cycle power plant located in the Pacific Northwest. The report was used to support the syndication and rating of over $100M of debt. The analysis included valuing both hedged and unhedged positions for the facility and conducting extensive due diligence regarding how NW power markets are likely to evolve and the role of independent power in a market dominated by vertically integrated public and investor-owned utilities.

Independent Market Report to support the refinancing of the Dynegy corporate revolver. The effort included analysis of multiple U.S. power markets, valuation of the fleet of generation assets and associated contracts, and review of regulatory conditions impacting the Company's ability to realize earnings in markets with competitive auctions to serve load.

Multiple forecasts of California power market prices including support of a bid for a cogeneration facility located in the San Francisco Bay area and sale of La Rosita.

Forecast of the New England power markets to support a bid for the First Light Generation Assets.

Forecast of the California and SPP power markets to support a bid for assets from the EIF portfolio.

Analysis of the ERCOT, PJM and MISO markets for multiple bids for merchant gas fired generation plants.

Development of multiple Confidential Information Memorandums to support the sale of power plants. CIMs included description of the wholesale power markets and summaries of the key attributes of the assets to be sold in auction.

Preparation of sale offering of the Audrain power plant in response to Ameren solicitation to acquire new resources. Effort included evaluation of likely competitors and the development of the bid strategy.

Advise on pricing for offering power contracts as well as the sale of gas-fired combined cycle power plant in the South-East. Pricing and sale price based upon projections of the value of the power plant as a merchant unit, assessment of potential competitors, and the analysis of transmission constraints.

Additional Expertise - Expert Testimony

Before the Hawaii Public Utilities Commission, Direct Testimony of James A. Heidell, Docket No. HG-T-13. Direct testimony addressing Hawaii Gas' request for a rate increase. Testimony on behalf of Hawaii Gas regarding rate design and recovery of fuel costs.

Before the North Dakota Public Service Commission, Direct Testimony of James A. Heidell, Docket Nos. PU-17-140, PU-17-141, & PU-17-143. Direct testimony addressing Otter Tail Power Company's request for advanced determination of prudence for owning and operating a combustion turbine and wind project.

Before the North Dakota Public Service Commission, Direct Testimony of James A. Heidell, Docket No. PU-17-120. Direct testimony addressing Northern State Power Company's request for advanced determination of prudence for adding 1,550 MW of wind through a combination of self-build, build-own-transfer, and PPAs.

Before the Arizona Corporation Commission, Direct and Settlement Testimony Of James A. Heidell, Docket No. E-01345A-16-0036 and Docket No. E-01345A-16-0123 In The Matter Of The Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return.

Before the Public Utilities Commission of Nevada, Direct and Rebuttal Testimony Of James A. Heidell, Docket No. 16-06006, In The Matter of the Application of Sierra Pacific Power Company, d/b/a NV Energy, Filed pursuant to NRS 704.110(3), addressing its annual revenue requirement for general rates charged to all classes of Electric customers.

Before the Public Service Commission of Maryland, Rebuttal Testimony Of James A. Heidell, Case No. 9173, Phase II In The Matter Of The Current And Future Financial Condition Of Baltimore Gas And Electric Company.

Before the Indiana Utility Regulatory Commission, Rebuttal Testimony in Northern Indiana Public Service Company's request to raise rates in Cause No. 43526. Testimony on behalf of the utility related to ratchets and other mechanisms appropriate to recover costs allocated to large energy using customer classes.

Before Public Service Commission of the State of North Dakota, Direct and Rebuttal Testimony in Montana Dakota Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone II Generating Station Case Nos. PU-06-481 and PU-06-482. On behalf of Montana-Dakota Utilities. 2007 & 2008. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2010.8.82. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2007.7.79. On behalf of Montana-Dakota Utilities.

Before the Minnesota Public Utilities Commission, Direct and Rebuttal testimony on behalf of Montana-Dakota Utilities regarding a Certificate of Need for the Big Stone II Power Plant, Docket No. CN-05-619. On behalf of Montana-Dakota Utilities.

Before the Ontario Electric Board, Expert Report regarding the 2006 Electric Rate Distribution Handbook and Rate Mitigation, on behalf of Hydro One Networks, Inc. January 2005.

Before the Washington Utilities and Transportation Commission, Direct Testimony in 2004 General Rate Case Regarding Electric Cost of Service & Rate Design and Gas Rate Design, April 2004. On behalf of Puget Sound Energy.

Before the Washington Utilities and Transportation Commission, Direct Testimony in 2001 General Rate Case Regarding Electric Cost of Service & Rate Design, November 2001. On behalf of Puget Sound Energy.

Before the Washington Utilities and Transportation Commission, Testimony Regarding the Need for a Special Competitive Rate for Intel. Docket No. UE-960299, 1996. On behalf of Puget Power.

Before the Washington Utilities and Transportation Commission, Rebuttal Testimony in the Merger of Puget Power and Washington Natural Gas Regarding Electric Rates, Docket Nos. UE-95-1270 & UE-960185, 1995. On behalf of Puget Power.

City of Rochester, Minnesota v. Southern Minnesota, State of Minnesota, County of Olmsted File No: 55-C3-05-002712. Testimony on behalf of the City of Rochester regarding the interpretation of a power contract. Testimony and deposition 2008.

Amana Society, Inc. and Amana Farms, Inc. v. GHD, Inc. and Excel Engineering, Inc. Testimony on behalf of GHD, INC regarding the economic performance of a manure digester and evaluation of claims of damages by Amana. Expert Report 2012, Jury Trial September 2012.

Affidavit of James A. Heidell & Mark Repsher, Appropriate Approach to Calculating the Weighted Cost of Capital, Docket No. ER14-2940-0000, U.S. Federal Energy Regulatory Commission, October 15, 2014.

Affidavit of James A. Heidell & Mark Repsher, on behalf of Peabody Energy Corporation to stay the final Clean Power Plan rule, September 9, 2015.

Declaration and report of James A. Heidell & Mark Repsher, Utility and Allied Petitioners' motion to stay the final Clean Power Plan rule, October 16, 2015.

Public Document

Exhibit JAH-2

Case Nos. PU-12-813, et al.

North Dakota Load Forecast

Year	GWH	ND Obligation (MW)
2017		
2018	[CONFIDENTIAL]	
2019		
2020		
2021	[PROECTED INFORMATION]	
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		
2046		
2047		
2048		
2049		
2050		
2051		
2052		
2053		

Average Annual Growth Rates	Energy	Demand
2017 - 2027		
2027 - 2037		

Notes

Energy Source: NSP Scenario Allocator Calscs_070617.SENS BASE.xlsx

Demand Source: NSP Response to NDPSC 7-002

IOUs With 40,000 to 100,000 Customers

Company Name	Holding Company Name	Bundled Total Revenue ($ 000s)	Bundled Total Sales (MWh)	Wholesale Power Purchased (MWh)	Merchant Percent of Sales	Owned Capacity (MW)	Bundled Total Retail Sales ($/MWh)	Bundled Total Customers	Bundled Total Retail ($/Customer)	Bundled Total Retail (kWh/Cust)	Distribution Assets ($)	Transmission Assets ($)	Generation Assets ($)
Cheyenne Light Fuel & Power Co	Black Hills Corp	142,567	1,297,038	872,070	67%	168	110	41,177	3,462	31,499	169,677,073	35,782,689	5,881,932
Wheeling Power Co	American Electric Power Co Inc	237,619	3,630,655	1,375,848	38%	816	65	41,403	5,739	87,691	159,966,684	139,450,908	5,288,319
Kingsport Power Co	American Electric Power Co Inc	147,654	2,086,994	2,096,587	100%	-	71	47,309	3,121	44,114	141,614,957	30,491,454	2,747,741
Upper Peninsula Power Co	WEC Energy Group Inc	110,660	782,686	678,021	87%	80	141	47,991	2,306	16,309	155,585,651	-	28,392,532
UGI Utilities Inc	UGI Corp	86,415	743,704	706,412	95%	-	116	60,792	1,421	12,234	124,834,999	40,857,588	4,678,772
Unitil Energy Systems	Unitil Corp	119,564	647,342	663,826	100%	1	185	66,124	1,808	9,790	254,937,465	-	11,438,880
Black Hills Power Inc	Black Hills Corp	210,133	1,775,358	1,181,453	67%	479	118	70,536	2,979	25,170	353,240,830	117,708,458	53,471,914
UNS Electric Inc	Uns Energy Corp	166,400	1,628,038	1,212,283	74%	350	102	94,203	1,766	17,282	434,153,225	122,552,601	45,005,308
Black Hills Colorado Electric Utility Co LP	Black Hills Corp	245,624	1,918,199	1,911,537	100%	-	128	94,835	2,590	20,227	272,021,509	173,881,055	32,622,019

Notes:
All data from 2015.

ces:
s Energy Velocity Suite
Capital IQ
SNL Energy Data

Utilities excluded from the analysis are either island utilities, or utilities with retail choice

Resource Expansion Plan Forecast for NSPD: NSP Scenarios

Case/ Scenario*	Assumptions	Basis	Details	Strategist SO Family "Master" File
1	Current	Reference Case	No restack except solar	SO - _1_REFERENCE UPDATED.xlsm
2	Current	Preferred Plan	No restack except solar, modified to be 1000MW early wind, accelerated CSG, remove only 200MW early utility scale solar (net +200 by 2030)	SO - _2_PREFERRED UPDATED.xlsm
3A	Current	Preferred Plan	Current with Legacy Purchase/Sale and Jur Future	SO - _3_A_SHARED LEGACY.xlsm
3B	Current	Preferred Plan	Current with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	SO - _3_B_SHARED LEGACY.xlsm
3C	Current	Preferred Plan	Current with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	SO - _3_C_SHARED LEGACY.xlsm
4A	Current	Preferred Plan	ND separation Jan 2023, Replace with CT	SO - _4_2023 FULL SEPARATION.xlsm
5A	Current	Preferred Plan	ND separation Jan 2025, Replace with CT	SO - _5_2025 FULL SEPARATION.xlsm
5B	Current	Preferred Plan	ND separation Jan 2025, Replace with CC	SO - _5_2025 FULL SEPARATION.xlsm
5C	Current	Preferred Plan	ND separation Jan 2025, Replace with CT, No Nuclear	SO - _5_N_2025 FULL SEPARATION.xlsm
5D	Current	Preferred Plan	ND separation Jan 2025, Replace with CC, No Nuclear	SO - _5_N_2025 FULL SEPARATION.xlsm
6A	Current	Preferred Plan	ND separation Jan 2027, Replace with CT	SO - _6_2027 FULL SEPARATION.xlsm

* this corresponds to the calc tab in the "Scenario Allocator Calcs" files

Base Restack Resources
Small Solar (never allocated to ND)

Base Assumptions
CO2 - $21.50 starting in 2022
Fuel/markets as of 2/28/2017
Spring 2017 load forecast
Current "Strategic Plannning" renewable costs

Resource Expansion Plan Forecast for NSPD: NSP Scenarios

Sensitivities		SO Families
C	Low gas/markets	No suffix: main file with 100% of all costs/dispatch
D	High gas/markets	" - Shared Legacy": only has units/costs that comprise legacy system
U	PVRR	" - MN": only has units/costs that are allocated to MN
DT	PVRR CC, HG	" - ND": only has units/costs that are allocated to ND
DU	PVRR, HG	

ND SHARES RESOURCE?

CBED Wind	1	2	3A	3B	3C	4A*	5A*	5B*	5C*	5D*	6A*
Jeffers Wind	Y	Y	Y	N	Y	N	N	N	N	N	N
Big Blue	Y	Y	Y	N	Y	N	N	N	N	N	N
Community Wind South (Zephyr)	Y	Y	Y	N	Y	N	N	N	N	N	N
Ridgewind Power Partners	Y	Y	Y	N	Y	N	N	N	N	N	N
Adams Wind Generation	Y	Y	Y	N	Y	N	N	N	N	N	N
Danielson Wind Farm	Y	Y	Y	N	Y	N	N	N	N	N	N
Ewington Energy Systems	Y	Y	Y	N	Y	N	N	N	N	N	N
Grant County Wind	Y	Y	Y	N	Y	N	N	N	N	N	N
North Community Turbines	Y	Y	Y	N	Y	N	N	N	N	N	N
Valley View Transmission	Y	Y	Y	N	Y	N	N	N	N	N	N
Uilk Wind Farm	Y	Y	Y	N	Y	N	N	N	N	N	N
Hilltop Power	Y	Y	Y	N	Y	N	N	N	N	N	N
Winona County Wind	Y	Y	Y	N	Y	N	N	N	N	N	N
Woodstock Municipal Wind	Y	Y	Y	N	Y	N	N	N	N	N	N
Small Solar											
Outland/Slayton Solar	Y	Y	Y	N	Y	N	N	N	N	N	N
Best Power (St. Johns)	Y	Y	Y	N	Y	N	N	N	N	N	N
Solar Gardens / Solar Rewards	N	N	N	N	N	N	N	N	N	N	N
Biomass											
Koda Energy	Y	Y	Y	N	Y	Y	Y	Y	N	N	Y
WM Renewable Energy/MN Methane	Y	Y	Y	N	Y	Y	Y	Y	N	N	Y
Pine Bend	Y	Y	Y	N	Y	Y	Y	Y	N	N	Y
FibroMinn	Y	Y	Y	N	Y	Y	Y	Y	N	N	Y
Laurentian Energy Authority	Y	Y	Y	N	Y	Y	Y	Y	N	N	Y
St. Paul Cogen	Y	Y	Y	N	Y	Y	Y	Y	N	N	Y

ND SHARES RESOURCE?

Resource Expansion Plan Forecast for NSPD: NSP Scenarios

	1	2	3A	3B	3C	4A*	5A*	5B*	5C*	5D*	6A*
187 MW of Solar Portfolio											
Marshall Solar	Y	Y	Y	N	Y	N	N	N	N	N	N
NorthStar Solar	Y	Y	Y	N	Y	N	N	N	N	N	N
CAPCON											
Calpine MEC 2	Y	Y	Y	Y	Y	N	N	N	N	N	N
Aurora Solar	Y	Y	Y	Y	Y	N	N	N	N	N	N
New PTC Wind	Y, 400 MW	Y, 1500 MW	N	N	Y, 1500 MW	N	N	N	N	N	N
New Thermals	Y	Y	N	N	N	N	N	N	N	N	N
New Renewables	Y	Y	N	N	N	N	N	N	N	N	N
Nuclear Legacy	Y	Y	Y	Y	Y	Y	Y	Y	N	N	Y
Thermal Legacy	Y	Y	Y	Y	Y	N	N	N	N	N	N
Renew Legacy	Y	Y	Y	Y	Y	N	N	N	N	N	N

* indicates sharing for "after separation." These cases are the same as Scenario 3A prior to separation

Source (all sheets): NSP and PA Consulting Group analysis

Resource Expansion Plan Forecast for NSPD: PA Summary - Energy

Scenario Description	Scenario Name	Field	Units	2020	2021	2022	2023	2024	2025	2026
NSP Preferred	Scen 2	ND Load	GWH	2,472	2,475	2,479	2,486	2,500	2,501	2,504
Legacy does not share disputed	Scen 3_B		GWH	2,472	2,475	2,479	2,486	2,500	2,501	2,504
Legacy share disputed + 1550 Wind	Scen 3_C		GWH	2,472	2,475	2,479	2,486	2,500	2,501	2,504
Separation 2025 CT replacement	Scen 5_A		GWH	2,472	2,475	2,479	2,486	2,500	2,501	2,504
Separation 2025 CC replacement	Scen 5_B		GWH	2,472	2,475	2,479	2,486	2,500	2,501	2,504
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GWH	2,472	2,475	2,479	2,486	2,500	2,501	2,504
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GWH	2,472	2,475	2,479	2,486	2,500	2,501	2,504
NSP Preferred	Scen 2	ND Shared Gen	GWH	2,418	2,419	2,422	2,428	2,441	2,440	2,441
Legacy does not share disputed	Scen 3_B		GWH	2,008	1,931	1,901	1,887	1,868	1,849	1,832
Legacy share disputed + 1550 Wind	Scen 3_C		GWH	2,418	2,419	2,383	2,369	2,352	2,333	2,313
Separation 2025 CT replacement	Scen 5_A		GWH	2,123	2,046	2,015	1,996	1,975	858	883
Separation 2025 CC replacement	Scen 5_B		GWH	2,123	2,046	2,015	1,996	1,975	858	883
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GWH	2,123	2,046	2,015	1,996	1,975	0	0
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GWH	2,123	2,046	2,015	1,996	1,975	0	0
NSP Preferred	Scen 2	NDSpecific Gen	GWH	0	0	0	0	0	0	0
Legacy does not share disputed	Scen 3_B		GWH	0	0	0	0	0	0	0
Legacy share disputed + 1550 Wind	Scen 3_C		GWH	0	0	0	0	0	0	0
Separation 2025 CT replacement	Scen 5_A		GWH	0	0	0	0	0	201	201
Separation 2025 CC replacement	Scen 5_B		GWH	0	0	0	0	0	1,643	1,621
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GWH	0	0	0	0	0	302	302
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GWH	0	0	0	0	0	2,501	2,503
NSP Preferred	Scen 2	System Purchases (Sales)	GWH	54	56	57	58	60	61	62
Legacy does not share disputed	Scen 3_B		GWH	464	544	578	599	632	652	672
Legacy share disputed + 1550 Wind	Scen 3_C		GWH	54	56	96	117	148	168	190
Separation 2025 CT replacement	Scen 5_A		GWH	348	429	463	491	525	1,441	1,419
Separation 2025 CC replacement	Scen 5_B		GWH	348	429	463	491	525	0	0
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GWH	348	429	463	491	525	2,199	2,201
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GWH	348	429	463	491	525	0	0
NSP Preferred	Scen 2	Pcnt of Load Market Purchase	%	2%	2%	2%	2%	2%	2%	2%
Legacy no share disputed	Scen 3_B		%	19%	22%	23%	24%	25%	26%	27%
Legacy share disputed + 1550 Wind	Scen 3_C		%	2%	2%	4%	5%	6%	7%	8%
Separation 2025 CT replacement	Scen 5_A		%	14%	17%	19%	20%	21%	58%	57%
Separation 2025 CC replacement	Scen 5_B		%	14%	17%	19%	20%	21%	0%	0%
Separation 2025 CT replacement - No Nuclear	Scen 5_C		%	14%	17%	19%	20%	21%	88%	88%
Separation 2025 CC replacement - No Nuclear	Scen 5_D		%	14%	17%	19%	20%	21%	0%	0%

Resource Expansion Plan Forecast for NSPD: PA Summary - Energy

Scenario Description	Scenario Name	Field	Units	2027	2028	2029	2030	2031	2032	2033
NSP Preferred	Scen 2	ND Load	GWH	2,511	2,527	2,529	2,533	2,541	2,558	2,562
Legacy does not share disputed	Scen 3_B		GWH	2,511	2,527	2,529	2,533	2,541	2,558	2,562
Legacy share disputed + 1550 Wind	Scen 3_C		GWH	2,511	2,527	2,529	2,533	2,541	2,558	2,562
Separation 2025 CT replacement	Scen 5_A		GWH	2,511	2,527	2,529	2,533	2,541	2,558	2,562
Separation 2025 CC replacement	Scen 5_B		GWH	2,511	2,527	2,529	2,533	2,541	2,558	2,562
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GWH	2,511	2,527	2,529	2,533	2,541	2,558	2,562
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GWH	2,511	2,527	2,529	2,533	2,541	2,558	2,562
NSP Preferred	Scen 2	ND Shared Gen	GWH	2,450	2,465	2,466	2,471	2,485	2,500	2,511
Legacy does not share disputed	Scen 3_B		GWH	1,668	1,658	1,631	1,646	1,557	1,550	1,543
gacy share disputed + 1550 Wind	Scen 3_C		GWH	2,138	2,112	2,061	2,075	1,973	1,959	1,937
paration 2025 CT replacement	Scen 5_A		GWH	837	857	812	739	519	519	408
Separation 2025 CC replacement	Scen 5_B		GWH	837	857	812	739	519	519	408
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GWH	0	0	0	0	0	0	0
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GWH	0	0	0	0	0	0	0
NSP Preferred	Scen 2	NDSpecific Gen	GWH	0	0	0	0	0	0	0
Legacy does not share disputed	Scen 3_B		GWH	0	0	0	101	101	101	101
Legacy share disputed + 1550 Wind	Scen 3_C		GWH	0	0	0	0	101	101	101
Separation 2025 CT replacement	Scen 5_A		GWH	201	201	201	201	302	302	302
Separation 2025 CC replacement	Scen 5_B		GWH	1,674	1,671	1,717	1,794	2,023	2,040	2,155
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GWH	302	302	302	302	302	302	302
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GWH	2,511	2,527	2,529	2,533	2,541	2,558	2,562
NSP Preferred	Scen 2	System Purchases (Sales)	GWH	61	63	63	62	56	58	52
Legacy does not share disputed	Scen 3_B		GWH	843	869	899	786	883	908	919
gacy share disputed + 1550 Wind	Scen 3_C		GWH	373	416	468	458	468	499	524
paration 2025 CT replacement	Scen 5_A		GWH	1,473	1,469	1,516	1,592	1,721	1,737	1,853
Separation 2025 CC replacement	Scen 5_B		GWH	0	0	0	0	0	0	0
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GWH	2,209	2,225	2,227	2,231	2,239	2,256	2,260
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GWH	0	0	0	0	0	0	0
NSP Preferred	Scen 2	Pcnt of Load Market Purchase	%	2%	2%	2%	2%	2%	2%	2%
Legacy no share disputed	Scen 3_B		%	34%	34%	36%	31%	35%	35%	36%
Legacy share disputed + 1550 Wind	Scen 3_C		%	15%	16%	19%	18%	18%	19%	20%
Separation 2025 CT replacement	Scen 5_A		%	59%	58%	60%	63%	68%	68%	72%
Separation 2025 CC replacement	Scen 5_B		%	0%	0%	0%	0%	0%	0%	0%
Separation 2025 CT replacement - No Nuclear	Scen 5_C		%	88%	88%	88%	88%	88%	88%	88%
Separation 2025 CC replacement - No Nuclear	Scen 5_D		%	0%	0%	0%	0%	0%	0%	0%

Resource Expansion Plan Forecast for NSPD: PA Summary - Energy

Scenario Description	Scenario Name	Field	Units	2034	2035	2036	2037	2038	2039	2040
NSP Preferred	Scen 2	ND Load	GWH	2,568	2,578	2,596	2,600	2,606	2,618	2,636
Legacy does not share disputed	Scen 3_B		GWH	2,568	2,578	2,596	2,600	2,606	2,618	2,636
Legacy share disputed + 1550 Wind	Scen 3_C		GWH	2,568	2,578	2,596	2,600	2,606	2,618	2,636
Separation 2025 CT replacement	Scen 5_A		GWH	2,568	2,578	2,596	2,600	2,606	2,618	2,636
Separation 2025 CC replacement	Scen 5_B		GWH	2,568	2,578	2,596	2,600	2,606	2,618	2,636
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GWH	2,568	2,578	2,596	2,600	2,606	2,618	2,636
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GWH	2,568	2,578	2,596	2,600	2,606	2,618	2,636
NSP Preferred	Scen 2	ND Shared Gen	GWH	2,517	2,528	2,548	2,553	2,559	2,568	2,587
Legacy does not share disputed	Scen 3_B		GWH	1,382	1,163	1,120	1,120	911	891	893
gacy share disputed + 1550 Wind	Scen 3_C		GWH	1,776	1,558	1,514	1,512	1,303	1,281	1,263
paration 2025 CT replacement	Scen 5_A		GWH	220	0	0	0	0	0	0
Separation 2025 CC replacement	Scen 5_B		GWH	220	0	0	0	0	0	0
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GWH	0	0	0	0	0	0	0
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GWH	0	0	0	0	0	0	0
NSP Preferred	Scen 2	NDSpecific Gen	GWH	0	0	0	0	0	0	0
Legacy does not share disputed	Scen 3_B		GWH	101	201	201	201	201	201	302
Legacy share disputed + 1550 Wind	Scen 3_C		GWH	101	201	201	201	201	201	201
Separation 2025 CT replacement	Scen 5_A		GWH	302	302	302	302	302	302	302
Separation 2025 CC replacement	Scen 5_B		GWH	2,347	2,578	2,596	2,600	2,606	2,617	2,635
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GWH	302	302	302	302	302	302	302
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GWH	2,567	2,578	2,596	2,600	2,606	2,617	2,635
NSP Preferred	Scen 2	System Purchases (Sales)	GWH	51	50	48	48	48	49	48
Legacy does not share disputed	Scen 3_B		GWH	1,085	1,213	1,274	1,279	1,494	1,525	1,440
Legacy share disputed + 1550 Wind	Scen 3_C		GWH	690	819	881	887	1,102	1,135	1,171
paration 2025 CT replacement	Scen 5_A		GWH	2,045	2,276	2,293	2,298	2,304	2,315	2,333
Separation 2025 CC replacement	Scen 5_B		GWH	0	0	0	0	0	0	0
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GWH	2,265	2,276	2,293	2,298	2,304	2,315	2,333
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GWH	0	0	0	0	0	0	0
NSP Preferred	Scen 2	Pcnt of Load Market Purchase	%	2%	2%	2%	2%	2%	2%	2%
Legacy no share disputed	Scen 3_B		%	42%	47%	49%	49%	57%	58%	55%
Legacy share disputed + 1550 Wind	Scen 3_C		%	27%	32%	34%	34%	42%	43%	44%
Separation 2025 CT replacement	Scen 5_A		%	80%	88%	88%	88%	88%	88%	89%
Separation 2025 CC replacement	Scen 5_B		%	0%	0%	0%	0%	0%	0%	0%
Separation 2025 CT replacement - No Nuclear	Scen 5_C		%	88%	88%	88%	88%	88%	88%	89%
Separation 2025 CC replacement - No Nuclear	Scen 5_D		%	0%	0%	0%	0%	0%	0%	0%

Resource Expansion Plan Forecast for NSPD: PA Fuel Mix Summary

Scenario Description	Scenario Name	Field	Units	2020	2021	2022	2023	2024	2025	2026
NSP Preferred	2 Energy Mix	Coal	GWH	746	756	785	814	582	636	633
Legacy no share disputed	3B Energy Mix	Coal	GWH	746	756	785	814	582	633	632
Legacy share disputed + 1550 Wind	3C Energy Mix	Coal	GWH	746	756	785	814	582	633	632
Separation 2025 CT replacement	5A-B Energy Mix	Coal	GWH	746	756	785	814	582	0	0
Separation 2025 CC replacement	5A-B Energy Mix	Coal	GWH	746	756	785	814	582	0	0
Separation 2025 CT replacement - No Nuclear	5A-B Energy Mix	Coal	GWH	746	756	785	814	582	0	0
Separation 2025 CC replacement - No Nuclear	5A-B Energy Mix	Coal	GWH	746	756	785	814	582	0	0
NSP Preferred	2 Energy Mix	Nuclear	GWH	793	767	793	769	801	770	796
Legacy no share disputed	3B Energy Mix	Nuclear	GWH	793	767	793	769	801	770	796
Legacy share disputed + 1550 Wind	3C Energy Mix	Nuclear	GWH	793	767	793	769	801	770	796
Separation 2025 CT replacement	5A-B Energy Mix	Nuclear	GWH	793	767	793	769	801	815	842
Separation 2025 CC replacement	5A-B Energy Mix	Nuclear	GWH	793	767	793	769	801	815	842
Separation 2025 CT replacement - No Nuclear	5A-B Energy Mix	Nuclear	GWH	793	767	793	769	801	0	0
Separation 2025 CC replacement - No Nuclear	5A-B Energy Mix	Nuclear	GWH	793	767	793	769	801	0	0
Preferred	2 Energy Mix	Bio	GWH	76	75	75	69	57	57	55
Legacy no share disputed	3B Energy Mix	Bio	GWH	26	26	26	26	17	17	17
Legacy share disputed + 1550 Wind	3C Energy Mix	Bio	GWH	76	75	75	69	57	57	55
Separation 2025 CT replacement	5A-B Energy Mix	Bio	GWH	76	75	75	69	57	43	40
Separation 2025 CC replacement	5A-B Energy Mix	Bio	GWH	76	75	75	69	57	43	40
Separation 2025 CT replacement - No Nuclear	5A-B Energy Mix	Bio	GWH	76	75	75	69	57	0	0
Separation 2025 CC replacement - No Nuclear	5A-B Energy Mix	Bio	GWH	76	75	75	69	57	0	0
NSP Preferred	2 Energy Mix	Gas	GWH	93	131	142	148	175	183	215
Legacy no share disputed	3B Energy Mix	Gas	GWH	93	131	142	148	175	179	204
Legacy share disputed + 1550 Wind	3C Energy Mix	Gas	GWH	93	131	142	148	175	179	204
Separation 2025 CT replacement	5A-B Energy Mix	Gas	GWH	93	131	142	148	175	201	201
Separation 2025 CC replacement	5A-B Energy Mix	Gas	GWH	93	131	142	148	175	1,643	1,621
Separation 2025 CT replacement - No Nuclear	5A-B Energy Mix	Gas	GWH	93	131	142	148	175	302	302
Separation 2025 CC replacement - No Nuclear	5A-B Energy Mix	Gas	GWH	93	131	142	148	175	2,501	2,503
NSP Preferred	2 Energy Mix	Hydro	GWH	126	143	148	148	149	77	52
Legacy no share disputed	3B Energy Mix	Hydro	GWH	126	143	148	148	149	77	52
Legacy share disputed + 1550 Wind	3C Energy Mix	Hydro	GWH	126	143	148	148	149	77	52
Separation 2025 CT replacement	5A-B Energy Mix	Hydro	GWH	126	143	148	148	149	0	0
Separation 2025 CC replacement	5A-B Energy Mix	Hydro	GWH	126	143	148	148	149	0	0
Separation 2025 CT replacement - No Nuclear	5A-B Energy Mix	Hydro	GWH	126	143	148	148	149	0	0
ration 2025 CC replacement - No Nuclear	5A-B Energy Mix	Hydro	GWH	126	143	148	148	149	0	0

Resource Expansion Plan Forecast for NSPD: PA Fuel Mix Summary

Scenario Description	Scenario Name	Field	Units	2020	2021	2022	2023	2024	2025	2026
NSP Preferred	2 Energy Mix	Solar / Wind	GWH	794	875	913	904	926	936	944
Legacy no share disputed	3B Energy Mix	Solar / Wind	GWH	423	422	421	391	381	374	368
Legacy share disputed + 1550 Wind	3C Energy Mix	Solar / Wind	GWH	794	875	875	846	837	829	822
Separation 2025 CT replacement	5A-B Energy Mix	Solar / Wind	GWH	491	489	488	459	449	0	0
Separation 2025 CC replacement	5A-B Energy Mix	Solar / Wind	GWH	491	489	488	459	449	0	0
Separation 2025 CT replacement - No Nuclear	5A-B Energy Mix	Solar / Wind	GWH	491	489	488	459	449	0	0
Separation 2025 CC replacement - No Nuclear	5A-B Energy Mix	Solar / Wind	GWH	491	489	488	459	449	0	0
NSP Preferred	2 Energy Mix	Market	GWH	-134	-244	-338	-339	-167	-138	-170
Legacy no share disputed	3B Energy Mix	Market	GWH	276	243	183	202	406	461	444
Legacy share disputed + 1550 Wind	3C Energy Mix	Market	GWH	-134	-244	-299	-281	-78	-23	-38
Separation 2025 CT replacement	5A-B Energy Mix	Market	GWH	161	128	68	93	299	1,441	1,419
Separation 2025 CC replacement	5A-B Energy Mix	Market	GWH	161	128	68	93	299	0	0
Separation 2025 CT replacement - No Nuclear	5A-B Energy Mix	Market	GWH	161	128	68	93	299	2,199	2,201
Separation 2025 CC replacement - No Nuclear	5A-B Energy Mix	Market	GWH	161	128	68	93	299	0	0
NSP Preferred	2 Energy Mix	Total	GWH	2,494	2,503	2,519	2,514	2,523	2,521	2,524
Legacy no share disputed	3B Energy Mix	Total	GWH	2,484	2,488	2,498	2,499	2,510	2,510	2,512
Legacy share disputed + 1550 Wind	3C Energy Mix	Total	GWH	2,494	2,503	2,519	2,514	2,523	2,521	2,523
Separation 2025 CT replacement	5A-B Energy Mix	Total	GWH	2,485	2,490	2,500	2,501	2,512	2,501	2,503
Separation 2025 CC replacement	5A-B Energy Mix	Total	GWH	2,485	2,490	2,500	2,501	2,512	2,501	2,503
Separation 2025 CT replacement - No Nuclear	5A-B Energy Mix	Total	GWH	2,485	2,490	2,500	2,501	2,512	2,501	2,503
Separation 2025 CC replacement - No Nuclear	5A-B Energy Mix	Total	GWH	2,485	2,490	2,500	2,501	2,512	2,501	2,503

Resource Expansion Plan Forecast for NSPD: PA Fuel Mix Summary

Scenario Description	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NSP Preferred	383	395	371	380	386	370	386	404	386	397	407	184	202	204
Legacy no share disputed	383	395	371	380	388	371	387	405	387	398	408	185	203	205
Legacy share disputed + 1550 Wind	383	395	371	380	388	371	387	405	387	398	408	185	203	205
Separation 2025 CT replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CC replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CT replacement - No Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CC replacement - No Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NSP Preferred	768	794	768	699	490	490	385	208	0	0	0	0	0	0
Legacy no share disputed	768	794	768	699	490	490	385	208	0	0	0	0	0	0
Legacy share disputed + 1550 Wind	768	794	768	699	490	490	385	208	0	0	0	0	0	0
Separation 2025 CT replacement	813	840	812	739	518	519	408	220	0	0	0	0	0	0
Separation 2025 CC replacement	813	840	812	739	518	519	408	220	0	0	0	0	0	0
Separation 2025 CT replacement - No Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CC replacement - No Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Preferred	40	20	4	4	1	1	1	1	1	1	1	1	1	1
Legacy no share disputed	17	4	4	4	1	1	1	1	1	1	1	1	1	1
Legacy share disputed + 1550 Wind	40	20	4	4	1	1	1	1	1	1	1	1	1	1
Separation 2025 CT replacement	25	16	0	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CC replacement	25	16	0	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CT replacement - No Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CC replacement - No Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NSP Preferred	350	339	367	346	355	445	492	658	887	932	945	1,166	1,187	1,210
Legacy no share disputed	155	143	163	254	246	225	225	222	327	315	319	322	311	402
Legacy share disputed + 1550 Wind	155	143	163	153	246	225	225	222	327	315	319	322	311	301
Separation 2025 CT replacement	201	201	201	201	302	302	302	302	302	302	302	302	302	302
Separation 2025 CC replacement	1,674	1,671	1,717	1,794	2,023	2,040	2,155	2,347	2,578	2,596	2,600	2,606	2,617	2,635
Separation 2025 CT replacement - No Nuclear	302	302	302	302	302	302	302	302	302	302	302	302	302	302
Separation 2025 CC replacement - No Nuclear	2,511	2,527	2,529	2,533	2,541	2,558	2,562	2,567	2,578	2,596	2,600	2,606	2,617	2,635
NSP Preferred	52	52	52	52	51	49	47	47	47	47	46	46	46	46
Legacy no share disputed	52	52	52	52	51	49	47	47	47	47	46	46	46	46
Legacy share disputed + 1550 Wind	52	52	52	52	51	49	47	47	47	47	46	46	46	46
Separation 2025 CT replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CC replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CT replacement - No Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
aration 2025 CC replacement - No Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Resource Expansion Plan Forecast for NSPD: PA Fuel Mix Summary

Scenario Description	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NSP Preferred	922	978	1,000	999	975	963	863	841	837	755	741	741	738	683
Legacy no share disputed	347	345	328	328	322	318	237	216	214	132	122	122	121	85
Legacy share disputed + 1550 Wind	801	794	767	765	743	731	634	612	609	526	514	513	511	455
Separation 2025 CT replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CC replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CT replacement - No Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CC replacement - No Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NSP Preferred	10	-31	-14	72	295	249	392	410	421	465	460	468	443	491
Legacy no share disputed	795	802	851	824	1,047	1,107	1,280	1,469	1,602	1,703	1,705	1,931	1,935	1,897
Legacy share disputed + 1550 Wind	325	349	420	496	631	698	886	1,074	1,207	1,310	1,313	1,539	1,546	1,628
Separation 2025 CT replacement	1,473	1,469	1,516	1,592	1,721	1,737	1,853	2,045	2,276	2,293	2,298	2,304	2,315	2,333
Separation 2025 CC replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CT replacement - No Nuclear	2,209	2,225	2,227	2,231	2,239	2,256	2,260	2,265	2,276	2,293	2,298	2,304	2,315	2,333
Separation 2025 CC replacement - No Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NSP Preferred	2,524	2,547	2,547	2,551	2,553	2,566	2,567	2,569	2,578	2,596	2,600	2,606	2,617	2,636
Legacy no share disputed	2,516	2,535	2,536	2,539	2,546	2,561	2,563	2,568	2,578	2,596	2,600	2,606	2,617	2,635
Legacy share disputed + 1550 Wind	2,523	2,545	2,545	2,548	2,551	2,566	2,566	2,569	2,578	2,596	2,600	2,606	2,617	2,635
Separation 2025 CT replacement	2,511	2,527	2,529	2,533	2,541	2,558	2,562	2,567	2,578	2,596	2,600	2,606	2,617	2,635
Separation 2025 CC replacement	2,511	2,527	2,529	2,533	2,541	2,558	2,562	2,567	2,578	2,596	2,600	2,606	2,617	2,635
Separation 2025 CT replacement - No Nuclear	2,511	2,527	2,529	2,533	2,541	2,558	2,562	2,567	2,578	2,596	2,600	2,606	2,617	2,635
Separation 2025 CC replacement - No Nuclear	2,511	2,527	2,529	2,533	2,541	2,558	2,562	2,567	2,578	2,596	2,600	2,606	2,617	2,635

Resource Expansion Plan Forecast for NSPD: PA Fuel Mix Summary II

2025 NSPD Fuel Mix - NSP Scenario Analysis

Scenario ID	Scenario Name	Coal	Nuclear	Bio	Gas	Hydro	Wind / Solar	Market	Total
Scen 2	NSP Preferred	25%	31%	2%	7%	3%	37%	-5%	100%
Scen 3_B	Legacy ND does not share disputed	25%	31%	1%	7%	3%	15%	18%	100%
Scen 3_C	Legacy share disputed + 1550 Wind	25%	31%	2%	7%	3%	33%	-1%	100%
Scen 5_A	Separation 2025 CT replacement	0%	33%	2%	8%	0%	0%	58%	100%
Scen 5_B	Separation 2025 CC replacement	0%	33%	2%	66%	0%	0%	0%	100%
Scen 5_C	Separation 2025 CT replacement - No Nuclear	0%	0%	0%	12%	0%	0%	88%	100%
Scen 5_D	Separation 2025 CC replacement - No Nuclear	0%	0%	0%	100%	0%	0%	0%	100%

2035 NSPD Fuel Mix - NSP Scenario Analysis

Scenario ID	Scenario Name	Coal	Nuclear	Bio	Gas	Hydro	Wind / Solar	Market	Total
Scen 2	NSP Preferred	15%	0%	0%	34%	2%	32%	16%	100%
Scen 3_B	Legacy ND does not share disputed	15%	0%	0%	13%	2%	8%	62%	100%
Scen 3_C	Legacy share disputed + 1550 Wind	15%	0%	0%	13%	2%	24%	47%	100%
Scen 5_A	Separation 2025 CT replacement	0%	0%	0%	12%	0%	0%	88%	100%
Scen 5_B	Separation 2025 CC replacement	0%	0%	0%	100%	0%	0%	0%	100%
Scen 5_C	Separation 2025 CT replacement - No Nuclear	0%	0%	0%	12%	0%	0%	88%	100%
Scen 5_D	Separation 2025 CC replacement - No Nuclear	0%	0%	0%	100%	0%	0%	0%	100%

Scenario ID	Scenario Name	PVRR 2040 ($M)	Delta to Preferred
Scen 2	NSP Preferred	2,256	
Scen 3_B	Legacy ND does not share disputed	2,162	(95)
Scen 3_C	Legacy share disputed + 1550 Wind	2,160	(96)
Scen 5_A	Separation 2025 CT replacement	2,027	(230)
en 5_B	Separation 2025 CC replacement	2,165	(91)
en 5_C	Separation 2025 CT replacement - No Nuclear	1,972	(284)
Scen 5_D	Separation 2025 CC replacement - No Nuclear	2,066	(190)

Resource Expansion Plan Forecast for NSPD: PA Summary - Capacity

Scenario Description	Scenario Name	Field	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
NSP Preferred	Scen 2	ND Load	GW	395	398	400	402	405	408	410	412	414	415
Legacy no share disputed	Scen 3_B		GW	395	398	400	402	405	408	410	412	414	415
Legacy share disputed + 1550 Wind	Scen 3_C		GW	395	398	400	402	405	408	410	412	414	415
Separation 2025 CT replacement	Scen 5_A		GW	395	398	400	402	405	408	410	412	414	415
Separation 2025 CC replacement	Scen 5_B		GW	395	398	400	402	405	408	410	412	414	415
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GW	395	398	400	402	405	408	410	412	414	415
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GW	395	398	400	402	405	408	410	412	414	415
NSP Preferred	Scen 2	ND Shared Gen	GW	576	595	607	621	575	541	540	553	559	561
Legacy no share disputed	Scen 3_B		GW	561	578	578	580	525	461	432	378	363	363
Legacy share disputed + 1550 Wind	Scen 3_C		GW	576	595	596	604	550	486	456	401	383	382
Separation 2025 CT replacement	Scen 5_A		GW	573	590	591	591	536	155	155	153	150	150
Separation 2025 CC replacement	Scen 5_B		GW	573	590	591	591	536	155	155	153	150	150
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GW	573	590	591	591	536	58	58	57	57	57
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GW	573	590	591	591	536	58	58	57	57	57
NSP Preferred	Scen 2	ND Specific Gen	GW	0	0	0	0	0	0	0	0	0	0
Legacy no share disputed	Scen 3_B		GW	0	0	0	0	0	0	0	0	0	0
Legacy share disputed + 1550 Wind	Scen 3_C		GW	0	0	0	0	0	0	0	0	0	0
Separation 2025 CT replacement	Scen 5_A		GW	0	0	0	0	0	219	219	219	219	219
Separation 2025 CC replacement	Scen 5_B		GW	0	0	0	0	0	371	371	371	371	371
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GW	0	0	0	0	0	329	329	329	329	329
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GW	0	0	0	0	0	371	371	371	371	371
NSP Preferred	Scen 2	System Purchases (Sales)	GW	-181	-197	-206	-219	-171	-134	-131	-141	-146	-147
Legacy no share disputed	Scen 3_B		GW	-166	-180	-178	-178	-121	-54	-22	0	0	0
Legacy share disputed + 1550 Wind	Scen 3_C		GW	-181	-197	-195	-202	-145	-78	-46	0	0	0
Separation 2025 CT replacement	Scen 5_A		GW	-178	-192	-191	-189	-132	0	0	0	0	0
Separation 2025 CC replacement	Scen 5_B		GW	-178	-192	-191	-189	-132	-118	-115	-111	-107	-106
Separation 2025 CT replacement - No Nuclear	Scen 5_C		GW	-178	-192	-191	-189	-132	0	0	0	0	0
Separation 2025 CC replacement - No Nuclear	Scen 5_D		GW	-178	-192	-191	-189	-132	-21	-18	-16	-14	-13
NSP Preferred	Scen 2	Pcnt of Load Market Purchase	%	-46%	-50%	-52%	-54%	-42%	-33%	-32%	-34%	-35%	-35%
Legacy no share disputed	Scen 3_B		%	-42%	-45%	-45%	-44%	-30%	-13%	-5%	8%	12%	12%
Legacy share disputed + 1550 Wind	Scen 3_C		%	-46%	-50%	-49%	-50%	-36%	-19%	-11%	3%	8%	8%
Separation 2025 CT replacement	Scen 5_A		%	-45%	-48%	-48%	-47%	-33%	8%	9%	10%	11%	11%
Separation 2025 CC replacement	Scen 5_B		%	-45%	-48%	-48%	-47%	-33%	-29%	-28%	-27%	-26%	-26%
Separation 2025 CT replacement - No Nuclear	Scen 5_C		%	-45%	-48%	-48%	-47%	-33%	5%	6%	6%	7%	7%
Separation 2025 CC replacement - No Nuclear	Scen 5_D		%	-45%	-48%	-48%	-47%	-33%	-5%	-4%	-4%	-3%	-3%

Resource Expansion Plan Forecast for NSPD: PA Summary - Capacity

Scenario Description	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NSP Preferred	418	420	421	423	425	428	429	432	434	436	438
Legacy no share disputed	418	420	421	423	425	428	429	432	434	436	438
Legacy share disputed + 1550 Wind	418	420	421	423	425	428	429	432	434	436	438
Separation 2025 CT replacement	418	420	421	423	425	428	429	432	434	436	438
Separation 2025 CC replacement	418	420	421	423	425	428	429	432	434	436	438
Separation 2025 CT replacement - No Nuclear	418	420	421	423	425	428	429	432	434	436	438
Separation 2025 CC replacement - No Nuclear	418	420	421	423	425	428	429	432	434	436	438

NSP Preferred	562	567	594	592	604	603	612	608	621	617	627
Legacy no share disputed	364	319	305	303	272	217	214	210	180	165	163
Legacy share disputed + 1550 Wind	383	337	323	321	290	235	232	228	198	183	180
Separation 2025 CT replacement	150	116	116	115	86	57	56	56	56	56	56
Separation 2025 CC replacement	150	116	116	115	86	57	56	56	56	56	56
Separation 2025 CT replacement - No Nuclear	57	57	57	57	57	57	56	56	56	56	56
Separation 2025 CC replacement - No Nuclear	57	57	57	57	57	57	56	56	56	56	56

NSP Preferred	0	0	0	0	0	0	0	0	0	0	0
Legacy no share disputed	110	110	110	110	110	219	219	219	219	219	329
Legacy share disputed + 1550 Wind	0	110	110	110	110	219	219	219	219	219	219
Separation 2025 CT replacement	219	329	329	329	329	329	329	329	329	329	329
Separation 2025 CC replacement	371	371	371	371	371	371	371	371	371	371	371
Separation 2025 CT replacement - No Nuclear	329	329	329	329	329	329	329	329	329	329	329
Separation 2025 CC replacement - No Nuclear	371	371	371	371	371	371	371	371	371	371	371

NSP Preferred	-144	-146	-173	-169	-178	-176	-183	-176	-186	-181	-190
Legacy no share disputed	-55	-8	0	0	0	-9	-4	0	0	0	-54
Legacy share disputed + 1550 Wind	0	-27	-12	-7	0	-27	-22	-15	0	0	0
Separation 2025 CT replacement	0	-24	-23	-21	0	0	0	0	0	0	0
Separation 2025 CC replacement	-102	-66	-65	-63	-31	0	0	0	0	0	0
Separation 2025 CT replacement - No Nuclear	0	0	0	0	0	0	0	0	0	0	0
Separation 2025 CC replacement - No Nuclear	-9	-7	-7	-4	-2	0	0	0	0	0	0

NSP Preferred	-34%	-35%	-41%	-40%	-42%	-41%	-43%	-41%	-43%	-41%	-43%
Legacy no share disputed	-13%	-2%	2%	3%	10%	-2%	-1%	1%	8%	12%	-12%
Legacy share disputed + 1550 Wind	8%	-6%	-3%	-2%	6%	-6%	-5%	-3%	4%	8%	9%
Separation 2025 CT replacement	12%	-6%	-6%	-5%	3%	10%	10%	11%	11%	12%	12%
Separation 2025 CC replacement	-24%	-16%	-16%	-15%	-7%	0%	0%	1%	2%	2%	3%
Separation 2025 CT replacement - No Nuclear	8%	8%	8%	9%	9%	10%	10%	11%	11%	12%	12%
Separation 2025 CC replacement - No Nuclear	-2%	-2%	-2%	-1%	0%	0%	0%	1%	2%	2%	3%

Regulatory Disallowances

State	10-K year(s)	Request ($million)	Allowance ($million)	Disallowance ($million)	Reason(s) for Request	Result / Reason(s) for Disallowance
CO	2008		$4.5		Transmission Cost Adjustment	Only transmission costs allowed.
CO	2009	$159.3	$112.2	$47.1	Rate increase	Black box settlement.
CO	2009, 2010	$177.4	$130.5	$46.9	Rate increase	Reduction in ROE.
CO	2012	$141.9	$114.0	$27.9	Rate increase	Reduction in ROE.
CO	2013		$8.2		2012 earnings test issues settlement	Refund.
CO	2014	$107.2	$39.4	$67.8	Rate increase	$98.7 -- Separation of CACJA projects $27.9 -- Reduction in ROE $23.9 -- Adjustment to HTY $15.2 -- Updated sales forecasts $ 5.3 -- Reduction of property taxes $33.8 -- Other
CO	2014	$49.0	$28.0	$21.0	Recovery of capital and O&M costs	
MN	2007	$168.0	$115.0	$53.0	Rate increase	Return of a large customer to NSP-MN. Reduction in ROE.
MN	2007	$34.4	$30.0	$4.4	Transmission Cost Recovery tariff	Identified costs did not meet criteria.
MN	2009	$12.1	$10.4	$1.7	Transmission Cost Recovery tariff	Certain plant costs went over budget.
MN	2009	$136.0	$91.4	$44.6	Rate increase	$40 -- 10-year license extension of nuclear plant. Reduction in ROE.
MN	2012	$151.0	$72.8	$78.2	Rate increase	Reduction in ROE. Reduction in depreciation expense.

State	10-K year(s)	Request ($million)	Allowance ($million)	Disallowance ($million)	Reason(s) for Request	Result / Reason(s) for Disallowance
MN	2013	$209.0	$103.0	$106.0	Rate increase	$43 -- Reduction in ROE $34 -- Sherco Unit 3 $15 -- Nuclear plants $ 4 -- Incentive compensation $26 -- Sales forecast $13 -- Pension $ 6 -- Employee benefits $ 5 -- Black Dog remediation $24 -- Theoretical depcreciation reserve $ 7 -- Wholesale allocation $ 5 -- Other $20 -- Deferrals $24 -- Reduction in revenue, depreciation expense
MN	2014	$748.0	$415.0	$333.0	Plant improvement project	$333 million to be recovered without ROE over the life of the project.
MN	2015	$221.3	$166.1	$55.2	Rate increase	Disallowance of plant costs. Property tax true-up. Other.
MN	2016	$297.1	$244.7	$52.4	Rate increase	Reduction in ROE.
NM	2008	$17.3	$10.8	$6.5	Rate increase	Reduction in ROE. Historical DSM expenditures. Rate case and prepaid pension expenses.
NM	2008			$17.0		Fuel and power cost adjustment.
NM	2009	$24.6	$14.2	$10.4	Rate increase	
NM	2011	$19.9	$13.5	$6.4	Rate increase	Black box settlement.
NM	2014	$45.9	$33.1	$12.8	Rate increase	Reduction in ROE.
NM	2015	$24.3			Rate increase	Outcome not detailed.
NM	2016	$41.4			Rate increase	Outcome not detailed.
ND	2008	$20.5	$12.8	$7.7		
ND	2012	$20.4	$15.7	$4.7	Rate increase	
ND	2013	$14.9	$11.0	$3.9	Rate increase	Reduction in ROE.

State	10-K year(s)	Request ($million)	Allowance ($million)	Disallowance ($million)	Reason(s) for Request	Result / Reason(s) for Disallowance
SD	2009	$18.6	$10.9	$7.7	Rate increase	Reduction in ROE. Nuclear plant lifespan adjustment.
SD	2012	$14.6	$8.0	$6.6	Rate increase	Reduction in ROE.
SD	2012	$19.4			Rate increase	Outcome not detailed.
SD	2013		$11.6			No details given.
SD	2014	$15.6	$7.8	$7.8	Rate increase	No details given.
TX	2007	$48.0	$23.0	$25.0	Rate increase	Fuel expense.
TX	2009	$61.3	$57.4	$3.9	Rate increase	Reduced depreciation
TX	2011	$63.7	$52.5	$11.2	Rate increase with franchise fees	No details given.
TX	2013	$90.2	$50.8	$39.4	Rate increase	No details given.
TX	2014	$48.1	$37.0	$11.1	Rate increase	No details given.
TX	2014	$13.0	$4.0	$9.0	Implement TCRF	No details given.
TX	2015, 2016	$42.1	$4.0	$38.1	Rate increase	$11.5 -- Wholesale load reductions $ 0.3 -- Incentive compensation $ 8.9 -- Capital structure investment $ 3.7 -- Capital structure $ 4.6 -- O&M expense $ 2.7 -- Depreciation expense $ 0.9 -- Property taxes $ 1.6 -- Revenue adjustments $ 4.2 -- SPP transmission expansion plan $ 6.3 -- Reduced ROE $ 3.7 -- Reduced capital structure $ 1.2 -- Other
TX	2016	$65.5	$51.8	$13.7	Rate increase	No details given.
TX	2016	$16.1			Increase in TCRF revenue	Outcome not detailed.
WI	2007	$67.4	$39.4	$28.0	Rate increase	ROE updates. Forecast updates.
WI	2007	$17.8	$5.9	$11.9	Fuel surcharge	Open surcharge application not settled.

State	10-K year(s)	Request ($million)	Allowance ($million)	Disallowance ($million)	Reason(s) for Request	Result / Reason(s) for Disallowance
WI	2008	$47.1	$5.6	$41.5	Rate increase	$31.6 -- Decline in fuel and market power prices $ 5.5 -- Change in nuclear outage accounting $ 4.4 -- Other
WI	2008	$19.7	$19.7	$0.0	Increase in fuel and market power prices	
WI	2008		$1.4		Test year case	Nuclear decommissioning expenses
WI	2009	$30.4	$6.4	$24.0	Rate increase	Adjustments to ROE and capital structure. Reduced interchange agreement fixed charge billings. Disallowance of certain employee expenses. Reduction for a nuclear plant decommissioning and depreciation expense.
WI	2010	$29.1	$21.1	$8.0	Rate increase	No details given.
WI	2011	$29.2	$12.2	$17.0	Rate increase	Updated fuel costs. Delays in nuclear plant changes. Reduction in ROE.
WI	2012	$39.1	$35.5	$3.6	Rate increase	No details given.
WI	2013	$34.3	$23.6	$10.7	Rate increase	Reduction in ROE.
WI	2014	$20.6	$14.2	$6.4	Rate increase	Adjusted forecast for fuel and purchase power costs.
WI	2015	$27.4	$7.6	$19.8	Rate increase	$9.1 -- Capital investments $3.8 -- ROE and capital structure adjustments $2.4 -- O&M expenses $4.5 -- Fuel and purchased power
WI	2016	$29.9	$22.5	$7.4	Rate increase	$3.4 -- Rate base investments $0.7 -- Generation and transmission expenses $0.4 -- Fuel and purchased power

Source

Xcel Energy Data Request No. 4-2.

Resources Acquired, Disputed Resources, and Production

Source	2016 MWH	Pcnt
Sherco 1 & 2	6,541,289	13.4%
Other Steam Generation	6,408,290	13.2%
Nuclear	13,860,816	28.5%
Hydro	93,578	0.2%
Other	8,527,001	17.5%
C-BED Wind	894,659	1.8%
Other Disputed Solar & Biomass	958,666	2.0%
Purchased Power (MWH)	11,349,859	23.3%
Total Energy Generation (MWH)	**48,634,158**	**100%**
Sales to Consumers	34,621,919	
Sales for Resales	5,922,958	
Non-Requirements Sales for Resale	6,897,102	
Energy Furnished without Charge	278	
Company Use	48,463	
[illegible]s	1,143,438	
	48,634,158	

Resources Acquired, Disputed Resources, and Production

Project	Fuel	Own / PPA	UCAP (MW)	MWH	PPA Termination	NDPSC Treatment
KODA Energy, LLC	Bio	PPA	12.0	99,975	05/17/2019	Recovered in full under settlement in PU-12-813
Laurentian Energy Authority, L.L.C.	Bio	PPA	31.2	264,543	12/31/2026	Recovered in full under settlement in PU-12-813. NSP has filed for an ADP to terminate PPA under a buyout agreement
Pine Bend	Bio	PPA	4.1	36,538	12/31/2025	Recovered in full under settlement in PU-12-813. NSP has filed for an ADP to terminate PPA under a buyout agreement
St. Paul Cogeneration	Bio	PPA	25.0	153,880	04/30/2023	Recovered in full under settlement in PU-12-813
WM Renewable Energy, LLC	Bio	PPA	4.0	38,413	03/31/2020	Recovered in full under settlement in PU-12-813
Benson Power, LLC	Bio	PPA	52.0	344,054	06/30/2028	Recovered in full under settlement in PU-12-813. NSP has filed for an ADP to buy out PPA and close the facility
Mankato Energy Center Expansion (MEC II)	CC Gas	PPA	Unknown		05/31/2039	ADP dismissed without prejudice - cost recovery can be considered in the future
Best Power (St. Johns)	Solar	PPA	0.2		05/27/2030	Pay proxy price for energy
Best Power International LLC	Solar	PPA	0.4	1,897	11/30/2030	Pay proxy price for energy
Marshall Solar	Solar	PPA	31.1	3,185	01/06/2042	Denied ADP for resource
North Star Solar	Solar	PPA	50.0	13,455	12/31/2041	Denied ADP for resource
Slayton Solar, LLC	Solar	PPA	0.8	2,726	01/01/2033	Pay proxy price for energy
Adams Wind Generations, LLC	Wind (C-BED)	PPA	3.9	57,476	03/08/2031	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
Big Blue	Wind (C-BED)	PPA	5.1	119,255	20 Yrs From COD	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
Danielson Wind Farms, LLC	Wind (C-BED)	PPA	3.2	53,515	03/10/2031	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
ington Energy Systems, LLC	Wind (C-BED)	PPA	3.1	71,153	05/27/2028	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
nt County Wind, LLC	Wind (C-BED)	PPA	4.7	64,930	08/08/2030	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
Hilltop Power, L.L.C.	Wind (C-BED)	PPA	0.2	2,685	02/19/2029	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
Jeffers Wind Energy Center	Wind (C-BED)	PPA	6.6	171,204	10/09/2028	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
North Community Turbines LLC	Wind (C-BED)	PPA	2.8	50,970	05/27/2031	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
North Wind Turbines LLC	Wind (C-BED)	PPA	2.5	48,219	05/27/2031	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
Ridgewind Power Partners, LLC	Wind (C-BED)	PPA	3.8	89,130	01/12/2031	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
Ulk Wind Farm, LLC	Wind (C-BED)	PPA	0.0	14,343	01/14/2030	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
Valley View Transmission	Wind (C-BED)	PPA	1.4	29,916	11/29/2031	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
Winona County Wind LLC	Wind (C-BED)	PPA	0.0	84	10/26/2031	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
Woodstock Municipal Wind, LLC	Wind (C-BED)	PPA	0.0	2,270	01/24/2031	Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813
Zephyr Wind	Wind (C-BED)	PPA	30.0	119,509		Pay proxy price for energy from C-BED projects based upon settlement in PU-12-813