414 Nicollet Mall
Minneapolis, Minnesota 55401

January 4, 2017

—Via Electronic Filing—

Ms. Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 East Capitol Avenue
Pierre, SD 57501

RE: RESOURCE TREATMENT FRAMEWORK

Dear Ms. Van Gerpen:

On December 31, 2016, Northern States Power Company, doing business as Xcel Energy, submitted to the North Dakota Public Utilities Commission and the Minnesota Public Utilities Commission an Application for Consideration of a Resource Treatment Framework to Address Jurisdictional Cost Allocation issues.

The Company made this filing consistent with the terms of a Negotiated Agreement adopted by the North Dakota Commission on March 9, 2016 in conjunction with Case Nos. PU-12-813. et. al. We are providing to you a copy of our application for informational purposes.

If you have any questions regarding this information, please call or e-mail me at 605-339-8350 or steven.t.kolbeck@xcelenergy.com

Sincerely,

Steven Kolbeck
PRINCIPAL MANAGER

STATE OF MINNESOTA BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION	STATE OF NORTH DAKOTA BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION D/B/A XCEL ENERGY JURISDICTIONAL COST ALLOCATION MATTERS

MPUC Docket No. E-002/M-16-223 NDPSC Case Nos. PU-12-813*, et. al.*

APPLICATION FOR CONSIDERATION OF A RESOURCE TREATMENT FRAMEWORK TO ADDRESS JURISDICTIONAL COST ALLOCATION ISSUES

I. INTRODUCTION

Northern States Power Company, a Minnesota corporation, doing business as Xcel Energy (NSPM or Xcel Energy or the Company), respectfully submits this Application for consideration of a Resource Treatment Framework (RTF or Framework) simultaneously to the North Dakota Public Service Commission (NDPSC) and the Minnesota Public Utilities Commission (MPUC) (collectively the Commissions).[1]

Since the time the *Negotiated Agreement* was adopted in North Dakota and we submitted our *Compliance Filing* in Minnesota, we have completed resource planning and ratemaking analyses, and benefitted from conversations with the Minnesota and North Dakota Commissions, their Staffs, and other stakeholders. Through this work, we see a path that no longer selects future resources on the basis of a wholly integrated NSP System; rather, we recommend a framework that would allow Minnesota and North Dakota to gradually become more independent of one other

[1] With respect to North Dakota, the purpose of this Application is to build upon prior rate case settlements and the NDPSC-adopted *Negotiated Agreement*. *See N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, *et al.*, ORDER ADOPTING REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT (NDPSC Feb. 26, 2014) (provided as Appendix D); *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT (NDPSC Dec. 31, 2008) (provided as Appendix E); *N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, *et al.*, ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT (NDPSC Mar. 9, 2016) (stating the Company's obligation to file a "Resource Treatment Framework" or "RTF") (provided as Appendix A). For Minnesota, this Application is submitted consistent with the Company's commitments made in our June 13, 2016, *Compliance Filing* submitted in MPUC Docket No. E002/M-16-223, as well as the MPUC's Letter on *Guiding Principles for Future Cost Allocation Proposals* filed on September 15, 2016, in the same docket. *See Compliance Filing on Jurisdictional Cost Issues*, Docket No. E002/M-16-223, COMPLIANCE FILING (MPUC June 13, 2016) (provided as Appendix B); *Compliance Filing on Jurisdictional Cost Issues*, Docket No. E002/M-16-223, LETTER – GUIDING PRINCIPLES FOR FUTURE COST ALLOCATION PROPOSALS (MPUC Sept. 15, 2016) (provided as Appendix C).

with respect to future resource selection. We believe this will provide each state with greater flexibility and customization around energy resource planning and selection.

With this Application, the Company asks each Commission to engage in a dialogue with the goal of achieving consensus on the future structure of the NSP System. To be clear, we are not seeking orders that will allow us to finalize an end state through this Application. Rather, we seek consensus on (a) the structure the NSP System will take over the long term; and (b) each state's responsibility for the Legacy System in which it has participated for generations.[2] We believe addressing past generation resource selections that were supported in Minnesota and questioned in North Dakota (Disputed Resources) is integral to resolving the latter issue.[3]

To facilitate moving ahead, we present feasible future system structures consistent with our recommendation (including Pseudo Separation and Legal Separation),[4] and proposals for addressing the Disputed Resources. We also provide supporting information regarding these different structures from a qualitative/feasibility perspective; resource planning analyses; and outlines of potential revenue requirement impacts to facilitate discussion and achieve consensus on the appropriate path forward.

II. <u>OVERVIEW</u>

The Company, along with the five states it serves in the upper Midwest, have long benefitted from operating an integrated system. Three principles, which we previously articulated, have been the foundation to achieving alignment amongst all participants:

- Retain the integrated nature of the NSP System to capture the benefits of scale and diversity for all of our customers;

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[2] We define the Legacy System as all of the generating resources of the NSP System after a reasonable allocation of the Disputed Resources identified in footnote 3, below. For discussion purposes, we have identified the resources that could comprise the Legacy System based on a potentially equitable allocation of Disputed Resources in Schedule 4.

[3] We consider the following resources to be Disputed Resources, more specifically identified in Schedule 3: (1) certain CBED and smaller solar resources; (2) all biomass PPAs currently serving the NSP System; (3) the Company's PPAs for its 187 MW solar portfolio; (4) the Company's PPA for the capacity and energy of the Mankato Energy Center expansion (MEC II) project; and (5) solar gardens developed under Minn. Stat. § 216B.1691, subd. 2f. Based on the NDPSC's decision in Case No PU-15-95 and the MPUC's decision in Docket No. E002/M-15-330, we are not considering the Aurora Solar project to be a Disputed Resource.

[4] Pseudo Separation preserves the current corporate and overall ratemaking structure of Xcel Energy, but treats each future resource as direct assigned to the jurisdiction(s) that supports it, requiring development of new cost recovery and accounting methods. Legal Separation involves creation of a separate operating company for North Dakota, which provides a more complete separation and eliminates the need for future alignment between the states on all future decision making – but is more complex and costly to implement.

- Respect the sovereign nature of each of the states we serve, while ensuring that they understand and bear the costs and risks associated with their decisions; and
- Ensure the Company has an opportunity to fully recover its cost of service in each state served by the NSP System.[5]

These principles can only function appropriately when all participants in the System are aligned in equitably sharing both the benefits and costs of the NSP System on a proportional basis. In the last decade, however, we have experienced an erosion in the alignment that is necessary to successfully operate an integrated system. Fundamental disagreements have arisen and persisted between the MPUC and NDPSC, including differences of opinion regarding resource need, renewable and thermal resources, and other ratemaking structures such as depreciation and demand allocations. These fundamental disagreements have resulted in the misalignment between the states we serve around the integration of the NSP System, resulting in the Disputed Resources as well as mismatched rate recovery for these resources and uncertainty around any future resource selection. Since we do not anticipate this misalignment ameliorating into the next decade, we are providing a framework to manage known and unknown misalignments between Minnesota and North Dakota.

A. Our Proposal

Based on our analyses, we conclude that the most robust and equitable RTF will address past disagreements first, then gradually move away from a fully-integrated resource portfolio serving all states and toward development of separate generation portfolios serving North Dakota and the remainder of the NSP System as NSP System resources are retired or added in the future. Through a less integrated system, our North Dakota customers would be able to select resources more independently and would see little immediate cost impact – but may potentially bear somewhat higher risk due to our North Dakota customers being served by a smaller and less diverse resource portfolio commensurate with their size and scope. At the same time, our Minnesota stakeholders would be able to more efficiently pursue state energy goals with less interstate conflict and potential delay, with little incremental cost.

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[5] NSPM has been able to bring the benefits of carbon-free nuclear generation, low-cost coal and natural gas generation, and significant imported hydroelectric generation to our customers in Minnesota, North Dakota, and South Dakota by aggregating our customers across state lines with our sister company, Northern States Power Company, a Wisconsin corporation (NSPW), serving Wisconsin and Michigan through the FERC jurisdictional Interchange Agreement. *Xcel Energy Operating Cos.*, FERC Docket No. ER01-1014, RESTATED AGREEMENT TO COORDINATE PLANNING AND OPERATIONS AND INTERCHANGE POWER AND ENERGY BETWEEN NORTHERN STATES POWER COMPANY (MINNESOTA) AND NORTHERN STATES POWER COMPANY (WISCONSIN) (Jan. 19, 2001); *see also N. States Power Co., a Minn. Corp.*, FERC Docket No. ER15-1575, LETTER ORDER (June 22, 2015) (unpublished letter order of Xcel Energy's most recent update to the Interchange Agreement).

Our RTF provides a framework to achieve this outcome. As a preliminary matter, we believe an equitable framework must acknowledge that our customers have historically benefitted from the economies of scale and diversity of resources available to a larger, integrated system that shares resources. To achieve a fair and balanced RTF, NSP System customers who have participated in those benefits for decades should continue to share the costs and liabilities incurred to create and operate the Legacy System.[6]

Moreover, the time is right to achieve the intertwined goals of aligning the states' roles with respect to accountability for the Legacy System and establishing greater flexibility for the Company to serve our North Dakota and Minnesota customers even where their priorities differ. The NSP System is changing, apart from any new decisions that may be made in the future. We anticipate unavoidable expirations of several key power purchase agreements (PPAs) and the planned retirement of key baseload generation such as Sherco 1 and 2. At the same time, we do not anticipate significant additional capacity needs until the mid-2020s. This timing provides a window in approximately the 2020 timeframe to resolve past issues and also achieve a form of separation that permits more independent future energy choices in the NSP System states when we reach the 2020s and beyond. Our RTF seeks to leverage this timing opportunity to achieve an equitable outcome for each state we serve.

To that end, we propose the following Resource Treatment Framework:

1. All currently anticipated and past resource selection and other disagreements will be permanently addressed and the Legacy System established.

2. All NSPM states will continue to be served by the Legacy System and all of our customers will enjoy the benefits and bear the burdens of the Legacy System.

3. With respect to future new resource additions, the Company will be able to assess and propose resources for North Dakota and the remainder of the NSP System separately.

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[6] Continued service for North Dakota from the Legacy System was a key component of the *Settlement Agreement* in Case No. PU-12-813, which formed the basis for our RTF. *See N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, *et al.*, ORDER ADOPTING REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT at 15, Negotiating Principle 3 of Settlement Agreement(NDPSC Feb. 26, 2014) (Appendix D).

a. When a resource need arises in North Dakota, that need will be met by a resource sized for, dedicated to serve only, and fully recovered in North Dakota.

b. When a resource need arises in, or new resources are otherwise planned for, the remainder of the NSP System, those resources will be sized for, dedicated to serve only, and fully recovered in the remainder of the NSP System. Consequently, our North Dakota jurisdiction will not obtain the benefits or pay the costs associated with new NSP System resource additions.

c. Xcel Energy may propose particular future resources to be utilized concurrently by North Dakota and the remainder of the NSP System should circumstances warrant, and will propose cost-sharing arrangements at that time.

4. Over time, the generation portfolio serving North Dakota and the remainder of the NSP System will materially separate as units of the NSP System retire or expire.

5. South Dakota may elect to join North Dakota under this framework or remain part of the NSP System consistent with its own outlooks.[7]

Each enumerated item in our RTF presents multiple questions and sub-questions that need to be resolved to distill this framework into an implementable solution. Our purpose in this proceeding is to solve two fundamental questions: (1) what structure will the integrated NSP System take in the future; and (2) what resources will continue to be shared as part of the Legacy System, which includes addressing the Disputed Resources. This Application presents the economic, ratemaking, and policy analyses to begin a robust discussion between the Commissions and the Company on these questions, as well as to offer potential answers. It is our goal through the course of this proceeding to ultimately reach a consensus outcome with the Commissions, which would align the states into the future.

[7] Throughout the remainder of this document, we largely refer to North Dakota as the entity separating from the NSP System under our proposed RTF. We recognize South Dakota may also wish to consider whether to participate with North Dakota, and our RTF is intended to provide that optionality to our South Dakota customers. We are presenting this optionality as part of our RTF as the South Dakota Public Utilities Commission (SDPUC) is currently undertaking a review of our fuel clause rider recovery. *See In the Matter of Comm'n Staff's Request to Investigate N. States Power Co. d/b/a Xcel Energy's Proposed Fuel Clause Rider*, Docket No. EL16-037, ORDER SUSPENDING FUEL CLAUSE RIDER FOR 180 DAYS (SDPUC Dec. 12, 2016).

To serve North Dakota and Minnesota separately at a future time, it is first necessary to determine how this can occur. Two potential structures can support our proposed RTF: (1) Pseudo Separation and (2) Legal Separation. Pseudo Separation does not require corporate structure changes, but direct assigns the costs and benefits of each resource to the jurisdiction(s) that supports it. Pseudo Separation therefore requires new cost recovery and accounting methods to be developed, implemented, and managed over time. Legal Separation would involve creation of a separate operating company for North Dakota. This more complete separation eliminates the need for future agreement or compromise between the states, but is more complex and costly to implement at the outset. Each of these structures can ultimately result in the same resource outcomes envisioned by our proposed RTF and each structure has benefits and drawbacks.

Regardless of the structure, we envision that all states will continue to be served by the Legacy System. In light of this, separate generation portfolios would only be implemented over time as aging resources drop off the system and need replacement. The result would be a more gradual, long-term move toward separation.

That said – and based on the potential for accelerated transformation of the NSP System via our next Integrated Resource Plan (IRP) to be filed in 2019, with which North Dakota may not agree – we could identify a fixed date to begin serving North Dakota by its own resource portfolio. As discussed in more detail in this Application, we believe that this portfolio should include the nuclear resources of the Legacy System. This approach would create freedom to more fully develop and plan for a separate future for North Dakota sooner by spurring a load-serving need in North Dakota for generation development in that state. At the same time, continued service from our nuclear fleet provides hedge value and baseload support while being consistent with the equities of ensuring that our customers retain liabilities consistent with their past participation in and enjoyment of the Legacy System. This alternative separation scenario could therefore provide North Dakota with the benefits of Legacy System resources that the NDPSC has historically supported, while moving North Dakota toward a stand-alone resource portfolio sooner.

We will also need to determine the extent to which existing or planned resources will comprise the Legacy System. This determination requires us to address the Disputed Resources. While there are multiple possible outcomes that could achieve an equitable result, we believe a reasonable approach could be:

- All Disputed Resources except for the MEC II PPA will be allocated to the remainder of the NSP System and not North Dakota;

- The necessary accelerated depreciation due to the mismatch of book life in North Dakota as compared to the remainder of the NSP System for Sherco Units 1 & 2 will be allocated to and recovered from the remainder of the NSP System;
- No portion of costs or savings associated with the Company's proposed new wind projects[8] will be allocated to North Dakota, but rather will be fully allocated to the remainder of the NSP System; and
- North Dakota's allocated share of the MEC II PPA will be recovered in North Dakota.

Our resource planning analysis indicates that this approach could generate a reasonably balanced outcome, as the costs of allocating the Disputed Resources and the Sherco Units 1 & 2 accelerated depreciation to the NSP System other than North Dakota will be offset by the fuel savings to the remainder of the System provided by the Company's proposed new wind additions over their life. Conversely, recovery of the MEC II PPA in North Dakota will help ensure that sufficient capacity and energy is available to our North Dakota customers as we transform the NSP System. A resolution along these lines allows us to establish a baseline from which we can begin planning a less integrated future.

B. Achieving Consensus

For our RTF to be successful, we cannot overstate the importance of obtaining the support, approval, and alignment of both Commissions with respect to each of the above questions. Failure to find consensus will drive us toward lowest common denominator planning and resource-by-resource negotiations, meaning we could only implement resources acceptable to all states in the NSP System. This, in turn, means we would be less able to pursue more holistic solutions, such as development of North Dakota generation or a more emissions-free energy future, that could otherwise be pursued during the coming fleet transformation.

We look forward to an open and robust dialogue to ultimately meet the goals and objectives of all the states currently served by the NSP System. To that end, we propose an approximately eighteen-month procedural schedule to provide the

[8] Pursuant to our most recent Minnesota IRP, the MPUC ordered the Company to acquire at least 1000 MW of wind by 2020. On October 24, 2016, in Docket No. E002/M-16-777, the Company notified the MPUC that it intends to acquire at least 750 MW of wind resources based on its self-build proposal and its most recent wind request for proposal (RFP) process. *See In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of Wind Generation from the Co.'s 2016-2030 Integrated Res. Plan*, Docket No. E002/M-16-777, PETITION at 1(MPUC Oct. 24, 2016). Based on the results of the Company's wind RFP process, it appears likely that we will propose 1500 MW to be added from our self-build and RFP selections, with supplemental information supporting our proposal forthcoming in the first quarter of 2017.

Commissions and our stakeholders with ample time to analyze, issue discovery, and to work through the issues presented in this Application. The last portion of this Application identifies a procedural proposal to review our recommendation as well as discussion of how our proposal would be implemented.

Should the Commissions ultimately approve a common Framework, we would seek to obtain the necessary approvals and implement the RTF as quickly as is reasonable. We envision that a Pseudo Separation outcome could be implemented in a rate case following the completion of review of this Application, likely in 2020. Should a Legal Separation structure be preferred, we anticipate that we could complete the significant work to form the new operating company and seek approvals in all regulatory forums (Minnesota, North Dakota, the Federal Energy Regulatory Commission (FERC), and others) by approximately 2020. The work assessing and discussing this Application will inform the future of the NSP System, and we welcome this robust discussion.

C. Remainder of Filing

The remainder of this filing provides the detailed support for our Application, and will address the following:

- *The Need for Change:* provides a brief historical context for the need for an RTF.
- *Analytical Framework*: outlines the different potential RTF structures.
- *Resource Planning Analysis*: sets forth our resource planning analysis, assumptions, and results that underpin our consideration of RTF alternatives.
- *Revenue Requirement Analysis*: summarizes how rates are impacted by the RTF alternatives.
- *Recommendation and Next Steps*: outlines the Company's recommendation and proposal for implementation.
- *Conclusion:* summarizes our proposal.

Xcel Energy is making this Application in North Dakota in compliance with the *Negotiated Agreement* approved on March 9, 2016, pursuant to N.D.A.C. § 69-02-02-04 and in Minnesota as a Miscellaneous Filing pursuant to Minn. R. 7829.1300. Required compliance information is provided in Schedules 1 and 2 to this Application.

III. THE NEED FOR CHANGE

We begin this Application by presenting the case for change within the NSP System. Prior rate case settlements and the *Negotiated Agreement* in North Dakota, as well as the *Compliance Filing* submitted in Minnesota, introduced the Company's concerns with respect to disagreements regarding resource selection, cost recovery, and system planning in the states we serve. At the same time, we recognize the benefits of service via the fully-integrated NSP System and the appropriateness of preserving those benefits through individual resource resolutions. To date, we have not fully succeeded in reconciling the benefits of integration and the lack of full cost recovery for certain investments in all states served.

This portion of the Application explains how and why we developed the current integrated system, addresses why the status quo is not sustainable for the Company and may not be preferable to the states we serve, and introduces known and potential system changes that may further prompt the need for change. This information forms the initial basis for the development of our RTF proposal.

A. Evolution of the Integrated NSP System

For several generations, the integrated NSP System has successfully provided service on a multi-jurisdictional basis to our customers in Minnesota, North Dakota, and South Dakota, and through coordination with NSPM's sister company, NSPW, to customers in Wisconsin and Michigan. Collectively, the NSP System serves approximately 1.6 million electric customers in these five states.

The NSP System developed as part of an electric service model that required or supported various large-scale investments to serve customers over time, particularly during lengthy periods of high load growth. These investments created the integrated NSP System in its current form, which reflects the Company's ongoing responsiveness to the circumstances it has faced to date. We believe this responsiveness has benefited all system participants along the way. However, we also recognize that the Company has not always fully outlined how the integrated NSP System came to be in its current form, or how this evolution has benefited system participants. To address this in part, Schedule 5 to this Application explains the historic development and drivers of the integrated NSP System.

By way of summary, integration was a function of the needs of our customers during past eras of significant load growth, supply uncertainty, and pricing volatility. Each resource in the NSP System – whether generation or transmission[9] – was developed in consideration of the whole, balancing the need for diversity and hedges against supply and cost volatility encountered at various times over the past several decades when economies of scale were only available through integrated system planning. This

[9] Consistent with long-standing ratemaking practices, distribution costs have been direct assigned to particular jurisdictions.

integrated approach supported achievement of economies of scale system-wide, allowed the states we serve to share in the costs of resources, and provided diversity and hedge benefits that might not otherwise have been available.

On behalf of all customers, we have taken advantage of the geographic, supply, and resource diversity that the five-state NSP System provides, with all states sharing in the costs and benefits of this system. While maintaining an integrated system at times requires necessary compromises between the various customer groups and jurisdictions we serve, this diversity continues to act as a "hedge" for customers against fuel cost variability, concentrated geographic changes to the system, and supply problems. It also provides value to stakeholders in the form of assurance that energy supply would be adequate and reliable regardless of market changes.

In light of the historic benefits of integration within the NSP System, our RTF first recognizes that all states that have participated in the development of the Legacy System should also continue to pay their fair share of its costs. This concept is discussed in more detail later in this Application.

B. Current Stressors on the System

Despite this successful history, the current integrated NSP System faces many challenges today that result from evolution in the industry as well as disagreements on a variety of issues as between Minnesota and North Dakota. Because these disagreements are varied, it has become clear that the term we have historically used to describe the drivers of resource disagreements between Minnesota and North Dakota – "divergent energy policies" – is insufficient to fully describe the fundamental difference in outlooks between the NDPSC and the MPUC.

It would be correct to say that some disagreements between the MPUC and NDPSC are driven by renewable energy or other clear legislative mandates such as Minnesota's Renewable Energy Standard (RES) or the Minnesota Metro Emissions Reduction Program (MERP). Others, however, are driven by more fundamental differences between the needs and wants of our various customers. These differences include not only the mid-nineties passage of externality laws in Minnesota[10] and the concomitant passage of anti-externality laws in North Dakota,[11] but also the perception of how to meet load-serving needs and incorporate the availability of competitive markets for energy, ancillary services, and capacity to provide our customers with the power they need.

[10] Minn. Stat. § 216B.2422, subd. 3; H.F. 1253, 78th Leg., Reg. Sess. (Minn. 1993).

[11] N.D.C.C. § 49-02-23; H.B. 1312, 59th Leg. Reg. Sess. (N.D. 1995).

Further, regulators in North Dakota have both formally and informally called into question material Company investments or initiatives – even those that had been previously recovered, in part, from our North Dakota customers. These included concerns over:

- the Company's Demand Side Management (DSM) programs;[12]
- Legislative requirements in Minnesota to add wind and biomass resources in order to continue to operate its nuclear facilities, and the establishment of a Renewable Development Fund (RDF);[13]
- Company investments in its High Bridge plant under MERP;[14]
- Cost recovery of existing resources such as community-based economic development (CBED), small solar, and biomass PPAs;[15]
- Company investments in wind facilities such as Grand Meadow,[16] Prairie Rose,[17] Odell, and Pleasant Valley;[18] and

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[12] *N. States Power Co. Demand Side Management & Cost Recovery Rider Tariff*, Case No. PU-08-171, ORDER (Nov. 5, 2008) (denying the Company's proposed cost recovery tariff rider).

[13] *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ADVOCACY STAFF POST-HEARING BRIEF at 19-23 (NDPSC Aug. 22, 2008) (arguing that it was unjust and unreasonable to require North Dakota ratepayers to pay the costs incurred due to Minnesota's renewable energy standards); *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT at 3, 14 of Settlement Agreement (NDPSC Dec. 31, 2008) (Appendix E).

[14] *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ADVOCACY STAFF POST-HEARING BRIEF at 12-19 (NDPSC Aug. 22, 2008) (arguing that the costs incurred due to MERP should not be included in the Company's revenue requirement); *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT at 12 of Settlement Agreement (NDPSC Dec. 31, 2008) (Appendix E) (acknowledging that investments in the High Bridge power plant was a primary issue of dispute in the proceeding).

[15] *N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, *et al.*, ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT at 4 (NDPSC Mar. 6, 2016) (Appendix A) (excluding the costs and volumes of fifteen CBED and two small solar PPAs from the calculation of the Company's North Dakota Fuel Cost Recovery Rider); *N. States Power Co. Elec. Rate Increase Application*, Case Nos. PU-12-813, *et al.*, ORDER ADOPTING REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT at 17-18 Settlement Agreement (NDPSC Feb. 26, 2014) (Appendix D) (calling into question twenty-three of the Company's existing renewable PPAs related to CBED, solar, and biomass).

[16] *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT at 12 of Settlement Agreement (NDPSC Dec. 31, 2008) (Appendix E) (acknowledging that the Grand Meadow wind farm was a primary issue of dispute).

[17] *N. States Power Co. Advance Determination of Prudence – Geronimo Wind Application*, Case No. PU-12-59, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 2-4 (NDPSC Dec. 21, 2012).

[18] *N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, *et al.*, ORDER ADOPTING REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT at 22 of Settlement Agreement (NDPSC Feb. 26, 2014) (Appendix D) (reserving disposition of the Odell and Pleasant Valley wind projects until adoption of the Negotiated Agreement).

- Company costs related to the 187 MW solar portfolio (now resized as a 162 MW portfolio) and the 100 MW Aurora Solar PPA.[19]

We note also that some misalignment between Minnesota and North Dakota is a result of resource selection by the MPUC that was not necessarily supported by the Company but for which it was necessary for us to seek approval in North Dakota. For example, the Company advocated against selection of the Aurora Solar project in the Minnesota Certificate of Need proceeding but the project was nonetheless selected.[20] Thereafter, the Company defended the project before the NDPSC notwithstanding our reservations, but the NDPSC has not approved the project. In this instance, the Company was nonetheless able to resolve its inability to recover the North Dakota share of that project through commercial arrangements. However, without a robust RTF, the Company will be left with few tools but to cancel these types of projects in the future.

Resource selection differences are not the only factor impacting the health of the integrated System. Equitable and consistent cost allocation for shared resources is also necessary to maintain integration. However, in our 2008 North Dakota rate case, Case No. PU-07-776, depreciation schedules for Sherco Units 1, 2, & 3, among other plants,[21] were established that differed from those of the other states of the NSP System. This was due to different outlooks regarding the future of these plants in North Dakota than in the other states of the NSP System.[22] The resulting mismatch in remaining lives is an example of rate structure misalignment between Minnesota and North Dakota.

Furthermore, in our most recent North Dakota rate case, Case No. PU-12-813, the NDPSC raised concerns regarding the jurisdictional demand allocation methodology used to allocate demand-related costs across the NSPM jurisdictions. Minnesota,

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[19] *See N. States Power Co. Advance Prudence – 187 MW Solar Energy Portfolio Application*, Case No. PU-14-810, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 3-4 (NDPSC June 17, 2015); *N. States Power Co. Advance Prudence – 100 MW Aurora Solar, LLC Application*, Case No. PU-15-095, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 3-4 (NDPSC Sept. 16, 2015).

[20] *See In the Matter of the Petition of N. States Power Co. d/b/a Xcel Energy for Approval of Cost Recovery of the Aurora Power Purchase Agreement*, Docket No. E002/M-15-330, ORDER DENYING RECOVERY OF NORTH DAKOTA-RELATED PURCHASED-POWER COSTS at 2 (MPUC Apr. 13, 2016).

[21] In addition to Sherco Units 1, 2, & 3, other combustion plants with differing depreciation schedules due to extended service lives include the Angus C. Anson generating station, the Granite City plant, the High Bridge plant, the Inver Hills plant, the Key City plant, and the Prairie Island nuclear plant. *See N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT at 10 of Settlement Agreement (NDPSC Dec. 31, 2008) (Appendix E).

[22] *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ADVOCACY STAFF POST-HEARING BRIEF at 8-10 (NDPSC Aug. 22, 2008).

North Dakota, and South Dakota have been utilizing the 12 CP method for over thirty years as an equitable way to allocate shared costs across the NSP System. While the Company was able to settle the jurisdictional allocator issue with NDPSC Staff in the rate case *Settlement Agreement*[23] and *Negotiated Agreement*,[24] the NDPSC's focus on the uniform jurisdictional allocator signaled to the Company that the integrated NSP System is being stressed potentially to the breaking point. Ensuring agreement on this fundamental cost allocation is critical to equitable cost recovery across the NSP System, and to identifying the type of structure that should be implemented to support our RTF.

These stressors on the NSP System present business concerns as well as regulatory considerations. The different and sometimes conflicting regulatory views on the projects supported (or not supported) by the Commissions is creating increasing uncertainty for the Company with respect to business planning and the likelihood of future cost recovery. Incomplete recovery of investments that are ordered by one jurisdiction but not supported in another erodes the baseline principle that recovering the costs of reasonable investments made on behalf of customers is foundational to the success of any utility. While we have worked creatively to manage interstate conflicts in the past, continuing to accept lower cost recovery due to differing resource approvals in the states we serve is not sustainable. These ongoing disagreements therefore lead to the conclusion that a less integrated future may be preferable.

C. <u>Forecasted System Transformation</u>

There are many unknowns as we plan for the future of the NSP System. Environmental regulations are in a state of potential flux; tax laws may change; demand may fluctuate more than expected; and fuel costs may change unpredictably. While these areas of uncertainty make it impossible to predict the future in several respects, this section of our Application is intended to look to the known resource planning future. In particular, we know that the Company will experience significant PPA expirations and the retirements of Sherco Units 1 & 2 in the next decade, regardless of future resource plan proceedings. This upcoming period of significant resource expirations (without the need for additional baseload capacity before the mid-2020s) presents a window of opportunity to implement an RTF structure that

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[23] *N. States Power Co. 2013 Elec. Rate Increase Application*, Case No. PU-12-813, *et al.*, ORDER ADOPTING REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT at 18-20 of Settlement Agreement (NDPSC Feb. 26, 2014) (Appendix D).

[24] *N. States Power Co. 2013 Elec. Rate Increase Application*, Case No. PU-12-813, *et al.*, ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT at 7 of Negotiated Agreement (NDPSC Mar. 9, 2016) (Appendix A).

permits greater flexibility and customer responsiveness before future resource selections must be made.

We also anticipate that Minnesota stakeholders will continue to state a preference for a more renewable future in the years ahead,[25] furthering Minnesota's carbon reduction goals.[26] Conversely, we know that North Dakota stakeholders are unlikely to agree with Minnesota's preference to give greater weight to the present value of societal cost (PVSC) of resources than to the present value of revenue requirements (PVRR) perspective. These known factors make it more challenging to maintain an integrated system that satisfies the needs of the Company and its various stakeholders, but also present the right reasons and timing to implement a more separate future.

1. Current IRP

As discussed in the Company's recent IRP,[27] Xcel Energy anticipates significant upcoming reductions in energy resources due to several key changes occurring in the next 10 to 15 years, including:

- 2023: Blue Lake Units 1-4 (natural gas combustion turbines (CTs)) cease operation (153 MW);
- 2025: Manitoba Hydro contracts expire (850 MW);
- 2026: Cottage Grove Combined Cycle Energy Center contract expires (262 MW); and
- 2027: Mankato Energy Center Combined Cycle (MEC I) contract expires (375 MW).

The Company also faces the impending retirement of a number of baseload system resources. In the Company's recent IRP proceeding, the MPUC approved the

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[25] *See* Minn. Stat. § 216B.243, subd. 3a (providing that the MPUC "may not issue a certificate of need under this section for a large energy facility that generates electric power by means of a nonrenewable energy source, or that transmits electric power generated by means of a nonrenewable energy source, unless the applicant for the certificate has demonstrated to the commission's satisfaction that it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive . . . than power generated by a renewable energy source").

[26] *See* Minn. Stat. § 216H.02, subd. 1.

[27] *See In the Matter of Xcel Energy's 2016-2030 Integrated Res. Plan*, Docket No. E002/RP-15-21, MINUTES – OCTOBER 13, 2016 AGENDA (MPUC Nov. 1, 2016) (detailing the MPUC's determinations regarding the Company's IRP), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={281E9278-B77B-4DA1-917F-A3BDBD55CDB4}&documentTitle=201611-126198-01. MPUC deliberations occurred on October 13, 2016; no order has yet issued. We will provide an update to the record once an order has issued. *See also 2015 Upper Midwest Integrated Res. Plan*, Case No. PU-15-019, RESOURCE PLAN 2016-2030 (NDPSC Jan. 5, 2015) (The Company files its IRP in North Dakota for informational purposes; consistent with past practice, the NDPSC did not act on the Company's IRP).

Company's plan to retire Sherco Units 1 & 2 in 2026 and 2023, respectively, with a combined impact in excess of 1,300 MW.

At the same time, newer technologies such as distributed energy resources and demand response continue to impact system demand and the types of resources available to meet that demand. The Commissions' perspectives on the correct response to these changes may contribute to future misalignment.

Because of the Company's current load profile and forecast, however, the Company does not anticipate the need to add significant additional baseload capacity until Sherco Unit 1 is retired in 2026.[28] The lack of immediate capacity need combined with existing System changes provides an opportunity to separate North Dakota before the next large capacity resources are added to the System. While long lead-times are needed to plan for large future resource additions, the gap in anticipated capacity needs make now the right time to identify a long-term solution for current and potential future stressors on the NSP System. We can then implement separate solutions for each jurisdiction when the need to add resources does arise.

2. <u>Future Changes</u>

In addition to these known retirements and expirations, further evolution of the NSP System may also be under consideration, which could heighten and accelerate potential future disagreements regarding integrated System resources. In the 2030s, more than 2500 MWs of additional system resources are also scheduled to retire, including:

- 2030: Monticello Nuclear Generating Plant (671 MW)
- 2033: Prairie Island Nuclear Generating Plant Unit 1 (548 MW)
- 2034: Prairie Island Nuclear Generating Plant Unit 2 (548 MW)
- 2037: Allen S. King Plant (511 MW)
- 2040: Sherco Unit 3 (860 MW)

While retirement of these resources will occur at some future time, retirement along the timelines noted above is not certain. In the Company's recent IRP proceeding, the MPUC directed the Company to file its next resource plan on February 1, 2019, and to describe in that filing our plans and possible scenarios for the cost-effective and orderly retirement of our aging baseload fleet. The MPUC also required the

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[28] The MPUC also determined in that proceeding that it is more likely than not that there will be a need for 750 MW of intermediate capacity coinciding with the retirement of Sherco Unit 1 in 2026, and authorized the Company to file a petition for a Certificate of Need to meet that need.

Company to evaluate, in addition to generation resource options and alternatives, combinations of supply-side (distributed and centralized), demand-side, and transmission solutions that could, in the aggregate, meet post-retirement energy and capacity needs as well as contribute to grid support. These directives, which could accelerate closures of large baseload plants ahead of current anticipated useful lives, will generate additional discussion in the states we serve.

As we continue to analyze the potential retirement of other baseload generation, recovery of the costs of the assets and liabilities incurred by our customers' use of these assets through depreciation reserves and other rate recovery methods is critical to the success of our RTF. At the same time, we recognize that prospective acceleration of the retirement of these baseload resources – potentially through our next IRP filed in early 2019 – may further misalign the Commissions with respect to the future of the NSP System. These considerations highlight the importance of identifying a consensus RTF for resource planning approaches, the future of the NSP System, and equitable cost recovery in the context of this proceeding. In the next section of this Application, we therefore identify potential structural solutions to achieve our RTF, and walk through our qualitative analyses of the viability of each option.

IV. ANALYTICAL FRAMEWORK

The path toward our recommended RTF began with our efforts to "Restack" the NSP System pursuant to ten principles set forth in the *Settlement Agreement* from our 2013 test year rate case in North Dakota.[29] While significant effort was expended to achieve the outcome envisioned in that *Settlement Agreement*, we were ultimately unsuccessful. Consequently, we agreed to the *Negotiated Agreement's* terms that obligated the Company to develop an RTF and propose it to the NDPSC. Since the NDPSC's adoption of the *Negotiated Agreement*, the MPUC has also analyzed the stresses on integration of the NSP System and ordered that the Company present a compliance filing identifying the important historical background and principles that were driving our development of the RTF, considering our obligations under the *Negotiated Agreement*. This resulted in our June 2016 *Compliance Filing*.

Through these proceedings, we have articulated to both Commissions that an RTF should:

[29] *See N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, *et al*, ORDER ADOPTING REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT at 14-17 of Settlement Agreement (NDPSC Feb. 26, 2014) (Appendix D).

(1) be forward looking to address future resource selection disagreements (policy divergence) amongst the states, should they occur;

(2) find opportunities to continue an integrated approach to serving all of our customers, where possible; and

(3) continue to keep the existing, or legacy, fleet available to all of our customers in all of the states we serve.

These principles continue to form the basis of our decision-making process, as have the six principles provided by the MPUC.[30] Last, the input we have received from the Commissions and their respective Staffs has been helpful in our development of an RTF.

Our RTF considers the extent to which there may be tension between these principles, as well as the extent to which they are consistent with each other. This has included determining whether relatively recent disagreements over resource selection (as compared to the entire history of the System) will predominate the evolution of the NSP System or whether there is likely to be more agreement than less going forward. This puts primacy on the first principle, which requires an RTF to be forward looking. The less disagreement that occurs, the more integrated an RTF can be, highlighting the second principle. While we hope that the level of disagreement amongst the states will moderate in the future, an RTF can only be successful if it is sufficiently robust to address material disagreements that continue to exist and will likely occur in the future – particularly as resources on the NSP System, and the utility industry as a whole, continue to evolve.

To this end, our RTF is primarily a forward-looking framework, while also addressing past and likely near-term future jurisdictional disagreements. We therefore begin our analysis by setting forth potential future resource pricing and corporate structure alternatives that could support our long-term RTF, and assessing which of those alternatives may be feasible and productive (this Section IV). This initial identification of alternatives also provides the underpinnings of our long-term review of resource options (Section V), as well as the revenue requirement impacts of our recommended resolution of Disputed Resources (set forth in Sections V and VI) and of feasible structural alternatives for the future (also discussed in Sections V and VI). Taken together, we believe this analytical framework, focused resource planning, and

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[30] *See Compliance Filing on Jurisdictional Cost Issues*, Docket No. E002/M-16-223, LETTER – GUIDING PRINCIPLES FOR FUTURE COST ALLOCATION PROPOSALS at 1-2 (MPUC Sept. 15, 2016) (Appendix C).

revenue requirement analyses provide the information needed to promote discussion around a viable long-term RTF.

A. <u>Alternatives for the Future</u>

Our work in developing an RTF has been focused on four alternatives for the future structure of the NSP System. In this section of the Application, we describe our qualitative assessment of these alternatives in terms of whether they are viable options that can achieve the RTF development principles described above. We note, however, that not one of these structures is alone a sufficiently robust RTF. Rather, we determined that a broader framework that can be supported by several structures is more appropriate for our RTF, so that we may present sufficient optionality to achieve consensus between the Company and the Commissions on the appropriate path forward. This section will discuss the different structures we analyzed to ultimately reach the RTF proposal presented in this Application.

Consistent with the record developed in support of the *Negotiated Agreement* and as further articulated in our *Compliance Filing*, we identified four structures upon which we focused our analysis:

(1) *Regulatory Alignment ("Full Recovery")*: Better align the resource selection processes of the states to reach consensus on resource selection. Should a state direct the acquisition of a particular resource that is not approved by the other states, then all costs of the resource will be recovered from only the approving states or the Company will not move forward with that particular resource.

(2) *Proxy Pricing*: States that reject a particular resource will pay a "proxy price" for that resource to better align the costs of a particular resource with that state's resource selection outlook.

(3) *Pseudo-Separation*[31]: Separate the generation portfolios serving North Dakota and the remainder of the NSP System, without changing the corporate structure of NSPM, by assigning the benefits and burdens of a resource to the states that support it and developing separate resources for non-approving states should they be needed.

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[31] In past filings with the NDPSC, we have sometimes referred to this structure as the "Pricing Zone Concept." *See N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, *et al.*, PRE-FILED DIRECT TESTIMONY OF DAVID SEDERQUIST IN SUPPORT OF NEGOTIATED AGREEMENT at 8 (NDPSC Nov. 30, 2015).

(4) *Separate Operating Company or Legal Separation*: Establish a separate operating company to serve our North Dakota customers.

We have described these structures as being part of a spectrum of options – meaning they span a range of outcomes from full integration with every resource serving a unified NSP System, to full, legal separation with a new operating company serving our North Dakota customers.

In analyzing each alternative, the Company is focused on selecting the most effective solution that delivers on the principles of state sovereignty and cost recovery. Feasibility of implementation is also imperative. To that end, the next section outlines the conceptual opportunities and challenges associated with each RTF alternative. We further identify obstacles to implementation or to achievement of overall equity. Our quantitative resource planning and revenue requirement analyses follow this baseline assessment of alternatives.

1. <u>Regulatory Alignment</u>

Regulatory alignment seeks to maintain the integrated nature of the NSP System while recognizing that we have entered a period in which interjurisdictional disagreements have become commonplace. In concept, the states we serve would agree that only those customers of states that approve a given resource will bear the costs of that resource even if the resource serves the entire System. In the event agreement cannot be reached, the Company would not move forward with a particular resource.

Regulatory alignment, then, places a high value on maintaining integration. Additionally, that agreement must be reached on the cost allocations before the Company will move forward with a given resource speaks to the principles of state sovereignty and cost recovery. But it does so at the risk of planning to meet only those common resource needs consistent with all states' planning paradigms. This may mean the Company would not implement resource additions that a particular state may consider a high priority but which another state (or states) does not support.

Notably, seeking early input to help pursue better alignment of regulatory outcomes was a component of the settlement adopted by the NDPSC in our 2008 North Dakota rate case.[32] There, the focus was on bolstering the NDPSC's oversight of Company resource decisions by formalizing the filing and review of the Company's Upper Midwest IRPs in North Dakota and requiring that our analyses include North

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[32] *See N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT at 4-6 of Settlement Agreement (NDPSC Dec. 31, 2008) (Appendix E).

Dakota modeling sensitivities. The *Settlement* in that proceeding also provided the NDPSC with an opportunity to assess the Company's resource decisions prior to implementation through the filing of Advance Determination of Prudence (ADP) applications with the NDPSC for "major" transmission and generation resources.[33]

To date, our experience has been that these procedural changes have only underscored the extent of jurisdictional disagreements. For example, the North Dakota analysis now included in the Company's IRP filing has only served to further illustrate the differences between North Dakota and Minnesota without providing a procedural avenue to reconcile those differences. Should we move forward with a regulatory alignment structure, it will be necessary to modify the IRP process so IRPs can act as a true vehicle to better align outcomes in the states we serve. This is especially the case as significant resource retirements are being considered.

Similarly, bringing forward resources for evaluation under North Dakota's ADP law[34] has provided earlier identification of resource selection disagreements without means of resolving those disagreements. When we undertook the 2008 rate case settlement, the North Dakota ADP statute was recently enacted. Prior to that time, almost all resource decisions were reviewed after the fact in North Dakota rate cases. Under the rate case review paradigm, new resources (and retired resources) could be assessed in a holistic manner while reviewing all of the Company's other costs and their drivers. While we appreciate advanced reviews of resource selections by the NDPSC through the ADP process, this process can result in review of individual resources with less consideration of the larger, system-wide context in which resources are selected.

Additionally, interpretation of the ADP statute has evolved in a way that creates a new form of uncertainty regarding resource approvals. Under the NDPSC's interpretation of the ADP statute, resource *approval* is binding for future cost recovery purposes but *rejection* of an ADP is not binding. Consequently, although an ADP provides some guidance as to potential future NDPSC action on a particular resource, a rejection provides no definitive decision upon which the Company can act.

The use of ADPs has been helpful where agreement exists and in providing earlier identification of potential disagreements between the NSPM states regarding certain resources. This has given the Company more information as it assesses whether to move forward with a resource and in seeking commercial solutions where

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[33] *N. States Power Co. Elec. Rate Increase Application.*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT at 4-7 of Settlement Agreement (NDPSC Dec. 31, 2008) (Appendix E); *In the Matter of Xcel Energy's Filing on Jurisdictional Cost Issues*, Docket No. E002/M-16-223, COMPLIANCE FILING at 21-23 (MPUC June 13, 2016) (Appendix B).

[34] N.D.C.C. § 49-05-16.

disagreements exist. Accordingly, up to now, rejection of an ADP by the NDPSC has not resulted in any project cancellations. However, this is not sustainable. To the extent the Company's ability to recover its costs is put in jeopardy by failure to obtain an ADP, it may become necessary to cancel such projects rather than risk under recovery of investments.

The various ADP proceedings have also provided additional clarity or confirmation regarding various aspects of the NDPSC's planning paradigm,[35] including: (1) recognition by the NDPSC that the state that hosts a particular resource retains the ultimate decision-making responsibility regarding its future; (2) the NDPSC's requirement to better match the timing of load serving need and resource additions; and (3) movement toward accepting that resources, though perhaps not intended to meet a specifically identified load-serving need, drive down overall system cost.[36] Future resource alignment, if it is the preferred outcome, will benefit from understanding these principles.

We modeled certain outcomes based on regulatory alignment with respect to known Disputed Resources in our IRP, but at this time, we cannot predict where or to what extent each of the states we serve might compromise to achieve regulatory alignment over the longer term. Nor do we gain more information about the viability of Regulatory Alignment by modeling structural changes, since Regulatory Alignment assumes continuation of full integration of the NSP System. As such, we present the Regulatory Alignment option as a general approach, rather than an alternative that is transformative from a resource planning or ratemaking standpoint. We anticipate further dialogue on this option through this proceeding.

2. Proxy Pricing

Another alternative structure is to institute a proxy pricing overlay to resource selections of the various NSPM states. This type of structure is premised on the

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[35] *N. States Power Co. Elec. Rate Case*, Case No. PU-400-87-6, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 30 (Mar. 24, 1988) ("We expect NSP to continue to use least cost planning to supply energy at the lowest possible cost. In this regard, we define 'least cost planning' or 'integrated resource planning' for an electric utility to be the consideration of both supply- and demand-side options in selecting the least cost method of meeting the energy and demand needs of customers. The demand-side and supply-side resources considered will be evaluated in terms of benefit/cost criteria. A resource will be considered as passing the primary test for cost effectiveness if it can satisfy load at a lower cost to the utility than any other resource. Once this test is satisfied, the resource will be further considered in terms of other impacts: rate impacts, environmental impacts, load profile impacts and other pertinent impacts. If these other impacts do not negatively outweigh a favorable benefit/cost ratio for the resource, the resource should be adopted.").

[36] *See, e.g.*, *N. States Power Co. Advance Prudence – 200 MW Courtenay Wind Farm Application*, Case No. PU-15-181, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (NDPSC Aug. 24, 2015).

concept that different states value different types of resources differently. Thus, the logic behind proxy pricing is that all states accept that resources provide, at a minimum, capacity and energy to the NSP System and that those benefits should be paid for by all jurisdictions. The use of proxy pricing would provide that payment for the capacity and energy supplied by a particular resource while leaving the difference between the proxy price and the actual price (either positive or negative) to be recovered from the jurisdictions that support a particular resource type over others.

The Proxy Pricing concept is intended to address the "type" question when analyzing resources from a size, type, and timing perspective. It may also require compromises regarding size and timing, recognizing that adding a certain size and type of resource today may affect the size and type of other resources needed in the future.

A Proxy Pricing structure can be most successful when utilized to level differences between jurisdictions regarding 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 the other state does not, utilizing a Proxy Pricing regime can mitigate the cost shift of the mandated resources to the non-mandating states while still having all states contribute to the energy and capacity of a particular resource. By addressing a particular set of resources, such as those required by renewable energy mandates, the application of proxy pricing is cabined to a small subset of resources.

However, a Proxy Pricing structure is less capable of addressing different views regarding resource additions when they are not easily defined as mandated or when there is a mismatch in size and timing as well as type. It would be necessary and complex to determine the extent to which proxy pricing is needed in each case where there is disagreement on a type of resource, and only some level of agreement on the need for a resource of a particular size at a particular time.

Accordingly, a Proxy Pricing outcome requires ongoing inter-jurisdictional coordination and is most effective when a limited set of resources that would be subject to proxy pricing can be clearly defined. In such circumstances, larger system integration is feasible and a minority of resources can be addressed through proxy pricing. This is consistent with our experience addressing the different renewable energy mandates between our Texas and New Mexico jurisdictions. For example, the New Mexico Renewable Portfolio Standard required the acquisition of five solar PPAs. To retain the integration of the Texas/New Mexico system, Southwestern Public Service Company proposed, and the New Mexico Public Regulation Commission approved, a proxy pricing model that allowed: (1) Texas to pay its allocated share of the costs of the PPAs up to the system avoided energy costs, which meant Texas retail customers were indifferent as to the acquisition of the PPAs; and (2) New Mexico to pay the remainder of the PPA costs to keep Southwestern Public Service Company whole.

Recent history makes clear, however, that (as discussed previously in Section III.B of this Application) the resource misalignment between the NSPM states touch more than just those resources related to Minnesota's renewable mandates and that trend may well continue into the future. By way of example, the Company has developed a plan to add significant wind resources beyond what is currently needed for compliance, because doing so is economically beneficial. While we have not brought that plan before either Commission for formal approval, initial feedback from the Commissions leads us to believe that our proposal may receive different treatment in North Dakota and Minnesota.

Further, as new technologies become available we would likely need to institute new proxy pricing terms to address the impact of these technologies on the system. These experiences call into question whether proxy pricing is a viable long-term solution.

Our experience in negotiating the "Restack" of the NSP System under the settlement of our 2013 test year North Dakota rate case, Case No. PU-12-813, further underscores the weaknesses of the Proxy Pricing approach. There, even though the parties were working from ten guiding principles, they were unable to reach agreement on proxy pricing. Key impediments to success included determining the appropriate pricing proxies and how to address resources added to the NSP System that were not determined as "needed" under North Dakota's resource planning paradigms. These concerns continue to counsel against a Proxy Pricing structure at this time.

3. Pseudo Separation

Given the difficulties in developing an equitable Proxy Pricing structure, we also explored how to maintain the overall integration of the NSP System and legal structure of NSPM by allowing the system to continue to jointly serve North Dakota, South Dakota, and Minnesota while direct assigning certain generating resource costs and benefits to individual states where there is disagreement. We call this a "Pseudo Separation" because it would effectively separate generation portfolios serving different states, but would not legally alter the existing Xcel Energy corporate structure nor impact other ratemaking paradigms in the states.

At its simplest, a Pseudo Separation structure assigns the entire bundle of benefits and burdens of a resource to the states that support it without changing the corporate structure of NSPM. The bundle of benefits and burdens includes costs (such as the PPA price for contracted resources or capital and operations and maintenance (O&M) of Company-owned resources); revenues (from sale of output into the Midcontinent Independent System Operator (MISO) energy market or of unit-specific capacity); resource planning/adequacy attributes (such as capacity value and energy); and other values (such as environmental credits). In many ways, Pseudo Separation identifies the economic portions of how a particular generation interacts with rates and seeks to ensure costs and benefits are allocated to the cost causative and supportive jurisdictions.

The first question with respect to Pseudo Separation was whether it is feasible, which includes determining how, if at all, we could assign the costs, revenues, and attributes of a particular resource to a particular jurisdiction. We also needed to assess how states that do not participate in a particular resource would be served when that resource is dispatched by MISO. Our feasibility screen indicated that Pseudo Separation was technically feasible though complex, as it would require ongoing accounting and other operational refinements.

At its core, Pseudo Separation would account for generation activities on a generator level rather than on the system-wide level upon which we allocate costs and revenues today. Pseudo Separation would essentially reallocate the economic impacts of the federal market overlay, bi-lateral transaction, and MISO dispatch of the NSP System to particular states. More specifically, to implement Pseudo Separation, MISO day-ahead and real-time market transaction revenues would be allocated to each generator so that revenues can then be allocated to particular jurisdictions based on their participation (or lack thereof) in a particular generation resource. Non-participating jurisdictions would pay the MISO locational marginal price (LMP) as if market purchases were being made in place of dispatching system generation resources in which they do not participate. Pseudo Separation would also address the revenues from generation margins and ancillary services, revenue sufficiency guarantee uplifts, and other MISO market constructs. Capacity sales and purchases would be similarly allocated, as well as renewable energy credits (RECs) and other non-power-based attributes of a particular resource. Similarly, each state's load could be treated as a separate entity for bidding purposes. We provide additional detail regarding the mechanics of Pseudo Separation in Schedule 6.

For resource planning purposes, under Pseudo Separation, we would establish separate Loads and Resources tables for each state to reflect the specific generation mix in which a particular state has chosen to participate. We would then plan for each state's load serving needs and energy policy priorities separately. Over time, this would result in different resource mixes serving different states.

We anticipate several advantages to a Pseudo Separation structure. By separating resource assignments as between North Dakota and the remainder of the NSP System, Pseudo Separation would enable the Company to plan for differing future views of need and resource selection between the states we serve. Because we would be direct assigning costs to the jurisdiction(s) for which the future resource is selected and approved, cost recovery would also be more specific to the state(s) that approved the resource. This structure therefore allows the Company to plan for resources with more flexibility in each part of the System, and with more certainty that the otherwise reasonable costs of a selected investment will be recoverable.

Further, Pseudo Separation does not require structural changes to the Xcel Energy corporate organization since NSPM would continue to provide service in Minnesota, North Dakota, and South Dakota. Rather, the separation occurs at the resource selection and cost allocation level, meaning that once there is agreement on resolution of past resources, Pseudo Separation could be implemented in our next rate case following the end of this proceeding. As such, the overall implementation of this structure is expected to be less expensive and less complex up front than creating a new North Dakota-serving corporate subsidiary would be under the Legal Separation alternative discussed below.

Pseudo Separation also presents challenges, as it requires some initial interstate decisions regarding how to assign pricing, and may require ongoing cooperation between the NSPM states to manage a Pseudo Separation structure into the future. While we currently manage resources on a system-wide, aggregated basis, Pseudo Separation would require a unit-specific management approach. This, in turn, requires related ratemaking choices to manage the newly unit-specific nature of the system.

For example, we would need to determine – and obtain approval in multiple jurisdictions for – the appropriate load node pricing to be paid by a particular jurisdiction. Because the vast bulk of the NSP System is located in Minnesota, the main load pricing node providing the cost the Company pays for energy is MISO's NSP.NSP node,[37] located in the heart of the NSP System in Minnesota. A successful Pseudo Separation structure would require determination of the energy costs paid by each load node. There are multiple ways to accomplish this: we could use NSP.NSP as the pricing node system-wide; we could use each and every load node closer to our

[37] By managing the NSP System on an integrated basis, we bid our various loads at their node but allocate costs as an integrated whole. Since the vast bulk of NSP System load is located at the NSP.NSP load node, our average System costs generally reflect this load node pricing.

load – such as OTP.NSP for our North Dakota load; or we could use the load nodes closest to the generation being dispatched. Each of these choices is justifiable, but will need to be made initially and continually agreed to in all of the NSPM states to achieve sustainable implementation of this structure.

A Pseudo Separation structure also would likely require us to change other ways we analyze and operate the NSP System. For example, we currently consider distributed energy resources as generating resources serving the entire system in our resource planning. However, these resources are not dispatched by MISO and instead are viewed by MISO as a reduction in load for MISO's energy market operations. Consequently, we receive no MISO revenues for these generation resources and pay no market costs for the equivalently-reduced load. We would therefore need to shift allocation factors between the states, and find agreement between states as to how this should be accomplished to equitably establish a Pseudo Separation structure. In addition, MISO has recently proposed a capacity market structure for retail choice states.[38] While this does not impact the NSP System directly, the Pseudo Separation structure would need to be changed to accommodate a new federal overlay if such changes occur in the future.

Lastly, implementing a Pseudo Separation structure could impact the NSPM/NSPW relationship through the existing Interchange Agreement. We would have to make appropriate accommodations to address this.

We believe each of these tasks is achievable and would maintain all other benefits of the System status quo while addressing generation resources and ensuring equitable management of the costs incurred on the NSP System to date. Accordingly, we believe this alternative warrants further discussion.

4. Legal Separation

The final structure we analyzed was the creation of a separate operating company, "NSP-Dakota" or "NSPD," to serve our North Dakota customers. We evaluated the Legal Separation option because it provides stability and flexibility on a going-forward basis that we believe can provide long-term value to the Company, our customers, and our various stakeholders. However, Legal Separation is also the most complex and difficult alternative to implement initially.

[38] *Midcontinent Indep. Sys. Operator, Inc.*, FERC Docket No. ER17-284, PROPOSED COMPETITIVE RETAIL SOLUTION IN NEW MODULE E-3 AND CORRESPONDING REVISIONS TO EXISTING TARIFF SECTIONS IN Modules A, D, AND E-1 (Nov. 1, 2016).

Under a Legal Separation structure, we would serve our customers in North Dakota through a separate operating company that would continue to be part of the Xcel Energy Inc. corporate family. At the time of creation, NSPD would be the regulated entity in North Dakota and its rate base, operating expenses, and fuel costs would form the basis of its rates. This is in contrast to the allocated portion of the NSPM rate base, operating expenses, and fuel costs that are currently underlying the rates of our North Dakota customers. This revenue requirement structural shift, which is addressed in the Revenue Requirement Analysis section of this Application, is a key component of evaluating this RTF structure.

Once formed, a separate operating company provides a platform from which we can address the resource needs of the jurisdictions we serve on a truly individual basis. The key advantages of Legal Separation are certainty and flexibility by creating distinct entities with distinct needs and the capacity to take on separate legal liabilities and separate corporate ownership of assets. This structure permanently removes the need for agreement between all states regarding the reasonableness and prudence of not only resource selection, but also all costs (such as depreciation and taxes) that may lead to incompatible ratemaking and cost recovery outcomes across the NSPM states.

Legal Separation also creates greater opportunities for the Company to more fully participate in valued investments in North Dakota, such as development of gas generation, without requiring the agreement of the other NSPM states or to incur liabilities for NSPM. By legally separating, the new operating company would own its own assets, have its own contractual relationships with third-parties, and therefore have its own corporate existence separate from NSPM and the regulatory requirements or decisions of other states.

Consistent with our proposed RTF, Legal Separation does not mean that we must fully dis-integrate the NSP System. Rather, it will merely change the relationship of our North Dakota customers to the remainder of the NSP System. More specifically, we envision that rather than being allocated a share of the costs of the Legacy System, NSPD would transition to a unit-specific supply agreement with the NSP System to take service from the Legacy System. NSPD could then work with North Dakota regulators to establish future resource selections that suit North Dakota's views of need and appropriate types of cost-effective resources for North Dakota customers.

That said, establishing a new operating company requires significant up-front cost and effort. It would first be necessary to determine the size, scope, and structure of the new operating company. For example, we would need to establish whether NSPD will serve only our North Dakota load, or whether it will also serve our South Dakota load – which would effectively double the amount of customers served. It is also necessary to determine what assets will be owned by each operating company after separation. This determination requires evaluation of the distribution system, transmission assets, and generating resources. Issues such as size of load of the new operating company, costs of providing service through MISO, and supply mix and form will all need to be determined.

Decisions regarding what assets would comprise NSPD's rate base and how to provide transmission and generation service to NSPD would be multifaceted. For example, if the current North Dakota-based transmission assets become part of the NSPD rate base, close to 100 different transmission agreements will need to be assigned or amended to accommodate transmission service to the new entity. This is but one example of the implications of unwinding the integrated system in order to establish NSPD.

We would also need to determine how a new operating company should be managed at the corporate level, what employees it will have, and what services it will take from its affiliates within Xcel Energy Inc. It would then be necessary to establish service agreements that direct assign specific costs and allocate common costs, including, for example, how we would support our Dilworth and East Grand Forks customers in Minnesota from service centers in North Dakota.

We would also need to determine immediate supply options and mid-term plans for meeting generation and transmission needs of the new operating company. This includes ensuring that any liabilities incurred for use of the NSP System stay with the new operating company, as well as determining how to structure a supply agreement with the NSP System. Additionally, it would be necessary to determine whether and how NSPD would utilize the market structures that were not available to it when the NSP System was developing. This determination includes assessing how to provide hedges against MISO market costs that will no longer be provided to North Dakota by the larger NSP System.

Last, Legal Separation is potentially costly. We estimate that an investment of several million dollars will be required to establish a new operating company.

These structural decisions would present challenges, but – like the challenges associated with Pseudo Separation – we do not believe that they are insurmountable. Further, the very process of working through these issues would provide our stakeholders greater insight into the contributions and costs to the System of the various states we serve.

B. Initial Conclusions

As a result of our evaluation, we concluded the RTF should enable the Legacy System to serve all states while affording North Dakota and Minnesota a certain degree of control in their future resource selections. To that end, we propose to have the RTF allow for the separation of North Dakota from the NSP System. A separation alternative becomes particularly desirable as we look ahead to an overall fleet transformation.

Two of the future separation structures presented – Pseudo Separation and Legal Separation – could, over time, satisfy this RTF.[39] Either structure would result in our North Dakota customers being served by their own resource mix – either as part of NSPM or as a separate operating company. Therefore, it is necessary to determine whether it is economically feasible and reasonable to serve North Dakota outside the integrated system. It is also necessary to determine the impact of the loss of the North Dakota load to the remainder of the NSP System. These questions form the basis of our resource planning analysis, which is described in more detail in Section V below.

A revenue requirement analysis is also necessary to evaluate the costs of establishing Pseudo Separation, or of forming a new operating company under a Legal Separation structure. Our revenue requirement analysis is described in Section VI of the Application.

V. RESOURCE PLANNING ANALYSIS

In addition to the qualitative assessment of various structures that might support our RTF, we undertook a robust resource planning analysis that identified the costs and benefits of system integration. Our analysis also assessed cost mitigation strategies so that an implemented RTF would result in reasonable impact to all our customers.

We utilized our Strategist resource planning tool to facilitate our resource planning analysis. While Strategist is a useful tool, it is a modeling tool and therefore only as good as the assumptions that underlie the model. We believe that we have used reasonable assumptions to conduct our analysis, but we stress that these are only assumptions. Further, it is necessary to recognize that the impacts of the RTF could be permanent – or at least last for decades, during which the NSP System will evolve, along with technologies, legal requirements, and the industry as a whole. It is not fully possible to predict all the forms this evolution will take, nor all the potential impacts

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[39] Either RTF separation structure can be expanded to include South Dakota.

on our customers. Therefore, while we believe our resource planning analysis supports our recommendation, it is intended to validate our more qualitative assessment of the need for and reasonableness of our proposed RTF rather than to determine optimal resource choices as in a resource plan or resource selection proceeding.

The steps in our resource planning analysis, which are described in more detail in this section of our Application, are as follows:

- *Evaluate an Equitable Legacy System through allocation of Disputed Resources*: First, we validated the potentially equitable allocation of Disputed Resources which underlie our resource planning analysis to help ensure that we are fairly allocating costs and benefits for those Disputed Resources.

- *Establish the Baseline Future NSP System:* Next, to evaluate options for the future of the NSP System, we established a "status quo" baseline. However, even that process cannot be based on static information. Our resource planning analysis begins with the presently known future of the NSP System, consistent with the outcome of our most current IRP proceeding (referred to as the IRP Plan). However, most of the assumptions that were developed for the IRP proceeding are nearly two years old, as we first submitted the IRP in early January of 2015. Consequently, we also present a view of the IRP with updated modeling assumptions, as well as our currently forecasted amount of wind acquisitions and updated pricing that we will fully present to the MPUC in March (referred to as the Updated Plan). These analyses establish a baseline from which to continue to analyze our RTF.

- *Determine the Impact of the North Dakota Load on the NSP System*: We then assessed the impact of the North Dakota load on the NSP System to understand the effect of the potential loss of the North Dakota load on the remainder of the NSP System and the effect to North Dakota of exiting the integrated system. With this information, we sought to identify a date on which we could equitably establish a separate North Dakota-based generation portfolio.

- *Assess Continued Service to North Dakota from the Legacy System*: We also examined the reasonableness of continuing to serve North Dakota from the Legacy System. As discussed earlier in the Application, the various principles we have established for managing the NSP System recognize the history and value of the Legacy System; therefore, to develop an RTF we needed a resource planning assessment of the equities of continuing to serve North Dakota from the Legacy System. We identified two potential generation portfolios that could serve North Dakota and reflect a high capital cost and low capital cost resources to separately serve our North Dakota customers. These potential portfolios act as comparison points by which we could determine the impacts and validity of our proposed path to continue to largely serve North Dakota with the Legacy System after the point of separation identified in the second phase of our analysis.

- *Evaluate a North Dakota Separation Scenario:* We then analyzed a scenario under which North Dakota would largely leave the Legacy System (an exit scenario) after the 2025 equitable exit date established by our analysis. While we are not proposing an exit scenario, we recognize that either or both Commissions may prefer an exit scenario if the baseload resources presently existing on the NSP System should evolve more quickly than presently contemplated, as such an exit scenario could better allocate the costs and liabilities of an accelerated transformation of the NSP System. We also believe that informing the record with an exit scenario is important. As described above, should an exit scenario occur, we are proposing that our North Dakota customers continue to be served by our nuclear portfolio to provide baseload generation and fuel diversity to North Dakota and for reasons of equity. Therefore, our analysis of these scenarios includes continued service in North Dakota by our nuclear fleet.

Our resource planning analysis is equally applicable to both the Pseudo Separation and Legal Separation structures, as the cost of particular generation portfolios would likely be equivalent under both structures. The main difference between the two would be that under the Pseudo Separation structure, the costs of different service options would be allocated through state-based ratemaking allocations, whereas under a Legal Separation structure the costs of different service options would be allocated contractually between the new NSPD and the remainder of the NSP System.

We have conducted our analysis on a present value of societal cost (PVSC) basis (with externalities) and a present value of revenue requirements (PVRR) basis (without externalities).[40] Our potential allocation of Disputed Resources, described further in Section VI.A, is included in our analysis.

[40] Consistent with the proceedings in NDPSC Case No. PU-12-59, we have removed the capacity credit from the PVRR analysis presented in this Application. We provide a PVRR analysis with the capacity credit included for all scenarios analyzed in this Application in Schedule 7 as the $PVRR_{cc}$ sensitivities. Please see Schedule 7 for a further discussion regarding the analyses and our modeling assumptions.

A. Potential Equitable Resolution of Disputed Resources

To establish a resource planning analysis baseline, we first sought to determine a potentially equitable allocation of the Disputed Resources. Based on the implementation timing of our RTF, we also sought to determine the impact of our new wind additions (currently scheduled to go in-service in 2020 – at the same time we plan to implement our RTF) as part of our resource planning analysis. Beginning with our Updated Plan, we compared (1) an RTF that continued service by the Legacy System comprised of all resources on the NSP System and an allocation of the new wind additions to all states consistent with current allocation methods to (2) an RTF that allocated the North Dakota share of the Disputed Resources, except MEC II, to the remainder of the NSP System, as well as allocating all of the new wind resources to all states of the NSP System except North Dakota, consistent with the description of an equitable path forward on the Disputed Resources above. A summary of the results of that analysis are presented in Table 1, below. We present the annual impact in Schedule 7.

Table 1: Costs of the Reallocation of Disputed Resources Compared to Shared 1500 MW Wind

PVRR, $M	**MN/SD/NSPW**	**ND**
Shared Legacy, Jur Future, Share 1500MW wind	48,435	2,430
Shared Legacy, Jur Future, Jur Reallocated Disputed Resources and wind	48,404	2,467
PVRR Delta, $M	**MN/SD/NSPW**	**ND**
Shared Legacy, Jur Future, Share 1500MW wind	-	-
Shared Legacy, Jur Future, Jur Reallocated Disputed Resources and wind	(32)	37

As shown in Table 1, over the modeling period, reallocating the North Dakota share of the Disputed Resources to the remainder of the NSP System while also allocating all of our new wind additions to the remainder of the NSP System results in approximately $32 million savings on a PVRR basis to the NSP System states and approximately $37 million in additional costs on a PVRR basis to North Dakota. The impact of these long-term cost shifts are moderated by the fact that in the near term, North Dakota will realize immediate cost savings from this potential allocation of Disputed Resources (as shown in our revenue requirements analysis below). Because of the long-term savings to Minnesota and the short-term savings to North Dakota, we believe this analysis validates a potential path to address Disputed Resources.

B. The Baseline Future NSP System

Having reached one potentially equitable resolution of past Disputed Resources, our next task was to establish a baseline against which to measure the potential effects of future changes to the NSP System. We identified the Reference Case from our IRP proceeding as a reasonable comparison point against which to measure the future of the NSP System. The Reference Case represents a future look at the NSP System that we believe would have met our minimum system needs and compliance obligations in all states. The Reference Case assumes that Sherco Units 1 & 2 will run through the planning period's end at 2030, adds 400 MW of wind by 2020, has 287 MW of utility scale solar representing our 187 MW solar portfolio and the Aurora Solar project, and then adds only combustion turbines to meet capacity needs consistent with the Loads and Resources analysis presented in our recent IRP.[41]

Given that the assumptions underlying the Reference Case are from the December 2014 modeling underlying our January 2015 initial IRP filing, we then updated the Reference Case to account for new, updated assumptions regarding load growth, renewable energy pricing, and gas pricing, among others. This provides us a similar comparison point with updated assumptions rather than carry forward our 2014 modeling assumption from the IRP proceeding. We also applied the same updated assumptions to the outcome of the IRP. The Updated Reference Case removes three combustion turbines from the Reference Case in 2025, 2027, 2031, 2032, and 2033, and adds an additional combined cycle unit in 2032.[42]

We also modeled an expansion plan based on the IRP Plan. This includes the addition of at least 1000 MW of wind by 2020, the closure of Sherco Units 1 & 2 in 2026 and 2023, respectively, and an additional 800 MW of utility scale solar additions.[43] We note that notwithstanding the MPUC's decision that all resource types be considered to meet capacity needs in the out-years of the planning period, our analysis here assumes those needs are met by combustion turbines for the sake of simplicity and uniformity. Additionally, given the uncertainty surrounding the costs of acquiring demand response resources, the MPUC's order for up to 400 MW of

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[41] The use of combustion turbines to meet capacity needs is consistent with our IRP assumptions and is assumed throughout our resource planning analysis. We recognize that many of the capacity needs in the mid-2020s will be due to expiration of PPAs that may be renewed. However, given the uncertainty as to the terms of any potential renewal, our analysis in this Application assumes combustion turbine additions in place of PPA renewal throughout.

[42] Expansion plans for the Reference Case and the Updated Reference Case are provided in Schedule 7.

[43] Consistent with current practice, our resource planning analysis assumes that the costs for Solar Gardens (labelled "small solar" in the IRP Plan) are wholly recovered in Minnesota and not allocated to the other states of the NSP System.

demand response resources in 2025 is not included in our analysis.[44] Table 2 below provides the IRP Plan.

Table 2: IRP Plan

IRP Expansion Plan	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Small Solar	10	259	159	91	83	76	17	20	24	29	34	41	49	59	71	85	-	-	-	-	-	1,107
Large Solar	-	-	287	-	-	-	200	100	100	200	100	100	-	400	-	-	-	-	-	-	-	1,487
Wind	350	200	200	-	1,200	-	-	-	-	-	400	200	-	-	-	-	-	-	-	-	-	2,550
PPA CT	-	-	-	-	-	-	-	-	-	-	460	460	460	230	-	-	-	-	-	-	-	1,610
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	778	778	-	778	778	3,457
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	-	-	-	-	-	230
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	-	-	-	-	-	786

We then updated the IRP Plan (Updated Plan) using current assumptions much like we did for our Reference Case. This updating also accounted for our currently known wind expansion plans. These updates include a new sales forecast, updates to gas pricing assumptions, and updated renewable energy pricing for wind and solar. Our updated assumptions are presented in Schedule 7. Table 3, below provides our Updated Plan.

Table 3: Updated Plan

Updated Expansion Plan	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Small Solar	10	259	159	91	83	76	17	20	24	29	34	41	49	59	71	85	-	-	-	-	-	1,107
Large Solar	-	-	287	-	-	-	-	300	100	200	100	100	-	400	-	-	-	-	-	-	-	1,487
Wind	350	200	200	-	1,500	-	-	-	-	-	100	200	-	-	-	-	-	-	-	-	-	2,550
PPA CT	-	-	-	-	-	-	-	-	-	-	230	460	230	230	-	-	-	460	-	-	-	1,610
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	778	-	-	778	1,556	3,457
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	-	-	-	-	-	230
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	-	-	-	-	-	786

Table 4, below, provides the system-wide impact of our Reference Case, our Updated Reference Case, our IRP Plan, and our Updated Plan on a PVSC and PVRR basis.

Table 4: Cost of Resource Plan to NSP System

	BASE CASE	
Total System, $M*	**PVSC**	**PVRR**
IRP Reference Case	43,513	38,603
IRP Plan	43,375	39,552
Updated Reference Case	44,987	40,753
Updated Plan	44,069	40,955
Delta, IRP Assum	(138)	949
Delta, Current Assum	(918)	202

** NPV calculations in this table are through 2040*

The North Dakota impact analysis is presented in Table 5 on a PVSC basis and PVRR basis.

[44] Additional demand response resources could be a substitute for the combustion turbines identified in the IRP Plan.

Table 5: Cost of Resource Plan to North Dakota

	BASE CASE	
ND Jur, $M*	**PVSC**	**PVRR**
IRP Reference Case	2,441	2,243
IRP Plan	2,413	2,272
Updated Reference Case	2,224	2,068
Updated Plan	2,169	2,062
Delta, IRP Assum	(28)	29
Delta, Current Assum	(54)	(6)

* *NPV calculations in this table are through 2040*

Figures 1 and 2, below, show the system-wide costs of the IRP Plan and the Updated Plan compared to each respective Reference Case, relative to each other on a PVSC and PVRR basis.

Figure 1

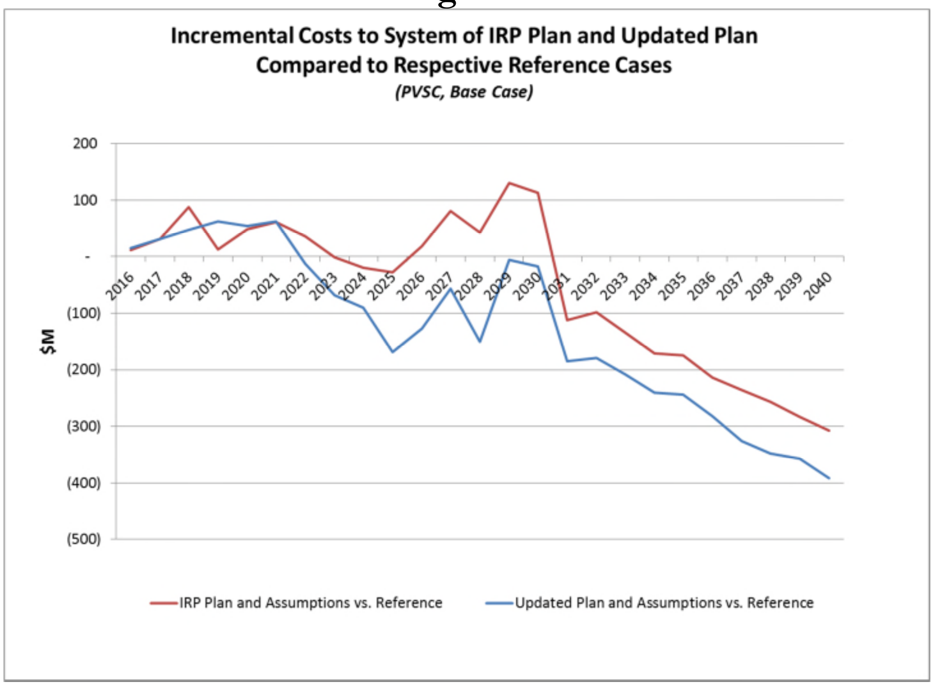
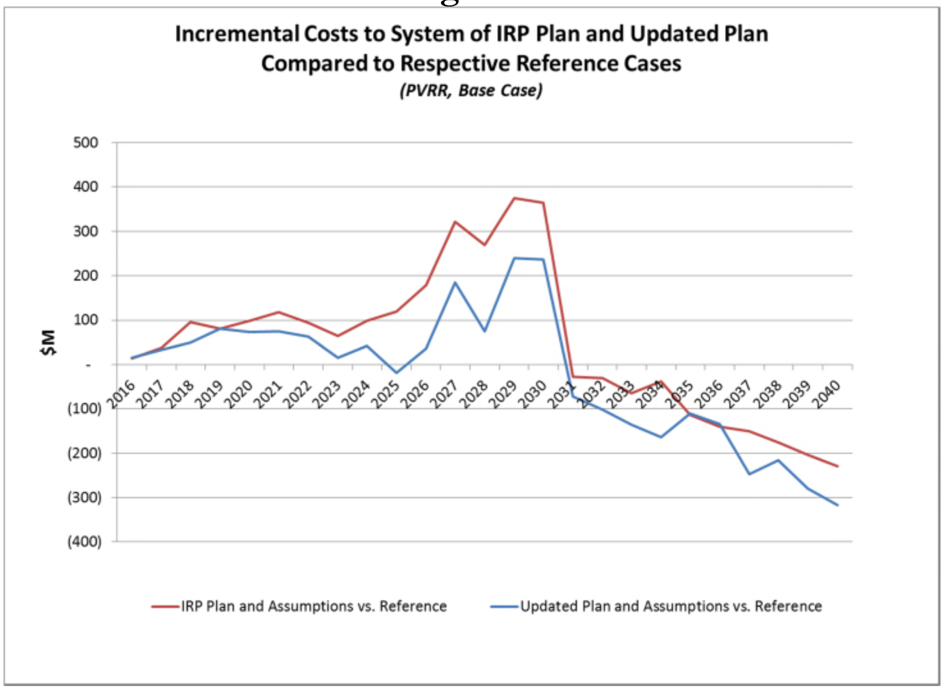


Figure 2



Figures 3 and 4, below, show the cost impact to North Dakota of the IRP Plan and the Updated Plan compared to each respective Reference Case, relative to each other on a PVSC and PVRR basis.

Figure 3

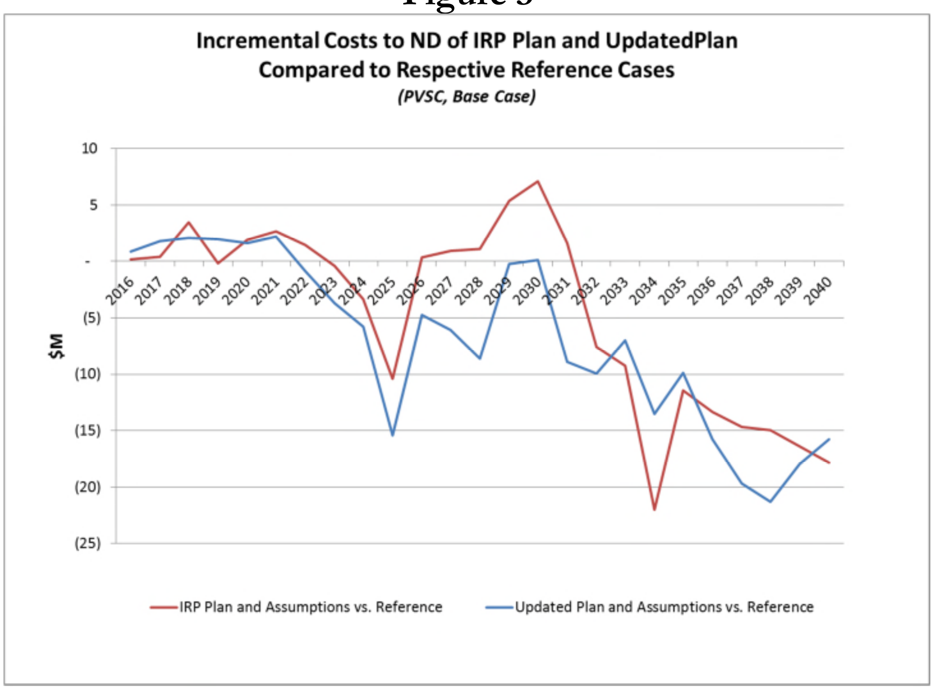
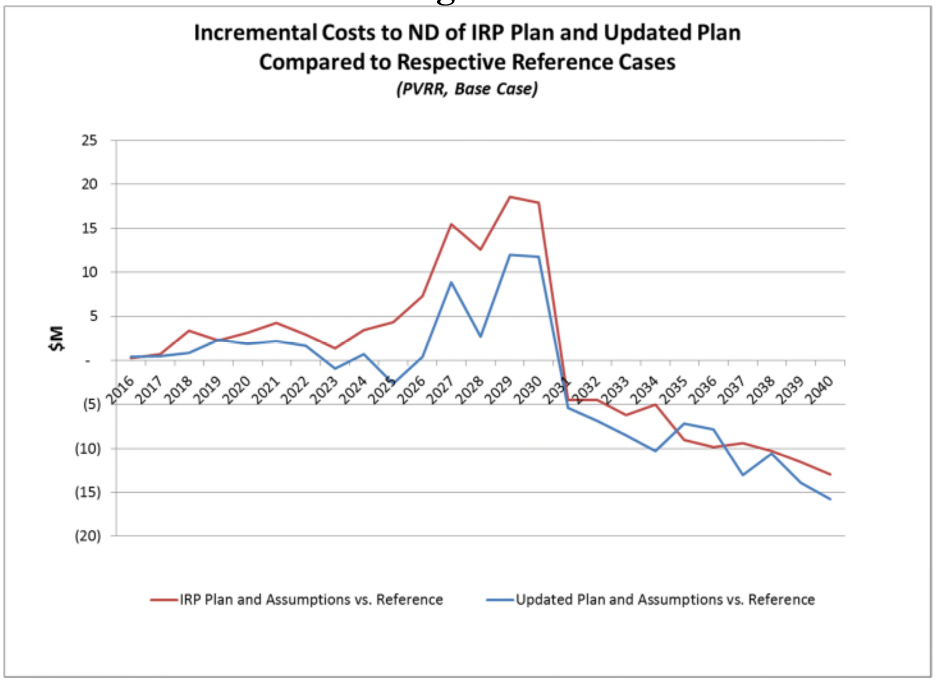


Figure 4



Our baseline analysis identified that based on the modeling assumptions in our recently MPUC-approved IRP, the IRP Plan was more expensive than the Reference Case on a PVRR basis, while on a PVSC basis was somewhat less expensive than the Reference Case over the life of the plan. When we updated both the Reference Case and the IRP Plan with new information, especially renewable pricing and the increased amount of production tax credit (PTC)-eligible wind in the model, the results changed and the Updated Plan became less expensive on both a PVSC and PVRR basis.

That said, both the IRP Plan and the Updated Plan accelerate the need to make material capital investments in the NSP System due to the closure of Sherco Units 1 & 2 in the mid-2020s when compared to their respective Reference Case. In the long-run, this is smoothed out as the capital investments planned for 2030 in the Reference Cases are merely accelerated and there is less cost impact than in the Reference Cases in 2030 and beyond due to depreciation of the capital investment beginning earlier. The impacts of accelerated investments are also materially mitigated in the Updated Plan based on the fuel savings attributable to increasing the amount of PTC-eligible wind on the System. However, given the accelerated impact to system costs and informal concerns raised by the NDPSC and its Staff regarding the accelerated closure of Sherco Units 1 & 2, we are assuming that the Updated Plan will still be unacceptable in North Dakota, notwithstanding its overall lower modeled costs over its life.

Establishing this baseline view helps to demonstrate that our proposed RTF is appropriate. The MPUC approved a resource plan that was least cost when externalities were accounted for and not least cost when they were not. This tends to support an assumption that the resource planning outlooks of North Dakota and Minnesota are incompatible.

C. North Dakota Load and the NSP System

We next performed an examination of the impact of the North Dakota load on the NSP System. We undertook this analysis to determine the magnitude of the costs of the NSP System carried by our North Dakota customers and what the impact would be to the remainder of the NSP System should it lose the customer base that constitutes our North Dakota load.

We chose 2023 as the earliest date to perform this analysis because it is the earliest reasonable time by which we can permit and install new generation resources in North Dakota. Additionally, we performed this analysis to better understand the impacts of our North Dakota load on our current system profile – specifically, what would occur to the NSP System from a cost perspective should it lose the North Dakota load before and after the shutdown of Sherco Unit 2 at the end of 2023 and after the shutdown of Sherco Unit 1 at the end of 2026. Additionally, we modeled the assumption of continued service to North Dakota from the Legacy System to quantitatively validate the qualitative assumptions that underlie our proposed RTF.

Table 6, below, identifies the impact of the loss of North Dakota load on the remainder of the NSP System in 2023, 2025, and 2027 on a PVSC, PVRR, and rate impact basis. Table 6 includes the impact of continued sharing of the Legacy System by all NSP System customers.

Table 6: Impact of Loss of ND Load on Remainder of NSP System

	BASE CASE		LOW GAS		HIGH GAS	
MN/SD/NSPW, $M	**PVSC**	**PVRR**	**PVSC**	**PVRR**	**PVSC**	**PVRR**
Updated Plan	52,493	48,302	49,213	45,106	57,477	53,201
Shared Legacy, Jur Future	52,350	48,348	49,182	45,203	57,296	53,164
Loss of ND Load, 2023	52,614	48,462	49,399	45,344	57,477	53,240
Loss of ND Load, 2025	52,496	48,365	49,282	45,248	57,360	53,141
Loss of ND Load, 2027	52,439	48,314	49,228	45,197	57,307	53,090

	BASE CASE		LOW GAS		HIGH GAS	
Delta, $M	**PVSC**	**PVRR**	**PVSC**	**PVRR**	**PVSC**	**PVRR**
Updated Plan	-	-	-	-	-	-
Shared Legacy, Jur Future	(144)	45	(31)	97	(181)	(37)
Loss of ND Load, 2023	121	160	186	238	(0)	40
Loss of ND Load, 2025	2	63	68	142	(117)	(59)
Loss of ND Load, 2027	(54)	12	15	91	(171)	(111)

Figures 5 and 6, below, identify the impact of the loss of North Dakota load on the remainder of the NSP System in 2023, 2025, and 2027 on a PVSC and PVRR basis. Figures 5 and 6 also identify the impact of continued sharing of the Legacy System.

Figure 5

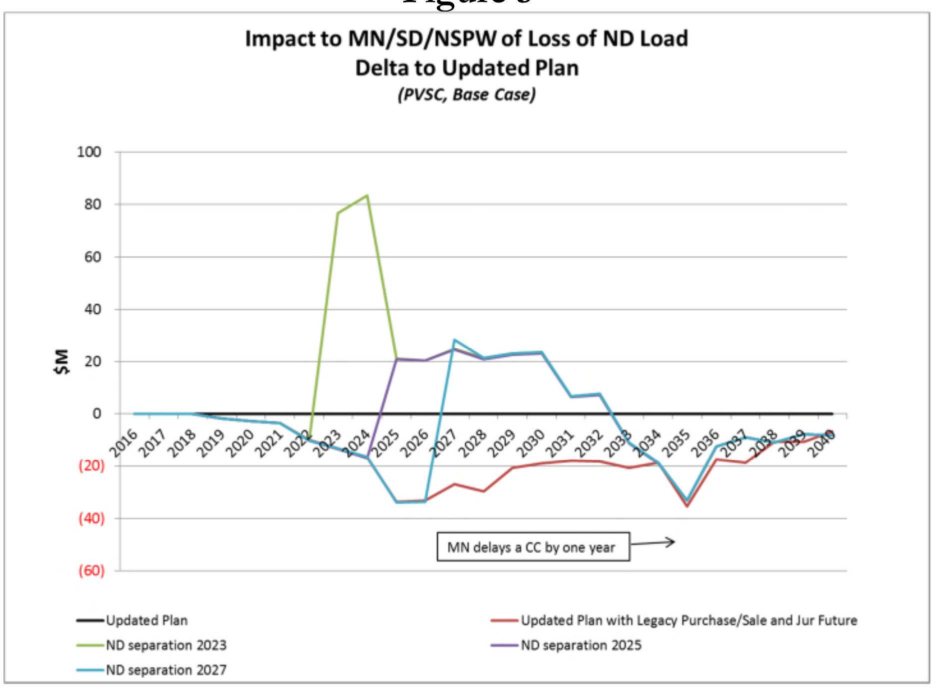
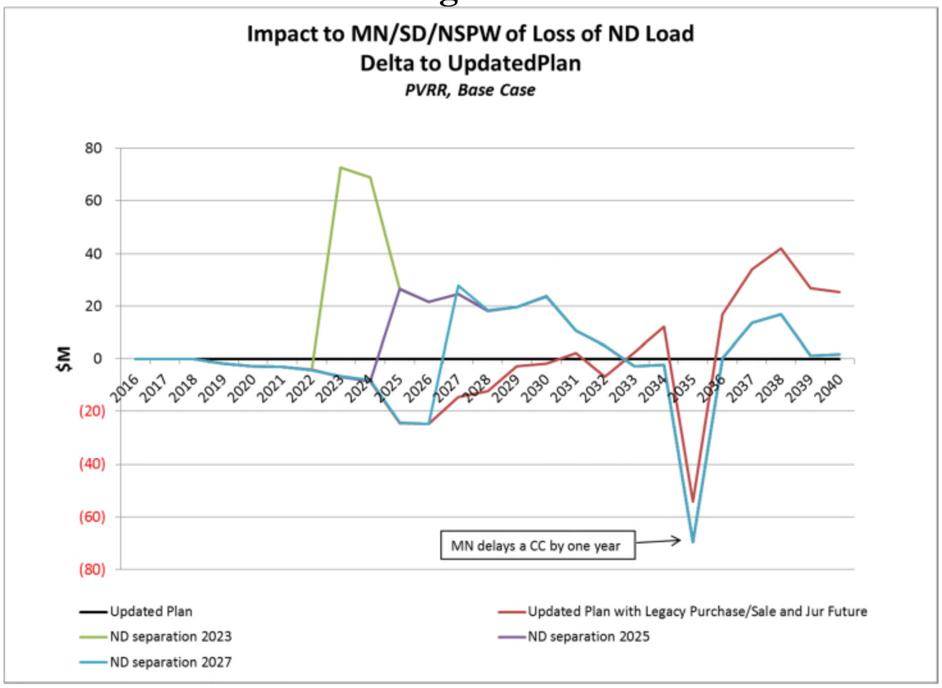


Figure 6



Loss of the North Dakota load also impacts the Updated Plan. The loss of North Dakota load results in two fewer 230 MW combustion turbines added to the system through 2030. Additions of combustion turbines and a combined cycle unit in 2035 are also delayed by the loss of the North Dakota load. We present the Updated Plans in Schedule 7.

As shown above, the later that the NSP System loses the support of the North Dakota load, the more the impact to the remainder of the NSP System is mitigated. We can also infer from this analysis that the inverse is true regarding the effects on our North Dakota customers from staying on the NSP System longer. Said differently, the earlier the North Dakota load separates from the NSP System, the earlier the cost shifts occur to the remainder of the System. However, the true impact to our North Dakota customers from separating from the NSP System cannot be fully modeled without assumptions about the generation portfolio that would serve North Dakota as a stand-alone system.

This analysis leads us to several conclusions. First, continued service from the Legacy System is reasonable and materially mitigates the impacts to the remainder of the NSP System from the loss of our North Dakota load. Second, 2025 is the most equitable date for the NSP System to lose the North Dakota load, should that be the preferred outcome of the Commissions. This is because the cost impacts of a 2025 date are equitably balanced between savings to North Dakota and impacts to the remainder of the NSP System by the loss of the North Dakota load. Third, to retain these equities, our North Dakota customers should continue to be served by the Legacy System from the implementation of our RTF, expected to be in 2020, until 2025 under any circumstances. Therefore, the remainder of our resource planning analysis utilizes a 2025 date as the appropriate measuring point for North Dakota service scenarios.

D. Reasonableness of Continued Service from the Legacy System

After establishing key baseline information in the analyses above, we then sought to validate the reasonableness of continued service to North Dakota from the NSP System beginning in 2025. We undertook our validation analysis by developing two potential generation portfolio scenarios that we believe would identify the low-end of costs and high-end of costs of serving North Dakota separately, and also allow assessment of the volatility of these scenarios when compared to the Legacy System. Recognizing the myriad of different service options that may be available, we believe that these scenarios provide reasonable "bookends" to quantitatively validate the qualitative assessments that underlie our proposed RTF. Because this analysis is focused on serving North Dakota, we present our figures here on a PVRR basis only.

The first generation portfolio we developed was based on full service to our North Dakota customers from only combustion turbines (the CT Scenario). Under this scenario, we assumed that a combustion turbine fleet would be installed in 2025, consistent with our analysis above, and that our North Dakota customers would be served from the Legacy System until then. We developed this scenario to analyze the costs of least-cost capacity resources with low capacity factors which therefore require material reliance on energy markets to serve our North Dakota load.

The CT Scenario adds only combustion turbines to serve our North Dakota load with the majority of the energy supplied by the markets. The resource additions are in 2025 (230 MW), 2031 (115 MW), and 2041 (115 MW). For the alternative where North Dakota continues to be served by the Legacy System, with jurisdictional planning for future resources, resource needs requiring resource additions have combustion turbines being added in 2031, 2035, 2041, and 2051 and are all sized at 115 MW.

The second generation portfolio we developed was based on full service to our North Dakota customers from combined cycle plants (the CC Scenario). Under this scenario, we assumed that the combined cycle fleet would be installed in 2025, consistent with our analysis above, and that our North Dakota customers would be served from the Legacy System until then. We developed this scenario to analyze the costs of higher capacity factor resources which have higher initial capital costs that mitigate reliance on energy markets to serve our North Dakota compared to the CT Scenario.

In this scenario, a single 389 MW combined cycle plant was added in 2025 to serve our North Dakota load. A combined cycle plant was not an option for the scenario where North Dakota continues to be served by the Legacy System, with jurisdictional planning for future resources, as the incremental load-serving need was not large enough to justify a larger unit. Resource needs are therefore met by combustion turbines in the Legacy System scenario as described above.

We used the CC and CT Scenarios, which represent extremes on both ends of potential service options, to provide comparison points for continued service to North Dakota by the Legacy System. Recognizing that the CT Scenario and CC Scenario are single fuel and rely on market purchases for some or most of the energy needs of our North Dakota customers, we also performed an analysis for high and low gas sensitivities. Additionally, for the purposes of validating our RTF, we performed this analysis on the CT and CC Scenarios without the inclusion of the support of the Company's nuclear fleet, as described above.

Table 7, below, identifies the costs of service to North Dakota from the CT Scenario, Legacy System, and CC Scenario on a PVSC and PVRR basis under our base case and high and low gas sensitivities, as well as the differential between these scenarios and our Updated Plan. Figure 7 represents the PVRR view of these scenarios compared to our Updated Plan graphically for our base case. Figure 8 represents the PVRR view of the base case, high gas, and low gas scenarios compared to our Updated Plan graphically.

Table 7: Cost of North Dakota Service Scenarios

	BASE CASE		LOW GAS		HIGH GAS	
ND, $M	**PVSC**	**PVRR**	**PVSC**	**PVRR**	**PVSC**	**PVRR**
Updated Plan	2,711	2,567	2,521	2,384	2,993	2,846
Shared Legacy, Jur Future	2,899	2,515	2,575	2,245	3,243	2,903
Loss of ND Load, 2025, CT, No Nuclear	2,958	2,477	2,522	2,120	3,382	3,005
Loss of ND Load, 2025 CC, No Nuclear	2,786	2,512	2,485	2,218	3,218	2,948

	BASE CASE		LOW GAS		HIGH GAS	
Delta, $M	**PVSC**	**PVRR**	**PVSC**	**PVRR**	**PVSC**	**PVRR**
Updated Plan	-	-	-	-	-	-
Shared Legacy, Jur Future	188	(52)	54	(139)	251	57
Loss of ND Load, 2025, CT, No Nuclear	247	(90)	1	(264)	389	159
Loss of ND Load, 2025 CC, No Nuclear	75	(55)	(36)	(166)	225	102

Figure 7

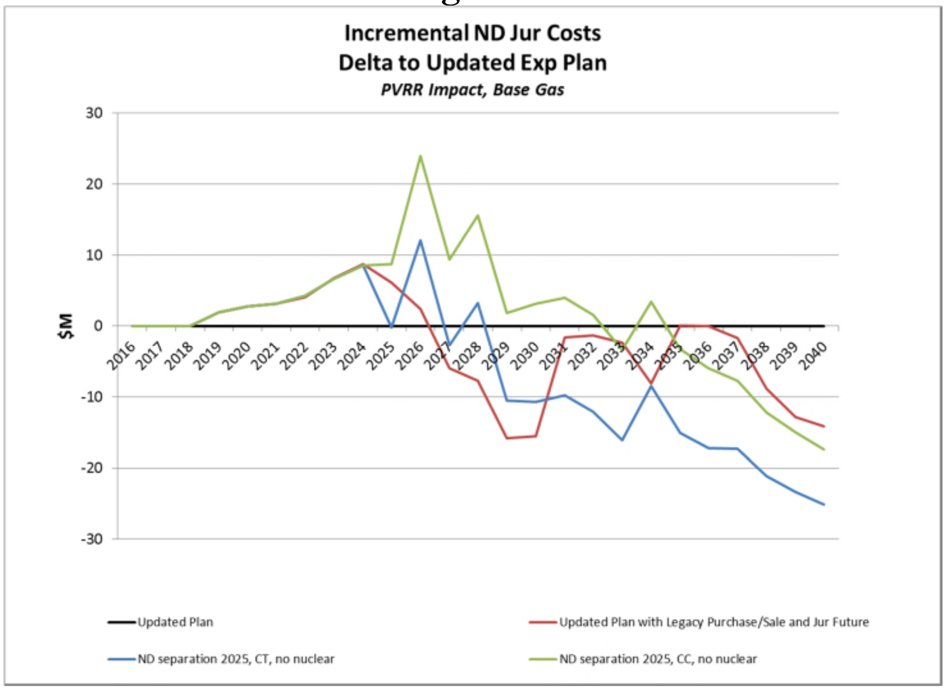
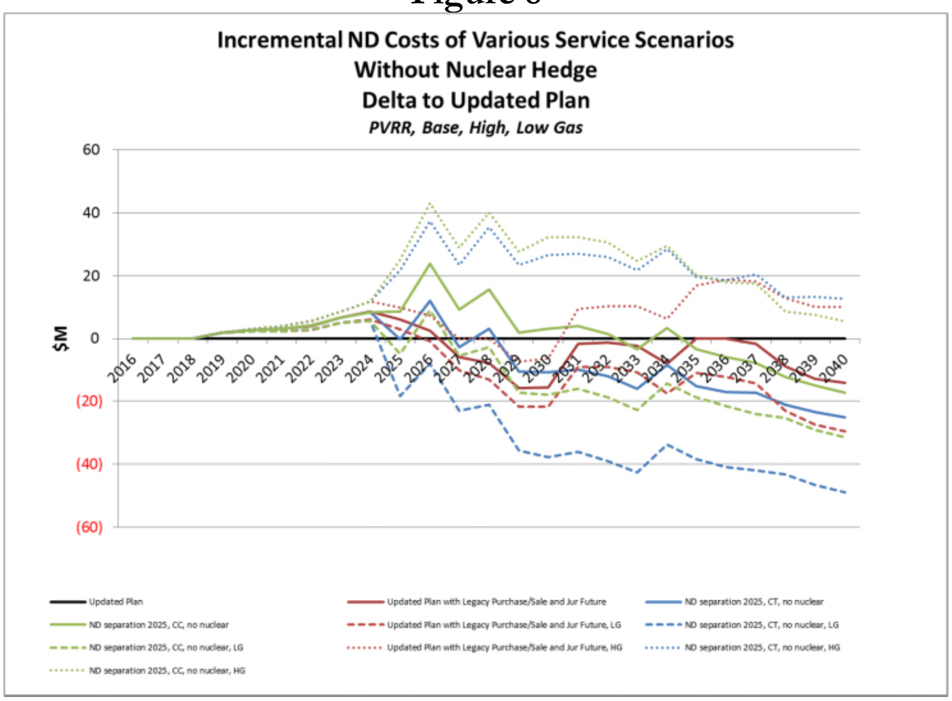


Figure 8



Using our base case assumptions, the CT Scenario is the lowest cost. As shown in Figure 7, the capital costs of installing the first 230 MW of combustion turbines results in less rate impact when compared to our Updated Plan than either continued service from the Legacy System or in the CC Scenario. However, as shown in Table 7 and Figure 8, the CT Scenario is the most volatile, as it had the largest range of outcomes when assessing the base case, as well as high and low gas scenarios. The exposure to the energy markets based on the assumed ten percent capacity factor of the combustion turbines and the impact on energy markets from gas prices, leads us to conclude that service from only combustion turbines may not be prudent.

In contrast, the Legacy System performed reasonably in our base case and in a high and low gas scenario, especially through the 2020s. While not the cheapest scenario under our base case, continued service from the Legacy System reduces the need for capital investment in 2025, making this a less impactful outcome in the early years of the analysis period. Additionally, through the 2020s, service by the Legacy System was least volatile, demonstrating the hedge value of the Legacy System. Of note, the Legacy System scenario under our base case assumptions outperformed the CC Scenario under our low gas sensitivity through 2030, which further demonstrates the value of the fuel diversity of the Legacy System.

The CC Scenario was the most impactful in the early years but also a reasonable service option when compared to our Updated Plan in a base case scenario. The performance of the CC Scenario was materially impacted by the lumpiness of constructing these types of generators, with material capital investments in the early years of this scenario but with that capacity and energy being sufficient for many years. And while more volatile than the Legacy System, it was less volatile than the CT scenario when comparing the base case to the high and low gas sensitivities.

Based on this, we conclude that continued service to North Dakota from the Legacy System is reasonable as it results in no immediate impact to rates, is less expensive than service under our Updated Plan over its life under base case assumptions, and is the least volatile of the scenarios should gas prices materially change (either to serve the CC Scenario with gas or the impact to the market energy providing ninety percent of the energy in the CT Scenario). Consequently, we believe that this analysis quantitatively validates the qualitative assessments that led to our proposed RTF.

E. <u>North Dakota Separation Scenarios</u>

Lastly, we analyzed separation scenarios to provide context for the Commissions and also to provide an alternative view should the judgment of the Commissions be that the evolution of the Legacy System will accelerate in the future should continued service from the entire Legacy System not be preferred by the Commissions past 2025. To mitigate some of the volatility identified in the CT Scenario and CC Scenario analyzed above and to retain the equity of the incurred liabilities for the use of the Legacy System proposed as part of our RTF, we paired our nuclear fleet to the

CT Scenario and CC Scenario for our analysis of separation scenarios (CT Scenario + Nuclear and CC Scenario + Nuclear, respectively). The expansion plans for these scenarios are provided in Schedule 7.

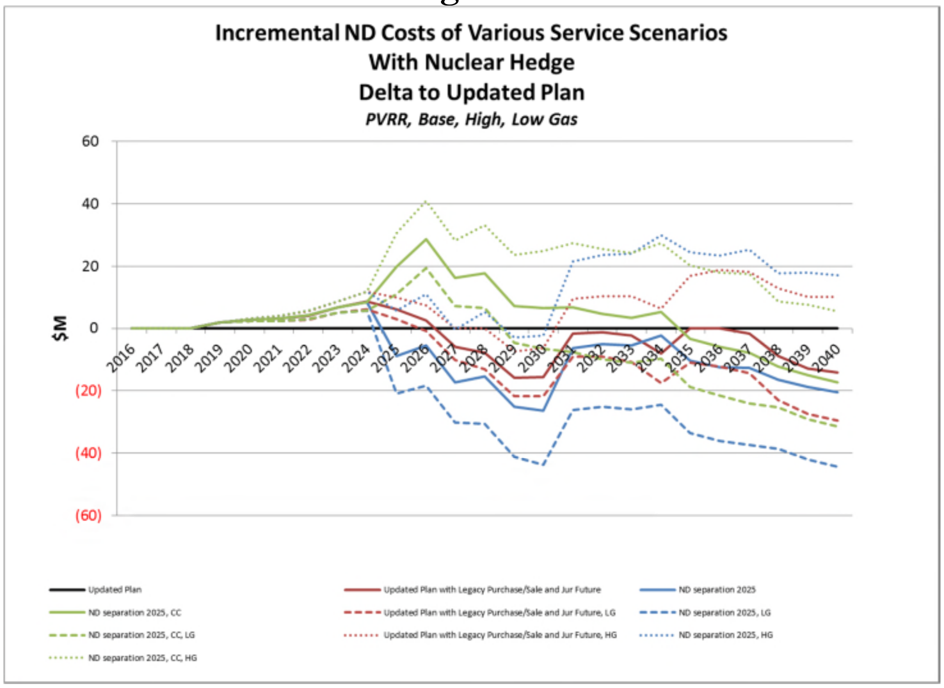
From a resource planning standpoint, we would expect that the addition of approximately twenty percent of capacity needs being met by a high capacity alternative fuel source would materially mitigate the volatility of the CC Scenario and CT Scenario and also offset earlier capital investment needs, which could lead to better overall cost performance. Our analysis bears this out. Table 8 identifies the PVSC and PVRR performance of the CT Scenario + Nuclear, the CC Scenario + Nuclear, and continued service from the Legacy System as well as a comparison to our Updated Plan. Figure 9 provides a graphic representation of our modeling outputs.

Table 8: ND Service Scenarios with Nuclear Hedge

	BASE GAS		LOW GAS		HIGH GAS	
ND Jur, $M	**PVSC**	**PVRR**	**PVSC**	**PVRR**	**PVSC**	**PVRR**
Updated Plan	2,711	2,567	2,521	2,384	2,993	2,846
Shared Legacy, Jur Future	2,899	2,515	2,575	2,245	3,243	2,903
Loss of ND Load, 2025, CT	2,884	2,456	2,491	2,130	3,307	2,944
Loss of ND Load, 2025 CC	2,780	2,534	2,507	2,265	3,182	2,937

	BASE GAS		LOW GAS		HIGH GAS	
Delta, $M	**PVSC**	**PVRR**	**PVSC**	**PVRR**	**PVSC**	**PVRR**
Updated Plan	-	-	-	-	-	-
Shared Legacy, Jur Future	188	(52)	54	(139)	251	57
Loss of ND Load, 2025, CT	173	(111)	(30)	(254)	314	98
Loss of ND Load, 2025 CC	69	(33)	(14)	(119)	189	92

Figure 9



Comparing the outputs of Table 7 with Table 8, we can see that the CT scenario performs better when paired to our nuclear portfolio than without it from both a PVRR analysis as well as from a volatility perspective, with the nuclear portfolio providing a fuel and market hedge for the CT Scenario. The CC scenario also performed better over its life when tied to our nuclear portfolio due to the offset of capital investment provided by carrying forward our nuclear portfolio, as well as the fuel hedge provided by alternative, baseload fuel sources. Additionally, on a PVRR basis, the Legacy System performed in the midpoint, with the least volatility, when compared to the other two scenarios.

Based on this, we conclude that continued service to North Dakota from the Legacy System continues to be the most prudent path forward under any RTF structure. However, should the Commissions choose to separate North Dakota from the Legacy System sooner than its natural retirement dates, continued service from our nuclear fleet is a key component of doing so, as it would provide material fuel hedge value and offset initial capital investments to help smooth a transition to stand-alone service for our North Dakota customers.

F. <u>Resource Planning Conclusions</u>

Based on our resource planning analysis, continued service to North Dakota from the Legacy System would be a reasonably equitable outcome. However, should the Commissions determine that a more complete separation should be undertaken, then doing so in 2025 with continued service to our North Dakota customers from our nuclear fleet is a reasonable time and way to do so. Last, our resource planning analysis confirmed that our potentially equitable method to address the Disputed Resources provides immediate cost savings to our North Dakota customers while providing overall cost savings to the remainder of the NSP System over time.

In summary, our Resource Planning Analysis yields the following key findings:

- **Fair Treatment of Disputed Resources** – Table 1 shows that reallocating the Disputed Resources over the remainder of the NSP System while also allocating all of our wind additions to the remainder of NSP System results in an equitable outcome for both our North Dakota customers and our customers being served by the remainder of the NSP System.
- **Reduced Costs of Our Updated Plan** - Figures 1 through 4 demonstrate that the Updated Plan (with incremental wind) is less costly than the IRP Plan from both a PVRR and PVSC basis for both the NSP System and North Dakota.
- **Impacts and Timing of Dissolving the Legacy System** - Figures 5 and 6 demonstrate that continued service from the Legacy System is reasonable and mitigates cost shifting to the remainder of the NSP System and that 2025 is the most equitable time for North Dakota to separate (should the Commissions choose to do so).
- **Costs and Risks of Replacement Generation Options** - Figures 7 and 8 demonstrate that if North Dakota separates in 2025 and chooses to self-supply generation resources, a combined cycle resource offers the highest expected portfolio cost and lower risk profile while combustion turbine resources offer the lowest expected portfolio cost with a higher risk profile. Importantly, this validates the reasonableness of continued service from the Legacy System.
- **Benefits of Legacy System and Nuclear** – Figures 8 and 9 also demonstrate how the diversity of resources in the Legacy System, or at least our nuclear fleet, help provide the lowest risk profile for North Dakota in terms of replacement generation options with a mid-range cost impact.

VI. REVENUE REQUIREMENT ANALYSIS

As noted above, the Company's resource planning analysis is intended to illustrate the viability of certain service scenarios in the future. It is not intended to propose or support a particular resource selection. In addition, certain aspects of our proposed RTF – including the resolution of the Disputed Resources and potential Pseudo or Legal Separation – are likely to have some degree of revenue requirement impact, depending on the assumptions made about their implementation. Therefore, our revenue requirement analysis is intended to help the Commissions assess the more immediate potential rate impacts of implementing our RTF.

There are two aspects to our revenue requirement analysis. First, we assess the possible cost impact to each state of resolving past and near-future resource selection disagreements. Second, we compare the cost impacts of either a Pseudo Separation structure or Legal Separation structure.

We began our revenue requirement analysis with the Company's revenue requirement projection for 2020 with data as of late 2015 for each jurisdiction served by the NSP System – North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan.[45] The forecasted 2020 revenue requirement is a representation of the Company's projected cost of serving each state on an "all-in" basis, including base rates, fuel costs, and rider revenue. We chose 2020 as the representative year because it is consistent with our next Minnesota rate case schedule, which is needed to implement a Pseudo Separation structure, and is likely the earliest we can achieve Legal Separation. This data provides a baseline against which we can compare cost and revenue shifts across jurisdictions that are likely to be caused by defining the Legacy System and resolving the Disputed Resources through our RTF.

For purposes of establishing a baseline, we assumed a shared system with resources similar to those presented in the most recent Minnesota IRP, with typical ratemaking adjustments in each jurisdiction. Actual cost recovery will, of course, be governed by ratemaking proceedings in each state. This Application is not intended to set forth a specific cost allocation request, precise cost determinations, or a cost recovery petition. More specific cost assessments and proposed cost allocation methods (through services agreements and other affiliated interest structures) would be made in the future, depending on the outcomes amongst the NSPM states on the specific components of our RTF.

The goal of our revenue requirement analysis is to identify change levels, generally, to facilitate review of our proposed RTF. More specific and detailed analyses will be performed should we move forward with an RTF that involves Pseudo Separation or Legal Separation.

[45] Both Wisconsin and Michigan are served by NSPW, such that a reference to NSPW is intended to encompass both our Wisconsin and Michigan customers.

A. Resolving Resource Disagreements

Under the current integrated NSP System, the Company's costs are allocated across the jurisdictions we serve based on each jurisdiction's relative contributions to cost-causation. As discussed earlier in this Application, however, not all costs are fully recovered through this allocation due to differing views between the jurisdictions we serve. In the instance of Pseudo Separation, we would seek to allocate costs of the Disputed Resources through review of this Application and subsequent rate case filings. In the instance of Legal Separation, we would seek to allocate costs of Disputed Resources through the implementation of a supply agreement for NSPD and the remainder of the NSP System.

Recognizing that there are many different equitable resolutions to these misalignments that would result in reasonable outcomes, we look forward to discussions with the Commissions and all of our stakeholders to determine a solution that can gain consensus. That said, we believe that one reasonable approach would generally recognize the differing resource selection preferences of North Dakota and Minnesota, and allocate the costs of Disputed Resources accordingly with moderate net impact (on a percentage basis) for either state.

First, we could envision removing the Disputed Resources (Minnesota-based CBED, certain solar, and biomass resources) that have been disallowed or otherwise disfavored by the NDPSC from North Dakota rates. Similarly, we recognize that our plan to retire Sherco Units 1 & 2 in the 2020s, rather than have them serve out their full remaining useful lives as reflected in our North Dakota depreciation rates for these units, has been received differently in our North Dakota and Minnesota jurisdictions. Therefore, we believe it could be equitable to recover the difference in depreciation expense for these resources from the remainder of the NSP System on an amortized basis. This creates a modest increase in Minnesota rates on a percentage basis.

To offset the modest increase in Minnesota costs, we believe it could be reasonable to allocate the proposed new, cost-effective wind additions to the remainder of the NSP System, with their approval. As discussed above, the new wind resources are cost-effective over the life of the proposed assets. Since this analysis examines only 2020, the entire benefit of the new wind over the asset life on the remaining NSP System is not shown.

Lastly, we believe it would be reasonable to allocate the MEC II PPA costs and benefits consistent with current allocation methods between the states we serve, as this resource was supported in Minnesota but also provides reliable supply options to

North Dakota as it looks toward a more independent resource planning future. This is assumed in the baseline model.

B. Costs of Pseudo Separation

As part of our feasibility analysis for a Pseudo Separation structure, we identified the likely need for additional staff to manage the Pseudo Separation, as well as additional investment in our information technology infrastructure to support the more complex accounting and allocation processes required to undertake the Pseudo Separation structure. While we will prepare in-depth estimates of the likely actual costs of implementing the Pseudo Separation should that be the outcome of this proceeding, for purposes of this Application we are providing a high-level estimate of $1 million of additional costs for this structure on a revenue requirements basis.

Because one of the primary benefits of the Pseudo Separation structure is that it retains the existing nature of NSPM except with regards to generation, we believe it could be reasonable to allocate these costs consistent with current allocation methods.

Table 9, below, identifies the revenue requirement impact of what we believe is a reasonable potential resolution to past disputes over resource selection.

Table 9

$ million rev req	2020 Test Period				Notes
	ND Jur	MN Jur	SD Jur	NSPW	Notes
Baseline Model (nearest million)	$251	$3,739	$294	$869	A
Pseudo-Separation Differences					
Biomass	($6.6)	$5.1	$0.4	$1.1	B
CBED Wind	($2.3)	$1.8	$0.1	$0.4	B
Solar	($1.2)	$0.9	$0.1	$0.2	B
Replacement cost for Disputed Resources	$3.1	($2.4)	($0.2)	($0.5)	C
New Wind and Fuel Savings	$4.1	($3.2)	($0.2)	($0.7)	B
Sherco Units 1 and 2 retirements	($1.3)	$1.0	$0.1	$0.2	D
Additional accounting and IT	$0.1	$0.7	$0.1	$0.2	E
Total Pseudo-Separation Differences	($4.1)	$4.0	$0.3	$0.9	
Difference % from Baseline	-1.6%	0.1%	0.1%	0.1%	

Notes:

A	Includes 1500 MW new wind and 2022 Sherco 1 & 2 ret.
B	Shift to remaining jurisdictions
C	Paid back to remaining jurisdictions
D	Depreciation difference shift to remaining jurisdictions
E	$1m rough estimate for additional allocation complexity

As demonstrated in Table 9, this allocation of resources resulted in less than a one percent increase to rates in the remainder of the NSP System while acknowledging North Dakota's concern with the Disputed Resources and beginning the process of separating North Dakota from the NSP System. At the same time, the impact to North Dakota is savings of about one and a half percent. Together, we believe these allocations reflect one reasonable set of cost impacts in each state, while also having the potential to better align the states we serve with the resources they support.

C. Costs of Legal Separation

In the event the approved RTF involves Legal Separation, it is necessary to consider the likely revenue requirement impacts associated with creating and operating NSPD, which, as a company, would necessarily be smaller than the current combined NSPM. Because a separate operating company would include only the revenues, expenses, rate base, and resources necessary to serve those customers in North Dakota, the new utility would have a lesser capitalization than the combined utility.

We determined that creating a separate legal entity would require some new costs, including dedicated oversight, financing, service company allocations, and regionally-shared transmission. Additionally, we would incur transaction costs for the creation and regulatory approvals necessary to establish NSPD.

1. Dedicated Oversight

First, a separate utility would likely require its own operating company president and board of directors and other oversight, as well as dedicated separate staffing. There are currently over one hundred Xcel Energy employees working in North Dakota and we would need to determine which of these would become NSPD employees and which would remain Xcel Energy Services Inc. (XES) or NSPM employees. Should we move forward with Legal Separation, further analysis will need to be conducted regarding this issue. For purposes of this high-level assessment only, we have provided an estimate of approximately $2 million.

2. Financing

Based on current analyses and the present lending marketplace, we anticipate a North Dakota utility would likely incur a higher cost of long-term debt due to its smaller asset base and revenues when compared to NSPM. We have roughly estimated that an NSPD entity's cost of long-term debt would be approximately 6 percent, compared to approximately 4.8 percent for NSPM. Should we move forward with Legal Separation, further analysis will need to be conducted regarding this issue. For purposes of this high-level assessment only, we have provided an estimate of approximately $1 million.

3. Service Company Allocations

We anticipate that Legal Separation will result in a shift of some corporate cost allocations from NSPM and NSPW to the new entity. Service company costs are presently billed directly from XES to each operating company on an administrative services agreement. The XES costs billed to NSPM are then allocated to each of the separate NSPM states based on currently-approved ratemaking allocation methodologies. An NSPD stand-alone entity would likely enter into its own administrative services agreement with XES and see an increase in its service company costs when it is direct billed for services rather than being allocated a share of NSPM's service company costs. Should we move forward with Legal Separation, further analysis will need to be conducted regarding this issue. For purposes of this high-level assessment only, we have provided an estimate of approximately $3 million.

4. Regionally-Shared Transmission

We also anticipate a shift in transmission costs with the establishment of a new North Dakota entity. Serving NSPD as a stand-alone entity rather than part of NSPM can impact the MISO charges as well as transmission rate base used to set retail rates. Consequently, we expect that the costs of providing transmission service to NSPD could increase and we have taken into consideration in our rate analysis . Schedule 8 provides additional information regarding transmission service to our North Dakota customers under an NSPD scenario. Should we move forward with Legal Separation, further analysis will need to be conducted regarding this issue. For purposes of this high-level assessment only, we have provided an estimate of approximately $5 million.

5. Transaction Costs

We currently estimate several million dollars in transaction costs to establish NSPD. Actual transaction costs will be a function of the assets that comprise NSPD and the work necessary to transfer these assets and the associated issues that relate to those particular assets. Transaction costs would be for the legal, regulatory, accounting, banking, and other activities that we would need to undertake to create NSPD.

Because creating a new operating company is outside of our normal operations, we believe it would be reasonable to allocate these transaction costs equally between NSPD and NSPM. Additionally, we believe it reasonable to amortize the transaction costs over the five-year period from 2020 to 2025 to mitigate the single year impact of these one-time costs to our customers. We propose amortization over five years for consistency with our resource planning analysis indicating that 2025 is the most equitable date for removing the North Dakota load from the NSP System, if Legal Separation is the Commissions' preferred outcome. Should we move forward with Legal Separation, further analysis will need to be conducted regarding this issue. For purposes of this high-level assessment, only, we have provided an estimate of approximately $10 million for analysis purposes only.

Table 10, below demonstrates the revenue requirement impact for creating and operating NSPD.

Table 10: Cost Impact of Legal Separation in 2020

$ million rev req		2020 Test Period				
	ND Jur	MN Jur	SD Jur	NSPW		Notes
Pseudo-Separation Differences except A&G	($4.2)	$3.2	$0.2	$0.7		F
Legal Separation Differences						
Dedicated Oversight additional A&G	$2.0	N/A	N/A	N/A		G
Financing	$1.0	N/A	N/A	N/A		H
Service Company Allocations	$3.0	($2.3)	($0.2)	($0.5)		I
Transmission	$5.0	($3.9)	($0.3)	($0.9)		J
Transaction Costs	$1.0	$1.0	$0.0	$0.0		K
Total Legal Separation Differences	$7.8	($1.9)	($0.2)	($0.7)		L
Difference % from Baseline	3.1%	-0.1%	-0.1%	-0.1%		

Notes:

F	From Table 9 not including incremental accounting and IT costs
G	$2m rough estimate
H	Treasury estimates 6% long term debt. $1m rough estimate.
I	$3m rough estimate
J	See Schedule 8
K	$10m estimate amortized over 5 yrs, 50% ND and 50 % to remaining NSPM
L	Total including Disputed Resources treatment and Legal Separation

As indicated by Table 10, creating and operating NSPD would create a modest impact to North Dakota rates on a percentage basis.

A rate impact analysis for a typical customer bill is also provided in Schedule 9. Overall, we believe the revenue requirement impacts of the solutions suggested in this section of the Application are reasonable to achieve our overall RTF.

VII. RECOMMENDATION

Underlying the development of our proposed RTF is the recognition that the current status quo is unsustainable. The Company's recent history of managing different resource selection outcomes with creative, one-off solutions has somewhat mitigated inequitable results. However, the Company is currently not recovering its full cost of service in all of the states it serves and has additional cost recovery risks into the future if differing approaches to resource selection cannot be resolved.[46]

[46] *See N. States Power Co. 2013 Elec. Rate Increase Application*, Case No. PU-12-813, *et al.*, ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT (NDPSC Mar. 9, 2016) (Appendix A).

Without the implementation of a framework to manage interjurisdictional disagreements, the Company is left with few options going forward. As we continue to evaluate resource needs and selections in the future, we can either choose not to implement a resource addition (or retirement) that does not have the full support of all jurisdictions, or implement a resource addition (or retirement) and fail to recover our full cost of service for that resource addition (or retirement). Neither of these options is satisfactory. Failure to implement resource additions or retirements that are not supported by all NSPM states fails to recognize the varying size and impact of the different jurisdictions on the overall NSP System. And failure to recover our full cost of service in all of the states we serve is inequitable to Xcel Energy, ultimately implicates free rider issues, and may lead to unjust and unreasonable rates in some jurisdictions.

Consequently, the development of our recommended RTF assumes that there will be continuing – and potentially exacerbated – disagreements between the NSPM states into the future. We therefore placed primacy on providing mechanisms for each state to make decisions separately as the NSP System evolves. We also sought to develop an RTF that provides certainty to the Company, our customers, regulators, and stakeholders now and into the future.

Further, as previously noted, fundamental principles of equity require that our North Dakota customers retain the liabilities they have incurred for their enjoyment of the NSP System. To that end, our proposed RTF includes the continued service of all of the NSP System states by the Legacy System.[47] In this way, all participants in the Legacy System remain responsible for the liabilities and benefits incurred historically while having greater optionality with respect to future resource selection. Our resource planning analysis supports our conclusion that retaining the existing NSP System for serving all of the NSPM states is reasonable from a PVRR and PVSC perspective. Retaining the Legacy System also provides a large, diverse supply portfolio that can provide a physical hedge against any future uncertainty in ways that market-based mechanisms cannot. Therefore, continuing to utilize the Legacy System to serve all of our customers is in the best interest of our customers, the Company, and all of our stakeholders.

With that said, we recognize that there may be interest in accelerating separation of the NSP System if the System is transformed earlier than presently anticipated due to early retirements of key baseload resources. Such transformation, we believe, is compatible with Minnesota's view of the future but may be incompatible with the

[47] As previously noted, Disputed Resources are not considered part of the Legacy System for purposes of this Application, but rather would be resolved through a separate allocation or assignment of those Disputed Resources.

outlooks of the other NSPM states. That will be a topic for our 2019 Minnesota IRP. However, should such transformation occur earlier than expected, any RTF must be sufficiently robust to accommodate it. To that end, an RTF should provide the ability for our customers to retain the benefits of today's NSP System for as long as is feasible, but also provide flexibility that enables the utility to propose future resources that meet the potentially differing goals and determinations of need in the various states we serve.

A. Proposed RTF

As we undertook our analyses, we came to believe that our proposed RTF should be just that – a framework. With an overall framework in mind, we can seek consensus between the states as to the appropriate structures to support that framework. To that end, our proposed RTF is as follows:

1. All currently anticipated and past resource selection and other disagreements will be permanently addressed and the Legacy System established.

2. All NSPM states will continue to be served by the Legacy System and all of our customers will enjoy the benefits and bear the burdens of the Legacy System.

3. With respect to future new resource additions, the Company will be able to assess and propose resources for North Dakota and the remainder of the NSP System separately.

    a. When a resource need arises in North Dakota, that need will be met by a resource sized for, dedicated to serve only, and fully recovered in North Dakota.

    b. When a resource need arises in, or new resources are otherwise planned for, the remainder of the NSP System, those resources will be sized for, dedicated to serve only, and fully recovered in the remainder of the NSP System. Consequently, our North Dakota jurisdiction will not obtain the benefits or pay the costs associated with new NSP System resource additions.

    c. Xcel Energy may propose particular future resources to be utilized concurrently by North Dakota and the remainder of the NSP System should circumstances warrant, and will propose cost-sharing arrangements at that time.

4. Over time, the generation portfolio serving North Dakota and the remainder of the NSP System will materially separate as units of the NSP System retire or expire.

5. South Dakota may elect to join North Dakota under this framework or remain part of the NSP System consistent with its own outlooks.

We believe this framework is consistent with the three principles guiding our management of the NSP System, the three principles guiding our development of the RTF, and the ten principles espoused in the 2013 test year rate case settlement agreement in North Dakota, as well as the guiding principles identified in Minnesota. Consequently, we believe that this RTF identifies the appropriate end state that we have been working toward for several years and will equitably address current and future disagreements among the NSPM states.

B. <u>Structures to Support the Proposed RTF</u>

Key to a successful implementation of our RTF will be the development of a resource management structure to support the outcome we envision. As discussed, we have been analyzing four separate structures to support an equitable resolution to interjurisdictional disagreement: (1) Regulatory Alignment; (2) Proxy Pricing; (3) Pseudo Separation; and (4) Legal Separation.

At this time, we are not recommending moving forward with a Regulatory Alignment structure. It remains unclear whether there can be opportunities for compromise or whether all of the states find value in continued integration into the future. Further, the Regulatory Alignment structure is the least robust method of addressing disagreements between the NSPM states and places the most financial risk on the Company. We do look forward to continued discussions to determine whether there may be opportunities to better align the regulatory frameworks of all the NSPM states through compromise. If a viable path can be found, there may be value in exploring opportunities to align the regulatory processes in all of our states to find common ground. But given the nature of current disagreements and the future evolution of the NSP System, we do not believe that a Regulatory Alignment structure can bridge the perceived gap between the states.

For several reasons, we also do not support a Proxy Pricing framework. First, previous failure to reach agreement on key aspects of a Proxy Pricing regime in North Dakota indicates that there will be difficulties in finding agreement between all of the NSPM states. This is mainly because different states value different resources differently.

Second, instituting a Proxy Pricing outcome requires continued agreement between the states; as new technologies continue to develop and legal structures evolve, a Proxy Pricing structure instituted today may not be able to appropriately address resources that have fundamentally different profiles than utility scale, central station resources – even if they are renewable. Continually modifying any Proxy Pricing RTF could continue to amplify the disagreements of the participants in the NSP System rather than provide the flexibility to address them.

Third, a Proxy Pricing structure will likely be insufficiently robust because it is difficult to predict all the possible permutations of resource selection outcomes that will need to be accommodated with a Proxy Pricing structure. As the NSP System continues to evolve, further disagreements are likely – which could implicate more and more resources that would need to be proxy priced, thereby further adding to potential inequities within the integrated NSP System.

We have determined that the Pseudo Separation structure is a viable option. It has the least near-term rate impacts and retains the current status quo regarding non-resource cost structures such as service company allocations and integrated transmission service. It also could achieve our overall goal of providing greater autonomy to the states we serve.

However, Pseudo Separation can result in long-term management difficulties. These concerns relate to ensuring that costs are appropriately allocated to the cost causative jurisdiction while accounting for common management costs appropriately. Like Proxy Pricing, the Pseudo Separation structure also requires continual review and refinement – and therefore continued agreement – regarding appropriate allocation methods between the states. Notwithstanding these challenges, if implemented with initial and ongoing cooperation from all stakeholders, Pseudo Separation is the least impactful structure to support our RTF.

If the Commissions do not support the Pseudo Separation structure, the Company is willing to move forward with Legal Separation. Legal Separation is the most complex and difficult to implement initially and can increase costs. That said, it provides stability and flexibility that we believe can provide long-term value to the Company, our customers, and our various stakeholders into the future. By creating a separate operating company, we can be more responsive to our differing customer needs and preferences in each of those states, presenting (as needed) different solutions in different jurisdictions to meet our customer needs, business goals, and desired regulatory outcomes.

VIII. NEXT STEPS

Through this filing, Xcel Energy is making its recommendation, informing the Commissions' consideration of alternatives and preferences, and seeking consensus on the path forward. With this information, the Company hopes to spur conversation over the next year with its regulators in both states to develop and implement a structure that can support our proposed RTF and that can be supported by all states served by the NSP System.

With respect to this Application, we propose an approximately eighteen-month evaluation period to review our recommendation, as discussed in depth below. We believe this proposed process will best manage the challenges presented in aligning the differing regulatory and legal processes of Minnesota and North Dakota. Generally, in Minnesota, the Company believes that consideration of the RTF is best handled through facilitating open discussion through written comments and replies.[48] Conversely, North Dakota law requires that all cases go before the NDPSC for record development. We therefore plan to build the record in North Dakota through pre-filed testimony and proceedings before the NDPSC given that there is no other procedural alternative available.

When considering issues of high complexity like those presented by the RTF, the Company understands the importance of ensuring ample time for discovery to answer questions and respond to concerns in the most transparent and consistent way possible. Accordingly, throughout the duration of the eighteen-month RTF evaluation period, the Company proposes to permit sufficient time for open rounds of discussion in both states. The Company also commits to cross-filing all comments and testimony filed in the respective state cases/dockets to ensure transparency of the information gathered in the other jurisdiction. Additionally, our proposed procedural schedule allows the stakeholders in each of our states to evaluate the comments and proposals of the stakeholders in the other states with sufficient time to substantively respond.

The Company proposes the following procedural schedules, specified by state, for consideration and evaluation of the RTF:

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[48] Because the Company believes that the possible issues that may arise with respect to consideration of the Application and RTF can be satisfactorily resolved on the basis of the current filing and subsequent rounds of comments from parties to the proceeding, the Company does not believe a contested case is warranted.

North Dakota

- By January 1, 2017: Filing of the Application
- January-April 2017: Ongoing discovery and outreach
- May 1, 2017: NSP Direct Testimony
- August 1, 2017: Staff Rebuttal Testimony
- September 15, 2017: NSP Surrebuttal Testimony
- November/December 2017: Hearing
- January/February: Briefing
- Post-Hearing Matters (work sessions; informal hearings; opportunities for settlement)
- June/July 2018: NDPSC Order

Minnesota

- By January 1, 2017: Filing of the Application
- January-March 2017: Ongoing discovery and outreach
- April 1, 2017: Intervenor Comments
- May 1, 2017: NSP Reply Comments (may be reflected in NSP North Dakota Direct Testimony)
- June 30, 2017: Intervenor Reply Comments
- September 15, 2017: NSP Reply Comments
- November/December 2017: Cross Reply Comments
- March/April 2017: Oral Argument and Deliberations
- June/July 2018: MPUC Order

The Company believes the above procedural timeframe permits ample opportunities for open dialogue between and discovery for all parties and the Commissions; ensures transparency between the jurisdictions of the information filed in both state cases/dockets; and allows sufficient periods of time to engage in discussion regarding settlement in both jurisdictions (before and after hearings) and between jurisdictions.

It is important to be clear that this process is intended to facilitate a reasonable but expeditious path forward for selection of the conceptual RTF. As stakeholders and the Company approach or achieve a mutually-agreeable RTF, the Company will then implement the RTF that results from this proceeding.

Should the RTF be supported by a Pseudo Separation structure, we envision that we can implement the necessary ratemaking and cost allocation changes through rate cases in Minnesota and North Dakota. We expect to do so in 2020 consistent with our current rate case schedule in Minnesota and potentially in North Dakota.

Should the RTF be supported by a Legal Separation structure, we would expect to expeditiously work to create NSPD and undertake any additional filings that may be needed (depending on the separation structure ultimately selected) with the MPUC, the NDPSC, and FERC. Given our proposed procedural schedule for this proceeding and the complexity in creating NSPD and resolving the myriad issues such as assignment of transmission agreements, creation of a FERC tariff, and other implications of legally separating our North Dakota operations from NSPM, we would expect to make the necessary filings for regulatory approval in approximately 2020.

Our anticipated eighteen-month timeframe to achieve conceptual approval of the RTF would be complete in approximately the middle of 2018, giving all parties ample time and a series of opportunities to work through the appropriate framework for long-term solutions to the issues outlined in this Application.

IX. CONCLUSION

Our proposed RTF will balance the historic equities of long-standing service by the integrated NSP System while addressing continued disagreement between the NSPM states regarding the most prudent evolution of the NSP System. By solving for past disagreements and charting a more separate path into the future, our RTF will provide flexibility to all impacted stakeholders and help to ensure the ongoing financial health of Xcel Energy.

As described previously, our RTF presents a general framework. Our resource planning and revenue requirement analysis validate the reasonableness of our proposal, but we believe additional discussion is needed. Through the course of this proceeding, we seek to find consensus on an RTF, as well as finality regarding past and near-term future disagreements among the states. We also seek to find consensus regarding the appropriate cost assignment and corporate structure to support our RTF.

We recognize that these issues are complex and that finding consensus may not be easy. However, we believe our proposal balances a variety of considerations discussed in this Application, and charts an equitable path upon which consensus can be found. Our proposed eighteen-month procedural timeline should provide all interested parties ample time to assess our proposal and undertake their own analyses.

At the conclusion of this proceeding, we hope to receive orders from the Commissions providing us with the necessary guidance to implement our RTF in 2020.

Respectfully submitted,

Northern States Power Company

INFORMATION REQUIRED BY MINN. R. 7829.1300

A. Summary of Filing

Pursuant to Minn. R. 7829.1300, subp. 1, a one-paragraph summary of the filing is provided as Attachment 1 to this Schedule 1.

B. Service on Other Parties

Pursuant to Minn. R. 7829.1300, subp. 2, Xcel Energy has served a copy of this Application on the Department of Commerce and the Office of the Attorney General – Residential Utilities and Antitrust Division. A summary of the filing has been served on all parties on the attached service list.

C. General Filing Information

Pursuant to Minn. R. 7829.1300, subp. 3, Xcel Energy provides the following required information:

1. Name, Address, and Telephone Number of Filing Party

Northern States Power Company, doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

2. Name, Address, Electronic Address, and Telephone Number of Filing Party Attorney

Alison C. Archer
Assistant General Counsel
Xcel Energy
401 Nicollet Mall
Minneapolis, MN 55401
Alison.C.Archer@xcelenergy.com
(612) 215-4662

3. Date of Filing

Date of Filing: December 31, 2016
Proposed Effective Date: Upon Commission Order

4. Statute Controlling Schedule for Processing Filing

No statute controls the schedule for processing this filing. Under Minn. R. 7829.0100, subp. 11, the Company's Application submission falls within the definition of a miscellaneous tariff filing, because no determination of Xcel Energy's general revenue requirement is necessary. Under Minn. R. 7829.1400, initial comments on a miscellaneous filing are due within 30 days of filing, with reply comments due 10 days thereafter; however, the Company respectfully requests waiver of those rules and that the Commission order a procedural schedule consistent with the Company's proposal.

5. Signature, Electronic Address, and Title of Utility Employee Responsible for Filing

Aakash H. Chandarana
Regional Vice-President
Rates and Regulatory Affairs
Xcel Energy
401 Nicollet Mall
Minneapolis, MN 55401
Aakash.Chandarana@xcelenergy.com
(612) 215-4663

6. Description of the Filing, Impact on Rates and Services, Impact on Any Affected Person, and Reasons for the Filing

The Company's Application for consideration of a Resource Treatment Framework addresses issues regarding energy resource planning and selection in Minnesota and North Dakota. The Application presents the results of focused analysis to determine the most appropriate structures to accommodate current and future misalignment between the states regarding resource additions and other system management issues related to the integrated NSP System.

A more comprehensive description of the filing, its impact on rates and services, its impact on any affected person, and the reasons for the filing are included in the Company's Application.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

In the Matter of Northern States Power Company, a Minnesota Corporation d/b/a Xcel Energy Jurisdictional Cost Allocation Matters

Docket No. E-002/M-16-223

APPLICATION FOR CONSIDERATION OF A RESOURCE TREATMENT FRAMEWORK TO ADDRESS JURISDICTIONAL COST ALLOCATION ISSUES

SUMMARY OF FILING

Please take notice that on December 31, 2016, Northern States Power Company, a Minnesota corporation doing business as Xcel Energy (Company), submitted to the Minnesota Public Utilities Commission its Application for Consideration of a Resource Treatment Framework to Address Jurisdictional Cost Allocation Issues (Application). The Application presents the results of the Company's analysis to determine the most appropriate structures to accommodate current and future misalignment between Minnesota and North Dakota regarding resource additions and other system management issues related to the integrated NSP System.

INFORMATION REQUIRED BY N.D.A.C. § 69-02-02-04

North Dakota Administrative Code section 69-02-02-04 governs the contents of an application filed with the North Dakota Public Service Commission (NDPSC). In compliance with Section 69-02-02-04, Northern States Power Company, a Minnesota corporation, doing business as Xcel Energy (NSPM or Xcel Energy or the Company) provides the following required information.

1. Full Name and Post-Office Address of Applicant:

Northern States Power Company, doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401

2. Authorization or Permission Sought

The Company's Application for Consideration of a Resource Treatment Framework to Address Jurisdictional Cost Allocation Issues (Application) addresses issues regarding energy resource planning and selection created by differences in resource outlooks between the states served by NSPM. The Application presents the results of the Company's analysis in determining the most appropriate structures to accommodate current and future misalignment between the NSPM states regarding resource additions and other system management issues related to the integrated NSP System.

3. Statutory Provision or Other Authority Under Which the Commission Authorization or Permission is Sought:

This Application is being filed in conformity with the Company's obligation to propose a Resource Treatment Framework addressing our long-term plans for managing differing state energy policies per the *Negotiated Agreement* entered into between the Company and NDPSC Advocacy Staff and adopted by the NDPSC in Case Nos. PU-12-813 *et al.* on March 9, 2016.[1]

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[1] *See N. States Power Co. 2013 Electric Rate Increase Application*, Case Nos. PU-12-813 *et al.*, ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT at 4, at 2-3 of Negotiated Agreement (NDPSC Mar. 9. 2016) (provided as Appendix A to the Application).

4. Number of Copies

An original and at least seven copies of the Application are being filed with the NDPSC consistent with N.D.A.C. § 69-02-02-04(2).

5. Articles of Incorporation and Certificate of Good Standing

The Company incorporates by reference the corporate papers filed in our Corporate Documents case, Case No. PU-09-664. The Company's Articles of Incorporation were filed on September 30, 2009, and our most recent Certificate of Good Standing was filed on January 15, 2016.

Disputed Resources

	Fuel	OWN/PPA	UCAP (MW)	Retirement	PPA Termination
Laurentian Energy Authority	Bio	PPA	31.2	--	12/31/2026
KODA Energy LLC	Bio	PPA	12.0	--	5/17/2019
FibroMinn	Bio	PPA	52.0	--	6/30/2028
St Paul Cogeneration	Bio	PPA	25.0	--	4/30/2023
WM Renewable Energy (MN Methane)	Bio	PPA	4.0	--	3/31/2020
Pine Bend	Bio	PPA	4.1	--	12/31/2025
Adams Wind Generations	Wind	PPA	3.9	--	3/8/2031
Big Blue	Wind	PPA	5.1	--	20 Yrs from COD
North Community Turbines	Wind	PPA	2.8	--	5/27/2031
North Wind Turbines	Wind	PPA	2.5	--	5/27/2031
Danielson Wind Farms	Wind	PPA	3.2	--	3/10/2031
Ewington Energy Systems LLC	Wind	PPA	3.1	--	5/27/2028
Grant County Wind, LLC	Wind	PPA	4.7	--	8/8/2030
Hilltop Power	Wind	PPA	0.2	--	2/19/2029
Jeffers Wind 20, LLC	Wind	PPA	6.6	--	10/9/2028
Ridgewind Power Partners LLC	Wind	PPA	3.8	--	1/12/2031
Uilk Wind Farm	Wind	PPA	0.0	--	1/14/2030
Valley View Transmission	Wind	PPA	1.4	--	11/29/2031
Winona County Wind	Wind	PPA	0.0	--	10/26/2031
Woodstock Municipal Wind, LLC	Wind	PPA	0.0	--	1/24/2031
Slayton	Solar	PPA	0.8 (X)	--	1/1/2033
Best Power (St. Johns)	Solar	PPA	0.2 (X)	--	5/27/2030
Best Power International (Sr. Notre Dame)	Solar	PPA	0.4 (X)	--	11/30/2030
Marshall Solar	Solar	PPA	31.1 (X) (Y)	--	1/6/2042
North Star Solar	Solar	PPA	50.0 (X) (Y)	--	12/31/2041
Mankato Energy Center Expansion (MEC II)	CC Gas	PPA	unknown	--	5/31/2039

(X) Solar UCAP - Accredited values based on MISO 50% nameplate rating for first year

(Y) Solar Resources with first full year of MISO accreditation 2018/19

Legacy System

	Fuel	OWN/PPA	UCAP (MW)	Retirement	PPA Termination
AS King 1	Coal	OWN	500.1	12/31/2037	--
Sherco 1	Coal	OWN	694.8	5/31/2027	--
Sherco 2	Coal	OWN	987.8	5/31/2024	--
Sherco 3	Coal	OWN	524.1	12/31/2040	--
Monticello 1	Nuclear	OWN	601.2	12/31/2030	--
Prairie Island 1	Nuclear	OWN	509.3	8/31/2033	--
Prairie Island 2	Nuclear	OWN	504.2	10/31/2034	--
Black Dog CC (5 &2)	CC Gas	OWN	218.0	12/31/2031	--
Angus Anson 2	CT Gas	OWN	87.1	12/31/2030	--
Angus Anson 3	CT Gas	OWN	76.4	12/31/2030	--
Angus Anson 4	CT Gas	OWN	142.2	5/31/2035	--
Blue Lake 7	CT Gas	OWN	143.3	5/31/2035	--
Blue Lake 8	CT Gas	OWN	141.3	5/31/2035	--
Flambeau 1	CT Gas	OWN	11.8	12/31/2018	--
Granite City 1-4	CT Gas	OWN	51.5	12/31/2023	--
Inver Hills 1	CT Gas	OWN	41.9	12/31/2026	--
Inver Hills 2	CT Gas	OWN	44.4	12/31/2026	--
Inver Hills 3	CT Gas	OWN	39.5	12/31/2026	--
Inver Hills 4	CT Gas	OWN	42.0	12/31/2026	--
Inver Hills 5	CT Gas	OWN	35.1	12/31/2026	--
Inver Hills 6	CT Gas	OWN	39.1	12/31/2026	--
Wheaton 1	CT Gas	OWN	40.5	12/31/2025	--
Wheaton 2	CT Gas	OWN	42.7	12/31/2025	--
Wheaton 3	CT Gas	OWN	39.5	12/31/2025	--
Wheaton 4	CT Gas	OWN	38.8	12/31/2025	--
HighBridge CC	CC Gas	OWN	528.8	5/31/2048	--
Riverside CC (9,10 & 7A)	CC Gas	OWN	454.8	3/31/2049	--
LS Power - Cottage Grove	CC Gas	PPA	231.0	--	9/30/2027
Calpine Mankato Energy Center	CC Gas	PPA	281.6	--	7/31/2026
Invenergy Cannon Falls	CT Gas	PPA	316.4	--	4/10/2025
French Island 3	Oil	OWN	59.6	12/31/2023	--
French Island 4	Oil	OWN	59.6	12/31/2023	--
Blue Lake 1	Oil	OWN	39.7	12/31/2023	--
Blue Lake 2	Oil	OWN	39.3	12/31/2023	--
Blue Lake 3	Oil	OWN	36.4	12/31/2023	--
Blue Lake 4	Oil	OWN	41.7	12/31/2023	--
Wheaton 5	Oil	OWN	0.0	12/31/2025	--
Wheaton 6	Oil	OWN	44.6	12/31/2025	--
Red Wing 1-2	Bio	OWN	17.0	12/31/2027	--
Wilmarth 1-2	Bio	OWN	18.0	12/31/2027	--
French Island 1-2	Bio	OWN	6.8	12/31/2023	--
BayFront 4	ST Gas	OWN	0.0	12/31/2023	--
Bay Front 5	Bio	OWN	11.0	12/31/2023	--
Bay Front 6	Bio	OWN	15.0	12/31/2023	--
Barron	Bio	PPA	2.0	--	Evergreen
HERC	Bio	PPA	23.0	--	12/31/2017
Diamond K Dairy	Bio	PPA	0.3	--	12/31/2024
Apple River Falls 1-4	Hydro	OWN	0.0	(W)	--
Big Falls 1-3	Hydro	OWN	4.0	(W)	--
Cedar Falls 1-3	Hydro	OWN	5.0	(W)	--
Chippewa Falls 1-6	Hydro	OWN	8.0	(W)	--
Cornell 1-4	Hydro	OWN	8.0	(W)	--
Dells 1-5	Hydro	OWN	0.0	(W)	--
Hayward 1	Hydro	OWN	0.0	(W)	--
Hennepin Island 1(St. Anothony Falls)	Hydro	OWN	9.0	(W)	--
Holcombe 1-3	Hydro	OWN	22.0	(W)	--
Jim Falls 1-3	Hydro	OWN	27.0	(W)	--

	Fuel	OWN/PPA	UCAP (MW)	Retirement	PPA Termination
Ladysmith 1-3	Hydro	OWN	0.0	(W)	--
Menomonie 1-2	Hydro	OWN	0.0	(W)	--
Riverdale 1-2	Hydro	OWN	0.0	(W)	--
Saxon Falls 1-2	Hydro	OWN	0.0	(W)	--
St. Croix Falls 1-8	Hydro	OWN	15.0	(W)	--
Superior Falls 1-2	Hydro	OWN	0.0	(W)	--
Thornapple 1-2	Hydro	OWN	0.0	(W)	--
Trego 1-2	Hydro	OWN	0.0	(W)	--
White River 1-2	Hydro	OWN	0.0	(W)	--
Wissota 1-6	Hydro	OWN	17.0	(W)	--
Manitoba Hydro - 375/325 MW PSA	Hydro	PPA	369.0	--	4/30/2025
Manitoba Hydro - 350 MW Diversity	Hydro	PPA	344.0	--	4/30/2025
Manitoba Hydro - 125 MW PSA	Hydro	PPA	123.0	--	4/30/2025
Manitoba Hydro - 4-Year Diversity	Hydro	PPA	74.0	--	5/31/2020
Byllesby	Hydro	PPA	2.1	--	2/28/2021
City of Hastings	Hydro	PPA	<1	--	6/30/2033
City of St. Cloud	Hydro	PPA	7.0	--	10/31/2021
Dairyland Power Cooperative			1.1	--	(V)
Eau Galle Hydro	Hydro	PPA	<1	--	7/31/2026
Lac Courte Orielles (Chippewa)	Hydro	PPA	<1	--	12/31/2021
Neshonoc	Hydro	PPA	0.4	--	12/31/2020
Rapidan Hydro Plant	Hydro	PPA	2.0	--	4/30/2017
SAF Hydroelectric, LLC	Hydro	PPA	6.0	--	12/18/2031
Grand Meadows (1-67)	Wind	OWN	17.0	12/31/2033	--
Nobles (1-134)	Wind	OWN	37.0	12/31/2035	--
Pleasant Valley	Wind	OWN	31.2	12/31/2040	--
Border	Wind	OWN	23.3	12/31/2040	--
Courtenay	Wind	OWN	0.0	12/31/2041	--
Agassiz Beach	Wind	PPA	0.3	--	2/27/2031
Boeve	Wind	PPA	0.3	--	8/8/2028
Carleton College	Wind	PPA	0.0	--	9/19/2024
Chanarambie Power Partners	Wind	PPA	12.8	--	12/14/2023
Cisco	Wind	PPA	1.3	--	5/27/2028
Fenton Power Partners I	Wind	PPA	38.9	--	11/12/2032
Fey Windfarm	Wind	PPA	0.3	--	9/3/2028
FPL Mower County	Wind	PPA	14.9	--	12/2/2026
JJN Windfarm	Wind	PPA	0.2	--	12/16/2029
Kas Brothers Windfarm	Wind	PPA	0.2	--	12/9/2031
k-Brink	Wind	PPA	0.3	--	2/12/2028
Lake Benton Power Partners (LBI)	Wind	PPA	12.6	--	12/13/2028
Lake Benton Power Partners II (LBII)	Wind	PPA	9.6	--	5/30/2025
Metro Wind LLC	Wind	PPA	0.0	--	2/28/2031
MinnDakota Wind	Wind	PPA	28.3	--	12/30/2022
Moraine Wind I	Wind	PPA	8.1	--	12/21/2018
Moraine Wind II Note (1)	Wind	PPA	11.5	--	2/17/2019
Lakota Ridge	Wind	PPA	1.3	--	4/30/2034
Shaokatan Hills	Wind	PPA	1.4	--	4/30/2034
Odell	Wind	PPA	0.0	--	7/29/2036
Olsen Windfarm	Wind	PPA	0.0	--	12/14/2031
Prairie Rose	Wind	PPA	0.0	--	12/10/2032
Rock Ridge Power Partners	Wind	PPA	0.4	--	4/11/2021
Shane's Wind Machine	Wind	PPA	0.3	--	8/10/2026
South Ridge Power Partners	Wind	PPA	0.4	--	4/11/2021
St. Olaf	Wind	PPA	0.0	--	10/5/2028
Velva Windfarm	Wind	PPA	2.2	--	12/31/2026
Windcurrent	Wind	PPA	0.3	--	5/30/2028
Wind Power Partners 1993 ("WPP-93")	Wind	PPA	3.9	--	5/2/2019
Windvest Power Partners	Wind	PPA	0.4	--	4/11/2021
Woodstock Wind Farm	Wind	PPA	1.2	--	6/23/2030

	Fuel	OWN/PPA	UCAP (MW)	Retirement	PPA Termination
Buffalo Ridge Wind Farm	Wind	PPA	0.2	--	12/17/2018
CG Windfarm	Wind	PPA	0.2	--	12/27/2028
Moulton Heights Wind Power Project	Wind	PPA	0.2	--	12/17/2018
Muncie Power Partners LLC	Wind	PPA	0.2	--	12/17/2018
North Ridge Wind Farm LLC	Wind	PPA	0.2	--	12/17/2018
TG Windfarm	Wind	PPA	0.2	--	12/27/2028
Tofteland Windfarm	Wind	PPA	0.2	--	12/27/2028
Vandy South Project	Wind	PPA	0.2	--	12/17/2018
Viking Wind Farm	Wind	PPA	0.2	--	12/17/2018
Vindy Power Partners	Wind	PPA	0.2	--	12/17/2018
Wilson-West Windfarm LLC	Wind	PPA	0.2	--	12/17/2018
Asian Children Support, Inc.	Wind	PPA	0.2	--	2/13/2028
Bangladesh Children Support	Wind	PPA	0.2	--	2/13/2028
Brandon Windfarm	Wind	PPA	0.2	--	4/30/2025
BT, LLC	Wind	PPA	0.2	--	9/25/2027
Burmese Children Support, Inc.	Wind	PPA	0.2	--	2/13/2028
G M, LLC	Wind	PPA	0.2	--	9/25/2027
Gar Mar Wind I	Wind	PPA	0.2	--	4/30/2025
Henslin Creek Windfarm	Wind	PPA	0.2	--	4/30/2025
Indian Children Support	Wind	PPA	0.2	--	2/13/2028
McNeilus Windfarm, LLC	Wind	PPA	0.2	--	9/25/2027
Salvadoran Children Support, Inc.	Wind	PPA	0.2	--	2/13/2028
SG (JCKD)	Wind	PPA	0.2	--	9/25/2027
Triton Windfarm	Wind	PPA	0.2	--	4/30/2025
Wasioja Windfarm, LLC	Wind	PPA	0.2	--	4/30/2025
Willhelm Wind	Wind	PPA	0.2	--	4/30/2025
REAP, LLC (REAP I)	Wind	PPA	0.2	--	9/27/2027
REAP, LLC (REAP II)	Wind	PPA	0.2	--	9/14/2021
Grant Windfarm	Wind	PPA	0.2	--	4/30/2025
Elsinore	Wind	PPA	0.2	--	9/14/2021
Ashland	Wind	PPA	0.2	--	4/30/2025
University of Minesota - UMORE Park	Wind	PPA	0.0	--	4/1/2021
Bendwind	Wind	PPA	0.2	--	2/28/2026
DeGreeff DP	Wind	PPA	0.2	--	4/4/2026
DeGreeffpa	Wind	PPA	0.2	--	3/7/2026
Groen Wind	Wind	PPA	0.2	--	4/23/2026
Hillcrest Wind	Wind	PPA	0.2	--	4/27/2026
Larswind	Wind	PPA	0.2	--	3/19/2026
Sierra Wind	Wind	PPA	0.2	--	4/30/2026
TAIR Wind	Wind	PPA	0.2	--	4/22/2026
Carstensen Wind	Wind	PPA	0.3	--	12/31/2024
Greenback Energy	Wind	PPA	0.3	--	1/24/2025
Lucky Wind	Wind	PPA	0.3	--	1/1/2025
Northern Lights Wind	Wind	PPA	0.3	--	1/24/2025
Stahl Wind Energy	Wind	PPA	0.3	--	1/1/2025
Autumn Hills (NAE)	Wind	PPA	0.2	--	2/14/2031
Florence Hills (NAE)	Wind	PPA	0.3	--	1/8/2031
Hope Creek LLC (NAE)	Wind	PPA	0.3	--	1/19/2031
Jack River LLC (NAE)	Wind	PPA	0.2	--	2/17/2031
Jessica Mills LLC (NAE)	Wind	PPA	0.2	--	2/22/2031
Julia Hills LLC (NAE)	Wind	PPA	0.2	--	2/23/2031
Soliloque Ridge LLC (NAE)	Wind	PPA	0.3	--	1/18/2031
Spartan Hills LLC (NAE)	Wind	PPA	0.3	--	1/12/2031
Sun River LLC (NAE)	Wind	PPA	0.2	--	2/23/2031
Tsar Nicolas (NAE)	Wind	PPA	0.2	--	2/16/2031
Twin Lake Hills (NAE)	Wind	PPA	0.3	--	1/3/2031
Winter Spawn LLC (NAE)	Wind	PPA	0.3	--	1/24/2031
Hadley Ridge LLC (NAE)	Wind	PPA	0.3	--	12/27/2030
Ruthton Ridge LLC (NAE)	Wind	PPA	0.3	--	1/22/2031

	Fuel	OWN/PPA	UCAP (MW)	Retirement	PPA Termination
Breezy Bucks-I	Wind	PPA	0.1	--	5/10/2026
Breezy Bucks-II	Wind	PPA	0.1	--	5/10/2026
Roadrunner-I	Wind	PPA	0.1	--	5/10/2026
Salty Dog-I	Wind	PPA	0.1	--	5/10/2026
Salty Dog-II	Wind	PPA	0.1	--	5/10/2026
Wally's Wind Farm	Wind	PPA	0.1	--	5/10/2026
Windy Dog-I	Wind	PPA	0.1	--	5/10/2026
MacBeth - 3	Wind	PPA	0.3	--	9/3/2025
MacBeth - 1	Wind	PPA	0.3	--	9/3/2025
MacBeth - 2	Wind	PPA	0.3	--	9/3/2025
Gary J.T.	Wind	PPA	0.3	--	8/27/2025
Jenna M.T.	Wind	PPA	0.3	--	8/27/2025
Krysta J.T.	Wind	PPA	0.3	--	8/27/2025
Mark J.P.	Wind	PPA	0.3	--	8/24/2025
Theresa M.T	Wind	PPA	0.3	--	8/27/2025
Minwind III	Wind	PPA	0.2	--	2/1/2025
Minwind IV	Wind	PPA	0.2	--	2/1/2025
Minwind IX	Wind	PPA	0.2	--	2/1/2025
Minwind V	Wind	PPA	0.2	--	2/1/2025
Minwind VI	Wind	PPA	0.2	--	2/1/2025
Minwind VII	Wind	PPA	0.2	--	2/1/2025
Minwind VIII	Wind	PPA	0.2	--	2/1/2025
Aurora Solar*	Solar	PPA	50.0 (X) (Y)	--	12/1/2014

(V) - Contract term is based on life of the Flambeau Plant
(W) Owned Hydro - for planning purposes, these resources extend through the planning period (currently 2053)
(X) Solar UCAP - Accredited values based on MISO 50% nameplate rating for first year
(Y) Solar Resources with first full year of MISO accreditation 2018/19
* As noted in the Application in footnote 3, we are not considering the Aurora Solar project to be a Disputed Resource.

EVOLUTION OF THE NSP SYSTEM

The electric utility industry has evolved significantly over the past several decades, as has the governing regulatory paradigm. This evolution and the new and emerging ways that utility systems can meet customer needs provides useful context for the Commissions' consideration of alternatives to the integrated NSP System. In this Schedule, we provide a discussion of the development of the integrated NSP System that exists today, illustrating how the System has evolved to address changes in the industry and in technology to meet customer needs. As each state in the System has participated in that evolution, each has also shared in the benefits and costs of developing it. Further, discussion of the optionality provided by the more recent marked-based approach pursued by the Federal Energy Regulatory Commission (FERC) can help to frame the benefits and burdens of integration to all the NSP System states and a Resource Treatment Framework (RTF) that equitably addresses these issues.

A. Historical Development Drove Integration

Almost from the beginning of electrification, electric utilities have focused on the twin goals of maximizing economies of scale and diversification to bring value for their businesses and their customers. These goals have been substantially driven by a combination of three important factors:

- technological advances that allow utilities to consolidate operations and increase efficiency;
- the development and expansion of substantial central station power and high-voltage transmission that allows customers to take advantage of multiple forms of generation resources on the same system (i.e., fuel diversity); and
- evolving environmental standards that encourage the development of new and more sustainable energy sources in conjunction with central stations.

Developing economies of scale and diversification has taken several different forms over the years, resulting in an integrated and highly-efficient grid that supports current robust markets for energy and ancillary services and emerging capacity markets.
For example, including generating power from a variety of sources in different locations and tied together with high-voltage transmission hedges risk better than having discrete community-specific generators. The Company's experience with this

dynamic is important. From the 1940s to the early 1960s, NSP focused on constructing a series of (largely coal-fired) generators in and around the Company's main load center of the Twin Cities. This resulted in the development and expansion of generators at Black Dog in the south metro, Riverside in Minneapolis, and High Bridge in St. Paul, as well as the construction of the King Plant in Bayport. These plants were tied together with high-voltage transmission that allowed all our customers on the system to take advantage of this low-cost central station power. The Company's load centers in North Dakota and South Dakota were largely served using a combination of imported energy using the existing transmission system and the purchase of capacity and energy from neighboring utilities who had power plants nearby.

By the late 1950s, however, it was becoming evident that the existing system and local generation plants could no longer produce and deliver enough electricity to meet the needs of the growing population and economy encompassing the NSP System. At the time, load was growing by 7 percent annually – doubling every 10 years. The then-existing transmission system was strained and it became evident that significant high-voltage upgrades to the transmission system and new generation sources had to be added to serve customers at that time and long into the future.

In the 1960s, the Company built the 345 kV transmission loop around the Twin Cities that follows the Highway 494/694 ring today. This was a feasible option and necessary for long-term community service reliability. In addition, the Company concluded that a 345 kV voltage line was needed to support the types of large electric generators that were going to be needed to support rapid load growth. Whereas in the past the system could withstand an outage of a smaller power plant and local generation support was available, once the larger plants came on-line, power would have to be imported from other states if one of the generators went off-line.

In addition, to provide greater reliability the Company embarked on a series of investments that benefited the area and supported the overall goals of maximizing economies of scale and enhancing diversity. NSP and six other regional utilities constructed a new 345 kV transmission line from the Twin Cities to St. Louis. Two other 345 kV lines, connecting the Twin Cities to Chicago and Omaha, were also built. NSP was also instrumental in developing and building a 500 kV transmission line from Winnipeg to the Twin Cities. This line facilitated the import of significant amounts of hydro-electric generation from Manitoba to Minnesota and the rest of the NSP System.

This transmission system development facilitated the Company's ability to support highly-efficient large central station generators in the 1970s. In that timeframe, NSP's new plant investments included the 529 MW Allen S. King plant (King) that became operational in 1968; 600 MW Monticello plant in 1971; 1,100 MW Prairie Island plant to the southeast which became fully operational in 1973 and 1974; and two 750 MW generators at the Sherburne County plant (Sherco) in 1976-77. In the 1980s, NSP expanded its Sherco site with the installation of the 850 MW Sherco Unit 3. These large generators were made possible because of the development of the regional transmission system and all of these generators allowed NSP to provide adequate and low-cost service to all of its customers in North Dakota, Minnesota, and the other states served by the integrated system.

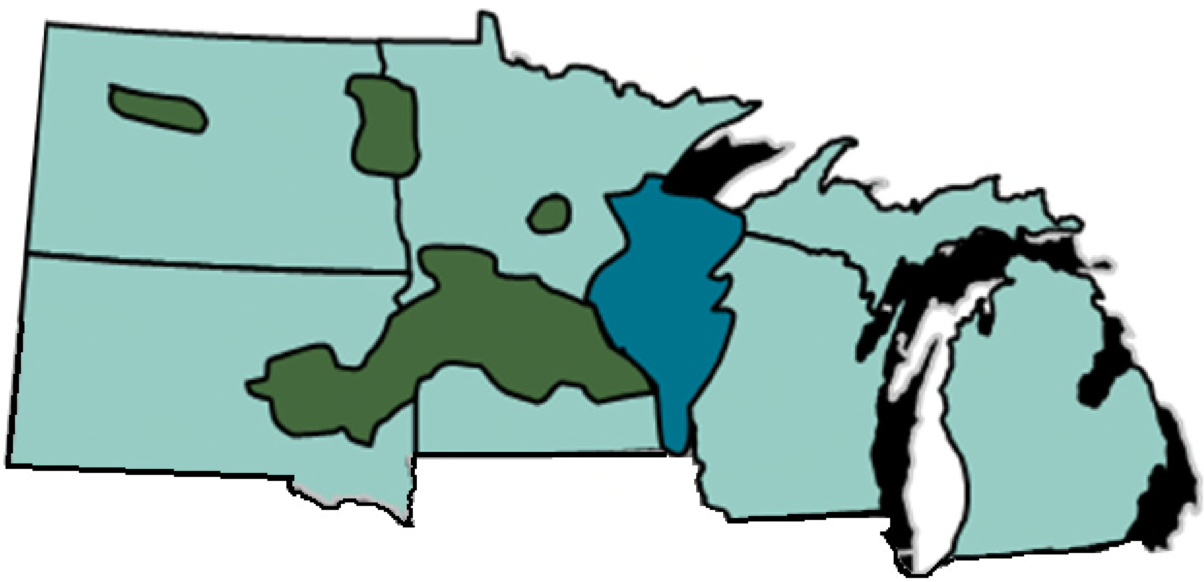
These larger generators were much more efficient and cost-effective, and allowed the system to be expanded in a way that served all customer needs throughout the five-state region. The addition of the 500 kV transmission line from Manitoba to Minnesota facilitated the import of a significant amount of carbon-free hydroelectric generation long before policymakers concluded that carbon-free electric generation provided additional value. Finally, in the 1980s and 1990s, the Company added a significant amount of natural gas generation to the system, including peaking units and combined-cycle intermediate units spread throughout the system to provide system support as well as energy and capacity to the system.

The development of these larger power plants supported customer needs by efficiently maximizing the economies of having a robust transmission system and several large central-station generation sources. This development also met the companion goal of diversifying fuel types to hedge the fuel cost risk of overreliance on any particular fuel source. As noted, from the 1960s through the 1990s, the Company added a significant amount of coal, nuclear, hydro and natural gas generation. Finally, since the mid-1990s to the present, the Company has deployed approximately 2,500 MW of renewable energy generation on its system that serves both significant environmental benefits as well a fuel hedge since that generation generally displaces fossil fuel generation.

It is important to note that while the modern NSPM obtained and served its North Dakota service territory prior to consolidating its operations in the Twin Cities, the service territory and load in North Dakota is physically isolated from the remainder of NSPM's service territory. In addition, our service territory in North Dakota is physically separated between the main metropolitan areas of North Dakota served by the Company: Fargo/West Fargo, Grand Forks, and Minot. This is illustrated in the service territory map provided in Figure 1, below.

Due to this, the bulk of our North Dakota load was served through alternative supply arrangements, most notably through agreement with what is now Great River Energy (GRE) via the Stanton Displacement Agreement.[1] The physical separation of our North Dakota customers also leads us to the conclusion that our recommended RTF is a viable option for, and consistent with, continued prudent service in North Dakota.

Figure 1: Service Territory Map



Development of a robust integrated NSP System was consistent with the regulatory paradigm that existed through most of that evolution. In the days before open access

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[1] NORTH DAKOTA-WESTERN MINNESOTA 230 KV FACILITIES CO-ORDINATING AGREEMENT BETWEEN MINNKOTA POWER COOPERATIVE, INC., OTTER TAIL POWER COMPANY, MINNESOTA POWER & LIGHT COMPANY, AND NORTHERN STATES POWER COMPANY (July 29, 1966); *see also* MISO Tariff, Attachment P, Contract No. 317. The Stanton Displacement Agreement is a Grandfathered Transmission Agreement in MISO. The agreement currently provides for GRE to provide the Company the output of Stanton, a coal-fired power plant in Stanton, North Dakota, which is typically about 188 MW per hour. At the same time, the Company delivers to GRE the same MW amount from Sherco (188 MW each hour). *See 2011 Annual Automatic Adjustment of Charges Report – Electric*, Docket No. E999/AA-11-792, NORTHERN STATES POWER COMPANY REPLY COMMENTS at 5 (July 11, 2012).

transmission and before regional energy and capacity markets, it was important for regional utilities, such as NSP, to ensure that it had adequate infrastructure to serve its customers under all reasonable circumstances. Essentially, building generation and associated transmission to serve the NSP System acted as a physical hedge against the risk of any shortfall – be it from capacity, mechanical failures, or other impacts to the System. Bigger was better as it hedged risk for all participants and there were few other options.

B. <u>Existence of Competitive Markets Creates Optionality</u>

Although stand-alone resources and intra-system integration were historic cornerstones of utility systems, significant regulatory changes in the past 30 years have moderated the importance of utilities having significant stand-alone resources in the same manner as in the past. This change in the regulatory landscape has transformed the industry, moving away from utilities planning and operating on a stand-alone basis toward a competitive market-based structure that allows many of the benefits of the larger system to be realized by market participants without actual ownership of assets.

First, in 1978, Congress enacted the Public Utility Regulatory Policy Act (PURPA) which began to bring about major changes in the industry. PURPA ushered in an era when independent power producers could, for the first time, build power plants to sell electricity on the open market and in competition with incumbent utilities. By injecting supply competition, PURPA set the stage for industry restructuring that resulted in the market-based approach that exists today.

Second, in 1992, passage of the Energy Policy Act hastened the movement to restructuring in a market-based format. The Energy Policy Act called for the creation of broad, competitive wholesale electric markets to be overseen by FERC. This began the long process of opening the nation's high-voltage grid to use on a comparable and non-discriminatory basis. Without going into great detail about the history of the transmission system development, it can be said that the system was historically built to deliver the power output of power plants to local utilities that serve their end-use customers in a defined geographic service territory. Utilities in adjoining areas interconnected their systems to maintain reliability and to make limited wholesale power transactions with their neighbors.

Under the auspices of the Energy Policy Act, in 1996 FERC issued Order Nos. 888 and 889, requiring all public utilities to provide open access to their transmission facilities. These landmark orders further required utilities to separate their marketing/generation functions from their transmission functions and to operate the transmission function in a separate way. Order No. 888 also set the stage for the voluntary formation of regional transmission organizations. These developments had a profound impact on the industry and made it possible, for the first time, for utilities to take advantage of competitive market forces regardless of whether the utility owned the power plants and transmission lines used to serve their customers. The planning principles and priorities espoused in Order No. 888 were further refined and made mandatory through Order No. 890 in 2007.

Third, four years after the issuance of Order Nos. 888 and 889, FERC issued Order No. 2000, which was designed to speed the development of regional transmission organizations and further encourage wholesale competition. This led to the development of the Midcontinent Independent System Operator (MISO) (formerly, the Midwest Independent System Operator) as an independent system operator in the early 2000s, further opening the regional system to competitive forces.

Fourth, and most importantly, beginning in 2005 MISO implemented its energy market function and began centralized dispatch of all generation across its upper-Midwest footprint. The centrally-operated market was expanded in 2009 to include ancillary services and in 2013 to include a capacity auction. This overall competitive market structure allows energy, capacity, and ancillary services to be transacted through a centralized market based on bids and offers that are cleared and administered by MISO.

The federal integration of the national transmission grid is currently continuing through implementation of FERC Order No. 1000, which mandates interregional transmission planning and competitive transmission development to further allow for market efficiencies to displace the historic economies of scale of large, stand-alone utility systems. And while controversial and subject to litigation, the creation of mandatory capacity markets in regions such as PJM on the east coast of the United States have impacted resource planning and other, historically utility- and state-specific responsibilities regarding resource adequacy. As a result, these functions are now regionally and market based as well.

Acknowledging that there are now options other than large, central station integrated utility systems by which utilities can provide safe and reliable service to their customers may change the value proposition of large integrated systems, especially for smaller states or load pockets. At the same time, the Company cannot move forward as if integration did not exist for the last century, but rather must resolve past disagreements on System resources and then chart a path for the future. Under any scenario, industry evolution will play a role as the existing NSP System ages and evolves.

Mechanics of North Dakota Pseudo Separation

The purpose of this Schedule is to identify, on a draft basis, the accounting mechanisms under a North Dakota Pseudo Separation. As explained in the Application, Pseudo Separation essentially reallocates the economic impacts the federal market overlay, bi-lateral transaction, and MISO dispatch of the NSP System to particular states. Pseudo Separation would also address the revenues from generation margins and ancillary services, revenue sufficiency guarantee uplifts, and other MISO market constructs. Capacity sales and purchases would be similarly allocated, as well as RECs and other non-power-based attributes of a particular resource. The Legacy System will be allocated to each jurisdiction using the existing methodology. To assist in a further understanding of the mechanics of a Pseudo Separation structure, the treatment of specific cost and revenue categories with respect to new resource additions as units of the NSP System retire or expire are explained, categorically, below.

We note, however, that while the Pseudo Separation concept is derived from the pricing zone concept in gas operations, we will be implementing it here for the first time with no experience in doing so. We expect that considerable trial and error may be necessary to achieve Pseudo Separation. We also expect that Pseudo Separation will require additional personnel and investments in our information technology infrastructure to manage. We look forward to working with our stakeholders in developing the specific accounting and other protocols to manage this complex endeavor.

Fuel and Purchased Power Expense

Under a Pseudo Separation structure, MISO costs and revenues would be separately tracked, with revenues from sales of energy into the MISO market being assigned to the specific jurisdiction(s) paying for the energy resource. MISO load costs, or purchases of energy from the MISO market, would be allocated to specific jurisdictions based on load-ratio share. For example, the Minnesota jurisdiction would be allocated MISO load costs based on the ratio of Minnesota jurisdiction calendar month sales to NSP System calendar month sales. The North Dakota jurisdiction would be allocated MISO load costs based on the ratio of North Dakota jurisdiction billing month sales to NSP system billing month sales. MISO load costs include Behind the Meter Generation (BTMG). BTMG reduces the amount of load settled through the MISO market. Fully resolving BTMG issues will be complex and we will need to work to find consensus on the final approach adopted.

It should be noted that a portion of the North Dakota load is currently included in the NSP.NSP load node. Should a requirement arise for specific North Dakota jurisdictional pricing of load, commercial and network models would need to be updated.

With respect to non-MISO load costs, fuel and non-MISO purchased power costs would be assigned to the specific jurisdiction(s) paying for the energy resource.

Ancillary Services Market (ASM)

MISO provides three primary ASM products – regulation, spinning, and supplemental reserves. Under a Pseudo Separation structure, ASM costs and revenues would be separately tracked by jurisdiction. Purchases of ASM from the MISO market that are divided into "reserve zones" by MISO would be allocated to each jurisdiction based on load-ratio share, similar to the MISO load cost allocations. For example, the Minnesota jurisdiction would be allocated ASM purchases based on the ratio of Minnesota jurisdiction calendar month sales to NSP System calendar month sales. The North Dakota jurisdiction would be allocated ASM purchases based on the ratio of North Dakota jurisdiction billing month sales to NSP System billing month sales. The revenues from ASM sales into the MISO market would be assigned to the specific jurisdiction(s) paying for the energy resource.

Trade Margins

Trade margins are addressed in two separate categories – non-asset based margins and asset based margins. With respect to non-asset based margins, under a Pseudo Separation scenario, no changes are anticipated to the current process of allocating these margins to jurisdictions. For asset based margins, only the specific jurisdiction(s) paying for the energy resource would benefit from any generation margins arising from excess sales related to the generating asset or PPA. Currently, the excess energy sold into the market is assigned the highest energy cost by hour. A sales summary by generator would be produced from Cost Calculator – an internal proprietary costing software – for the current month estimate, for actual resettlement versus its respective estimate, and for final resettlement versus its respective actual resettlement.

Plant Related

Plant records, including plant in-service, accumulated depreciation, accumulated deferred income tax, depreciation expense, and schedule M items, are currently maintained by generating plant. This would allow for plant-related costs to be assigned to a specific jurisdiction under a Pseudo Separation structure. Moreover, property tax expense is available by generating plant, allowing for costs to be assigned to a specific jurisdiction.

Operation and Maintenance Expense

Operation and maintenance expenses, including fuel handling expense, are currently available by generating plant in the general ledger, allowing for costs to be assigned to a specific jurisdiction. Under a Pseudo Separation structure, however, a methodology may need to be developed to allocate production costs that cannot be assigned to a specific generating plant or jurisdiction.

Other Electric Revenues

Other electric revenue, like ash handling and refuse derived fuel, are available by generating plant in the general ledger, allowing for the revenues to be assigned to a specific jurisdiction under a Pseudo Separation structure.

Capacity Costs

With respect to capacity costs, to the extent that Xcel Energy purchases capacity through a Power Purchase Agreement or other contractual arrangement that has separate and distinct capacity pricing, we would assign those costs to supporting jurisdiction(s) much like plant related costs.

With respect to capacity sales, such as through the MISO capacity markets or bilateral contracts, to the extent they represent a "slice of the system" we would expect to allocate those revenues on a pro-rata basis based on percentage of system participation by each jurisdiction in the sum-total of resources that make up that "slice of the system." To the extent that capacity sales are unit or station specific, we would expect to assign the revenues from those sales.

Demand Side Management

Demand Side Management costs are currently directly assigned and we would expect to continue doing so.

Conservation Improvement Program

Conservation Improvement Program costs are currently directly assigned and we would expect to continue doing so.

Renewable Energy Credits (RECs)

All RECs produced by qualified renewable generation resources are registered in the Midwest Renewable Energy Tracking System (M-RETS) database and are allocated to specific accounts by jurisdiction. Under the Pseudo Separation structure, only the specific jurisdiction(s) paying for the qualified renewable generation resources would receive an allocation of the RECs. Any sale of RECs would be from the jurisdictional portfolio and would be direct assigned to the jurisdiction from which the sale is made.

General Reporting and Gathering of Information

Under a Pseudo Separation structure, NSPM's general ledger and other systems, like CXL, Cost Calculator, and REC Tracker, may need to be modified to accommodate additional information reporting needs. NSPM currently possesses the sophisticated software systems required to precisely calculate and shadow results for accounting for granular ISO market transactions. These types of systems would need to be maintained for Pseudo Separation, along with securing access to results produced by such systems. Further, additional reporting would likely need to be developed to facilitate the gathering of information.

These are but some of the many different allocation changes that would be required to implement a Pseudo Separation structure. We look forward to working with our stakeholders in this proceeding to better refine issues concerning this structure. Should the Commissions approve moving forward with Pseudo Separation, we would provide more detailed allocation proposals in an upcoming rate case.

RESOURCE PLANNING

I. Modeling Assumptions

1. Capital Structure and Discount Rate

The rates shown in Table 1 were calculated by taking a weighted average of NSPM's Minnesota jurisdictional (85 percent) and NSPW's Wisconsin jurisdictional (15 percent) information from the February 2016 Corporate Assumptions Memo. The after-tax weighted average cost of capital of 6.49 percent is used to calculate the capital revenue requirements of generic resources. It is also used as the discount rate to determine the present value of revenue requirements.

Table 1: Capital Structure

	Capital Structure	Allowed Return	Before Tax Elec. WACC	After Tax Elec. WACC
L-T Debt	45.32%	4.92%	2.23%	1.31%
Common Equity	52.92%	9.76%	5.17%	5.17%
S-T Debt	1.76%	0.70%	0.01%	0.01%
Total			**7.41%**	**6.49%**

2. Inflation Rates

The inflation rate used for construction (capital) costs, non-fuel variable O&M, fixed O&M, and any other escalation factor related to general inflationary trends is the long term forecast from Global Insight for the "Chained Price Index for Total Personal Consumption Expenditures" published in the third quarter of 2015. This rate is 2.0 percent and will be applied throughout the entire planning period as a base assumption.

3. Reserve Margin

The reserve margin at the time of MISO's peak is 7.8 percent. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 7.8\%) - 1 = 2.41\%.$$

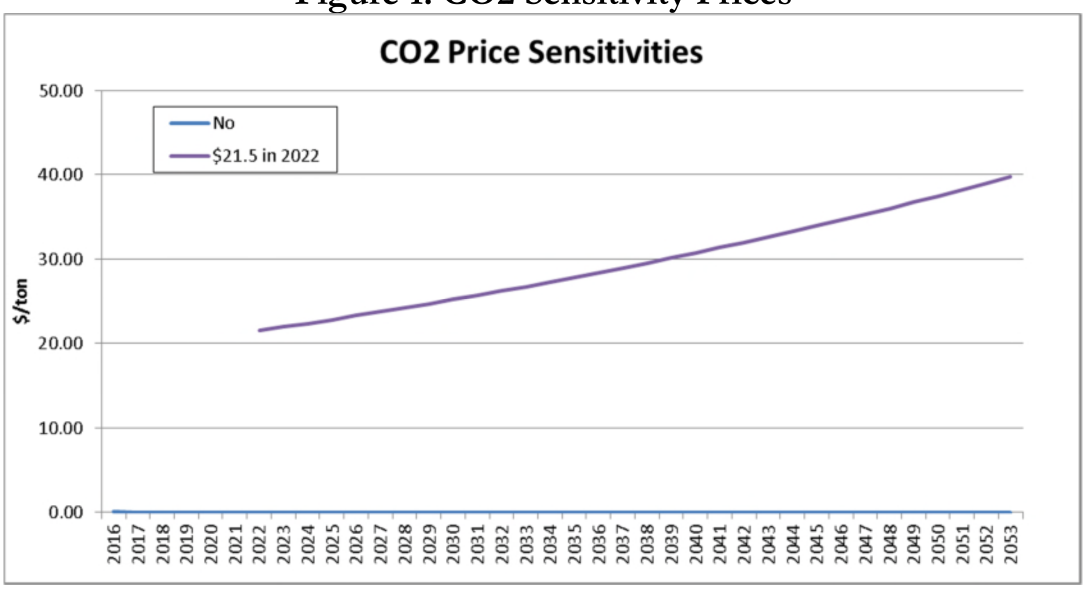
Table 2: Reserve Margin

Reserve Margin	
Coincidence Factor	5.00%
MISO Coincident Peak Reserve Margin %	7.80%
Effective RM Based on Non-coincident Peak	2.41%

4. <u>CO_2 Price Forecasts (PVSC Only)</u>

Figure 1 shows the annual CO_2 prices for the various CO_2 sensitivities that were used in the analysis. The base assumption is $21.50/ton starting in 2022 which is the average of $9/ton and $34/ton. The range of CO_2 costs is drawn from the Minnesota Public Utilities Commission's Order Establishing 2016 and 2017 Estimate of Future Carbon Dioxide Regulation Costs in Docket No. E999/CI-07-1199 issued August 5, 2016. All prices escalate at inflation.

Figure 1: CO2 Sensitivity Prices



5. <u>Externality Prices (PVSC Only)</u>

Externality prices are based on the high values from the Minnesota Public Utilities Commission's Notice of Comment Period on Updated Environmental Externality Values issued June 16, 2016, in Docket Nos. E999/CI-93-583 and E999/CI-00-1636, and are shown in Table 3 below. Prices are shown in 2016 dollars and escalate at inflation. Sulfur oxides (SOx) assumed zero regulatory cost due to large surplus of allowances and weak sales market and zero externality cost per Minnesota Public Utilities Commission policy.

Table 3: Externality Prices

MPUC Updated Externality Prices				
2016 $/ton				
	Urban	Metro Fringe	Rural	<200mi
NOx	$1,466	$399	$153	$153
PM10	$9,627	$4,326	$1,282	$1,282
CO	$3	$2	$1	$1
Pb	$5,808	$2,990	$671	$671

6. <u>Demand and Energy Forecast</u>

The Fall 2016 Load Forecast, developed by the Xcel Energy Load Forecasting group, was used. Table 4, below, shows the annual energy and demand.

Table 4: Demand and Energy Forecast

	Demand (MW)				Energy (GWh)		
Year	Model Output	W/ Hist DSM, Building Code Adj	Final w DSM/Eff Adjustments	Year	Model Output	W/ Hist DSM, Building Code	Final w DSM/Eff Adjustments
2016	10,333	9,214	9,137	2016	51,158	45,398	44,952
2017	10,409	9,350	9,206	2017	50,843	45,440	44,557
2018	10,453	9,453	9,243	2018	50,822	45,779	44,457
2019	10,529	9,588	9,309	2019	51,150	46,432	44,672
2020	10,605	9,695	9,318	2020	51,606	47,071	44,855
2021	10,719	9,848	9,369	2021	52,044	47,665	45,006
2022	10,797	9,996	9,423	2022	52,280	48,284	45,227
2023	10,871	10,106	9,432	2023	52,474	48,648	45,192
2024	10,933	10,205	9,430	2024	52,804	49,192	45,327
2025	11,042	10,340	9,464	2025	53,215	49,831	45,578
2026	11,114	10,462	9,485	2026	53,406	50,307	45,657
2027	11,183	10,593	9,515	2027	53,572	50,841	45,791
2028	11,264	10,730	9,551	2028	53,938	51,629	46,165
2029	11,388	10,849	9,569	2029	54,372	52,148	46,302
2030	11,488	10,982	9,677	2030	54,599	52,637	46,837

7. <u>DSM Forecasts</u>

The DSM forecast assumes impacts expected at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period.

Table 5: Base DSM Forecast

Year	Energy (MWh)	Demand (MW)
2016	446	91
2017	884	173
2018	1,322	255
2019	1,761	337
2020	2,216	473
2021	2,659	613
2022	3,057	739
2023	3,455	876
2024	3,865	1,013
2025	4,252	1,150
2026	4,651	1,287
2027	5,049	1,425
2028	5,464	1,562
2029	5,846	1,699
2030	5,800	1,745

8. <u>Demand Response Forecast</u>

The 2016 Load Management Forecast developed by the Xcel Energy Load Research group was used in the Resource Plan. Table 6 below shows the July demand.

Table 6: Load Management Forecast

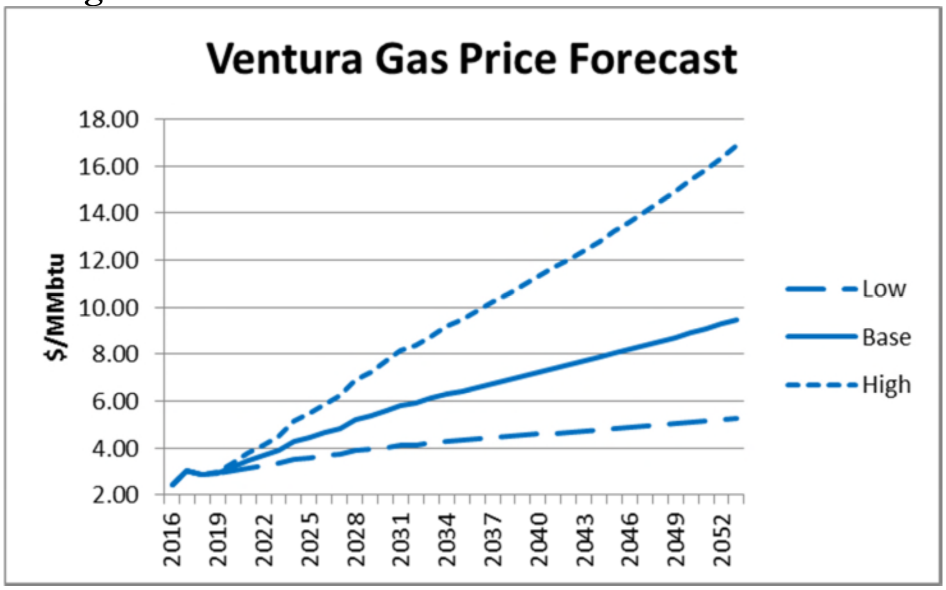
July Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023
LMF	915	921	930	940	948	957	966	974
July Demand (MW)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	
LMF	983	990	994	994	992	988	984	

9. <u>Gas Price Forecasts</u>

Henry Hub natural gas prices are developed using a blend of the latest market information (New York Mercantile Exchange futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA), and Petroleum Industry Research Associates (PIRA).

Gas Prices from September 6, 2016, were used. High and low gas price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base natural gas cost forecast.

Figure 2: Ventura Gas Price Forecast and Sensitivities



10. Gas Transportation Costs

Gas transportation variable costs include the gas transportation charges and the Fuel Lost & Unaccounted (FL&U) for all of the pipelines the gas flows through from the Ventura Hub to the generators facility. The FL&U charge is stated as a percentage of the gas expected to be consumed by the plant, effectively increasing the gas used to operate the plant and is at the price of gas commodity being delivered to the plant.

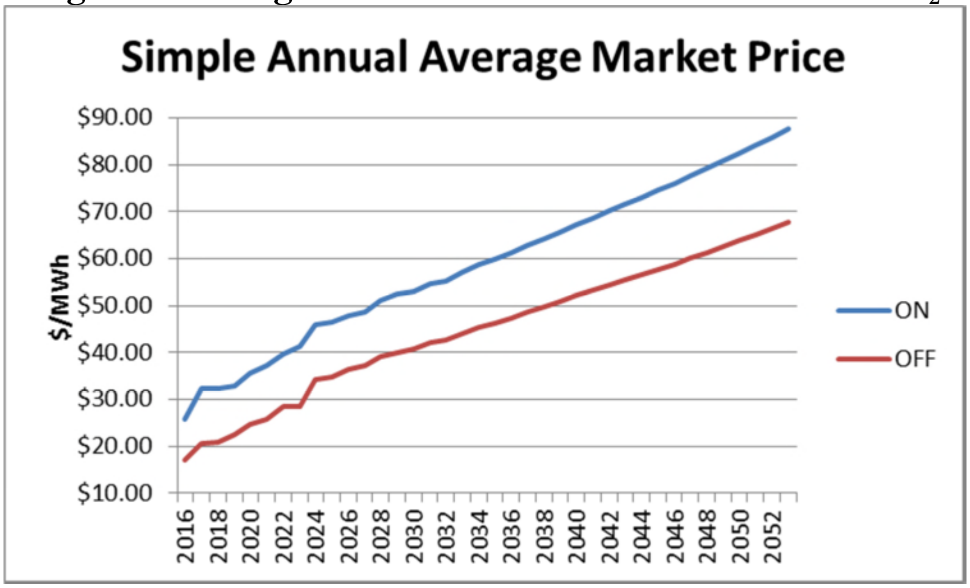
11. Gas Demand Charges

Gas demand charges are fixed annual payments applied to resources to guarantee that natural gas will be available (normally called "firm gas"). Typically, firm gas is obtained to meet the needs of the winter peak as enough gas is normally available during the summer.

12. Market Prices

In addition to resources that exist within the NSP System, the Company has access to energy markets operated by MISO. Market power prices are developed using a blend of market information from the Intercontinental Exchange for near-term prices and long-term fundamentally-based forecasts from Wood Mackenzie, CERA, and PIRA. Figure 3 below shows the market prices under no CO_2 assumptions.

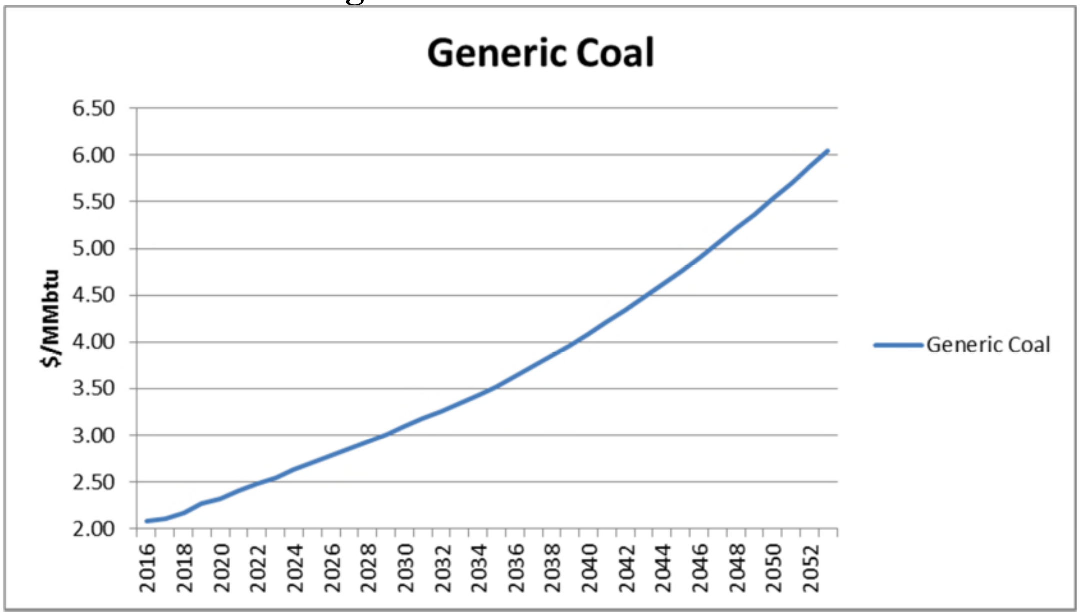
Figure 3: Average On and Off Peak Market Price-No CO_2



13. Coal Price Forecasts

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices. Typically coal volumes and prices are under contract on a plant-by-plant basis for a one- to five-year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Layered on top of the coal prices are transportation charges, SO_2 costs, freeze control, and dust suppressant, as required.

Figure 4: Coal Price Forecast



14. Surplus Capacity Credit (PVSC and PVRRcc Only)

The credit is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic combustion turbine.

Table 7: Surplus Capacity Credit

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
$/kw-mo	4.74	4.84	4.94	5.03	5.14	5.24	5.34	5.45	5.56	5.67
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
$/kw-mo	5.78	5.90	6.02	6.14	6.26	6.39	6.51	6.64	6.78	6.91
	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
$/kw-mo	7.05	7.19	7.33	7.48	7.63	7.78	7.94	8.10	8.26	8.43
	2046	2047	2048	2049	2050	2051	2052	2053		
$/kw-mo	8.59	8.77	8.94	9.12	9.30	9.49	9.68	9.87		

As discussed in the Application, we performed our resource planning analysis on a Present Value of Societal Cost (PVSC) basis, a Present Value of Revenue Requirements (PVRR) basis, and a Present Value of Revenue Requirements with capacity credit (PVRRcc) basis. We undertook a PVSC analysis to comply with Minnesota's externality requirements and we undertook the PVRRcc and PVRR to provide a comparable analysis without externalities (PVRRcc) consistent with North

Dakota's requirements and a more focused rate impact look (PVRR) to better understand the rate impacts of the different modelling runs. Only the PVSC and PVRcc views contain a credit for surplus capacity.

The inclusion of a surplus capacity credit accounts for the fact that any surplus capacity on a utility system has some inherent value. This value is derived from the potential ability to sell the surplus capacity to other utilities. For that reason, when a surplus capacity credit is included in the model, it assumes that surplus capacity is sold and that ratepayers derive value from that sale. Including a surplus capacity credit therefore has the effect of mitigating the impact of system length. Including a capacity credit in a model is consistent with general prudent resource planning principles.

With that said, the Company's history indicates that it does not sell all of its system length into the market. Therefore, to obtain a different view of the impact of system length on cost, we also undertook modelling efforts that did not include a surplus capacity credit in the PVRR view. By doing so, we can obtain modelling outputs that provide a range of costs regarding system length.

The actual impact on ratepayers is likely somewhere in between the PVRR and PVRRcc view. However, consistent with NDPSC Staff's concerns raised in PU-12-59 and the MPUC's interest in a rate impact analysis, we provided the PVRR view without capacity credit to obtain a "rate impact" view of system length and also provided the PVRRcc view to both have a comparison point to the PVSC assumptions.

15. <u>Transmission Delivery Costs</u>

Generic 2x1 combined cycle, generic CTs, generic wind, and generic solar have assumed transmission delivery costs. Table 8, below, shows the transmission delivery costs on a $/kw basis. The CC and CT costs were developed based on the average of several potential sites in Minnesota. The general site locations were investigated by Transmission Access for impacts to the transmission grid and expected resulting upgrade costs.

Table 8: Transmission Delivery Costs

	$/kw
CC	$ 429
CT	$ 158
Solar	$ 70
Wind	$ 96

16. Interconnection Costs

Estimates of interconnection costs of the generic resources were included in the capital cost estimates.

17. Effective Load Carrying Capability (ELCC) Capacity Credit for Wind Resources

Existing wind units are based on current MISO accreditation. New wind additions were given a capacity credit equal to 14.8 percent of their nameplate rating per the MISO 2012/2013 Wind Capacity Report.

18. ELCC Capacity Credit for Utility Scale Solar Photovoltaic (PV) Resources

Utility scale generic solar PV additions used in modeling the alternative plans were given a capacity credit equal to 50 percent of the AC nameplate capacity. This value is the MISO proposed solar capacity credit for the 2016/2017 planning year.

19. Spinning Reserve Requirement

Spinning Reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 94 MW and is based on a 12-month rolling average of spinning reserves carried by the NSP System within MISO.

20. Emergency Energy Costs

Emergency Energy Costs were assigned in the Strategist model if there were not enough resources available to meet energy requirements. The cost was set at $500/MWh in 2014, escalating at inflation which is about $150/MWh more than an oil unit with an assumed heat rate of 15 MMBtu/MWh. Emergency energy occurs only in rare instances.

21. Dump Energy / Wind Curtailment

Estimates of wind curtailment were represented in the Strategist model by the "dump energy" variable. Dump energy occurs whenever generation cannot be reduced enough to balance with load, a situation that occurs primarily due to the non-dispatchable nature of wind generation resources combined with minimum turn-down capabilities of must-run units under low load hours. In the NSP System, it is assumed that the excess generation can be sold into the MISO market. To approximate the price the excess energy could be sold for, 50 percent of the all-hours average market price modeled in Strategist was used.

22. Wind Integration Costs

Wind integration costs were priced based upon the results of the 2015 NSP System Wind Integration Cost Study. Wind integration costs contain five components:

1. MISO Contingency Reserves
2. MISO Regulating Reserves
3. MISO Revenue Sufficiency Guarantee Charges
4. Coal Cycling Costs
5. Gas Storage Costs

The results of the study as used in Strategist are shown below.

Table 9: Wind Integration Costs

	Wind Integration $/MWh		Coal Cycling $/MWh	
	Existing Resources	New Resources	Existing Resources	New Resources
2016	0.41	0.42	0.75	1.26
2017	0.42	0.43	0.77	1.28
2018	0.43	0.44	0.78	1.31
2019	0.44	0.45	0.80	1.33
2020	0.44	0.46	0.82	1.36
2021	0.45	0.46	0.83	1.39
2022	0.46	0.47	0.85	1.41
2023	0.47	0.48	0.87	1.44
2024	0.48	0.49	0.88	1.47
2025	0.49	0.50	0.90	1.50
2026	0.50	0.51	0.92	1.53
2027	0.51	0.52	0.94	1.56
2028	0.52	0.53	0.96	1.59
2029	0.53	0.54	0.98	1.62
2030	0.54	0.55	1.00	1.66

23. <u>Owned Unit Modeled Operating Characteristics and Costs</u>

Company-owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each company owned resource.

a. Retirement Date
b. Maximum Capacity
c. Current Unforced Capacity (UCAP) Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury, and particulate matter (PM)
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

24. Thermal Power Purchase Agreement (PPA) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA:

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury, and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

25. Renewable Energy PPAs and Owned Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each renewable energy PPA and owned unit.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind hourly patterns were developed through a "Typical Wind Year" process where individual months were selected from the years 2009 to 2014 to develop a typical year. Actual generation data from the selected months were used to develop the profiles for each wind farm. For farms where generation data was not complete or not available, data from nearby similar farms were used.

Solar hourly patterns were taken from Fall 2013 and updated to reflect the ELCC as stated above. The fixed panel pattern is an average of the four orientations and three years (2008-2010) of data and the single-axis tracking pattern is an average of three years of data.

26. Generic Assumptions

Generic resources were modeled based upon their expected operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each generic resource.

Thermal

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury, and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Renewable

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns

f. Capacity and Energy Payments
g. Integration Costs

Tables 10 through 12, below, show the assumptions for the generic thermal and renewable resources.

Table 10: Thermal Generic Information (Costs in 2016 Dollars)

Resource	Coal	Coal w/ Seq	2x1 CC	1x1 CC	CT	Small CT	Biomass
Nameplate Capacity (MW)	511	511	778.3	291.1	229.9	103.4	50
Summer Peak Capacity with Ducts (MW)	NA	NA	766.3	NA	NA	NA	NA
Summer Peak Capacity without Ducts (MW	485	485	649.8	290.2	226.1	100.8	50
Cooling Type	Dry	Dry	Dry	Dry	NA	Wet	Wet
Capital Cost ($/kw)	3,758	5,487	963	1,212	626	1,572	4,731
Electric Transmission Delivery ($/kw)	NA	NA	429	NA	158	NA	NA
Gas Demand ($/kw-yr)	0	0	8.96	11.98	0	0	0
Book life	30	30	40	40	30	30	30
Fixed O&M Cost ($000/yr)	16,973	25,546	7,813	4,299	614	886	5,382
Variable O&M Cost ($/MWh)	2.92	11.00	3.20	1.82	2.36	1.88	4.88
Ongoing Capital Expenditures ($/kw-yr)	9.96	24.31	4.50	4.97	6.11	1.93	14.67
Heat Rate with Duct Firing (btu/kWh)	NA	NA	7725	NA	NA	NA	NA
Heat Rate 100% Loading (btu/kWh)	9,156	12,096	6,822	7,830	9,942	8,867	14,421
Heat Rate 75% Loading (btu/kWh)	9,190	12,565	6,905	8,010	11,048	9,688	14,580
Heat Rate 50% Loading (btu/kWh)	9,710	13,600	6,943	8,583	14,601	11,161	15,570
Heat Rate 25% Loading (btu/kWh)	11,245	17,140	7,583	9,798	NA	15,067	18,650
Forced Outage Rate	6%	7%	3%	3%	3%	2%	4%
Maintenance (weeks/year)	2	5	5	4	2	2	7
CO2 Emissions (lbs/MMBtu)	216	9	118	118	118	118	211
SO2 Emissions (lbs/MWh)	0.447	0.371	0.005	0.005	0.007	0.007	0.577
NOx Emissions (lbs/MWh)	0.45	0.62	0.06	0.05	0.30	0.08	1.01
PM10 Emissions (lbs/MWh)	0.14	0.14	0.01	0.01	0.01	0.01	0.43
Mercury Emissions (lbs/Million MWh)	0.00007	0.00010	0.00000	0.00000	0.00000	0.00000	0.00017

Table 11: Renewable Generic Information (Costs in 2016 Dollars)

Resource	PTC Wind	Non-PTC Wind	30% ITC Solar	10% ITC Solar
Nameplate Capacity (MW)	200	200	50	50
ELCC Capacity Credit (MW)	29.6	29.6	25	25
Capital Cost ($/kw)	$1,312	$1,312	$1,094	$1,094
Electric Transmission Delivery ($/kw)	$96	$96	$70	$70
Book life	25	25	25	25
O&M Cost ($000/yr)	$4,617	$4,617	$471	$471
Ongoing Capital Expenditures ($000/yr)	$1,979	$1,979	$0	$0
Land Lease Payments ($000/yr)	$1,131	$1,131	$0	$0

Table 12: Renewable Generic ECC Costs

Year	PTC Wind	Non-PTC Wind	30% ITC Solar	10% ITC Solar
2019	14			
2020	15		44	
2021	15		45	
2022	15		46	
2023	16		47	
2024	16		48	
2025	16	38	48	52
2026	17	39	49	53
2027	17	40	50	54
2028	17	40	51	56
2029	18	41	52	57
2030	18	42	54	58
2031	18	43	55	59
2032	19	44	56	60
2033	19	45	57	61
2034	19	46	58	63
2035	20	47	59	64
2036	20	47	60	65
2037	21	48	61	66
2038	21	49	63	68
2039	22	50	64	69
2040	22	51	65	70
2041	22	52	67	72
2042	23	53	68	73
2043	23	54	69	75
2044		56	71	76
2045		57		78
2046		58		79
2047		59		81
2048		60		83
2049		61		84

27. <u>Distributed Generation</u>

Distributed solar additions have been accelerated from the March 2015 Supplemental Filing of the 2015 Upper Midwest Resource Plan by 422 MW in the pre-2021 timeframe in anticipation of the completion of several Solar*Reward Community projects and continuing our commitment to growing renewable resources. In addition, the costs and payment terms have been revised to payments for 20 years at 12¢/kWh.

III. Expansion Plans

Reference Case	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Small Solar	48	42	45	49	53	58	14	14	14	14	14	14	14	14	14	14	-	-	-	-	-	432
Large Solar	-	-	287	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	287
Wind	350	200	200	-	-	400	-	-	-	-	-	-	-	-	-	-	-	200	-	200	-	1,550
PPA CT	-	-	-	-	-	-	-	-	-	-	690	690	460	-	-	-	690	230	230	-	230	3,220
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	778	-	-	1,556	-	-	778	778	4,235
Fargo CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Updated Reference Case	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Small Solar	48	42	45	49	53	58	14	14	14	14	14	14	14	14	14	14	-	-	-	-	-	432
Large Solar	-	-	287	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	287
Wind	350	200	200	-	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,150
PPA CT	-	-	-	-	-	-	-	-	-	-	460	690	230	-	-	-	460	-	-	-	-	1,840
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	778	-	-	1,556	778	-	778	778	5,013
Fargo CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

IRP Plan	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Small Solar	10	259	159	91	83	76	17	20	24	29	34	41	49	59	71	85	-	-	-	-	-	1,107
Large Solar	-	-	287	-	-	-	200	100	100	200	100	100	-	400	-	-	-	-	-	-	-	1,487
Wind	350	200	200	-	1,200	-	-	-	-	-	400	200	-	-	-	-	-	-	-	-	-	2,550
PPA CT	-	-	-	-	-	-	-	-	-	-	460	460	460	230	-	-	-	-	-	-	-	1,610
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	778	778	-	778	778	3,457
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	-	-	-	-	-	230
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	-	-	-	-	-	786

Updated Plan	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Small Solar	10	259	159	91	83	76	17	20	24	29	34	41	49	59	71	85	-	-	-	-	-	1,107
Large Solar	-	-	287	-	-	-	-	300	100	200	100	100	-	400	-	-	-	-	-	-	-	1,487
Wind	350	200	200	-	1,500	-	-	-	-	-	100	200	-	-	-	-	-	-	-	-	-	2,550
PPA CT	-	-	-	-	-	-	-	-	-	-	230	460	230	230	-	-	-	460	-	-	-	1,610
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	778	-	-	778	1,556	3,457
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	-	-	-	-	-	230
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	-	-	-	-	-	786

Loss of ND Load, 2023	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Small Solar	10	259	159	91	83	76	17	20	24	29	34	41	49	59	71	85	-	-	-	-	-	1,107
Large Solar	-	-	287	-	-	-	-	300	100	200	100	50	-	400	-	-	-	-	-	-	-	1,437
Wind	350	200	200	-	1,500	-	-	-	-	-	100	200	-	-	-	-	-	-	-	-	-	2,550
PPA CT	-	-	-	-	-	-	-	-	-	-	230	460	230	-	-	-	230	230	230	-	-	1,610
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	778	-	-	778	778	2,679
Fargo CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	-	-	-	-	-	786

Loss of ND Load, 2025	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Small Solar	10	259	159	91	83	76	17	20	24	29	34	41	49	59	71	85	-	-	-	-	-	1,107
Large Solar	-	-	287	-	-	-	-	300	100	200	100	50	-	400	-	-	-	-	-	-	-	1,437
Wind	350	200	200	-	1,500	-	-	-	-	-	100	200	-	-	-	-	-	-	-	-	-	2,550
PPA CT	-	-	-	-	-	-	-	-	-	-	230	460	230	-	-	-	230	230	230	-	-	1,610
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	778	-	-	778	778	2,679
Fargo CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	-	-	-	-	-	786

Loss of ND Load, 2027	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Small Solar	10	259	159	91	83	76	17	20	24	29	34	41	49	59	71	85	-	-	-	-	-	1,107
Large Solar	-	-	287	-	-	-	-	300	100	200	100	50	-	400	-	-	-	-	-	-	-	1,437
Wind	350	200	200	-	1,500	-	-	-	-	-	100	200	-	-	-	-	-	-	-	-	-	2,550
PPA CT	-	-	-	-	-	-	-	-	-	-	460	460	-	-	-	-	230	230	230	-	-	1,610
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	778	-	-	778	778	2,679
Fargo CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	-	-	-	-	-	786

North Dakota Jurisdiction Expansion Plans

3A - Legacy Purchase/Sale	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Shared MW	532	540	550	577	577	593	593	594	538	474	444	389	371	370	371	326	312	310	279	225
Generic CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	115	-	-	-	115

5A - CT and Nuclear	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Shared MW	532	540	550	577	577	593	593	591	532	156	156	154	151	151	151	117	117	117	88	60
Generic CT	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	115	-	-	-	-

5B - CC and Nuclear	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Shared MW	532	540	550	577	577	593	593	591	532	156	156	154	151	151	151	117	117	117	88	60
Generic CC	-	-	-	-	-	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-

5C - CT	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Shared MW	532	540	550	577	577	593	593	591	532	60	60	60	60	60	60	60	60	60	60	60
Generic CT	-	-	-	-	-	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-

5D - CC	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Shared MW	532	540	550	577	577	593	593	591	532	60	60	60	60	60	60	60	60	60	60	60
Generic CC	-	-	-	-	-	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-

IV. Strategist Outputs

See attached.

Case	Assum	Basis	Details	Strat SO Name
1	Current	Reference Case	No restack except solar	_1_REFERENCE UPDATED
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)	_2_PREFERRED UPDATED
3A	Current	Preferred Plan	Current with Legacy Purchase/Sale and Jur Future	_3_A_SHARED LEGACY
3B	Current	Preferred Plan	Current with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	
3C	Current	Preferred Plan	Current with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	
4A	Current	Preferred Plan	ND separation Jan 2023, Replace with CT	_4_2023 FULL SEPARATION
5A	Current	Preferred Plan	ND separation Jan 2025, Replace with CT	_5_2025 FULL SEPARATION
5B	Current	Preferred Plan	ND separation Jan 2025, Replace with CC	
5C	Current	Preferred Plan	ND separation Jan 2025, Replace with CT, No Nuclear	
5D	Current	Preferred Plan	ND separation Jan 2025, Replace with CC, No Nuclear	
6A	Current	Preferred Plan	ND separation Jan 2027, Replace with CT	_6_2027 FULL SEPARATION

Base Restack Resources
Small Solar (never allocated to ND)

Base Assumptions
CO2 - $21.50 starting in 2022
Fuel/markets as of 9/6/2016
Fall 2016 load forecast
Current "Strategic Plannning" renewable costs

MN, SD, WI Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	IRP Reference Case with Updated Assumptions	48,491	38,685	2,479	2,456	2,413	2,541	2,628	2,786	2,821	2,899	2,888	2,972	2,902	3,041	3,132	3,235	3,156	3,498	3,592	3,759	3,724	3,824	3,926
2	Updated Plan	48,302	38,893	2,495	2,489	2,461	2,619	2,699	2,860	2,883	2,915	2,929	2,957	2,938	3,217	3,205	3,462	3,381	3,431	3,497	3,632	3,570	3,721	3,799
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	48,348	38,855	2,495	2,489	2,461	2,617	2,697	2,856	2,879	2,908	2,921	2,932	2,913	3,203	3,193	3,460	3,379	3,433	3,490	3,635	3,582	3,667	3,816
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	48,404	38,911	2,502	2,497	2,469	2,624	2,704	2,863	2,886	2,914	2,925	2,937	2,916	3,204	3,194	3,461	3,380	3,434	3,491	3,635	3,583	3,667	3,816
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	48,435	38,937	2,495	2,489	2,461	2,620	2,701	2,861	2,886	2,918	2,932	2,944	2,926	3,216	3,207	3,465	3,385	3,439	3,497	3,643	3,590	3,675	3,824
4A	ND separation 2023	48,462	39,028	2,495	2,489	2,461	2,617	2,697	2,856	2,879	2,988	2,999	2,983	2,960	3,242	3,223	3,482	3,405	3,441	3,502	3,629	3,568	3,651	3,799
5A	ND separation 2025, CT	48,365	38,931	2,495	2,489	2,461	2,617	2,697	2,856	2,879	2,908	2,921	2,983	2,960	3,242	3,223	3,482	3,405	3,441	3,502	3,629	3,568	3,651	3,799
5B	ND separation 2025, CC	48,365	38,931	2,495	2,489	2,461	2,617	2,697	2,856	2,879	2,908	2,921	2,983	2,960	3,242	3,223	3,482	3,405	3,441	3,502	3,629	3,568	3,651	3,799
5C	ND separation 2025, CT, no nuclear	48,362	38,928	2,495	2,489	2,461	2,617	2,697	2,856	2,879	2,908	2,921	2,990	2,960	3,245	3,213	3,475	3,396	3,443	3,500	3,635	3,569	3,651	3,799
5D	ND separation 2025, CC, no nuclear	48,362	38,928	2,495	2,489	2,461	2,617	2,697	2,856	2,879	2,908	2,921	2,990	2,960	3,245	3,213	3,475	3,396	3,443	3,500	3,635	3,569	3,651	3,799
6A	ND separation 2027	48,314	38,880	2,495	2,489	2,461	2,617	2,697	2,856	2,879	2,908	2,921	2,932	2,913	3,245	3,223	3,482	3,405	3,441	3,502	3,629	3,568	3,651	3,799

	Delta to Scen 2:																							
1	IRP Reference Case with Updated Assumptions	189	(208)	(16)	(33)	(48)	(78)	(71)	(73)	(62)	(16)	(41)	16	(36)	(177)	(73)	(228)	(225)	67	95	127	154	104	127
2	Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	45	(38)	(0)	0	0	(2)	(3)	(3)	(4)	(7)	(9)	(24)	(25)	(15)	(12)	(3)	(2)	2	(7)	2	12	(54)	17
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	102	18	7	7	8	5	4	4	3	(1)	(4)	(20)	(22)	(13)	(11)	(2)	(1)	3	(6)	3	13	(54)	17
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	133	44	(0)	0	0	1	1	1	3	3	3	(12)	(12)	(1)	2	2	4	9	0	10	20	(46)	25
4A	ND separation 2023	160	136	0	0	0	(2)	(3)	(3)	(4)	73	69	26	22	25	18	20	24	11	5	(3)	(2)	(70)	0
5A	ND separation 2025, CT	63	38	0	0	0	(2)	(3)	(3)	(4)	(7)	(9)	26	22	25	18	19	24	11	5	(3)	(2)	(70)	0
5B	ND separation 2025, CC	63	38	0	0	0	(2)	(3)	(3)	(4)	(7)	(9)	26	22	25	18	19	24	11	5	(3)	(2)	(70)	0
5C	ND separation 2025, CT, no nuclear	60	35	0	0	0	(2)	(3)	(3)	(4)	(7)	(9)	33	22	28	8	13	15	12	3	3	(1)	(70)	0
5D	ND separation 2025, CC, no nuclear	60	35	0	0	0	(2)	(3)	(3)	(4)	(7)	(9)	33	22	28	8	13	15	12	3	3	(1)	(70)	0
6A	ND separation 2027	12	(13)	0	0	0	(2)	(3)	(3)	(4)	(7)	(8)	(24)	(25)	28	18	20	24	11	5	(3)	(2)	(70)	0

ND Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	IRP Reference Case with Updated Assumptions	2,592	2,068	137	134	132	139	139	148	149	154	154	157	153	161	166	172	166	185	190	199	196	202	207
2	Updated Plan	2,567	2,062	138	135	133	141	141	150	151	153	154	155	154	170	169	184	178	180	184	191	186	194	200
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	2,515	2,052	138	135	133	143	144	153	155	160	163	161	156	164	161	168	162	178	182	188	178	194	200
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	2,467	2,007	130	127	125	136	137	147	149	154	158	156	153	162	160	167	179	180	180	187	176	193	198
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	2,430	1,973	138	135	133	140	140	149	148	150	151	149	144	151	147	163	157	172	176	182	171	187	192
4A	ND separation 2023	2,409	1,962	138	135	133	143	144	153	155	132	143	148	145	149	150	156	148	171	176	182	181	181	184
5A	ND separation 2025, CT	2,456	2,006	138	135	133	143	144	153	155	160	163	146	148	153	154	159	151	173	178	185	184	184	187
5B	ND separation 2025, CC	2,534	2,121	138	135	133	143	144	153	155	160	163	175	183	186	187	191	184	187	188	194	191	191	194
5C	ND separation 2025, CT, no nuclear	2,477	2,032	138	135	133	143	144	153	155	160	163	155	166	167	172	174	167	170	171	174	177	179	182
5D	ND separation 2025, CC, no nuclear	2,512	2,099	138	135	133	143	144	153	155	160	163	164	178	179	185	186	181	184	185	187	189	191	194
6A	ND separation 2027	2,503	2,054	138	135	133	143	144	153	155	160	162	161	156	167	177	181	173	176	178	185	183	184	187

	Delta to Scen 2:	(48)	(43)	(7)	(7)	(8)	(7)	(7)	(7)	(7)	(6)	(5)	(5)	(3)	(2)	(1)	(1)	17	2	(2)	(2)	(1)	(1)	(1)
1	IRP Reference Case with Updated Assumptions	25	6	(0)	(0)	(1)	(2)	(2)	(2)	(2)	1	(1)	3	(0)	(9)	(3)	(12)	(12)	5	7	9	10	7	8
2	Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	(52)	(10)	0	0	0	2	3	3	4	7	9	6	2	(6)	(8)	(16)	(16)	(2)	(1)	(2)	(8)	0	(0)
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	(100)	(55)	(7)	(7)	(8)	(5)	(4)	(4)	(3)	1	4	1	(0)	(8)	(9)	(17)	1	(0)	(3)	(4)	(10)	(1)	(1)
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	(137)	(89)	0	0	0	(1)	(1)	(1)	(3)	(3)	(3)	(6)	(10)	(19)	(22)	(21)	(21)	(7)	(8)	(9)	(15)	(7)	(8)
4A	ND separation 2023	(158)	(100)	0	0	0	2	3	3	4	(21)	(11)	(6)	(9)	(21)	(19)	(28)	(29)	(9)	(8)	(8)	(5)	(13)	(15)
5A	ND separation 2025, CT	(111)	(56)	0	0	0	2	3	3	4	7	9	(9)	(6)	(17)	(15)	(25)	(26)	(6)	(5)	(6)	(2)	(10)	(12)
5B	ND separation 2025, CC	(33)	59	0	0	0	2	3	3	4	7	9	20	29	16	18	7	6	7	5	3	5	(3)	(6)
5C	ND separation 2025, CT, no nuclear	(90)	(30)	0	0	0	2	3	3	4	7	9	(0)	12	(3)	3	(10)	(11)	(10)	(12)	(16)	(9)	(15)	(17)
5D	ND separation 2025, CC, no nuclear	(55)	37	0	0	0	2	3	3	4	7	9	9	24	9	16	2	3	4	2	(3)	3	(3)	(6)
6A	ND separation 2027	(64)	(8)	0	0	0	2	3	3	4	7	8	6	2	(3)	8	(3)	(5)	(4)	(6)	(6)	(3)	(11)	(13)

Reference Case Comparisons

			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	IRP Reference, MN	38,603	2,367	2,471	2,460	2,574	2,585	2,731	2,750	2,835	2,810	2,885	2,788	2,931	3,005	3,121	3,149	3,609	3,714	3,901	3,831	4,012	4,134
	IRP Expansion Plan, MN	39,552	2,382	2,509	2,553	2,653	2,680	2,843	2,841	2,897	2,905	3,001	2,959	3,237	3,263	3,477	3,496	3,585	3,688	3,842	3,798	3,908	4,004
	IRP Reference, ND	2,243	134	141	140	147	148	157	158	164	164	168	163	171	174	181	183	212	218	230	226	238	246
	IRP Expansion Plan, ND	2,272	135	141	143	149	151	161	161	166	167	173	170	186	187	200	201	207	214	223	221	229	236
	IRP Reference, Sys	40,847	2,502	2,611	2,600	2,721	2,733	2,887	2,909	2,999	2,974	3,054	2,951	3,102	3,179	3,302	3,332	3,821	3,932	4,130	4,058	4,250	4,380
	IRP Expansion Plan, Sys	41,824	2,516	2,650	2,696	2,802	2,831	3,005	3,003	3,063	3,073	3,173	3,129	3,423	3,449	3,677	3,697	3,793	3,902	4,065	4,019	4,137	4,240

MN, SD, WI Costs ($M)

		2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions	4,072	4,145	4,279	4,409	4,610	4,735	4,837	4,955	5,109	5,293	5,417	5,646	5,857	5,996	6,140	6,304	6,447
2	Updated Plan	3,838	3,940	4,012	4,108	4,295	4,403	4,502	4,859	5,019	5,116	5,234	5,449	5,647	5,781	5,943	6,124	6,269
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	3,872	3,982	4,039	4,133	4,326	4,435	4,534	4,905	5,071	5,167	5,284	5,508	5,637	5,842	6,016	6,196	6,346
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	3,872	3,983	4,040	4,134	4,326	4,436	4,534	4,905	5,071	5,167	5,284	5,508	5,637	5,842	6,016	6,196	6,346
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	3,880	3,991	4,048	4,143	4,336	4,446	4,544	4,905	5,071	5,167	5,284	5,508	5,637	5,842	6,016	6,196	6,346
4A	ND separation 2023	3,851	3,957	4,013	4,110	4,291	4,419	4,520	4,885	5,048	5,143	5,261	5,431	5,622	5,754	5,926	6,186	6,340
5A	ND separation 2025, CT	3,851	3,957	4,013	4,110	4,291	4,419	4,520	4,885	5,048	5,143	5,261	5,431	5,622	5,754	5,926	6,186	6,340
5B	ND separation 2025, CC	3,851	3,957	4,013	4,110	4,291	4,419	4,520	4,885	5,048	5,143	5,261	5,431	5,622	5,754	5,926	6,186	6,340
5C	ND separation 2025, CT, no nuclear	3,851	3,957	4,013	4,110	4,291	4,419	4,520	4,885	5,048	5,143	5,261	5,431	5,622	5,754	5,926	6,186	6,340
5D	ND separation 2025, CC, no nuclear	3,851	3,957	4,013	4,110	4,291	4,419	4,520	4,885	5,048	5,143	5,261	5,431	5,622	5,754	5,926	6,186	6,340
6A	ND separation 2027	3,851	3,957	4,013	4,110	4,291	4,419	4,520	4,885	5,048	5,143	5,261	5,431	5,622	5,754	5,926	6,186	6,340

	Delta to Scen 2:																	
1	IRP Reference Case with Updated Assumptions	235	205	267	301	315	332	334	96	90	178	183	197	210	214	197	180	177
2	Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	34	42	27	25	30	32	32	46	52	52	49	58	(10)	61	74	72	77
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	35	42	27	26	31	32	32	46	52	52	49	58	(10)	61	74	72	77
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	42	51	36	35	41	43	42	46	52	52	49	58	(10)	61	74	72	77
4A	ND separation 2023	14	17	1	2	(4)	15	17	26	29	27	26	(18)	(25)	(27)	(16)	62	71
5A	ND separation 2025, CT	14	17	1	2	(4)	15	17	26	29	27	26	(18)	(25)	(27)	(16)	62	71
5B	ND separation 2025, CC	14	17	1	2	(4)	15	17	26	29	27	26	(18)	(25)	(27)	(16)	62	71
5C	ND separation 2025, CT, no nuclear	14	17	1	2	(4)	15	17	26	29	27	26	(18)	(25)	(27)	(16)	62	71
5D	ND separation 2025, CC, no nuclear	14	17	1	2	(4)	15	17	26	29	27	26	(18)	(25)	(27)	(16)	62	71
6A	ND separation 2027	14	17	1	2	(4)	15	17	26	29	27	26	(18)	(25)	(27)	(16)	62	71

ND Costs ($M)

		2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions	216	220	228	236	246	253	259	265	272	283	289	302	313	321	328	337	344
2	Updated Plan	203	209	214	220	230	235	241	261	268	274	281	293	304	311	320	329	337
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	202	201	201	206	230	237	239	242	244	248	251	253	254	254	287	297	301
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	200	199	200	227	232	235	237	240	243	246	249	252	253	253	286	296	299
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	194	192	193	197	221	227	230	242	244	248	251	253	254	254	287	297	301
4A	ND separation 2023	188	190	193	198	224	230	233	236	239	243	246	251	254	258	263	268	265
5A	ND separation 2025, CT	191	193	196	199	225	232	234	238	240	244	247	252	255	259	264	269	273
5B	ND separation 2025, CC	195	197	199	203	205	208	212	216	220	224	228	233	237	241	246	251	255
5C	ND separation 2025, CT, no nuclear	186	188	191	195	221	228	231	235	238	241	245	250	253	257	262	267	271
5D	ND separation 2025, CC, no nuclear	195	197	199	203	205	208	212	216	220	224	228	233	237	241	246	251	255
6A	ND separation 2027	190	193	195	199	224	230	233	237	240	244	247	252	255	259	263	269	272

	Delta to Scen 2:	(1)	(1)	(1)	21	2	(2)	(2)	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
1	IRP Reference Case with Updated Assumptions	13	11	14	16	17	17	17	4	4	8	9	9	9	9	8	7	7
2	Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	(2)	(9)	(13)	(14)	1	1	(2)	(20)	(24)	(27)	(30)	(40)	(50)	(57)	(33)	(32)	(36)
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	(3)	(10)	(14)	7	2	(1)	(4)	(22)	(25)	(28)	(31)	(41)	(52)	(59)	(34)	(34)	(38)
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	(10)	(17)	(22)	(23)	(9)	(8)	(11)	(20)	(24)	(27)	(30)	(40)	(50)	(57)	(33)	(32)	(36)
4A	ND separation 2023	(15)	(19)	(21)	(22)	(6)	(5)	(8)	(25)	(29)	(32)	(34)	(42)	(50)	(53)	(57)	(62)	(72)
5A	ND separation 2025, CT	(13)	(16)	(19)	(21)	(4)	(4)	(7)	(24)	(28)	(30)	(33)	(41)	(49)	(52)	(56)	(61)	(64)
5B	ND separation 2025, CC	(8)	(12)	(15)	(17)	(24)	(27)	(29)	(45)	(48)	(50)	(53)	(60)	(68)	(71)	(74)	(79)	(82)
5C	ND separation 2025, CT, no nuclear	(17)	(21)	(23)	(25)	(9)	(8)	(11)	(27)	(30)	(33)	(35)	(43)	(51)	(54)	(58)	(63)	(66)
5D	ND separation 2025, CC, no nuclear	(8)	(12)	(15)	(17)	(24)	(27)	(29)	(45)	(48)	(50)	(53)	(60)	(68)	(71)	(74)	(79)	(82)
6A	ND separation 2027	(13)	(17)	(19)	(21)	(5)	(5)	(8)	(25)	(28)	(31)	(33)	(41)	(49)	(52)	(56)	(61)	(65)

Reference Case Comparisons

IRP Reference, MN	4,201	4,356	4,446	4,531	-	-	-	-	-	-	-	-	-	-	-	-	-
IRP Expansion Plan, MN	4,059	4,190	4,254	4,314	-	-	-	-	-	-	-	-	-	-	-	-	-
IRP Reference, ND	250	260	267	274	-	-	-	-	-	-	-	-	-	-	-	-	-
IRP Expansion Plan, ND	241	250	256	261	-	-	-	-	-	-	-	-	-	-	-	-	-
IRP Reference, Sys	4,451	4,617	4,713	4,804	-	-	-	-	-	-	-	-	-	-	-	-	-
IRP Expansion Plan, Sys	4,300	4,440	4,509	4,575	-	-	-	-	-	-	-	-	-	-	-	-	-

MN, SD, WI Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	IRP Reference Case with Updated Assumptions	53,855	42,763	2,559	2,539	2,490	2,622	2,711	2,864	3,176	3,277	3,270	3,427	3,370	3,521	3,587	3,715	3,664	3,942	4,006	4,241	4,254	4,422	4,574
2	Updated Plan	52,493	41,899	2,573	2,568	2,536	2,682	2,764	2,923	3,164	3,212	3,185	3,274	3,247	3,471	3,446	3,709	3,646	3,767	3,837	4,039	4,027	4,188	4,308
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	52,350	41,734	2,573	2,568	2,536	2,680	2,761	2,920	3,154	3,199	3,168	3,240	3,213	3,444	3,416	3,688	3,627	3,749	3,819	4,018	4,008	4,153	4,291
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	52,403	41,787	2,580	2,576	2,543	2,688	2,768	2,927	3,160	3,204	3,172	3,244	3,215	3,445	3,417	3,688	3,629	3,749	3,819	4,019	4,009	4,152	4,290
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	52,497	41,870	2,573	2,568	2,536	2,684	2,765	2,925	3,167	3,215	3,187	3,260	3,234	3,464	3,438	3,701	3,639	3,763	3,833	4,033	4,023	4,169	4,307
4A	ND separation 2023	52,614	42,023	2,573	2,568	2,536	2,680	2,761	2,920	3,154	3,289	3,268	3,295	3,267	3,496	3,468	3,732	3,669	3,774	3,845	4,028	4,008	4,155	4,295
5A	ND separation 2025, CT	52,496	41,904	2,573	2,568	2,536	2,680	2,761	2,920	3,154	3,199	3,168	3,295	3,267	3,496	3,467	3,732	3,669	3,773	3,844	4,028	4,008	4,155	4,295
5B	ND separation 2025, CC	52,496	41,904	2,573	2,568	2,536	2,680	2,761	2,920	3,154	3,199	3,168	3,295	3,267	3,496	3,467	3,732	3,669	3,773	3,844	4,028	4,008	4,155	4,295
5C	ND separation 2025, CT, no nuclear	52,439	41,847	2,573	2,568	2,536	2,680	2,761	2,920	3,154	3,199	3,168	3,287	3,252	3,484	3,442	3,711	3,646	3,765	3,833	4,025	4,005	4,155	4,295
5D	ND separation 2025, CC, no nuclear	52,439	41,847	2,573	2,568	2,536	2,680	2,761	2,920	3,154	3,199	3,168	3,287	3,252	3,484	3,442	3,711	3,646	3,765	3,833	4,025	4,005	4,155	4,295
6A	ND separation 2027	52,439	41,848	2,573	2,568	2,536	2,680	2,761	2,920	3,154	3,199	3,168	3,240	3,213	3,499	3,468	3,732	3,669	3,774	3,845	4,028	4,008	4,155	4,295

	Delta to Scen 2:	NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	IRP Reference Case with Updated Assumptions	1,362	864	(14)	(30)	(45)	(60)	(53)	(59)	11	65	85	153	123	50	141	6	18	176	169	201	226	234	266
2	Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	(144)	(165)	(0)	0	0	(2)	(3)	(3)	(10)	(13)	(17)	(34)	(33)	(27)	(30)	(21)	(19)	(18)	(18)	(21)	(19)	(35)	(17)
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	(90)	(112)	7	8	8	6	4	4	(4)	(8)	(13)	(30)	(32)	(26)	(29)	(21)	(17)	(18)	(18)	(21)	(19)	(36)	(17)
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	3	(29)	(0)	0	0	1	1	1	3	3	2	(14)	(13)	(7)	(9)	(9)	(7)	(4)	(4)	(6)	(4)	(20)	(1)
4A	ND separation 2023	121	124	0	0	0	(2)	(3)	(3)	(10)	77	83	21	20	25	21	23	24	7	8	(11)	(19)	(33)	(13)
5A	ND separation 2025, CT	2	5	0	0	0	(2)	(3)	(3)	(10)	(13)	(17)	21	20	25	21	23	23	6	7	(11)	(19)	(33)	(13)
5B	ND separation 2025, CC	2	5	0	0	0	(2)	(3)	(3)	(10)	(13)	(17)	21	20	25	21	23	23	6	7	(11)	(19)	(33)	(13)
5C	ND separation 2025, CT, no nuclear	(55)	(52)	0	0	0	(2)	(3)	(3)	(10)	(13)	(17)	14	6	13	(4)	1	0	(2)	(4)	(14)	(22)	(33)	(13)
5D	ND separation 2025, CC, no nuclear	(55)	(52)	0	0	0	(2)	(3)	(3)	(10)	(13)	(17)	14	6	13	(4)	1	0	(2)	(4)	(14)	(22)	(33)	(13)
6A	ND separation 2027	(54)	(51)	0	0	0	(2)	(3)	(3)	(10)	(13)	(17)	(34)	(34)	28	21	23	24	7	8	(11)	(19)	(33)	(13)

ND Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	IRP Reference Case with Updated Assumptions	2,790	2,224	135	132	131	140	140	149	167	173	171	183	172	188	184	191	186	207	205	217	217	224	234
2	Updated Plan	2,711	2,169	136	134	133	142	141	152	166	169	165	168	168	182	176	191	186	198	195	210	203	215	218
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	2,899	2,310	136	134	133	144	144	155	176	183	182	184	182	191	189	197	192	213	219	230	225	245	256
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	2,854	2,268	128	126	125	136	137	148	170	177	178	180	180	191	189	197	207	216	218	229	224	245	255
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	2,752	2,174	136	134	133	141	140	150	163	167	163	164	161	171	168	185	179	199	205	215	211	230	240
4A	ND separation 2023	2,850	2,267	136	134	133	144	144	155	177	163	175	181	178	183	184	191	184	213	219	228	232	238	243
5A	ND separation 2025, CT	2,884	2,299	136	134	133	144	144	155	177	183	182	179	181	187	188	194	188	216	222	231	235	241	246
5B	ND separation 2025, CC	2,780	2,295	136	134	133	144	144	155	177	183	182	193	201	204	205	210	203	209	211	218	218	221	224
5C	ND separation 2025, CT, no nuclear	2,958	2,378	136	134	133	144	144	155	177	183	182	202	214	215	221	223	218	222	225	229	233	236	241
5D	ND separation 2025, CC, no nuclear	2,786	2,301	136	134	133	144	144	155	177	183	182	189	204	205	211	212	207	211	213	216	219	221	224
6A	ND separation 2027	2,920	2,336	136	134	133	144	144	155	177	183	182	184	182	200	210	216	208	218	221	231	234	241	245

	Delta to Scen 2:	NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	IRP Reference Case with Updated Assumptions	79	54	(1)	(2)	(2)	(2)	(2)	(2)	1	4	6	15	5	6	9	0	(0)	9	10	7	14	10	16
2	Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	188	141	0	0	0	2	3	3	10	13	17	15	14	9	13	6	6	15	24	20	22	31	37
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	143	99	(7)	(8)	(8)	(6)	(4)	(4)	4	8	13	12	12	9	13	6	21	18	23	19	21	30	36
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	41	5	0	0	0	(1)	(1)	(1)	(3)	(3)	(2)	(4)	(6)	(11)	(8)	(6)	(7)	1	10	6	8	15	21
4A	ND separation 2023	138	98	0	0	0	2	3	3	10	(6)	10	13	10	1	9	(0)	(2)	15	24	19	29	24	24
5A	ND separation 2025, CT	173	130	0	0	0	2	3	3	10	13	17	11	14	5	12	3	1	18	27	22	32	26	27
5B	ND separation 2025, CC	69	126	0	0	0	2	3	3	10	13	17	25	33	22	29	19	17	11	16	9	15	6	6
5C	ND separation 2025, CT, no nuclear	247	209	0	0	0	2	3	3	10	13	17	34	46	33	46	32	31	24	29	19	30	22	22
5D	ND separation 2025, CC, no nuclear	75	132	0	0	0	2	3	3	10	13	17	21	36	23	35	21	21	13	18	6	15	6	6
6A	ND separation 2027	209	167	0	0	0	2	3	3	10	13	17	16	14	18	35	25	22	20	26	21	31	26	27

Reference Case Comparisons

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IRP Reference, MN	43,513	2,360	2,464	2,448	3,001	3,000	3,145	3,166	3,273	3,248	3,390	3,305	3,461	3,524	3,658	3,705	4,083	4,134	4,384	4,404	4,595	4,765
IRP Expansion Plan, MN	43,375	2,372	2,495	2,532	3,014	3,046	3,204	3,201	3,272	3,231	3,372	3,324	3,541	3,566	3,782	3,810	3,969	4,043	4,258	4,255	4,433	4,565
IRP Reference, ND	2,441	126	132	131	167	167	178	179	186	182	198	190	195	195	203	206	229	233	247	260	261	271
IRP Expansion Plan, ND	2,413	127	133	134	166	169	180	180	186	179	188	190	195	196	209	213	231	225	238	238	250	258
IRP Reference, Sys	45,955	2,487	2,597	2,579	3,168	3,166	3,323	3,346	3,459	3,430	3,589	3,495	3,656	3,719	3,861	3,911	4,312	4,367	4,631	4,664	4,857	5,037
IRP Expansion Plan, Sys	45,788	2,498	2,627	2,666	3,180	3,214	3,385	3,381	3,458	3,410	3,560	3,514	3,736	3,762	3,991	4,024	4,200	4,268	4,496	4,493	4,682	4,823

MN, SD, WI Costs ($M)

		2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions	4,702	4,754	4,874	5,039	5,175	5,339	5,460	5,601	5,791	6,023	6,168	6,406	6,608	6,772	6,943	7,138	7,306
2	Updated Plan	4,396	4,427	4,535	4,663	4,787	4,925	5,039	5,465	5,659	5,776	5,922	6,139	6,345	6,512	6,715	6,953	7,134
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	4,377	4,416	4,524	4,656	4,773	4,919	5,036	5,478	5,668	5,784	5,930	6,152	6,378	6,542	6,754	6,986	7,172
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	4,377	4,416	4,524	4,659	4,773	4,919	5,036	5,478	5,668	5,784	5,930	6,152	6,378	6,542	6,754	6,986	7,172
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	4,394	4,433	4,541	4,673	4,792	4,939	5,055	5,478	5,668	5,784	5,930	6,152	6,378	6,542	6,754	6,986	7,172
4A	ND separation 2023	4,387	4,416	4,527	4,655	4,770	4,916	5,035	5,469	5,657	5,767	5,911	6,151	6,339	6,512	6,736	6,970	7,143
5A	ND separation 2025, CT	4,387	4,416	4,527	4,655	4,770	4,916	5,035	5,469	5,657	5,767	5,911	6,151	6,339	6,512	6,736	6,970	7,143
5B	ND separation 2025, CC	4,387	4,416	4,527	4,655	4,770	4,916	5,035	5,469	5,657	5,767	5,911	6,151	6,339	6,512	6,736	6,970	7,143
5C	ND separation 2025, CT, no nuclear	4,387	4,416	4,527	4,655	4,770	4,916	5,035	5,469	5,657	5,767	5,911	6,151	6,339	6,512	6,736	6,970	7,143
5D	ND separation 2025, CC, no nuclear	4,387	4,416	4,527	4,655	4,770	4,916	5,035	5,469	5,657	5,767	5,911	6,151	6,339	6,512	6,736	6,970	7,143
6A	ND separation 2027	4,387	4,416	4,527	4,655	4,770	4,916	5,035	5,469	5,657	5,767	5,911	6,151	6,339	6,512	6,736	6,970	7,143

	Delta to Scen 2:																	
1	IRP Reference Case with Updated Assumptions	307	327	339	376	388	414	421	136	131	247	246	267	263	261	229	185	172
2	Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	(19)	(11)	(11)	(7)	(14)	(5)	(3)	13	9	8	8	13	32	30	40	33	38
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	(19)	(11)	(11)	(4)	(14)	(5)	(3)	13	9	8	8	13	32	30	40	33	38
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	(2)	5	6	10	5	14	16	13	9	8	8	13	32	30	40	33	38
4A	ND separation 2023	(9)	(11)	(8)	(8)	(17)	(9)	(4)	4	(2)	(9)	(11)	12	(6)	1	21	17	9
5A	ND separation 2025, CT	(9)	(11)	(8)	(8)	(17)	(9)	(4)	4	(2)	(9)	(11)	12	(6)	1	21	17	9
5B	ND separation 2025, CC	(9)	(11)	(8)	(8)	(17)	(9)	(4)	4	(2)	(9)	(11)	12	(6)	1	21	17	9
5C	ND separation 2025, CT, no nuclear	(9)	(11)	(8)	(8)	(17)	(9)	(4)	4	(2)	(9)	(11)	12	(6)	1	21	17	9
5D	ND separation 2025, CC, no nuclear	(9)	(11)	(8)	(8)	(17)	(9)	(4)	4	(2)	(9)	(11)	12	(6)	1	21	17	9
6A	ND separation 2027	(9)	(11)	(8)	(8)	(17)	(9)	(4)	4	(2)	(9)	(11)	12	(6)	1	21	17	9

ND Costs ($M)

		2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions	243	246	248	257	264	272	278	286	293	310	322	326	337	345	353	363	371
2	Updated Plan	223	225	230	241	242	258	269	279	286	293	300	311	327	333	341	352	361
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	260	258	261	268	288	298	302	306	310	315	320	327	332	334	364	376	381
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	259	257	260	286	291	296	300	304	308	313	319	326	330	333	362	374	380
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	243	242	244	250	269	279	283	306	310	315	320	327	332	334	364	376	381
4A	ND separation 2023	247	251	256	262	289	297	301	306	311	316	321	328	333	339	345	353	352
5A	ND separation 2025, CT	250	254	258	264	290	298	303	308	312	317	323	329	334	340	347	354	360
5B	ND separation 2025, CC	227	229	232	236	240	244	248	253	258	263	268	274	278	284	289	296	301
5C	ND separation 2025, CT, no nuclear	246	249	253	259	286	294	299	305	310	315	321	327	332	338	345	352	358
5D	ND separation 2025, CC, no nuclear	227	229	232	236	240	244	248	253	258	263	268	274	278	284	289	296	301
6A	ND separation 2027	250	254	258	263	289	297	301	307	312	317	323	329	334	340	346	354	359

	Delta to Scen 2:																	
1	IRP Reference Case with Updated Assumptions	20	21	18	16	21	14	10	7	7	17	22	14	9	11	13	11	10
2	Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	36	33	31	26	46	40	34	27	24	22	21	16	4	1	23	23	20
3B	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Reallocated Solar, CBED, Biomass	36	32	29	45	48	38	32	25	22	21	19	15	3	(0)	22	22	19
3C	Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	20	17	14	9	27	21	15	27	24	22	21	16	4	1	23	23	20
4A	ND separation 2023	24	27	26	21	47	39	33	27	25	23	22	17	6	6	5	1	(9)
5A	ND separation 2025, CT	27	30	28	22	48	40	34	29	26	25	23	18	7	7	6	2	(1)
5B	ND separation 2025, CC	4	5	2	(5)	(2)	(14)	(20)	(26)	(28)	(30)	(32)	(38)	(49)	(50)	(51)	(56)	(60)
5C	ND separation 2025, CT, no nuclear	23	25	23	18	44	36	31	26	24	22	21	16	5	5	4	(0)	(3)
5D	ND separation 2025, CC, no nuclear	4	5	2	(5)	(2)	(14)	(20)	(26)	(28)	(30)	(32)	(38)	(49)	(50)	(51)	(56)	(60)
6A	ND separation 2027	27	29	27	22	47	39	33	28	26	24	23	18	7	7	6	2	(1)

Reference Case Comparisons

	IRP Reference, MN	4,867	4,943	5,062	5,165	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRP Expansion Plan, MN	4,646	4,702	4,795	4,875	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRP Reference, ND	278	282	291	299	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRP Expansion Plan, ND	263	267	274	281	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRP Reference, Sys	5,145	5,225	5,353	5,464	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRP Expansion Plan, Sys	4,909	4,969	5,070	5,156	-	-	-	-	-	-	-	-	-	-	-	-	-

MN, SD, WI Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions	48,218	38,444	2,459	2,436	2,391	2,516	2,603	2,760	2,794	2,871	2,862	2,972	2,902	3,041	3,112	3,215	3,142	3,498	3,564	3,739	3,695	3,816	3,926	4,040	4,145	4,250	4,387
2	Updated Plan	48,062	38,686	2,474	2,467	2,438	2,593	2,673	2,832	2,855	2,887	2,903	2,957	2,938	3,217	3,202	3,460	3,381	3,431	3,492	3,632	3,564	3,689	3,771	3,830	3,924	4,008	4,108
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	48,035	38,606	2,474	2,467	2,438	2,591	2,671	2,829	2,851	2,879	2,893	2,930	2,912	3,200	3,183	3,449	3,372	3,424	3,485	3,622	3,558	3,659	3,774	3,835	3,938	4,023	4,125
4A	ND separation 2023	48,213	38,828	2,474	2,467	2,438	2,591	2,671	2,829	2,851	2,966	2,988	2,979	2,958	3,242	3,223	3,482	3,405	3,439	3,502	3,624	3,548	3,651	3,761	3,826	3,921	4,009	4,110
5A	ND separation 2025, CT	48,101	38,715	2,474	2,467	2,438	2,591	2,671	2,829	2,851	2,879	2,893	2,979	2,958	3,242	3,223	3,482	3,405	3,439	3,502	3,624	3,548	3,651	3,761	3,826	3,921	4,009	4,110
5B	ND separation 2025, CC	48,101	38,715	2,474	2,467	2,438	2,591	2,671	2,829	2,851	2,879	2,893	2,979	2,958	3,242	3,223	3,482	3,405	3,439	3,502	3,624	3,548	3,651	3,761	3,826	3,921	4,009	4,110
5C	ND separation 2025, CT, no nuclear	48,082	38,697	2,474	2,467	2,438	2,591	2,671	2,829	2,851	2,879	2,893	2,979	2,952	3,238	3,213	3,475	3,396	3,436	3,498	3,625	3,547	3,651	3,761	3,826	3,921	4,009	4,110
5D	ND separation 2025, CC, no nuclear	48,082	38,697	2,474	2,467	2,438	2,591	2,671	2,829	2,851	2,879	2,893	2,979	2,952	3,238	3,213	3,475	3,396	3,436	3,498	3,625	3,547	3,651	3,761	3,826	3,921	4,009	4,110
6A	ND separation 2027	48,051	38,665	2,474	2,467	2,438	2,591	2,671	2,829	2,851	2,879	2,894	2,930	2,912	3,245	3,223	3,482	3,405	3,439	3,502	3,624	3,549	3,651	3,761	3,826	3,921	4,009	4,110
	Delta to Scen 2:																											
1	IRP Reference Case with Updated Assumptions	156	(242)	(14)	(31)	(47)	(77)	(70)	(72)	(61)	(15)	(41)	16	(36)	(177)	(91)	(244)	(239)	67	72	107	132	127	155	210	222	242	279
2	Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	(28)	(80)	(0)	0	0	(2)	(3)	(3)	(4)	(7)	(10)	(26)	(26)	(17)	(20)	(10)	(9)	(6)	(6)	(11)	(6)	(31)	3	5	15	15	17
4A	ND separation 2023	151	142	0	0	0	(2)	(3)	(3)	(5)	80	85	22	20	24	21	23	24	9	10	(8)	(15)	(38)	(10)	(4)	(3)	1	2
5A	ND separation 2025, CT	38	29	0	0	0	(2)	(3)	(3)	(5)	(7)	(10)	23	20	24	21	22	24	9	10	(8)	(15)	(38)	(10)	(4)	(3)	1	2
5B	ND separation 2025, CC	38	29	0	0	0	(2)	(3)	(3)	(5)	(7)	(10)	23	20	24	21	22	24	9	10	(8)	(15)	(38)	(10)	(4)	(3)	1	2
5C	ND separation 2025, CT, no nuclear	20	10	0	0	0	(2)	(3)	(3)	(5)	(7)	(10)	23	14	21	11	16	15	6	7	(7)	(16)	(38)	(10)	(4)	(3)	1	2
5D	ND separation 2025, CC, no nuclear	20	10	0	0	0	(2)	(3)	(3)	(5)	(7)	(10)	23	14	21	11	16	15	6	7	(7)	(16)	(38)	(10)	(4)	(3)	1	2
6A	ND separation 2027	(12)	(21)	0	0	0	(2)	(3)	(3)	(5)	(7)	(10)	(27)	(26)	28	21	23	24	9	10	(8)	(15)	(38)	(10)	(4)	(3)	1	2

ND Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions	2,465	1,971	129	126	125	134	134	143	144	149	146	156	145	159	156	162	155	181	179	187	185	190	197	206	212	213	221
2	Updated Plan	2,449	1,973	130	128	127	137	136	146	147	149	147	148	148	166	160	175	169	177	173	184	175	184	187	190	196	200	210
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	2,459	2,009	130	128	127	139	139	150	151	156	157	156	153	164	161	168	162	177	182	188	178	193	199	201	201	201	206
4A	ND separation 2023	2,377	1,930	130	128	127	139	139	150	152	132	143	148	145	149	150	156	148	171	176	182	181	181	184	188	190	193	198
5A	ND separation 2025, CT	2,417	1,968	130	128	127	139	139	150	152	156	157	146	148	153	154	159	151	173	178	185	184	184	187	191	193	196	199
5B	ND separation 2025, CC	2,496	2,083	130	128	127	139	139	150	152	156	157	175	183	186	187	191	184	187	188	194	191	191	194	195	197	199	203
5C	ND separation 2025, CT, no nuclear	2,439	1,994	130	128	127	139	139	150	152	156	157	155	166	167	172	174	167	170	171	174	177	179	182	186	188	191	195
5D	ND separation 2025, CC, no nuclear	2,474	2,061	130	128	127	139	139	150	152	156	157	164	178	179	185	186	181	184	185	187	189	191	194	195	197	199	203
6A	ND separation 2027	2,461	2,012	130	128	127	139	139	150	152	156	157	156	154	167	177	181	173	176	178	185	183	184	187	190	193	195	199
	Delta to Scen 2:																											
1	IRP Reference Case with Updated Assumptions	16	(2)	(1)	(2)	(2)	(3)	(3)	(3)	(3)	(0)	(1)	8	(4)	(6)	(4)	(13)	(14)	4	6	3	9	5	11	15	16	13	11
2	Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	10	36	0	0	0	2	3	3	4	7	10	8	5	(2)	2	(6)	(7)	0	9	4	3	9	12	11	5	1	(4)
4A	ND separation 2023	(72)	(43)	0	0	0	2	3	3	5	(17)	(4)	0	(4)	(16)	(9)	(19)	(21)	(6)	2	(2)	6	(3)	(2)	(3)	(5)	(7)	(12)
5A	ND separation 2025, CT	(32)	(5)	0	0	0	2	3	3	5	7	10	(2)	0	(13)	(6)	(16)	(18)	(3)	5	1	9	(0)	1	0	(2)	(5)	(11)
5B	ND separation 2025, CC	47	110	0	0	0	2	3	3	5	7	10	26	34	21	27	17	15	10	15	9	16	7	7	5	2	(1)	(7)
5C	ND separation 2025, CT, no nuclear	(11)	21	0	0	0	2	3	3	5	7	10	6	18	2	13	(1)	(2)	(7)	(2)	(10)	2	(5)	(4)	(4)	(7)	(9)	(15)
5D	ND separation 2025, CC, no nuclear	25	88	0	0	0	2	3	3	5	7	10	15	29	14	25	11	12	7	12	3	14	7	7	5	2	(1)	(7)
6A	ND separation 2027	12	40	0	0	0	2	3	3	5	7	10	8	6	1	17	7	4	(1)	4	0	8	(1)	0	0	(3)	(5)	(11)

Reference Case Comparisons

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	IRP Reference, MN		38,407	2,360	2,464	2,448	2,550	2,561	2,704	2,724	2,807	2,786	2,885	2,788	2,931	2,989	3,106	3,139	3,604	3,670	3,865	3,831	3,986	4,122	4,201	4,343	4,440	4,527
	IRP Expansion Plan, MN		39,365	2,372	2,495	2,532	2,628	2,655	2,816	2,813	2,868	2,881	3,001	2,959	3,234	3,263	3,477	3,496	3,585	3,663	3,825	3,770	3,904	4,000	4,057	4,177	4,249	4,314
	IRP Reference, ND		2,130	126	132	131	140	140	151	152	158	154	167	158	162	162	170	171	200	204	215	225	223	232	237	245	252	259
	IRP Expansion Plan, ND		2,165	127	133	134	143	145	157	157	161	157	165	167	176	177	190	193	207	201	211	208	216	222	226	234	240	246
	IRP Reference, Sys		40,536	2,487	2,597	2,579	2,690	2,701	2,855	2,876	2,965	2,940	3,053	2,946	3,093	3,152	3,275	3,310	3,803	3,874	4,080	4,056	4,210	4,353	4,438	4,588	4,692	4,786
	IRP Expansion Plan, Sys		41,530	2,498	2,627	2,666	2,771	2,800	2,973	2,970	3,029	3,038	3,165	3,126	3,410	3,440	3,666	3,689	3,792	3,864	4,035	3,978	4,121	4,222	4,283	4,411	4,490	4,559

MN, SD, WI Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions	4,579	4,715	4,819	4,942	5,104	5,293	5,417	5,637	5,821	5,964	6,112	6,280	6,427
2	Updated Plan	4,291	4,403	4,502	4,827	4,996	5,096	5,221	5,419	5,608	5,744	5,907	6,108	6,263
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	4,301	4,423	4,525	4,856	5,023	5,122	5,244	5,454	5,634	5,786	5,960	6,149	6,309
4A	ND separation 2023	4,286	4,406	4,510	4,840	5,003	5,097	5,221	5,430	5,595	5,737	5,918	6,133	6,286
5A	ND separation 2025, CT	4,286	4,406	4,510	4,840	5,003	5,097	5,221	5,430	5,595	5,737	5,918	6,133	6,286
5B	ND separation 2025, CC	4,286	4,406	4,510	4,840	5,003	5,097	5,221	5,430	5,595	5,737	5,918	6,133	6,286
5C	ND separation 2025, CT, no nuclear	4,286	4,406	4,510	4,840	5,003	5,097	5,221	5,430	5,595	5,737	5,918	6,133	6,286
5D	ND separation 2025, CC, no nuclear	4,286	4,406	4,510	4,840	5,003	5,097	5,221	5,430	5,595	5,737	5,918	6,133	6,286
6A	ND separation 2027	4,286	4,406	4,510	4,840	5,003	5,097	5,221	5,430	5,595	5,737	5,918	6,133	6,286

	Delta to Scen 2:													
1	IRP Reference Case with Updated Assumptions	288	312	317	115	109	197	196	217	213	220	205	172	164
2	Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	10	20	23	30	27	26	23	35	26	43	53	41	45
4A	ND separation 2023	(5)	3	8	13	7	1	0	10	(13)	(7)	11	25	23
5A	ND separation 2025, CT	(5)	3	8	13	7	1	0	10	(13)	(7)	11	25	23
5B	ND separation 2025, CC	(5)	3	8	13	7	1	0	10	(13)	(7)	11	25	23
5C	ND separation 2025, CT, no nuclear	(5)	3	8	13	7	1	0	10	(13)	(7)	11	25	23
5D	ND separation 2025, CC, no nuclear	(5)	3	8	13	7	1	0	10	(13)	(7)	11	25	23
6A	ND separation 2027	(5)	3	8	13	7	1	0	10	(13)	(7)	11	25	23

ND Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions	231	237	243	250	256	270	281	284	294	301	309	317	324
2	Updated Plan	215	229	239	244	250	256	262	273	288	293	299	308	316
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	228	235	237	240	243	246	249	253	254	254	258	264	269
4A	ND separation 2023	224	230	233	236	239	243	246	251	254	258	263	268	265
5A	ND separation 2025, CT	225	232	234	238	240	244	247	252	255	259	264	269	273
5B	ND separation 2025, CC	205	208	212	216	220	224	228	233	237	241	246	251	255
5C	ND separation 2025, CT, no nuclear	221	228	231	235	238	241	245	250	253	257	262	267	271
5D	ND separation 2025, CC, no nuclear	205	208	212	216	220	224	228	233	237	241	246	251	255
6A	ND separation 2027	224	230	233	237	240	244	247	252	255	259	263	269	272

	Delta to Scen 2:													
1	IRP Reference Case with Updated Assumptions	16	8	5	6	5	14	19	11	6	8	10	9	8
2	Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future	13	6	(1)	(4)	(7)	(10)	(13)	(20)	(34)	(39)	(40)	(44)	(47)
4A	ND separation 2023	9	1	(6)	(7)	(11)	(13)	(16)	(22)	(34)	(35)	(36)	(41)	(51)
5A	ND separation 2025, CT	11	2	(4)	(6)	(10)	(12)	(15)	(21)	(33)	(34)	(35)	(40)	(43)
5B	ND separation 2025, CC	(9)	(21)	(27)	(27)	(30)	(32)	(34)	(40)	(52)	(52)	(53)	(57)	(61)
5C	ND separation 2025, CT, no nuclear	6	(1)	(8)	(9)	(12)	(15)	(17)	(23)	(35)	(36)	(37)	(42)	(45)
5D	ND separation 2025, CC, no nuclear	(9)	(21)	(27)	(27)	(30)	(32)	(34)	(40)	(52)	(52)	(53)	(57)	(61)
6A	ND separation 2027	10	1	(6)	(7)	(10)	(12)	(15)	(21)	(33)	(34)	(35)	(40)	(44)

Reference Case Comparisons

	IRP Reference, MN	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRP Expansion Plan, MN	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRP Reference, ND	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRP Expansion Plan, ND	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRP Reference, Sys	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRP Expansion Plan, Sys	-	-	-	-	-	-	-	-	-	-	-	-	-

MN, SD, WI Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, LG	50,337	41,371	2,559	2,539	2,490	2,621	2,708	2,859	3,160	3,252	3,260	3,417	3,368	3,588	3,647	3,742	3,679	3,685	3,716	3,886	3,824	3,908	4,009	4,099	4,060	4,151	4,259
2	Updated Plan, LG	49,213	40,596	2,573	2,568	2,536	2,682	2,764	2,924	3,165	3,209	3,167	3,244	3,207	3,400	3,370	3,614	3,538	3,591	3,644	3,788	3,707	3,791	3,865	3,917	3,863	3,944	4,022
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	49,182	40,502	2,573	2,568	2,536	2,681	2,762	2,921	3,157	3,198	3,155	3,215	3,178	3,379	3,347	3,600	3,527	3,584	3,637	3,779	3,702	3,771	3,866	3,916	3,873	3,956	4,039
4A	ND separation 2023, LG	49,399	40,771	2,573	2,568	2,536	2,681	2,762	2,921	3,157	3,290	3,252	3,267	3,228	3,427	3,395	3,641	3,567	3,607	3,661	3,788	3,702	3,772	3,865	3,921	3,864	3,951	4,028
5A	ND separation 2025, CT, LG	49,282	40,653	2,573	2,568	2,536	2,681	2,762	2,921	3,157	3,198	3,155	3,267	3,228	3,427	3,394	3,640	3,566	3,607	3,661	3,788	3,702	3,772	3,865	3,921	3,864	3,951	4,028
5B	ND separation 2025, CC, LG	49,282	40,653	2,573	2,568	2,536	2,681	2,762	2,921	3,157	3,198	3,155	3,267	3,228	3,427	3,394	3,640	3,566	3,607	3,661	3,788	3,702	3,772	3,865	3,921	3,864	3,951	4,028
5C	ND separation 2025, CT, no nuclear, LG	49,252	40,624	2,573	2,568	2,536	2,681	2,762	2,921	3,157	3,198	3,155	3,263	3,218	3,420	3,381	3,631	3,556	3,603	3,656	3,788	3,700	3,772	3,865	3,921	3,864	3,951	4,028
5D	ND separation 2025, CC, no nuclear, LG	49,252	40,624	2,573	2,568	2,536	2,681	2,762	2,921	3,157	3,198	3,155	3,263	3,218	3,420	3,381	3,631	3,556	3,603	3,656	3,788	3,700	3,772	3,865	3,921	3,864	3,951	4,028
6A	ND separation 2027, LG	49,228	40,599	2,573	2,568	2,536	2,681	2,762	2,921	3,157	3,198	3,155	3,215	3,177	3,431	3,395	3,641	3,567	3,607	3,661	3,788	3,702	3,772	3,865	3,921	3,864	3,951	4,028

	Delta to Scen 2:	NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, LG	1,124	775	(14)	(30)	(45)	(61)	(56)	(65)	(6)	44	93	173	162	188	277	128	141	94	72	98	117	117	145	182	197	207	237
2	Updated Plan, LG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	(31)	(95)	(0)	0	0	(2)	(2)	(3)	(8)	(10)	(13)	(29)	(29)	(21)	(23)	(14)	(11)	(7)	(7)	(9)	(5)	(20)	1	(1)	10	12	17
4A	ND separation 2023, LG	186	174	0	0	0	(2)	(2)	(3)	(8)	82	85	23	22	27	24	27	29	16	18	(0)	(5)	(19)	0	4	2	7	6
5A	ND separation 2025, CT, LG	68	56	0	0	0	(2)	(2)	(3)	(8)	(10)	(13)	23	22	27	24	26	29	16	17	(0)	(5)	(19)	0	4	2	7	6
5B	ND separation 2025, CC, LG	68	56	0	0	0	(2)	(2)	(3)	(8)	(10)	(13)	23	22	27	24	26	29	16	17	(0)	(5)	(19)	0	4	2	7	6
5C	ND separation 2025, CT, no nuclear, LG	39	27	0	0	0	(2)	(2)	(3)	(8)	(10)	(13)	19	12	20	11	17	18	12	13	0	(7)	(19)	0	4	2	7	6
5D	ND separation 2025, CC, no nuclear, LG	39	27	0	0	0	(2)	(2)	(3)	(8)	(10)	(13)	19	12	20	11	17	18	12	13	0	(7)	(19)	0	4	2	7	6
6A	ND separation 2027, LG	15	3	0	0	0	(2)	(2)	(3)	(8)	(10)	(12)	(29)	(29)	31	24	27	29	16	18	(0)	(5)	(19)	0	4	2	7	6

ND Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, LG	2,590	2,139	135	132	131	140	140	149	166	171	169	183	173	186	187	192	186	191	188	196	192	195	202	209	207	208	214
2	Updated Plan, LG	2,521	2,086	136	134	133	142	141	151	166	169	163	165	164	177	170	184	178	186	182	193	183	190	192	195	192	197	205
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	2,575	2,151	136	134	133	144	144	154	174	179	176	176	174	179	175	181	175	190	195	201	190	204	209	212	203	203	206
4A	ND separation 2023, LG	2,444	2,024	136	134	133	144	144	154	174	150	157	162	158	160	159	163	154	175	180	186	183	183	184	188	188	189	192
5A	ND separation 2025, CT, LG	2,491	2,068	136	134	133	144	144	154	174	179	176	160	161	164	162	166	157	178	183	188	186	185	187	190	190	191	194
5B	ND separation 2025, CC, LG	2,507	2,139	136	134	133	144	144	154	174	179	176	182	189	191	189	192	183	184	185	189	185	183	184	184	185	186	187
5C	ND separation 2025, CT, no nuclear, LG	2,522	2,104	136	134	133	144	144	154	174	179	176	172	183	182	183	183	175	176	177	178	180	181	182	186	186	187	189
5D	ND separation 2025, CC, no nuclear, LG	2,485	2,117	136	134	133	144	144	154	174	179	176	172	185	185	187	187	180	181	181	182	182	183	184	184	185	186	187
6A	ND separation 2027, LG	2,541	2,119	136	134	133	144	144	154	174	179	176	177	174	177	184	188	178	181	182	188	185	185	187	190	190	191	193

	Delta to Scen 2:	NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, LG	69	53	(1)	(2)	(2)	(2)	(2)	(2)	0	3	6	18	8	9	17	8	8	5	6	2	9	5	10	14	15	11	9
2	Updated Plan, LG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	54	65	0	0	0	2	2	3	8	10	13	11	9	3	5	(3)	(4)	4	12	7	7	14	18	17	11	7	1
4A	ND separation 2023, LG	(77)	(62)	0	0	0	2	2	3	8	(19)	(6)	(3)	(7)	(17)	(11)	(21)	(24)	(11)	(2)	(8)	(0)	(8)	(8)	(8)	(5)	(7)	(13)
5A	ND separation 2025, CT, LG	(30)	(18)	0	0	0	2	2	3	8	10	13	(6)	(3)	(13)	(8)	(18)	(21)	(8)	1	(5)	2	(5)	(5)	(5)	(2)	(5)	(12)
5B	ND separation 2025, CC, LG	(14)	52	0	0	0	2	2	3	8	10	13	17	25	14	19	8	5	(2)	3	(4)	1	(7)	(8)	(11)	(7)	(11)	(18)
5C	ND separation 2025, CT, no nuclear, LG	1	18	0	0	0	2	2	3	8	10	13	7	18	5	13	(1)	(3)	(10)	(5)	(15)	(4)	(10)	(9)	(9)	(7)	(10)	(16)
5D	ND separation 2025, CC, no nuclear, LG	(36)	31	0	0	0	2	2	3	8	10	13	7	20	8	17	3	1	(6)	(1)	(12)	(1)	(7)	(8)	(11)	(7)	(11)	(18)
6A	ND separation 2027, LG	20	33	0	0	0	2	2	3	8	10	12	11	9	1	15	4	(0)	(5)	(0)	(6)	2	(5)	(5)	(5)	(2)	(5)	(12)

MN, SD, WI Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions, LG	4,296	4,403	4,482	4,578	4,710	4,858	4,951	5,136	5,289	5,398	5,511	5,640	5,751
2	Updated Plan, LG	4,047	4,136	4,214	4,470	4,609	4,683	4,778	4,945	5,103	5,206	5,328	5,484	5,602
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	4,059	4,158	4,239	4,504	4,642	4,716	4,810	4,984	5,144	5,257	5,384	5,540	5,665
4A	ND separation 2023, LG	4,046	4,141	4,225	4,484	4,618	4,687	4,781	4,955	5,089	5,198	5,337	5,509	5,627
5A	ND separation 2025, CT, LG	4,046	4,141	4,225	4,484	4,618	4,687	4,781	4,955	5,089	5,198	5,337	5,509	5,627
5B	ND separation 2025, CC, LG	4,046	4,141	4,225	4,484	4,618	4,687	4,781	4,955	5,089	5,198	5,337	5,509	5,627
5C	ND separation 2025, CT, no nuclear, LG	4,046	4,141	4,225	4,484	4,618	4,687	4,781	4,955	5,089	5,198	5,337	5,509	5,627
5D	ND separation 2025, CC, no nuclear, LG	4,046	4,141	4,225	4,484	4,618	4,687	4,781	4,955	5,089	5,198	5,337	5,509	5,627
6A	ND separation 2027, LG	4,046	4,141	4,225	4,484	4,618	4,687	4,781	4,955	5,089	5,198	5,337	5,509	5,627

Delta to Scen 2:

1	IRP Reference Case with Updated Assumptions, LG	248	267	268	109	101	175	172	192	186	192	183	156	149
2	Updated Plan, LG	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	12	22	25	34	32	32	32	39	41	51	56	56	63
4A	ND separation 2023, LG	(2)	6	11	15	9	3	2	10	(14)	(8)	9	25	26
5A	ND separation 2025, CT, LG	(2)	6	11	15	9	3	2	10	(14)	(8)	9	25	26
5B	ND separation 2025, CC, LG	(2)	6	11	15	9	3	2	10	(14)	(8)	9	25	26
5C	ND separation 2025, CT, no nuclear, LG	(2)	6	11	15	9	3	2	10	(14)	(8)	9	25	26
5D	ND separation 2025, CC, no nuclear, LG	(2)	6	11	15	9	3	2	10	(14)	(8)	9	25	26
6A	ND separation 2027, LG	(2)	6	11	15	9	3	2	10	(14)	(8)	9	25	26

ND Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions, LG	215	220	225	230	234	246	256	257	266	271	277	283	288
2	Updated Plan, LG	201	214	223	224	229	233	238	247	261	264	267	275	280
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	220	226	227	228	229	231	233	235	237	234	242	240	243
4A	ND separation 2023, LG	216	222	223	225	226	228	230	233	237	237	246	243	238
5A	ND separation 2025, CT, LG	218	223	224	226	228	229	231	234	238	238	247	244	246
5B	ND separation 2025, CC, LG	189	191	193	195	198	200	203	206	208	211	213	217	219
5C	ND separation 2025, CT, no nuclear, LG	213	219	221	223	225	227	229	232	236	236	245	242	244
5D	ND separation 2025, CC, no nuclear, LG	189	191	193	195	198	200	203	206	208	211	213	217	219
6A	ND separation 2027, LG	217	221	223	225	227	229	231	234	238	238	247	244	246

Delta to Scen 2:

1	IRP Reference Case with Updated Assumptions, LG	14	6	2	6	5	13	18	10	5	7	10	8	8
2	Updated Plan, LG	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	19	11	4	4	(0)	(3)	(5)	(12)	(24)	(30)	(25)	(35)	(38)
4A	ND separation 2023, LG	15	7	0	1	(3)	(5)	(8)	(14)	(24)	(27)	(21)	(32)	(42)
5A	ND separation 2025, CT, LG	17	8	2	2	(1)	(4)	(6)	(13)	(23)	(26)	(20)	(30)	(34)
5B	ND separation 2025, CC, LG	(12)	(24)	(30)	(28)	(31)	(33)	(35)	(41)	(53)	(54)	(54)	(58)	(61)
5C	ND separation 2025, CT, no nuclear, LG	12	5	(2)	(1)	(4)	(6)	(9)	(15)	(25)	(28)	(22)	(32)	(36)
5D	ND separation 2025, CC, no nuclear, LG	(12)	(24)	(30)	(28)	(31)	(33)	(35)	(41)	(53)	(54)	(54)	(58)	(61)
6A	ND separation 2027, LG	16	7	0	1	(2)	(4)	(7)	(13)	(23)	(26)	(20)	(31)	(34)

MN, SD, WI Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, HG	59,955	45,354	2,559	2,539	2,490	2,623	2,714	2,869	3,194	3,301	3,323	3,507	3,468	3,739	3,823	3,952	3,914	4,295	4,380	4,710	4,837	5,133	5,366	5,556	5,770	5,940	6,203
2	Updated Plan, HG	57,477	43,631	2,573	2,568	2,536	2,682	2,763	2,923	3,175	3,225	3,207	3,305	3,279	3,545	3,530	3,817	3,770	3,978	4,075	4,359	4,447	4,718	4,908	5,054	5,237	5,389	5,605
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	57,296	43,435	2,573	2,568	2,536	2,680	2,760	2,918	3,165	3,211	3,189	3,269	3,243	3,515	3,496	3,792	3,746	3,954	4,050	4,332	4,422	4,680	4,885	5,027	5,218	5,369	5,588
4A	ND separation 2023, HG	57,477	43,658	2,573	2,568	2,536	2,680	2,760	2,918	3,165	3,299	3,287	3,321	3,294	3,563	3,542	3,829	3,780	3,966	4,062	4,324	4,401	4,661	4,872	5,020	5,202	5,357	5,570
5A	ND separation 2025, CT, HG	57,360	43,541	2,573	2,568	2,536	2,680	2,760	2,918	3,165	3,211	3,188	3,321	3,294	3,562	3,541	3,828	3,779	3,966	4,061	4,324	4,401	4,661	4,872	5,020	5,202	5,357	5,570
5B	ND separation 2025, CC, HG	57,360	43,541	2,573	2,568	2,536	2,680	2,760	2,918	3,165	3,211	3,188	3,321	3,294	3,562	3,541	3,828	3,779	3,966	4,061	4,324	4,401	4,661	4,872	5,020	5,202	5,357	5,570
5C	ND separation 2025, CT, no nuclear, HG	57,260	43,441	2,573	2,568	2,536	2,680	2,760	2,918	3,165	3,211	3,188	3,304	3,268	3,538	3,508	3,798	3,747	3,946	4,040	4,310	4,392	4,661	4,872	5,020	5,202	5,357	5,570
5D	ND separation 2025, CC, no nuclear, HG	57,260	43,441	2,573	2,568	2,536	2,680	2,760	2,918	3,165	3,211	3,188	3,304	3,268	3,538	3,508	3,798	3,747	3,946	4,040	4,310	4,392	4,661	4,872	5,020	5,202	5,357	5,570
6A	ND separation 2027, HG	57,307	43,488	2,573	2,568	2,536	2,680	2,760	2,918	3,165	3,211	3,189	3,269	3,242	3,566	3,542	3,829	3,780	3,966	4,062	4,324	4,401	4,661	4,872	5,020	5,202	5,357	5,570

Delta to Scen 2:

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, HG	2,477	1,723	(14)	(30)	(45)	(59)	(49)	(54)	19	76	116	203	189	194	293	134	144	317	306	352	390	415	459	502	533	551	598
2	Updated Plan, HG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	(181)	(197)	(0)	0	0	(2)	(3)	(4)	(10)	(14)	(19)	(36)	(36)	(30)	(34)	(25)	(24)	(24)	(24)	(27)	(25)	(38)	(22)	(27)	(19)	(20)	(17)
4A	ND separation 2023, HG	(0)	27	0	0	0	(2)	(3)	(4)	(11)	74	80	16	16	17	12	11	10	(12)	(13)	(35)	(46)	(57)	(35)	(35)	(34)	(32)	(35)
5A	ND separation 2025, CT, HG	(117)	(90)	0	0	0	(2)	(3)	(4)	(11)	(14)	(19)	16	15	17	11	11	9	(12)	(14)	(35)	(46)	(57)	(35)	(35)	(34)	(32)	(35)
5B	ND separation 2025, CC, HG	(117)	(90)	0	0	0	(2)	(3)	(4)	(11)	(14)	(19)	16	15	17	11	11	9	(12)	(14)	(35)	(46)	(57)	(35)	(35)	(34)	(32)	(35)
5C	ND separation 2025, CT, no nuclear, HG	(217)	(190)	0	0	0	(2)	(3)	(4)	(11)	(14)	(19)	(1)	(10)	(7)	(22)	(19)	(24)	(32)	(35)	(49)	(55)	(57)	(35)	(35)	(34)	(32)	(35)
5D	ND separation 2025, CC, no nuclear, HG	(217)	(190)	0	0	0	(2)	(3)	(4)	(11)	(14)	(19)	(1)	(10)	(7)	(22)	(19)	(24)	(32)	(35)	(49)	(55)	(57)	(35)	(35)	(34)	(32)	(35)
6A	ND separation 2027, HG	(171)	(144)	0	0	0	(2)	(3)	(4)	(11)	(14)	(18)	(36)	(37)	21	12	11	10	(12)	(13)	(35)	(46)	(57)	(35)	(35)	(34)	(32)	(35)

ND Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, HG	3,126	2,370	135	132	131	140	140	150	168	174	174	189	179	195	198	205	201	228	227	244	250	265	279	291	302	308	322
2	Updated Plan, HG	2,993	2,274	136	134	133	142	142	152	167	170	167	170	170	187	181	198	195	212	210	229	229	246	254	261	271	279	294
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	3,243	2,460	136	134	133	144	145	156	177	184	185	188	187	200	200	210	206	234	242	258	259	287	302	310	317	323	335
4A	ND separation 2023, HG	3,276	2,485	136	134	133	144	145	156	178	168	184	192	192	199	205	214	210	247	255	270	281	294	303	314	321	329	341
5A	ND separation 2025, CT, HG	3,307	2,513	136	134	133	144	145	156	178	184	186	190	195	202	208	218	214	250	258	273	284	297	306	316	323	332	343
5B	ND separation 2025, CC, HG	3,182	2,506	136	134	133	144	145	156	178	184	186	205	215	221	226	233	230	243	247	259	266	276	283	290	296	302	311
5C	ND separation 2025, CT, no nuclear, HG	3,382	2,601	136	134	133	144	145	156	178	184	186	213	230	234	247	253	251	260	265	274	282	289	298	308	315	323	334
5D	ND separation 2025, CC, no nuclear, HG	3,218	2,542	136	134	133	144	145	156	178	184	186	206	223	228	240	245	245	253	257	264	270	276	283	290	296	302	311
6A	ND separation 2027, HG	3,336	2,543	136	134	133	144	145	156	178	184	185	188	188	216	231	240	235	252	257	272	283	297	306	316	323	331	342

Delta to Scen 2:

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, HG	134	96	(1)	(2)	(2)	(2)	(1)	(2)	1	4	7	19	9	8	17	7	6	16	17	14	22	19	25	30	32	29	27
2	Updated Plan, HG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	251	186	0	0	0	2	3	4	10	14	19	18	17	13	18	11	12	22	32	28	31	41	48	49	46	44	41
4A	ND separation 2023, HG	284	211	0	0	0	2	3	4	11	(3)	17	22	21	12	23	16	15	35	45	40	52	48	50	53	50	51	47
5A	ND separation 2025, CT, HG	314	239	0	0	0	2	3	4	11	14	19	20	25	15	27	19	19	38	48	44	55	51	52	55	53	53	48
5B	ND separation 2025, CC, HG	189	232	0	0	0	2	3	4	11	14	19	35	45	34	44	35	35	31	37	30	37	30	29	28	25	24	17
5C	ND separation 2025, CT, no nuclear, HG	389	327	0	0	0	2	3	4	11	14	19	43	59	47	66	54	56	48	55	44	54	43	44	47	44	44	40
5D	ND separation 2025, CC, no nuclear, HG	225	268	0	0	0	2	3	4	11	14	19	35	53	41	59	47	50	41	47	34	42	30	29	28	25	24	17
6A	ND separation 2027, HG	343	269	0	0	0	2	3	4	11	14	18	18	18	29	50	41	40	41	47	43	54	51	52	55	53	53	48

MN, SD, WI Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions, HG	6,540	6,806	7,009	7,238	7,539	7,930	8,182	8,526	8,835	9,115	9,412	9,747	10,043
2	Updated Plan, HG	5,924	6,151	6,335	7,049	7,350	7,553	7,802	8,119	8,429	8,733	9,107	9,516	9,834
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	5,899	6,134	6,321	7,061	7,355	7,557	7,808	8,130	8,495	8,774	9,133	9,542	9,867
4A	ND separation 2023, HG	5,882	6,117	6,305	7,033	7,325	7,522	7,764	8,138	8,442	8,754	9,157	9,517	9,810
5A	ND separation 2025, CT, HG	5,882	6,117	6,305	7,033	7,325	7,522	7,764	8,138	8,442	8,754	9,157	9,517	9,810
5B	ND separation 2025, CC, HG	5,882	6,117	6,305	7,033	7,325	7,522	7,764	8,138	8,442	8,754	9,157	9,517	9,810
5C	ND separation 2025, CT, no nuclear, HG	5,882	6,117	6,305	7,033	7,325	7,522	7,764	8,138	8,442	8,754	9,157	9,517	9,810
5D	ND separation 2025, CC, no nuclear, HG	5,882	6,117	6,305	7,033	7,325	7,522	7,764	8,138	8,442	8,754	9,157	9,517	9,810
6A	ND separation 2027, HG	5,882	6,117	6,305	7,033	7,325	7,522	7,764	8,138	8,442	8,754	9,157	9,517	9,810

	Delta to Scen 2:													
1	IRP Reference Case with Updated Assumptions, HG	616	655	674	188	189	377	379	406	406	382	305	231	209
2	Updated Plan, HG	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	(25)	(17)	(14)	11	5	4	5	11	66	41	26	26	33
4A	ND separation 2023, HG	(42)	(34)	(30)	(16)	(24)	(31)	(38)	19	13	21	50	1	(24)
5A	ND separation 2025, CT, HG	(42)	(34)	(30)	(16)	(24)	(31)	(38)	19	13	21	50	1	(24)
5B	ND separation 2025, CC, HG	(42)	(34)	(30)	(16)	(24)	(31)	(38)	19	13	21	50	1	(24)
5C	ND separation 2025, CT, no nuclear, HG	(42)	(34)	(30)	(16)	(24)	(31)	(38)	19	13	21	50	1	(24)
5D	ND separation 2025, CC, no nuclear, HG	(42)	(34)	(30)	(16)	(24)	(31)	(38)	19	13	21	50	1	(24)
6A	ND separation 2027, HG	(42)	(34)	(30)	(16)	(24)	(31)	(38)	19	13	21	50	1	(24)

ND Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions, HG	339	352	364	376	388	413	431	440	457	470	485	502	517
2	Updated Plan, HG	305	326	340	367	378	390	402	418	440	452	468	489	504
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	369	385	394	404	413	423	434	448	460	467	486	496	509
4A	ND separation 2023, HG	373	386	396	406	416	427	438	451	464	476	495	504	510
5A	ND separation 2025, CT, HG	375	388	397	408	417	428	440	453	466	477	496	505	518
5B	ND separation 2025, CC, HG	319	327	336	346	355	365	375	387	397	408	420	434	445
5C	ND separation 2025, CT, no nuclear, HG	367	379	389	400	410	421	433	446	459	470	489	498	516
5D	ND separation 2025, CC, no nuclear, HG	319	327	336	346	355	365	375	387	397	408	420	434	445
6A	ND separation 2027, HG	374	386	396	407	417	428	439	453	465	477	496	505	518

	Delta to Scen 2:													
1	IRP Reference Case with Updated Assumptions, HG	33	26	23	9	10	23	29	22	17	18	17	14	13
2	Updated Plan, HG	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	64	59	54	37	34	33	32	29	20	15	18	7	4
4A	ND separation 2023, HG	68	60	55	39	38	37	36	33	25	23	27	15	6
5A	ND separation 2025, CT, HG	69	61	57	41	39	38	38	34	26	24	28	17	14
5B	ND separation 2025, CC, HG	13	1	(5)	(21)	(23)	(25)	(27)	(32)	(43)	(44)	(48)	(55)	(59)
5C	ND separation 2025, CT, no nuclear, HG	61	53	49	33	32	32	31	27	19	17	21	9	12
5D	ND separation 2025, CC, no nuclear, HG	13	1	(5)	(21)	(23)	(25)	(27)	(32)	(43)	(44)	(48)	(55)	(59)
6A	ND separation 2027, HG	68	60	55	40	39	38	37	34	26	24	28	16	14

MN, SD, WI Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, LG	44,940	37,302	2,459	2,436	2,391	2,515	2,600	2,755	2,789	2,862	2,875	2,989	2,927	3,174	3,235	3,312	3,232	3,263	3,297	3,407	3,289	3,325	3,385	3,466	3,467	3,547	3,629
2	Updated Plan, LG	44,866	37,479	2,474	2,467	2,438	2,593	2,674	2,833	2,858	2,888	2,893	2,937	2,907	3,154	3,134	3,373	3,284	3,272	3,315	3,399	3,263	3,316	3,355	3,379	3,376	3,437	3,486
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	44,890	37,434	2,474	2,467	2,438	2,592	2,672	2,830	2,855	2,883	2,886	2,914	2,884	3,140	3,119	3,367	3,281	3,273	3,315	3,395	3,264	3,289	3,364	3,392	3,399	3,461	3,514
4A	ND separation 2023, LG	45,095	37,683	2,474	2,467	2,438	2,592	2,672	2,830	2,855	2,969	2,981	2,962	2,930	3,183	3,160	3,403	3,317	3,293	3,339	3,406	3,267	3,293	3,361	3,392	3,388	3,455	3,505
5A	ND separation 2025, CT, LG	44,984	37,572	2,474	2,467	2,438	2,592	2,672	2,830	2,855	2,883	2,886	2,962	2,930	3,183	3,160	3,403	3,317	3,293	3,339	3,407	3,267	3,293	3,361	3,392	3,388	3,455	3,505
5B	ND separation 2025, CC, LG	44,984	37,572	2,474	2,467	2,438	2,592	2,672	2,830	2,855	2,883	2,886	2,962	2,930	3,183	3,160	3,403	3,317	3,293	3,339	3,407	3,267	3,293	3,361	3,392	3,388	3,455	3,505
5C	ND separation 2025, CT, no nuclear, LG	44,996	37,584	2,474	2,467	2,438	2,592	2,672	2,830	2,855	2,883	2,886	2,969	2,931	3,187	3,159	3,405	3,318	3,297	3,342	3,413	3,269	3,293	3,361	3,392	3,388	3,455	3,505
5D	ND separation 2025, CC, no nuclear, LG	44,996	37,584	2,474	2,467	2,438	2,592	2,672	2,830	2,855	2,883	2,886	2,969	2,931	3,187	3,159	3,405	3,318	3,297	3,342	3,413	3,269	3,293	3,361	3,392	3,388	3,455	3,505
6A	ND separation 2027, LG	44,934	37,522	2,474	2,467	2,438	2,592	2,672	2,830	2,855	2,883	2,886	2,914	2,884	3,186	3,160	3,403	3,317	3,293	3,339	3,406	3,267	3,293	3,361	3,392	3,388	3,455	3,505

Delta to Scen 2:

1	IRP Reference Case with Updated Assumptions, LG	73	(177)	(14)	(31)	(47)	(78)	(74)	(78)	(69)	(26)	(19)	52	20	20	101	(61)	(52)	(9)	(18)	8	26	9	31	87	91	110	142
2	Updated Plan, LG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	24	(45)	(0)	0	0	(2)	(2)	(3)	(3)	(6)	(7)	(23)	(23)	(14)	(15)	(6)	(4)	1	(1)	(4)	1	(27)	9	13	23	24	28
4A	ND separation 2023, LG	229	204	0	0	0	(2)	(2)	(3)	(3)	81	87	25	22	29	26	30	32	21	24	8	4	(23)	6	13	13	18	18
5A	ND separation 2025, CT, LG	117	93	0	0	0	(2)	(2)	(3)	(3)	(5)	(7)	25	23	29	26	30	32	21	24	8	4	(23)	6	13	13	18	18
5B	ND separation 2025, CC, LG	117	93	0	0	0	(2)	(2)	(3)	(3)	(5)	(7)	25	23	29	26	30	32	21	24	8	4	(23)	6	13	13	18	18
5C	ND separation 2025, CT, no nuclear, LG	129	105	0	0	0	(2)	(2)	(3)	(3)	(5)	(7)	31	23	32	25	32	34	25	27	15	6	(23)	6	13	13	18	18
5D	ND separation 2025, CC, no nuclear, LG	129	105	0	0	0	(2)	(2)	(3)	(3)	(5)	(7)	31	23	32	25	32	34	25	27	15	6	(23)	6	13	13	18	18
6A	ND separation 2027, LG	67	43	0	0	0	(2)	(2)	(3)	(3)	(5)	(7)	(23)	(23)	32	26	30	32	21	24	8	4	(23)	6	13	13	18	18

ND Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, LG	2,280	1,902	129	126	125	134	133	143	144	148	146	158	146	161	163	167	160	167	163	168	161	162	167	173	174	174	179
2	Updated Plan, LG	2,266	1,897	130	128	127	137	136	146	147	149	146	146	146	161	155	169	162	166	162	170	157	162	162	164	164	168	175
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	2,199	1,885	130	128	127	139	138	149	150	154	153	151	148	155	151	156	149	159	163	165	150	159	162	162	155	154	155
4A	ND separation 2023, LG	2,043	1,736	130	128	127	139	138	149	150	124	131	135	130	132	130	134	124	140	144	147	140	135	136	137	137	138	139
5A	ND separation 2025, CT, LG	2,092	1,782	130	128	127	139	138	149	150	154	153	132	133	135	133	137	127	143	147	150	143	138	139	140	140	140	140
5B	ND separation 2025, CC, LG	2,226	1,930	130	128	127	139	138	149	150	154	153	164	171	173	171	173	164	162	162	165	158	153	153	153	153	153	153
5C	ND separation 2025, CT, no nuclear, LG	2,082	1,777	130	128	127	139	138	149	150	154	153	135	143	142	143	142	133	133	133	133	134	133	134	135	135	135	136
5D	ND separation 2025, CC, no nuclear, LG	2,180	1,883	130	128	127	139	138	149	150	154	153	148	160	160	161	161	153	153	153	153	153	153	153	153	153	153	153
6A	ND separation 2027, LG	2,145	1,837	130	128	127	139	138	149	150	154	153	151	148	149	156	159	149	146	146	150	143	138	138	139	139	140	140

Delta to Scen 2:

1	IRP Reference Case with Updated Assumptions, LG	14	4	(1)	(2)	(2)	(3)	(3)	(3)	(3)	(1)	0	11	1	(0)	8	(2)	(2)	1	1	(2)	5	(0)	5	9	10	7	4
2	Updated Plan, LG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	(67)	(13)	0	0	0	2	2	3	3	6	7	5	2	(6)	(4)	(12)	(13)	(7)	1	(5)	(7)	(3)	0	(2)	(9)	(13)	(19)
4A	ND separation 2023, LG	(223)	(161)	0	0	0	2	2	3	3	(25)	(15)	(12)	(16)	(29)	(24)	(35)	(38)	(26)	(18)	(22)	(16)	(27)	(26)	(27)	(27)	(30)	(36)
5A	ND separation 2025, CT, LG	(174)	(115)	0	0	0	2	2	3	3	5	7	(14)	(13)	(26)	(21)	(32)	(35)	(23)	(15)	(20)	(13)	(24)	(23)	(24)	(25)	(28)	(34)
5B	ND separation 2025, CC, LG	(40)	33	0	0	0	2	2	3	3	5	7	18	25	11	16	5	2	(5)	0	(5)	1	(9)	(9)	(11)	(11)	(15)	(21)
5C	ND separation 2025, CT, no nuclear, LG	(184)	(120)	0	0	0	2	2	3	3	5	7	(12)	(2)	(19)	(12)	(26)	(29)	(33)	(29)	(36)	(23)	(29)	(28)	(29)	(29)	(33)	(39)
5D	ND separation 2025, CC, no nuclear, LG	(86)	(14)	0	0	0	2	2	3	3	5	7	2	15	(1)	6	(8)	(9)	(13)	(9)	(17)	(4)	(9)	(9)	(11)	(11)	(15)	(21)
6A	ND separation 2027, LG	(121)	(60)	0	0	0	2	2	3	3	5	7	5	2	(12)	2	(10)	(13)	(20)	(16)	(20)	(14)	(24)	(23)	(25)	(25)	(28)	(35)

MN, SD, WI Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions, LG	3,696	3,776	3,838	3,915	4,018	4,123	4,194	4,361	4,496	4,584	4,673	4,775	4,864
2	Updated Plan, LG	3,547	3,610	3,673	3,826	3,940	3,998	4,072	4,219	4,359	4,430	4,511	4,630	4,720
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	3,570	3,642	3,708	3,863	3,975	4,032	4,104	4,263	4,377	4,476	4,575	4,682	4,778
4A	ND separation 2023, LG	3,558	3,628	3,696	3,851	3,960	4,013	4,086	4,227	4,336	4,413	4,507	4,661	4,762
5A	ND separation 2025, CT, LG	3,558	3,628	3,696	3,851	3,960	4,013	4,086	4,227	4,336	4,413	4,507	4,661	4,762
5B	ND separation 2025, CC, LG	3,558	3,628	3,696	3,851	3,960	4,013	4,086	4,227	4,336	4,413	4,507	4,661	4,762
5C	ND separation 2025, CT, no nuclear, LG	3,558	3,628	3,696	3,851	3,960	4,013	4,086	4,227	4,336	4,413	4,507	4,661	4,762
5D	ND separation 2025, CC, no nuclear, LG	3,558	3,628	3,696	3,851	3,960	4,013	4,086	4,227	4,336	4,413	4,507	4,661	4,762
6A	ND separation 2027, LG	3,558	3,628	3,696	3,851	3,960	4,013	4,086	4,227	4,336	4,413	4,507	4,661	4,762

	Delta to Scen 2:													
1	IRP Reference Case with Updated Assumptions, LG	150	166	165	89	78	125	122	142	137	153	162	146	144
2	Updated Plan, LG	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	23	32	36	37	35	34	33	44	18	46	64	52	58
4A	ND separation 2023, LG	11	18	24	26	20	15	14	7	(23)	(17)	(4)	32	42
5A	ND separation 2025, CT, LG	11	18	24	26	20	15	14	7	(23)	(17)	(4)	32	42
5B	ND separation 2025, CC, LG	11	18	24	26	20	15	14	7	(23)	(17)	(4)	32	42
5C	ND separation 2025, CT, no nuclear, LG	11	18	24	26	20	15	14	7	(23)	(17)	(4)	32	42
5D	ND separation 2025, CC, no nuclear, LG	11	18	24	26	20	15	14	7	(23)	(17)	(4)	32	42
6A	ND separation 2027, LG	11	18	24	26	20	15	14	7	(23)	(17)	(4)	32	42

ND Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions, LG	182	186	189	193	197	206	215	215	223	227	232	237	241
2	Updated Plan, LG	173	185	193	188	193	196	200	208	221	223	224	230	234
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	169	173	173	173	172	173	173	173	171	168	169	171	172
4A	ND separation 2023, LG	162	166	166	166	167	167	168	169	169	170	171	172	166
5A	ND separation 2025, CT, LG	163	167	167	168	168	168	169	170	170	171	172	173	174
5B	ND separation 2025, CC, LG	154	155	157	158	160	161	163	165	166	168	169	172	173
5C	ND separation 2025, CT, no nuclear, LG	159	164	164	165	165	166	167	168	168	169	170	171	172
5D	ND separation 2025, CC, no nuclear, LG	154	155	157	158	160	161	163	165	166	168	169	172	173
6A	ND separation 2027, LG	162	166	166	167	167	168	169	170	170	171	172	173	174

	Delta to Scen 2:													
1	IRP Reference Case with Updated Assumptions, LG	9	1	(3)	5	4	10	15	7	2	4	7	7	7
2	Updated Plan, LG	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	(4)	(12)	(20)	(16)	(20)	(23)	(26)	(35)	(50)	(55)	(56)	(59)	(62)
4A	ND separation 2023, LG	(11)	(19)	(27)	(22)	(26)	(29)	(32)	(40)	(52)	(53)	(54)	(58)	(68)
5A	ND separation 2025, CT, LG	(10)	(18)	(25)	(20)	(25)	(28)	(31)	(38)	(51)	(52)	(52)	(57)	(60)
5B	ND separation 2025, CC, LG	(19)	(30)	(36)	(30)	(33)	(35)	(37)	(44)	(55)	(56)	(55)	(58)	(61)
5C	ND separation 2025, CT, no nuclear, LG	(14)	(22)	(29)	(24)	(28)	(30)	(33)	(41)	(53)	(54)	(54)	(59)	(62)
5D	ND separation 2025, CC, no nuclear, LG	(19)	(30)	(36)	(30)	(33)	(35)	(37)	(44)	(55)	(56)	(55)	(58)	(61)
6A	ND separation 2027, LG	(11)	(19)	(27)	(21)	(25)	(28)	(31)	(39)	(51)	(52)	(53)	(57)	(61)

MN, SD, WI Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, HG	54,238	40,956	2,459	2,436	2,391	2,517	2,606	2,765	2,800	2,881	2,904	3,041	2,989	3,258	3,336	3,441	3,382	3,846	3,929	4,202	4,270	4,518	4,709	4,877	5,153	5,300	5,534
2	Updated Plan, HG	52,961	40,332	2,474	2,467	2,438	2,593	2,673	2,832	2,852	2,885	2,915	2,977	2,960	3,281	3,277	3,558	3,497	3,633	3,721	3,945	3,976	4,206	4,355	4,474	4,722	4,847	5,035
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	52,851	40,199	2,474	2,467	2,438	2,591	2,670	2,827	2,847	2,876	2,902	2,947	2,930	3,259	3,250	3,541	3,481	3,618	3,705	3,924	3,959	4,172	4,348	4,464	4,722	4,847	5,036
4A	ND separation 2023, HG	52,992	40,378	2,474	2,467	2,438	2,591	2,670	2,827	2,846	2,963	2,998	2,996	2,977	3,300	3,289	3,572	3,509	3,624	3,711	3,913	3,931	4,146	4,319	4,439	4,694	4,820	5,006
5A	ND separation 2025, CT, HG	52,877	40,264	2,474	2,467	2,438	2,591	2,670	2,827	2,846	2,876	2,901	2,996	2,977	3,299	3,289	3,572	3,508	3,623	3,711	3,913	3,931	4,146	4,319	4,439	4,694	4,820	5,006
5B	ND separation 2025, CC, HG	52,877	40,264	2,474	2,467	2,438	2,591	2,670	2,827	2,846	2,876	2,901	2,996	2,977	3,299	3,289	3,572	3,508	3,623	3,711	3,913	3,931	4,146	4,319	4,439	4,694	4,820	5,006
5C	ND separation 2025, CT, no nuclear, HG	52,819	40,206	2,474	2,467	2,438	2,591	2,670	2,827	2,846	2,876	2,901	2,989	2,962	3,286	3,268	3,553	3,488	3,611	3,698	3,905	3,926	4,146	4,319	4,439	4,694	4,820	5,006
5D	ND separation 2025, CC, no nuclear, HG	52,819	40,206	2,474	2,467	2,438	2,591	2,670	2,827	2,846	2,876	2,901	2,989	2,962	3,286	3,268	3,553	3,488	3,611	3,698	3,905	3,926	4,146	4,319	4,439	4,694	4,820	5,006
6A	ND separation 2027, HG	52,827	40,214	2,474	2,467	2,438	2,591	2,670	2,827	2,846	2,876	2,902	2,946	2,930	3,303	3,289	3,572	3,509	3,624	3,711	3,913	3,932	4,146	4,319	4,439	4,694	4,820	5,006

Delta to Scen 2:

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, HG	1,277	624	(14)	(31)	(47)	(77)	(67)	(67)	(52)	(3)	(11)	64	29	(23)	60	(117)	(115)	212	208	257	294	313	354	404	431	453	499
2	Updated Plan, HG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	(110)	(133)	(0)	0	0	(2)	(3)	(4)	(6)	(9)	(13)	(30)	(30)	(22)	(27)	(17)	(16)	(15)	(15)	(20)	(17)	(33)	(8)	(10)	(1)	(1)	1
4A	ND separation 2023, HG	31	46	0	0	0	(2)	(3)	(4)	(6)	78	83	19	17	18	13	14	12	(10)	(10)	(32)	(44)	(59)	(36)	(34)	(29)	(27)	(29)
5A	ND separation 2025, CT, HG	(84)	(68)	0	0	0	(2)	(3)	(4)	(6)	(9)	(13)	19	17	18	12	13	12	(10)	(10)	(32)	(44)	(59)	(36)	(34)	(29)	(27)	(29)
5B	ND separation 2025, CC, HG	(84)	(68)	0	0	0	(2)	(3)	(4)	(6)	(9)	(13)	19	17	18	12	13	12	(10)	(10)	(32)	(44)	(59)	(36)	(34)	(29)	(27)	(29)
5C	ND separation 2025, CT, no nuclear, HG	(142)	(126)	0	0	0	(2)	(3)	(4)	(6)	(9)	(13)	12	2	5	(9)	(5)	(9)	(22)	(23)	(39)	(50)	(59)	(36)	(34)	(29)	(27)	(29)
5D	ND separation 2025, CC, no nuclear, HG	(142)	(126)	0	0	0	(2)	(3)	(4)	(6)	(9)	(13)	12	2	5	(9)	(5)	(9)	(22)	(23)	(39)	(50)	(59)	(36)	(34)	(29)	(27)	(29)
6A	ND separation 2027, HG	(134)	(118)	0	0	0	(2)	(3)	(4)	(6)	(9)	(13)	(30)	(31)	22	13	14	12	(9)	(10)	(32)	(44)	(59)	(36)	(34)	(29)	(27)	(29)

ND Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, HG	2,798	2,113	129	126	125	134	134	144	145	150	148	161	151	167	169	175	170	201	201	214	218	230	242	253	268	272	285
2	Updated Plan, HG	2,728	2,075	130	128	127	137	136	146	147	149	148	150	150	170	165	182	177	190	188	204	201	216	221	228	241	248	262
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	2,857	2,183	130	128	127	139	140	151	153	158	161	162	160	175	175	184	180	202	209	221	218	241	252	258	268	272	282
4A	ND separation 2023, HG	2,874	2,197	130	128	127	139	140	151	153	141	157	165	163	171	176	185	181	212	219	232	238	247	255	263	270	278	288
5A	ND separation 2025, CT, HG	2,905	2,225	130	128	127	139	140	151	153	158	162	162	167	174	180	188	184	215	222	234	241	250	258	266	273	280	289
5B	ND separation 2025, CC, HG	2,899	2,295	130	128	127	139	140	151	153	158	162	187	197	203	208	215	211	221	224	235	239	246	252	258	264	270	278
5C	ND separation 2025, CT, no nuclear, HG	2,967	2,292	130	128	127	139	140	151	153	158	162	178	193	198	210	215	213	220	225	232	240	245	253	261	268	275	285
5D	ND separation 2025, CC, no nuclear, HG	2,910	2,306	130	128	127	139	140	151	153	158	162	182	199	204	215	219	218	226	229	235	241	246	252	258	264	270	278
6A	ND separation 2027, HG	2,937	2,257	130	128	127	139	140	151	153	158	161	162	161	188	203	211	205	217	221	234	241	250	258	266	273	280	289

Delta to Scen 2:

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, HG	70	39	(1)	(2)	(2)	(3)	(2)	(3)	(2)	0	0	11	0	(4)	4	(7)	(8)	11	12	10	17	14	20	25	27	24	22
2	Updated Plan, HG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	129	108	0	0	0	2	3	4	6	9	13	12	10	4	9	2	2	11	20	16	17	25	31	31	27	24	20
4A	ND separation 2023, HG	146	122	0	0	0	2	3	4	6	(8)	9	15	13	0	11	3	3	22	31	27	38	32	34	35	29	30	26
5A	ND separation 2025, CT, HG	178	150	0	0	0	2	3	4	6	9	13	12	17	4	15	6	6	25	34	30	41	34	36	38	32	32	27
5B	ND separation 2025, CC, HG	172	220	0	0	0	2	3	4	6	9	13	37	47	33	42	33	33	30	36	30	38	30	31	30	23	22	15
5C	ND separation 2025, CT, no nuclear, HG	239	217	0	0	0	2	3	4	6	9	13	28	43	28	45	33	35	30	36	28	39	30	32	33	27	27	23
5D	ND separation 2025, CC, no nuclear, HG	182	231	0	0	0	2	3	4	6	9	13	32	48	33	49	37	41	35	41	31	41	30	31	30	23	22	15
6A	ND separation 2027, HG	209	183	0	0	0	2	3	4	6	9	13	12	11	18	38	29	28	27	33	30	40	34	36	38	31	32	27

MN, SD, WI Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions, HG	5,944	6,182	6,368	6,578	6,853	7,200	7,431	7,756	8,047	8,307	8,580	8,889	9,164
2	Updated Plan, HG	5,428	5,630	5,798	6,413	6,686	6,874	7,102	7,400	7,692	7,965	8,299	8,671	8,964
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	5,419	5,629	5,801	6,428	6,696	6,882	7,108	7,420	7,731	8,002	8,333	8,689	8,983
4A	ND separation 2023, HG	5,397	5,607	5,780	6,404	6,672	6,852	7,074	7,417	7,697	7,979	8,339	8,680	8,953
5A	ND separation 2025, CT, HG	5,397	5,607	5,780	6,404	6,672	6,852	7,074	7,417	7,697	7,979	8,339	8,680	8,953
5B	ND separation 2025, CC, HG	5,397	5,607	5,780	6,404	6,672	6,852	7,074	7,417	7,697	7,979	8,339	8,680	8,953
5C	ND separation 2025, CT, no nuclear, HG	5,397	5,607	5,780	6,404	6,672	6,852	7,074	7,417	7,697	7,979	8,339	8,680	8,953
5D	ND separation 2025, CC, no nuclear, HG	5,397	5,607	5,780	6,404	6,672	6,852	7,074	7,417	7,697	7,979	8,339	8,680	8,953
6A	ND separation 2027, HG	5,397	5,607	5,780	6,404	6,672	6,852	7,074	7,417	7,697	7,979	8,339	8,680	8,953

	Delta to Scen 2:													
1	IRP Reference Case with Updated Assumptions, HG	516	552	570	166	167	327	330	356	356	341	281	218	200
2	Updated Plan, HG	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	(9)	(1)	2	15	10	8	6	20	39	37	33	18	19
4A	ND separation 2023, HG	(31)	(23)	(18)	(9)	(15)	(21)	(27)	17	6	13	39	9	(11)
5A	ND separation 2025, CT, HG	(31)	(23)	(18)	(9)	(15)	(21)	(27)	17	6	13	39	9	(11)
5B	ND separation 2025, CC, HG	(31)	(23)	(18)	(9)	(15)	(21)	(27)	17	6	13	39	9	(11)
5C	ND separation 2025, CT, no nuclear, HG	(31)	(23)	(18)	(9)	(15)	(21)	(27)	17	6	13	39	9	(11)
5D	ND separation 2025, CC, no nuclear, HG	(31)	(23)	(18)	(9)	(15)	(21)	(27)	17	6	13	39	9	(11)
6A	ND separation 2027, HG	(31)	(23)	(18)	(9)	(15)	(21)	(27)	17	6	13	39	9	(11)

ND Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions, HG	306	318	328	340	350	374	390	399	414	427	441	456	470
2	Updated Plan, HG	278	297	311	331	342	353	364	380	400	412	426	444	459
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	318	332	340	348	356	365	375	386	394	401	412	426	438
4A	ND separation 2023, HG	319	331	339	348	356	366	376	387	397	408	420	433	438
5A	ND separation 2025, CT, HG	321	332	340	349	358	367	377	388	398	409	421	434	446
5B	ND separation 2025, CC, HG	284	292	300	309	317	326	335	346	355	365	376	388	399
5C	ND separation 2025, CT, no nuclear, HG	316	328	337	346	355	365	375	386	396	407	419	432	444
5D	ND separation 2025, CC, no nuclear, HG	284	292	300	309	317	326	335	346	355	365	376	388	399
6A	ND separation 2027, HG	320	331	339	348	357	367	377	388	398	409	421	434	445

	Delta to Scen 2:													
1	IRP Reference Case with Updated Assumptions, HG	28	21	18	8	8	21	26	19	14	15	15	12	11
2	Updated Plan, HG	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	40	35	29	17	14	12	10	6	(7)	(11)	(14)	(18)	(21)
4A	ND separation 2023, HG	41	33	28	16	14	13	11	7	(3)	(4)	(6)	(11)	(21)
5A	ND separation 2025, CT, HG	43	35	30	18	15	14	13	8	(2)	(3)	(5)	(10)	(13)
5B	ND separation 2025, CC, HG	7	(6)	(11)	(23)	(25)	(27)	(29)	(34)	(45)	(47)	(50)	(56)	(60)
5C	ND separation 2025, CT, no nuclear, HG	39	31	26	15	13	12	11	6	(4)	(5)	(7)	(12)	(15)
5D	ND separation 2025, CC, no nuclear, HG	7	(6)	(11)	(23)	(25)	(27)	(29)	(34)	(45)	(47)	(50)	(56)	(60)
6A	ND separation 2027, HG	42	33	28	17	15	14	13	8	(2)	(3)	(5)	(10)	(13)

MN, SD, WI Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, LG	45,193	37,523	2,479	2,456	2,413	2,540	2,625	2,782	2,816	2,890	2,875	2,989	2,927	3,200	3,244	3,319	3,233	3,263	3,325	3,427	3,318	3,333	3,385	3,499	3,467	3,577	3,651
2	Updated Plan, LG	45,106	37,685	2,495	2,489	2,461	2,619	2,700	2,860	2,886	2,917	2,920	2,937	2,907	3,154	3,136	3,376	3,284	3,272	3,321	3,399	3,269	3,348	3,383	3,387	3,392	3,442	3,486
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	45,203	37,683	2,495	2,489	2,461	2,617	2,698	2,858	2,883	2,912	2,914	2,916	2,885	3,143	3,128	3,377	3,287	3,281	3,320	3,408	3,288	3,297	3,406	3,429	3,443	3,477	3,522
4A	ND separation 2023, LG	45,344	37,884	2,495	2,489	2,461	2,617	2,698	2,858	2,883	2,990	2,991	2,966	2,931	3,183	3,160	3,403	3,317	3,295	3,339	3,412	3,286	3,293	3,399	3,418	3,424	3,459	3,505
5A	ND separation 2025, CT, LG	45,248	37,788	2,495	2,489	2,461	2,617	2,698	2,858	2,883	2,912	2,914	2,966	2,931	3,183	3,160	3,403	3,317	3,295	3,339	3,412	3,286	3,293	3,399	3,418	3,424	3,459	3,505
5B	ND separation 2025, CC, LG	45,248	37,788	2,495	2,489	2,461	2,617	2,698	2,858	2,883	2,912	2,914	2,966	2,931	3,183	3,160	3,403	3,317	3,295	3,339	3,412	3,286	3,293	3,399	3,418	3,424	3,459	3,505
5C	ND separation 2025, CT, no nuclear, LG	45,276	37,815	2,495	2,489	2,461	2,617	2,698	2,858	2,883	2,912	2,914	2,979	2,939	3,194	3,159	3,405	3,318	3,303	3,344	3,423	3,290	3,293	3,399	3,418	3,424	3,459	3,505
5D	ND separation 2025, CC, no nuclear, LG	45,276	37,815	2,495	2,489	2,461	2,617	2,698	2,858	2,883	2,912	2,914	2,979	2,939	3,194	3,159	3,405	3,318	3,303	3,344	3,423	3,290	3,293	3,399	3,418	3,424	3,459	3,505
6A	ND separation 2027, LG	45,197	37,737	2,495	2,489	2,461	2,617	2,698	2,858	2,883	2,912	2,914	2,916	2,885	3,186	3,160	3,403	3,317	3,295	3,339	3,412	3,286	3,293	3,399	3,418	3,424	3,459	3,505

	Delta to Scen 2:																											
1	IRP Reference Case with Updated Assumptions, LG	87	(162)	(16)	(33)	(48)	(79)	(75)	(78)	(70)	(27)	(45)	52	20	46	107	(57)	(51)	(9)	4	28	48	(14)	3	112	74	135	165
2	Updated Plan, LG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	97	(2)	(0)	0	0	(2)	(2)	(2)	(3)	(5)	(6)	(21)	(22)	(11)	(8)	1	3	9	(1)	9	19	(51)	23	42	50	36	35
4A	ND separation 2023, LG	238	198	0	0	0	(2)	(2)	(2)	(3)	74	71	29	24	29	24	27	32	23	18	13	16	(55)	16	31	32	17	18
5A	ND separation 2025, CT, LG	142	103	0	0	0	(2)	(2)	(2)	(3)	(5)	(6)	29	24	29	24	27	32	24	18	13	16	(55)	16	31	32	17	18
5B	ND separation 2025, CC, LG	142	103	0	0	0	(2)	(2)	(2)	(3)	(5)	(6)	29	24	29	24	27	32	24	18	13	16	(55)	16	31	32	17	18
5C	ND separation 2025, CT, no nuclear, LG	169	130	0	0	0	(2)	(2)	(2)	(3)	(5)	(6)	42	31	39	23	29	34	31	23	25	21	(55)	16	31	32	17	18
5D	ND separation 2025, CC, no nuclear, LG	169	130	0	0	0	(2)	(2)	(2)	(3)	(5)	(6)	42	31	39	23	29	34	31	23	25	21	(55)	16	31	32	17	18
6A	ND separation 2027, LG	91	52	0	0	0	(2)	(2)	(2)	(3)	(5)	(5)	(21)	(22)	32	24	27	32	23	18	13	16	(55)	16	31	32	17	18

ND Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, LG	2,409	2,000	137	134	132	139	139	148	149	153	153	158	154	170	172	177	170	171	175	180	173	173	177	184	182	189	194
2	Updated Plan, LG	2,384	1,987	138	135	133	141	141	150	151	153	153	153	151	165	164	178	171	169	172	176	167	172	175	177	178	182	185
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	2,245	1,928	138	135	133	143	143	152	154	158	159	156	150	155	151	156	149	160	163	165	150	161	163	163	155	154	155
4A	ND separation 2023, LG	2,075	1,769	138	135	133	143	143	152	154	124	131	135	130	132	130	134	124	140	144	147	140	135	136	137	137	138	139
5A	ND separation 2025, CT, LG	2,130	1,821	138	135	133	143	143	152	154	158	159	132	133	135	133	137	127	143	147	150	143	138	139	140	140	140	140
5B	ND separation 2025, CC, LG	2,265	1,968	138	135	133	143	143	152	154	158	159	164	171	173	171	173	164	162	162	165	158	153	153	153	153	153	153
5C	ND separation 2025, CT, no nuclear, LG	2,120	1,816	138	135	133	143	143	152	154	158	159	135	143	142	143	142	133	133	133	133	134	133	134	135	135	135	136
5D	ND separation 2025, CC, no nuclear, LG	2,218	1,921	138	135	133	143	143	152	154	158	159	148	160	160	161	161	153	153	153	153	153	153	153	153	153	153	153
6A	ND separation 2027, LG	2,187	1,879	138	135	133	143	143	152	154	158	159	156	150	149	156	159	149	146	146	150	143	138	138	139	139	140	140

	Delta to Scen 2:																											
1	IRP Reference Case with Updated Assumptions, LG	25	14	(0)	(0)	(1)	(2)	(2)	(2)	(2)	1	(1)	5	3	5	8	(1)	(1)	2	3	4	5	2	2	7	4	7	9
2	Updated Plan, LG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	(139)	(59)	0	0	0	2	2	2	3	5	6	3	(1)	(10)	(13)	(22)	(22)	(9)	(9)	(11)	(17)	(11)	(12)	(14)	(23)	(27)	(29)
4A	ND separation 2023, LG	(309)	(218)	0	0	0	2	2	2	3	(29)	(22)	(18)	(22)	(33)	(34)	(44)	(46)	(29)	(28)	(29)	(27)	(36)	(39)	(40)	(41)	(44)	(46)
5A	ND separation 2025, CT, LG	(254)	(166)	0	0	0	2	2	2	3	5	6	(21)	(18)	(30)	(31)	(41)	(44)	(26)	(25)	(26)	(24)	(34)	(36)	(37)	(38)	(42)	(44)
5B	ND separation 2025, CC, LG	(119)	(19)	0	0	0	2	2	2	3	5	6	11	20	7	7	(5)	(7)	(8)	(10)	(11)	(10)	(19)	(22)	(24)	(25)	(29)	(31)
5C	ND separation 2025, CT, no nuclear, LG	(264)	(171)	0	0	0	2	2	2	3	5	6	(18)	(8)	(23)	(21)	(36)	(38)	(36)	(39)	(43)	(34)	(38)	(41)	(42)	(43)	(47)	(49)
5D	ND separation 2025, CC, no nuclear, LG	(166)	(66)	0	0	0	2	2	2	3	5	6	(5)	9	(6)	(3)	(17)	(18)	(16)	(19)	(23)	(14)	(19)	(22)	(24)	(25)	(29)	(31)
6A	ND separation 2027, LG	(196)	(108)	0	0	0	2	2	2	3	5	5	3	(1)	(16)	(8)	(19)	(22)	(23)	(26)	(26)	(25)	(34)	(36)	(38)	(39)	(42)	(45)

MN, SD, WI Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions, LG	3,728	3,796	3,855	3,929	4,023	4,123	4,194	4,370	4,532	4,615	4,700	4,799	4,884
2	Updated Plan, LG	3,551	3,610	3,673	3,858	3,963	4,017	4,085	4,249	4,398	4,468	4,547	4,646	4,726
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	3,595	3,655	3,718	3,911	4,023	4,077	4,143	4,317	4,381	4,532	4,632	4,729	4,815
4A	ND separation 2023, LG	3,563	3,641	3,706	3,896	4,005	4,058	4,125	4,228	4,363	4,430	4,515	4,715	4,815
5A	ND separation 2025, CT, LG	3,563	3,641	3,706	3,896	4,005	4,058	4,125	4,228	4,363	4,430	4,515	4,715	4,815
5B	ND separation 2025, CC, LG	3,563	3,641	3,706	3,896	4,005	4,058	4,125	4,228	4,363	4,430	4,515	4,715	4,815
5C	ND separation 2025, CT, no nuclear, LG	3,563	3,641	3,706	3,896	4,005	4,058	4,125	4,228	4,363	4,430	4,515	4,715	4,815
5D	ND separation 2025, CC, no nuclear, LG	3,563	3,641	3,706	3,896	4,005	4,058	4,125	4,228	4,363	4,430	4,515	4,715	4,815
6A	ND separation 2027, LG	3,563	3,641	3,706	3,896	4,005	4,058	4,125	4,228	4,363	4,430	4,515	4,715	4,815

Delta to Scen 2:

1	IRP Reference Case with Updated Assumptions, LG	176	186	182	71	60	106	109	121	134	147	154	153	158
2	Updated Plan, LG	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	44	45	45	53	60	60	58	68	(17)	64	85	83	89
4A	ND separation 2023, LG	12	31	33	39	42	41	40	(21)	(35)	(38)	(32)	69	89
5A	ND separation 2025, CT, LG	12	31	33	39	42	41	40	(21)	(35)	(38)	(32)	69	89
5B	ND separation 2025, CC, LG	12	31	33	39	42	41	40	(21)	(35)	(38)	(32)	69	89
5C	ND separation 2025, CT, no nuclear, LG	12	31	33	39	42	41	40	(21)	(35)	(38)	(32)	69	89
5D	ND separation 2025, CC, no nuclear, LG	12	31	33	39	42	41	40	(21)	(35)	(38)	(32)	69	89
6A	ND separation 2027, LG	12	31	33	39	42	41	40	(21)	(35)	(38)	(32)	69	89

ND Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions, LG	197	201	205	209	213	219	223	233	242	247	251	256	261
2	Updated Plan, LG	188	191	195	206	211	214	218	228	237	241	246	251	255
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	172	175	175	174	174	174	175	173	171	168	169	171	172
4A	ND separation 2023, LG	162	166	166	166	167	167	168	169	169	170	171	172	166
5A	ND separation 2025, CT, LG	163	167	167	168	168	168	169	170	170	171	172	173	174
5B	ND separation 2025, CC, LG	154	155	157	158	160	161	163	165	166	168	169	172	173
5C	ND separation 2025, CT, no nuclear, LG	159	164	164	165	165	166	167	168	168	169	170	171	172
5D	ND separation 2025, CC, no nuclear, LG	154	155	157	158	160	161	163	165	166	168	169	172	173
6A	ND separation 2027, LG	162	166	166	167	167	168	169	170	170	171	172	173	174

Delta to Scen 2:

1	IRP Reference Case with Updated Assumptions, LG	9	10	9	3	2	5	5	5	5	5	6	6	6
2	Updated Plan, LG	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, LG	(16)	(17)	(21)	(32)	(37)	(40)	(43)	(55)	(66)	(73)	(77)	(80)	(83)
4A	ND separation 2023, LG	(26)	(25)	(29)	(39)	(44)	(47)	(51)	(59)	(68)	(71)	(75)	(79)	(89)
5A	ND separation 2025, CT, LG	(25)	(24)	(28)	(38)	(43)	(46)	(49)	(58)	(67)	(70)	(74)	(78)	(82)
5B	ND separation 2025, CC, LG	(34)	(36)	(39)	(47)	(51)	(53)	(55)	(63)	(71)	(74)	(76)	(79)	(82)
5C	ND separation 2025, CT, no nuclear, LG	(29)	(28)	(31)	(41)	(46)	(48)	(52)	(60)	(69)	(72)	(76)	(80)	(83)
5D	ND separation 2025, CC, no nuclear, LG	(34)	(36)	(39)	(47)	(51)	(53)	(55)	(63)	(71)	(74)	(76)	(79)	(82)
6A	ND separation 2027, LG	(26)	(26)	(29)	(39)	(43)	(46)	(50)	(58)	(67)	(70)	(74)	(78)	(82)

MN, SD, WI Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, HG	54,492	41,177	2,479	2,456	2,413	2,542	2,632	2,791	2,827	2,909	2,904	3,041	2,989	3,285	3,345	3,448	3,383	3,846	3,957	4,222	4,299	4,526	4,709	4,910	5,153	5,329	5,557
2	Updated Plan, HG	53,201	40,538	2,495	2,489	2,461	2,619	2,699	2,859	2,880	2,913	2,941	2,977	2,960	3,281	3,279	3,561	3,497	3,633	3,726	3,945	3,982	4,237	4,383	4,481	4,739	4,851	5,035
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	53,164	40,448	2,495	2,489	2,461	2,617	2,696	2,855	2,875	2,905	2,929	2,949	2,931	3,261	3,260	3,552	3,488	3,626	3,710	3,937	3,983	4,180	4,389	4,501	4,766	4,863	5,044
4A	ND separation 2023, HG	53,240	40,579	2,495	2,489	2,461	2,617	2,696	2,855	2,875	2,985	3,008	3,000	2,978	3,300	3,289	3,572	3,509	3,626	3,711	3,918	3,951	4,146	4,358	4,465	4,730	4,825	5,006
5A	ND separation 2025, CT, HG	53,141	40,480	2,495	2,489	2,461	2,617	2,696	2,855	2,875	2,905	2,929	3,000	2,978	3,300	3,289	3,572	3,508	3,625	3,711	3,918	3,951	4,146	4,358	4,465	4,730	4,825	5,006
5B	ND separation 2025, CC, HG	53,141	40,480	2,495	2,489	2,461	2,617	2,696	2,855	2,875	2,905	2,929	3,000	2,978	3,300	3,289	3,572	3,508	3,625	3,711	3,918	3,951	4,146	4,358	4,465	4,730	4,825	5,006
5C	ND separation 2025, CT, no nuclear, HG	53,099	40,437	2,495	2,489	2,461	2,617	2,696	2,855	2,875	2,905	2,929	3,000	2,970	3,293	3,268	3,553	3,488	3,618	3,699	3,916	3,947	4,146	4,358	4,465	4,730	4,825	5,006
5D	ND separation 2025, CC, no nuclear, HG	53,099	40,437	2,495	2,489	2,461	2,617	2,696	2,855	2,875	2,905	2,929	3,000	2,970	3,293	3,268	3,553	3,488	3,618	3,699	3,916	3,947	4,146	4,358	4,465	4,730	4,825	5,006
6A	ND separation 2027, HG	53,090	40,429	2,495	2,489	2,461	2,617	2,696	2,855	2,875	2,905	2,930	2,949	2,931	3,303	3,289	3,572	3,509	3,626	3,711	3,918	3,951	4,146	4,358	4,465	4,730	4,825	5,006

	Delta to Scen 2:																											
1	IRP Reference Case with Updated Assumptions, HG	1,291	639	(16)	(33)	(48)	(77)	(67)	(68)	(53)	(4)	(37)	64	29	3	66	(113)	(114)	212	231	277	317	289	326	429	414	478	522
2	Updated Plan, HG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	(37)	(91)	(0)	0	0	(2)	(3)	(4)	(5)	(9)	(12)	(28)	(29)	(20)	(19)	(9)	(9)	(7)	(16)	(7)	1	(57)	6	20	27	11	8
4A	ND separation 2023, HG	40	41	0	0	0	(2)	(3)	(4)	(6)	71	67	23	18	18	10	11	12	(8)	(15)	(26)	(31)	(91)	(26)	(16)	(9)	(27)	(29)
5A	ND separation 2025, CT, HG	(59)	(58)	0	0	0	(2)	(3)	(4)	(6)	(9)	(12)	23	18	18	10	10	12	(8)	(15)	(27)	(31)	(91)	(26)	(16)	(9)	(27)	(29)
5B	ND separation 2025, CC, HG	(59)	(58)	0	0	0	(2)	(3)	(4)	(6)	(9)	(12)	23	18	18	10	10	12	(8)	(15)	(27)	(31)	(91)	(26)	(16)	(9)	(27)	(29)
5C	ND separation 2025, CT, no nuclear, HG	(102)	(101)	0	0	0	(2)	(3)	(4)	(6)	(9)	(12)	23	10	12	(11)	(8)	(9)	(15)	(27)	(29)	(35)	(91)	(26)	(16)	(9)	(27)	(29)
5D	ND separation 2025, CC, no nuclear, HG	(102)	(101)	0	0	0	(2)	(3)	(4)	(6)	(9)	(12)	23	10	12	(11)	(8)	(9)	(15)	(27)	(29)	(35)	(91)	(26)	(16)	(9)	(27)	(29)
6A	ND separation 2027, HG	(111)	(110)	0	0	0	(2)	(3)	(4)	(6)	(9)	(11)	(28)	(29)	22	10	11	12	(8)	(15)	(26)	(31)	(91)	(26)	(16)	(9)	(27)	(29)

ND Costs ($M)

		NPV	NPV 2040	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	IRP Reference Case with Updated Assumptions, HG	2,926	2,212	137	134	132	139	139	148	150	155	155	162	159	176	179	185	180	206	212	226	229	242	252	263	276	287	299
2	Updated Plan, HG	2,846	2,164	138	135	133	141	141	150	151	153	155	157	156	175	175	191	186	193	199	210	211	226	234	241	255	262	272
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	2,903	2,227	138	135	133	143	144	155	157	162	167	167	163	175	175	184	180	203	209	221	218	243	253	259	268	272	282
4A	ND separation 2023, HG	2,907	2,229	138	135	133	143	144	155	157	141	157	165	163	171	176	185	181	212	219	232	238	247	255	263	270	278	288
5A	ND separation 2025, CT, HG	2,944	2,263	138	135	133	143	144	155	157	162	167	162	167	174	180	188	184	215	222	234	241	250	258	266	273	280	289
5B	ND separation 2025, CC, HG	2,937	2,333	138	135	133	143	144	155	157	162	167	187	197	203	208	215	211	221	224	235	239	246	252	258	264	270	278
5C	ND separation 2025, CT, no nuclear, HG	3,005	2,330	138	135	133	143	144	155	157	162	167	178	193	198	210	215	213	220	225	232	240	245	253	261	268	275	285
5D	ND separation 2025, CC, no nuclear, HG	2,948	2,344	138	135	133	143	144	155	157	162	167	182	199	204	215	219	218	226	229	235	241	246	252	258	264	270	278
6A	ND separation 2027, HG	2,979	2,299	138	135	133	143	144	155	157	162	167	167	163	188	203	211	205	217	221	234	241	250	258	266	273	280	289

	Delta to Scen 2:																											
1	IRP Reference Case with Updated Assumptions, HG	81	48	(0)	(0)	(1)	(2)	(2)	(2)	(1)	1	(1)	5	3	1	5	(6)	(6)	13	13	16	18	16	18	23	21	25	27
2	Updated Plan, HG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	57	62	0	0	0	2	3	4	5	9	12	10	7	0	(0)	(7)	(6)	10	10	10	6	17	19	18	13	10	10
4A	ND separation 2023, HG	61	65	0	0	0	2	3	4	6	(12)	2	8	7	(4)	2	(6)	(5)	18	20	21	27	22	21	22	15	16	16
5A	ND separation 2025, CT, HG	98	99	0	0	0	2	3	4	6	9	12	6	11	(0)	5	(3)	(2)	22	24	24	30	24	23	25	18	18	17
5B	ND separation 2025, CC, HG	92	169	0	0	0	2	3	4	6	9	12	31	41	28	33	24	25	27	26	24	27	20	18	18	9	8	5
5C	ND separation 2025, CT, no nuclear, HG	159	166	0	0	0	2	3	4	6	9	12	22	37	23	36	23	27	27	26	22	28	20	19	21	13	13	13
5D	ND separation 2025, CC, no nuclear, HG	102	180	0	0	0	2	3	4	6	9	12	25	43	29	40	28	32	32	31	25	30	20	18	18	9	8	5
6A	ND separation 2027, HG	133	135	0	0	0	2	3	4	6	9	11	10	8	14	28	19	19	24	23	23	29	24	23	25	17	18	17

MN, SD, WI Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions, HG	5,975	6,202	6,386	6,592	6,858	7,200	7,431	7,766	8,083	8,339	8,608	8,913	9,184
2	Updated Plan, HG	5,433	5,630	5,798	6,445	6,709	6,893	7,115	7,430	7,731	8,003	8,335	8,687	8,970
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	5,444	5,641	5,810	6,476	6,744	6,926	7,147	7,474	7,734	8,058	8,389	8,736	9,020
4A	ND separation 2023, HG	5,403	5,620	5,790	6,449	6,717	6,897	7,114	7,418	7,724	7,996	8,347	8,733	9,007
5A	ND separation 2025, CT, HG	5,403	5,620	5,790	6,449	6,717	6,897	7,114	7,418	7,724	7,996	8,347	8,733	9,007
5B	ND separation 2025, CC, HG	5,403	5,620	5,790	6,449	6,717	6,897	7,114	7,418	7,724	7,996	8,347	8,733	9,007
5C	ND separation 2025, CT, no nuclear, HG	5,403	5,620	5,790	6,449	6,717	6,897	7,114	7,418	7,724	7,996	8,347	8,733	9,007
5D	ND separation 2025, CC, no nuclear, HG	5,403	5,620	5,790	6,449	6,717	6,897	7,114	7,418	7,724	7,996	8,347	8,733	9,007
6A	ND separation 2027, HG	5,403	5,620	5,790	6,449	6,717	6,897	7,114	7,418	7,724	7,996	8,347	8,733	9,007
	Delta to Scen 2:													
1	IRP Reference Case with Updated Assumptions, HG	543	572	587	147	148	307	316	336	352	336	273	226	214
2	Updated Plan, HG	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	11	11	11	31	35	33	32	44	3	55	55	49	50
4A	ND separation 2023, HG	(30)	(10)	(9)	4	7	4	(1)	(12)	(6)	(7)	12	46	37
5A	ND separation 2025, CT, HG	(30)	(10)	(9)	4	7	4	(1)	(12)	(6)	(7)	12	46	37
5B	ND separation 2025, CC, HG	(30)	(10)	(9)	4	7	4	(1)	(12)	(6)	(7)	12	46	37
5C	ND separation 2025, CT, no nuclear, HG	(30)	(10)	(9)	4	7	4	(1)	(12)	(6)	(7)	12	46	37
5D	ND separation 2025, CC, no nuclear, HG	(30)	(10)	(9)	4	7	4	(1)	(12)	(6)	(7)	12	46	37
6A	ND separation 2027, HG	(30)	(10)	(9)	4	7	4	(1)	(12)	(6)	(7)	12	46	37

ND Costs ($M)

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
1	IRP Reference Case with Updated Assumptions, HG	321	333	344	355	367	386	398	416	433	446	460	476	490
2	Updated Plan, HG	293	303	313	349	360	371	383	400	416	430	447	466	480
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	321	334	341	350	358	366	376	386	394	401	412	426	438
4A	ND separation 2023, HG	319	331	339	348	356	366	376	387	397	408	420	433	438
5A	ND separation 2025, CT, HG	321	332	340	349	358	367	377	388	398	409	421	434	446
5B	ND separation 2025, CC, HG	284	292	300	309	317	326	335	346	355	365	376	388	399
5C	ND separation 2025, CT, no nuclear, HG	316	328	337	346	355	365	375	386	396	407	419	432	444
5D	ND separation 2025, CC, no nuclear, HG	284	292	300	309	317	326	335	346	355	365	376	388	399
6A	ND separation 2027, HG	320	331	339	348	357	367	377	388	398	409	421	434	445
	Delta to Scen 2:													
1	IRP Reference Case with Updated Assumptions, HG	28	30	31	6	7	15	16	16	17	16	13	11	10
2	Updated Plan, HG	0	0	0	0	0	0	0	0	0	0	0	0	0
3A	Updated Plan with Legacy Purchase/Sale and Jur Future, HG	28	30	28	1	(3)	(5)	(7)	(14)	(22)	(29)	(35)	(39)	(42)
4A	ND separation 2023, HG	26	27	25	(1)	(4)	(5)	(7)	(13)	(19)	(22)	(27)	(32)	(42)
5A	ND separation 2025, CT, HG	28	29	27	0	(3)	(4)	(6)	(11)	(18)	(21)	(26)	(31)	(34)
5B	ND separation 2025, CC, HG	(8)	(12)	(14)	(40)	(43)	(45)	(47)	(54)	(61)	(65)	(71)	(77)	(81)
5C	ND separation 2025, CT, no nuclear, HG	24	25	23	(3)	(5)	(6)	(8)	(14)	(20)	(23)	(28)	(33)	(36)
5D	ND separation 2025, CC, no nuclear, HG	(8)	(12)	(14)	(40)	(43)	(45)	(47)	(54)	(61)	(65)	(71)	(77)	(81)
6A	ND separation 2027, HG	27	27	25	(1)	(3)	(4)	(6)	(12)	(18)	(21)	(26)	(31)	(35)

TRANSMISSION SERVICE IMPLICATIONS OF SEPARATING THE NORTH DAKOTA JURISDICTION

As noted in the accompanying Application, a number of alternative approaches exist for addressing the future energy needs of the North Dakota electric customers of Northern States Power Company, a Minnesota corporation (NSPM). These approaches range from full regulatory alignment to pseudo separation of the North Dakota portion of the five-state integrated NSP System,[1] to full legal separation through a separate North Dakota operating company (NSPD). The two structures we have identified as being able to support our proposed Resource Treatment Framework (RTF) are the Pseudo Separation structure and Legal Separation structure. For simplicity, this Schedule refers to the implementation of either of these structures as a "separation scenario."

From a transmission perspective, currently the North Dakota jurisdiction is responsible for about 5.3 percent of all transmission costs incurred on the integrated NSP System and correspondingly receives about 5.3 percent of all benefits from the delivery capability of that overall integrated NSP System. Analyzing the RTF impacts on the Company's North Dakota operations and the overall NSP System requires consideration of how transmission service would be provided in a separation scenario. Depending upon the chosen RTF structure and implementation, there are a number of possible outcomes. The purpose of this Schedule 8 is to provide a high-level description of the transmission service implications to our North Dakota and Minnesota customers. The Company estimates a range of costs and risks to North Dakota and Minnesota of separating the Company's North Dakota operations from the integrated NSP System if Legal Separation is ultimately selected as the appropriate structure to support our RTF.

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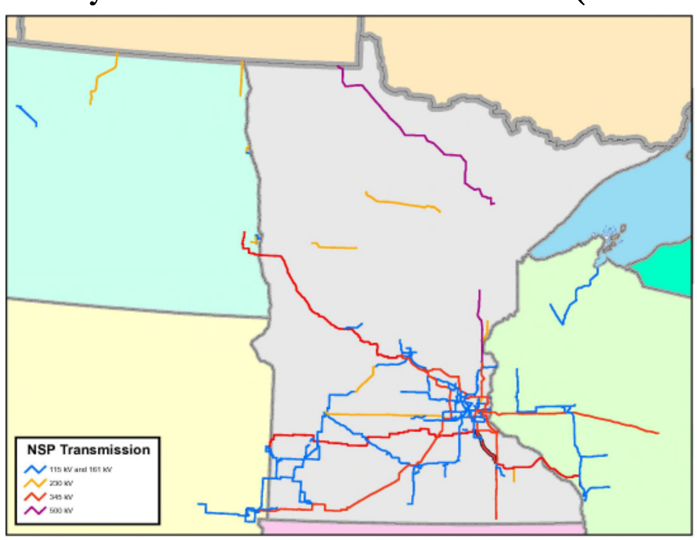
[1] NSPM's electric production and transmission system in Minnesota, North Dakota, and South Dakota is currently planned, built, and operated on an integrated basis with the production and transmission system of Northern States Power Company, a Wisconsin corporation (NSPW). Collectively, NSPM and NSPW integrate their operations facilities, known as the "NSP System," through a Federal Energy Regulatory Commission (FERC)-jurisdictional wholesale Interchange Agreement that allows the two companies to utilize all generation and transmission facilities on an integrated basis to effect the most economical and reliable supply to meet their combined electric load. *Xcel Energy Operating Cos.*, FERC Docket No. ER01-1014, RESTATED AGREEMENT TO COORDINATE PLANNING AND OPERATIONS AND INTERCHANGE POWER AND ENERGY BETWEEN NORTHERN STATES POWER COMPANY (MINNESOTA) AND NORTHERN STATES POWER COMPANY (WISCONSIN) (Jan. 19, 2001); *see also N. States Power Co., a Minn. Corp.*, FERC Docket No. ER15-1575, LETTER ORDER (June 22, 2015) (unpublished letter order of the most recent update to the Interchange Agreement).

A. Transmission System in the Region

NSPM is currently the largest retail electric provider in the State of North Dakota, providing service to three urban areas in the state: (i) Minot, (ii) the Grand Forks/East Grand Forks area, and (iii) the Fargo/Moorhead area. These three load centers are not contiguous themselves or contiguous with the remainder of the NSP System via transmission facilities owned by NSPM, and are thus considered "load pockets." NSPM currently serves the transmission needs for these load pockets through network transmission service reservations obtained under the Midcontinent Independent System Operator, Inc. (MISO) open access transmission, energy, and reserve markets tariff (MISO Tariff) and through individually negotiated pre-MISO transmission agreements, known as "grandfathered agreements" (GFAs) under the MISO Tariff.

In order to assess how transmission service could be provided to the Company's North Dakota load pockets in a separation scenario, it is important to understand the configuration of the system in North Dakota and the MISO Tariff and contractual arrangements that exist among neighboring utilities and the regional transmission organizations (RTOs)[2] that operate in the region. This, in turn, will inform how this configuration could affect future transmission service under evolving circumstances. Figure 1, below, depicts the NSP System transmission facilities (115 kV and above).

Figure 1: NSP System Transmission Facilities (115 kV and above)

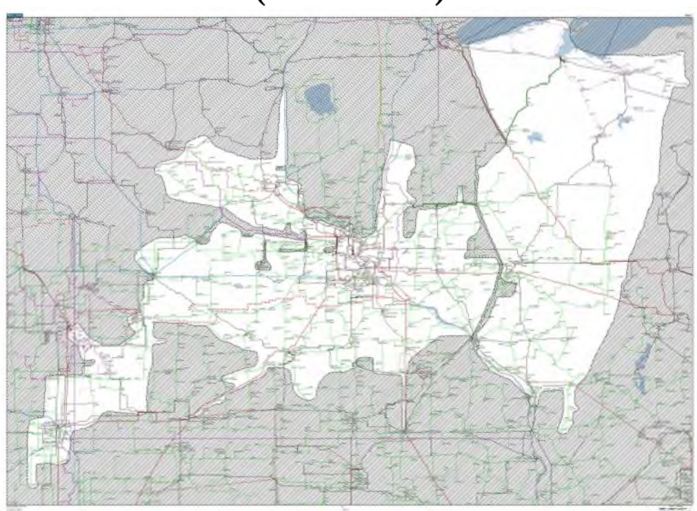


[2] Specifically, MISO and the Southwest Power Pool, Inc. (SPP) are RTOs as established pursuant to FERC Order No. 2000.

The electric delivery service for NSPM customers (including in Minnesota and North Dakota) is procured through the MISO Tariff. In all separation scenarios described herein, NSPM anticipates that it will continue to procure network transmission service through the MISO Tariff.

To serve the three load pockets, NSPM must rely upon both its own transmission facilities as well as other regional transmission infrastructure owned by other utilities. As depicted in Figure 1, the Company does not have contiguous transmission facilities in and around the three North Dakota load pockets that it serves. Indeed, as shown by Figure 2, below, the three North Dakota load pockets are not located within NSP's Local Balancing Authority (LBA).

Figure 2: NSP Local Balancing Authority (White area)



As can be seen, NSPM transmission facilities do not directly serve the Minot and Grand Forks areas, and each of these load pockets are located adjacent to transmission facilities of other utilities: Minot (adjacent to Great River Energy (GRE)); Grand Forks (adjacent to Minnkota Power Cooperative (Minnkota)); and Fargo (adjacent to Otter Tail Power Company (OTP)). The location of the Company's North Dakota load adjacent to the facilities of other utilities presents an important feature that could have significant implications in a separation scenario, as will be described in more detail below.

In addition, two of the load pockets (Grand Forks/East Grand Forks and Fargo/Moorhead) include loads on both sides of the North Dakota/Minnesota border served from common transmission facilities. Finally, while the Minot load pocket is served under the MISO Tariff, it is also interconnected to transmission facilities owned by utilities who are members of SPP, a separate RTO. These conditions specific to the transmission system in and around North Dakota may impact service to North Dakota customers in a separation scenario. They could create challenges for providing transmission service to one or more of these load pockets in the event the Company's North Dakota jurisdiction is separated from the integrated NSP System, as will be discussed in this Schedule 8.

1. MISO, SPP, Minnkota, and Seams

Other transmission-owning members of MISO have facilities that interconnect with the Company's transmission facilities in and around North Dakota. These third-party facilities are important to ensuring sufficient transmission capacity is available to serve the Company's North Dakota customers. The adjacent interconnected MISO transmission owners include GRE, OTP, Minnesota Power, and Montana-Dakota Utilities. All of these transmission-owning members of MISO are subject to the MISO Tariff as well.

The Company's North Dakota service territory is in the western part of the MISO footprint. In this area, MISO-controlled facilities are interconnected to other utilities and regional organizations that are not governed by the MISO Tariff. The situation is complicated by the fact that the transmission network in North Dakota is under the functional control of two separate RTOs (MISO and SPP), and other facilities (Minnkota) are interconnected with NSPM but not a member of any RTO. The presence of non-MISO facilities in the area raises implications of separating NSPM's North Dakota customers or transmission facilities from the larger NSP System.[3]

For example, Basin Electric Cooperative (Basin) and the Western Area Power Association (WAPA) have facilities that interconnect to the MISO footprint in the region. These two utilities are transmission-owning members of SPP. Members of SPP, such as WAPA and Basin, are subject to the SPP Tariff and have granted functional control of their transmission facilities to SPP.

Further, Minnkota has transmission facilities in northeastern North Dakota and northwestern Minnesota that are interconnected to NSPM's facilities. These facilities

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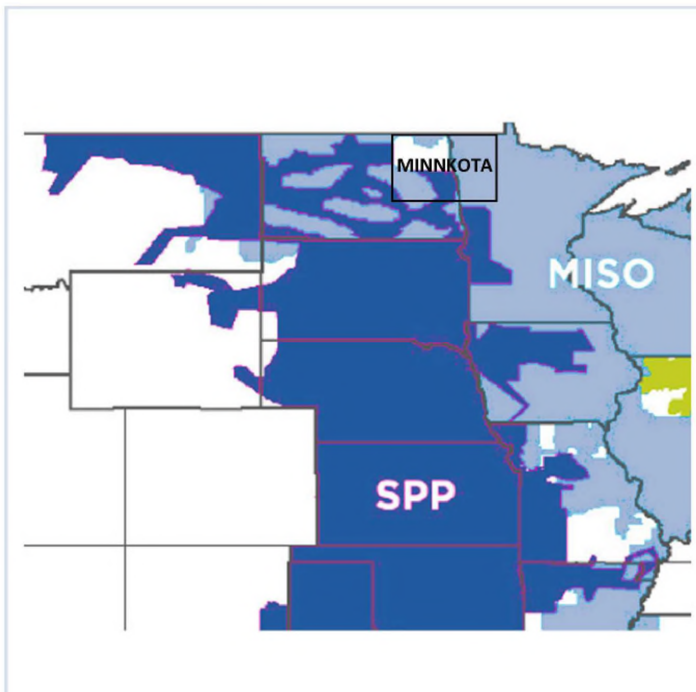
[3] *See Sw Power Pool, Inc.*, 153 FERC ¶ 61,367 (2015)(addressing ongoing seams issues between SPP and MISO related to the Central Power Electric Cooperative system).

are important to ensure adequate service to our North Dakota customers, particularly in Grand Forks/East Grand Forks. Minnkota is not a member of either MISO or SPP; Minnkota is an independent generation and transmission cooperative that operates pursuant to its own tariffs and cooperation agreements with neighboring utilities, MISO, and SPP.

Figure 3: SPP/Minnkota/MISO System Boundaries (approximate and illustrative)



The confluence of MISO, SPP, and Minnkota within the borders of North Dakota creates the need to coordinate planning and operations to ensure the overall electric grid operates safely and efficiently. MISO, SPP, and Minnkota each operate under separate tariffs and agreements, with sometimes divergent operational requirements, conditions, and rate structures. The divergence of tariffs and operational requirements, even with the interconnection of their respective facilities and electrical flows, creates what are known as "seams." It is necessary for utilities to manage and plan around the seams to ensure proper operations and cost allocation, and to minimize costs to customers.

Seams are managed through a series of agreements among RTOs. MISO and SPP are parties to a FERC-approved Joint Operating Agreement (JOA) that is intended to coordinate interregional planning and operations at the seams between their respective systems, including within North Dakota.

The JOA between MISO and SPP stipulates each region must maintain sufficient contract paths to serve its own generation and load obligations, and establishes procedures between the regions to allocate transmission capacity when necessary. The JOA sets a process for coordinating operations and setting consequences if the contract path has been exceeded. Section 5.2 of the JOA provides that if there is insufficient transmission capacity to support the contract path, the party responsible for the shortfall is required to pay. While the application of the JOA to the MISO/SPP seam in the MISO South region has been the subject of substantial litigation at FERC, with the issues largely being resolved,[4] seams issues arose between MISO and SPP in the north as well with the integration of the WAPA/Basin Integrated System (WAPA/Basin System) into SPP, and, as yet, those seams issues have not been comprehensively addressed.

Similarly, Minnkota has a series of legacy coordination agreements with its neighboring utilities (including NSPM). These GFAs predate FERC's Order Nos. 888 and 2000 requirements for comparably-provided open access transmission service under regional tariffs. The GFAs with Minnkota remain necessary to coordinate seams, particularly since Minnkota is not a member of any RTO. These agreements[5] date back to the 1960s and the Mid-Continent Area Power Pool, and provide a mechanism for neighboring utilities with non-contiguous transmission systems to interchange power and transmission service to each other's noncontiguous loads.

When FERC approved implementation of day-ahead and real-time markets in the MISO Tariff in 2005, FERC authorized a mechanism that allowed these legacy GFAs to continue in place, i.e., allowed the pre-MISO transmission service arrangements to remain in effect despite more recent delivery arrangements being superseded by the

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[4] *See Sw Power Pool, Inc.*, 154 FERC ¶ 61,021 (2016) (approving settlement between MISO and SPP regarding flows between MISO South and MISO North regions).

[5] As discussed herein, prior to FERC Order No. 888 and Order No. 2000 requirements for transmission owners to provide open access service and the subsequent MISO Tariff, these individually negotiated agreements were the typical way for neighboring utilities to grant a contract path for transmission delivery service to remote customers or loads. NSPM entered into a series of these legacy agreements to facilitate service to its noncontiguous North Dakota load pockets.

implementation of individual system or regional tariffs.[6] This prevented the disruption of the effectiveness of agreements already approved by FERC so as not to upset the long-standing arrangements of the parties. Further, since utilities such as Minnkota are not subject to FERC jurisdiction it was necessary to allow contractual arrangements with such entities to continue, thereby ensuring a smoother transition to the operation of the regional market and to help ensure utilities could continue efficient operations, even if they were not members of MISO or subject to FERC jurisdiction.[7]

A key GFA that has historically played a significant role in providing service to NSPM customers in North Dakota is a 1964 energy delivery swap agreement with GRE known as the "Stanton Agreement."[8] This agreement predates MISO and the advent of open access.[9] Although both NSPM and GRE are now transmission-owning

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[6] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 107 FERC ¶ 61,191 (2004); *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163 (2004), *order on reh'g*, 109 FERC ¶ 61,157 (2004), *order on reh'g*, 111 FERC ¶ 61,043 (2005); *Midwest Indep. Transmission Sys. Operator, Inc., et al.*, 111 FERC ¶ 61,176 (2005).

[7] There are over 100 GFAs that are recognized under the MISO Tariff. The complete list of those agreements can be found in Attachment P to the MISO Tariff, available at https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2013-03-27%20Docket%20No.%20ER13-1170-000.pdf. The GFAs that are relevant to the Company's service in North Dakota include:

- *Winnipeg – Grand Forks 230 kV Interconnection Coordinating Agreement*, among Manitoba Hydro, Minnkota Power Cooperative and Northern States Power Company, January 16, 1969, as amended (Attachment P No. 309);
- *North Dakota – Western Minnesota 230 kV Facilities Coordinating Agreement* among Minnkota Power Cooperative, Inc., Minnesota Power and Light Company, and Northern States Power Company, July 29, 1966, as amended (Attachment P No. 317); and
- *Transmission Service Agreement* among Great River Energy (formerly Northern Minnesota Power Association, Rural Cooperative Power Association, and United Power Association) and Northern States Power Company, August 17, 1964, as amended (Attachment P Nos. 323 and 390).

In addition, the Company is a party to GFAs allowing municipal utilities to use NSPM facilities for deliveries of WAPA preference power allocations to loads near the WAPA/NSPM boundary. *See, e.g.*, *Municipal Interconnection Agreement*, between Northern States Power Company and the City of Ada, MN, November 30 1992 (Attachment P No. 352); *Transmission Facilities Agreement* between Northern States Power Company and Water, Light, Power & Building Commission for the City of East Grand Forks, Minnesota, December 10, 1992 (Attachment P No. 431).

[8] *Transmission Service Agreement* among Great River Energy (formerly Northern Minnesota Power Association, Rural Cooperative Power Association, and United Power Association) and Northern States Power Company, August 17, 1964, as amended (Attachment P Nos. 323 and 390).

[9] The Stanton Agreement established an energy delivery "swap" or displacement using the generation resources and transmission of one utility to serve the nearby loads of the other utility on an equivalent basis. GRE owns and operates generation in North Dakota near Minot, but its largest load centers are near

members of MISO subject to the MISO Tariff and GRE has announced plans to retire the Stanton generating station, the transmission rights designated under the Stanton Agreement will continue and will provide some energy delivery hedge value to the parties in the future and the principles of this GFA remain a valuable part of the NSP System.

If a Legal Separation scenario is chosen, the Company believes it would likely be appropriate to assign the relevant GFAs to the North Dakota jurisdiction to allow North Dakota customers to retain the benefits of those agreements. For example, the Company anticipates that, if the North Dakota jurisdiction is separated from the NSP System, the Company would attempt to work with GRE and MISO to ensure that the value of the Stanton Agreement remains available to North Dakota customers. However, that outcome would ultimately be determined by negotiations with these other parties and would require FERC approval, and cannot be guaranteed.

2. *Current Transmission Service*

Under current circumstances, NSPM procures network transmission service for all of its customers throughout the integrated NSP System by making reservations for service under the MISO Tariff. This includes obtaining network transmission service for the customers in North Dakota. It is not necessary for NSPM to schedule deliveries separately using transmission service established through any of its GFAs. But the presence of these GFAs supports the Company's ability to take network service through MISO without incurring any additional charge for crossing separate transmission systems or for using transmission capacity enabled by the separate systems.[10]

Transmission service is charged through mechanisms contained in the MISO Tariff. Network transmission service is priced through a formula that applies a charge reflecting the embedded cost of transmission facilities included in the applicable "pricing zone" plus an amount reimbursing a variety of charges imposed by MISO.

Minneapolis, Minnesota. By contrast, NSPM serves three load centers in North Dakota (Minot, Fargo, and Grand Forks) while its generation fleet is predominantly located in central and southern Minnesota. The Stanton Agreement allowed NSPM to electrically exchange GRE resources generated in western North Dakota to physically serve Minot area loads, and GRE received NSPM resources generated in Minnesota to serve GRE loads in Minnesota.

[10] As discussed below, however, the existence of the GFAs remains important and termination of the grandfathered rights could present downstream cost and operating impacts that would need to be taken into account.

Pricing zones are financial concepts intended to ensure transmission costs are levied to loads commensurate with the firm demands on the system and the utility is reimbursed for its necessary transmission investment.

A pricing zone may include facilities or loads that are electrically non-contiguous. In the case of NSPM's North Dakota operations, customers in Fargo/Moorhead and Grand Forks/East Grand Forks and various transmission facilities in North Dakota are included in the NSP pricing zone for transmission pricing purposes even though the facilities and loads are adjacent to transmission facilities of OTP or Minnkota respectively. The Minot area load, however, is presently included in a joint NSP/GRE pricing zone to address GRE's significant transmission infrastructure in that area.[11]

Charges for network transmission service include (i) the applicable zonal rate applied to the load served, plus (ii) a variety of MISO administrative and other charges, including regionally-allocated transmission costs (e.g., MISO Schedule 26 and 26A). The zonal rate is based on a revenue requirement for the zonal transmission plant and the loads assigned to the pricing zone. The NSP pricing zone facilities and loads include both NSP System loads and facilities and third-party loads and facilities.

The NSP pricing zone net charges and MISO administrative and other regionally-allocated charges are spread to all customers in the NSP System on a load-ratio-share basis. Included in the net amount and similarly allocated are revenue credits the Company receives from MISO under the Tariff. This generally means that our Minnesota customers bear approximately 75 percent of the overall NSP System transmission cost and our North Dakota customers bear about 5.3 percent of the overall NSP System transmission costs. This establishes a revenue requirement split that reflects North Dakota's load-ratio share of the overall NSP System.[12]

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[11] In a joint pricing zone (JPZ), participants such as NSPM and GRE have negotiated a transmission revenue-sharing agreement to reflect their respective transmission investment used to serve customers in that area. The NSP System is also a participant in a JPZ for the NSP System pricing zone that includes the costs of certain facilities used for the provision of transmission service to the Fargo and Grand Forks load pockets.

[12] However, it should be noted that the amount of NSP System transmission plant in service located in North Dakota is less than five percent of the NSP System total. Five percent of the transmission plant in service on the NSP System in year ending 2016 equals about $161.5 million on a net book value basis. Transmission facilities located in North Dakota currently have a net book value of about $102.9 million. This disparity could be meaningful in a separation scenario, depending upon how the separation is effectuated because loads in North Dakota would continue to need to use NSP System facilities from outside North Dakota to receive reliable service.

B. Future Transmission Issues Presented

This section discusses ways transmission service could be provided to serve North Dakota customers in a separation scenario. While transmission service would continue to be procured through network transmission reservations under the MISO Tariff, each scenario creates specific issues that may change the costs and risks associated with transmission service.

Several separation scenarios exist, which are largely dependent upon whether the NSP System can be retained in some form or if full disaggregation through Legal Separation is the desired outcome. These scenarios are identified here and described in the next section.

1. Separation Scenarios if NSP System is Retained

The Company has identified three scenarios that could occur if the integrated NSP System is retained in some form. They are:

> *Regulatory Alignment*: As described in the Application, if the Company's jurisdictions can reach consensus on resource selection sufficiently to keep the NSP System operating in its present form, then there would be no need to change the way transmission service is provided to all customers. In short, the North Dakota jurisdiction would continue to receive and benefit from its load-ratio share of the integrated NSP System, i.e., currently about 5.3 percent of the NSP System.
>
> *Proxy Pricing*: Under this scenario, the structure of the NSP System stays in place but the energy component is priced differently for each jurisdiction, reflecting the jurisdiction's policy preferences. In this scenario, it is likely (though not assured) that transmission could continue to be served on an integrated basis as it is today. As described in the next section, this scenario could present variable outcomes depending upon how the proxy pricing is structured and how the NSP System evolves.
>
> *Pseudo-Separation:* NSPM could retain all of the transmission assets (including those located in North Dakota) and provide transmission service to North Dakota customers on the same basis as today. Once again, it is possible that transmission service could continue to be provided on an integrated basis,

although this raises a policy question of the fairness of a state participating in transmission service on an integrated basis if that state also requires a separate pricing zone for its energy, creating an asymmetrical cost and risk structure.

2. Separation Scenarios if Legal Separation is Chosen

The Company has identified three separation scenarios that could occur if the Commissions choose to have NSPM legally separate its North Dakota jurisdiction into a separate operating company. These scenarios vary depending upon how NSPD is structured and what assets it owns. They are:

NSPD as a Transmission-Dependent Utility Purchasing Transmission Through MISO: In this separation scenario, North Dakota electric distribution and generation facilities are legally separated from the NSP System but NSPM retains the transmission assets. NSPD would become a transmission-dependent utility and would take transmission service under the MISO Tariff in a way that is similar to how other transmission-dependent utilities take service. This avoids separation of the NSP System transmission assets and somewhat mitigates the costs and risks identified below with scenarios where NSPD becomes a transmission owner, needing to operate under the MISO Tariff and become a party to the GFAs that facilitate transmission service into the state. This scenario changes the cost profile to the North Dakota jurisdiction since NSPD would not own transmission and would, therefore, not receive any offsetting revenue credits from MISO.

NSPD as a Transmission-Owner Operating Within the Existing NSPM Load Zones: Ownership of the North Dakota transmission assets could be transferred to NSPD, with NSPD loads acting as a transmission owner within the larger NSP pricing zone separate from NSPM and NSPW. This scenario raises a number of cost and risk issues as described below. Further, this scenario would require renegotiation of a number of agreements and may be challenging to the extent that it results in cost shifting to other utilities or other states.

NSPD as a Transmission-Owner Operating Within a New NSPD Load Zone: Ownership of the North Dakota transmission assets could be transferred to NSPD with development of a separate North Dakota pricing zone under the MISO Tariff to charge North Dakota customers (including wholesale loads) accordingly. This scenario may not be feasible. At a minimum it would require MISO concurrence. In addition there are potential complications with GFA assignment to NSPD and transmission pricing zone negotiations with other MISO pricing zone participants.

C. Scenarios Discussion

Each of the scenarios described summarily above and in more detail below present a unique profile. The Company notes that each scenario carries individual issues and potential complications. While the Company has not comprehensively studied all of the scenarios, issues that have already been identified may include:

- Transmission cost shifting from one state jurisdiction to another among customers throughout the integrated NSP System;
- potential cost shifting among affected transmission owners;
- changes in the contractual and operational relationships with and among neighboring utilities;
- potential seams issues/costs/risks with SPP and Minnkota;
- MISO Tariff changes;
- rate design changes;
- changes to load metering requirements for transmission invoice settlements;
- allocation of costs for residual system support services between companies; and
- a variety of other potential changes necessary to effectuate ongoing transmission service to North Dakota customers.

Further, each scenario other than regulatory alignment could present risk of changes to seams costs. And some of the scenarios will require acceptance by a variety of stakeholders (MISO, FERC, the states, neighboring utilities) each of which may have its own interests that may not be aligned with the Company's interests.

At this time, the Company has not fully estimated all of the costs and risks under each scenario, except at an order-of-magnitude level for discussion. If a separation scenario is considered, the Company will undertake a more granular analysis of the costs and risks of providing transmission service post-separation.

1. *Scenarios That Retain the NSP System in Some Form*

a. Regulatory Alignment

In the event that the Company's jurisdictions are able to achieve sufficient compromise that the integrated NSP System can be retained, no change to the current transmission service function would be required. The North Dakota jurisdiction will continue to take its load-ratio share of service on the system and will reap a corresponding amount of the benefits of that system. Under current circumstances, this means that North Dakota customers will continue to pay about 5.3 percent of all NSP System transmission costs. Because NSPM is a transmission owner in MISO, this also means that NSPM receives credits and offsetting revenues from MISO. Under current circumstances, the North Dakota jurisdiction reaps its pro rata (5.3 percent) share of those credits and offsetting revenues. In a Regulatory Alignment scenario, this status quo would be maintained.

b. Proxy Pricing

Similar to the Regulatory Alignment scenario, if the jurisdictions are able to come to agreement on a way to more closely align resource cost responsibility through the current NSP System, it is likely that transmission service could continue to be procured and allocated to the jurisdictions on a pro rata basis as it is today. In this situation, NSPM (and NSPW, coordinated through the Interchange Agreement) would continue to be the transmission owner for the entire NSP System, including North Dakota, and would continue to make transmission service reservations and payments applicable to the entire system. In this type of voluntary scenario where the jurisdictions agree to adjust resource pricing in a manner that is fair to all jurisdictions, it would likely be fair for transmission to be procured on a pro rata basis, similar to current circumstances. North Dakota customers would remain in the current NSP and NSP/GRE pricing zones and would be allocated a share of the costs of transmission commensurate with already-established practices.

The Company could retain the current system-wide allocator that results in the current 5.3 percent allocation to North Dakota, hence a relatively unchanged transmission system cost allocation. The current use of the NSPM system-wide retail cost allocator actually benefits North Dakota customers due to the diversity of peak demand allocation with the rest of the NSP System when compared with MISO transmission cost allocation in the other scenarios.

There may be nuances in this scenario depending upon how proxy pricing is determined and which resources may be included or excluded. Further, as legacy generation resources are retired and new resources are added to the system, the transmission delivery arrangements from such resources may need to be adjusted to reflect those evolving circumstances. And to the extent proxy pricing results in inter-jurisdictional subsidization or unrecovered costs, a policy question would be raised as to the fairness of a state participating fully in the integrated NSP System's transmission assets while not participating fully in the generation component of the integrated NSP System.

c. Pseudo Separation

In a Pseudo Separation scenario, NSPM functionally separates its North Dakota jurisdiction from the integrated NSP System but does not legally separate into a North Dakota operating company. The impacts on the provision of network transmission service to customers in North Dakota would be minimal. In this situation, NSPM (and NSPW, coordinated through the Interchange Agreement) would continue to be the transmission owner for the entire NSP System, including North Dakota, and would continue to make transmission service reservations and payments applicable to the entire system.

In this scenario, it is possible that, from a transmission perspective, North Dakota customers could continue to be charged a load-ratio share of the transmission costs attributable to the overall system as they are today. The cost of transmission service could largely reflect the embedded cost calculated using North Dakota retail cost of service principles, plus the costs billed to the NSP System for MISO regional services. North Dakota customers would remain in the current NSP and NSP/GRE pricing zones as established in the normal course of business and would be allocated a share of the costs of transmission commensurate with already-established practices.

The Company could retain the current system-wide allocator that results in the current 5.3 percent allocation to North Dakota, hence a relatively unchanged transmission system cost allocation. The current use of the NSPM system-wide retail cost allocator actually benefits North Dakota customers due to the diversity peak demand allocation with the rest of the NSP System when compared with MISO transmission cost allocation in the other scenarios, though generation costs would be allocated as discussed in the Application.

This scenario, similarly raises a policy question of the fairness of a jurisdiction participating equally with the overall NSP System for transmission delivery while not participating equally from a generation perspective. Depending upon the potential inter-jurisdictional subsidization that could occur, it may be necessary to functionally separate the transmission delivery function in a way that better aligns the benefits of transmission delivery with the chosen generation portfolio. The details of this type of approach have not been studied and the implications of such a structure are not yet fully understood.

2. *Legal Separation Scenarios*

a. *Transmission Dependent Utility Service*

In this Legal Separation scenario, there is a legal separation of a North Dakota operating company but NSPM would retain the transmission facilities located in North Dakota (as today) and NSPM would operate NSPD as a transmission-dependent utility (TDU) with no owned transmission assets and taking service under the MISO Tariff. This transaction structure would result in NSPD operating as a distribution-only utility.

In this scenario, NSPD would take tariffed MISO network transmission service for each of the three load pockets.[13] The transmission charges to NSPD would be based on the NSP System transmission formula rate (and the formula rates of the other entities in the NSP pricing zone) using FERC ratemaking principles rather than the traditional retail cost of service model. NSPD would be charged the zonal rate for the NSP pricing zone and would be responsible for MISO administrative and other fees (e.g., MISO Schedule 26/26A regional charges) in proportion to its use.

Because NSPD would not be a transmission owner in this scenario, NSPD would not incur the costs of transmission asset investments and likewise would not participate in transmission revenue distribution under the MISO Tariff. The retail electric rate in NSPD would therefore have no direct transmission revenue requirement or credits

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[13] The Company would endeavor to assign the relevant GFAs to NSPD in order to preserve the benefits of those legacy agreements to the extent possible. It should be noted that FERC policy is generally to encourage utilities to take transmission service pursuant to the relevant RTO tariff and to phase out use of GFAs. While the Company believes that it should be able to assign the GFAs to NSPD, this is not entirely free from doubt and would need to be investigated in detail prior to separation.

for service sold, but instead would simply reflect the costs of transmission invoice settlements under the MISO Tariff.

The Company recognizes that NSPD taking transmission as a transmission-dependent utility would result in transmission costs being incurred somewhat differently. The Company estimates that this would result in a net transmission cost increase to NSPD compared to today's paradigm in the range of $2 to $4 million per year, largely as a result of a shift in the retail rate design necessitated by the way a TDU is billed for transmission services under the MISO Tariff.

b. NSPD Owns Transmission in the NSP Joint Pricing Zone

In this Legal Separation scenario, there is a legal separation of a North Dakota operating company, with ownership by NSPD of transmission assets. This would change the way transmission costs are allocated. Several steps would be necessary to implement this scenario:

- NSPD would become a transmission-owning member of MISO;
- the transmission assets physically located in North Dakota would be transferred to NSPD;
- the Company and other members of the JPZ agreement for the NSP pricing zone would add NSPD to the JPZ agreement and treat the NSPD facilities and loads separately from the NSPM and NSPW facilities and loads.[14]

NSPD would also need to replace NSPM as the party to the GRE JPZ agreement, which would require both agreement by GRE and FERC approval. In addition, NSPD and NSPM would need to enter into coordinating agreements to ensure that costs and responsibilities for residual or contracted service functions are allocated appropriately.[15]

[14] Note that all parties to the JPZ agreement would need to unanimously consent to this change. In the event that this scenario could result in costs being shifted from one transmission owner to others, obtaining consent to make this change would be challenging.

[15] Note that FERC approval would be required for the transfer of facilities to NSPD, the modifications of the NSP pricing zone JPZ and GRE/NSP pricing zone JPZ agreements, and any coordinating agreements between NSPD and NSPM.

Under this separation scenario, NSPD would be a party to the JPZ agreement and be eligible for the bundled load exemption under the MISO Tariff.[16] The NSPD MISO transmission formula revenue requirement would be calculated separately from that for NSPM and NSPW. The North Dakota transmission revenue adjustment charges would be based on the overall NSP and GRE/NSP pricing zones loads and revenue requirements using FERC ratemaking principles, with the net charges to NSPD determined pursuant to the bundled load exemption.

As previously noted, the physical transmission assets located in North Dakota do not reflect the pro rata share of transmission assets based on a load-ratio share of the overall System. In 2016, the transmission assets in North Dakota were valued at $102.9 million. However, 5.3 percent of the NSP System transmission assets (North Dakota's load-ratio share) would be $161.5 million for 2016, or a difference of about $60 million. The Company's projections are that the same differential order of magnitude would continue to exist in 2020 when a separate operating company could be established.

The allocation of NSP pricing zone costs would therefore reflect the under-investment by NSPD relative to its loads to ensure that North Dakota customers pay a sufficient amount to compensate the other JPZ member utilities for their overall investment in transmission. In this scenario, the North Dakota jurisdiction transmission revenue adjustment net of MISO would be on the order of $3 to $6 million per year, plus assignment of certain costs from NSPM for residual or contracted service functions.

c. Separate NSPD Pricing Zone

Finally, there is a possibility of completely separating North Dakota and creating its own MISO pricing zone. In this Legal Separation scenario, a North Dakota operating company owns North Dakota transmission assets, but NSPD is not a party to the

[16] The MISO bundled load exemption is a Tariff mechanism that exempts transmission owners who serve bundled load from paying certain charges under the Tariff. This exemption is found at Section 37.3a of the MISO Tariff and is designed to ensure that transmission owners serving bundled load do not collect revenues from MISO that are proportionately greater than the utility's revenue requirement. Without the bundled load exemption, "[t]his windfall would be at the expense of other [MISO] TOs without bundled retail load … who would receive aggregate revenues that are proportionately less than their revenue requirements." *Midwest Indep. Transmission Sys. Operator, Inc. and the Transmission Owners of the Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,090 at P 46 (2008), *reh'g denied*, 136 FERC ¶ 61,099 (2011).

NSP JPZ agreement. This would significantly change the way transmission costs are allocated.

In this scenario, NSPD would become a member of MISO separate from the remainder of the NSP System. The transmission assets physically located in North Dakota would be transferred to NSPD. NSPD, in its new capacity as a transmission owner in MISO, would have to develop a separate North Dakota pricing zone applicable to the North Dakota facilities and loads, with the new zone approved by FERC for inclusion in the MISO Tariff.[17] NSPD would also need to be designated as a party to the GRE JPZ agreement.[18] In addition, NSPD and NSPM would need to enter into coordinating agreements to ensure that costs and responsibilities for residual or contracted service functions are allocated appropriately.[19]

As previously noted in Scenario 3 above, the physical assets located in North Dakota ($102.9 million) do not reflect the pro rata share of transmission assets based on a load-ratio share of the overall system ($161.5 million), and this same delta range is expected to continue to exist in 2020 when a new operating company could be established.

To effectuate a separate NSPD transmission pricing zone, the Company would require reallocating a portion of the existing NSP System (or NSP pricing zone) costs to ensure that North Dakota customers receive an appropriate and fair allocation of the overall transmission system investment. Additionally, other MISO utilities could require NSPD to share in the costs of facilities in their pricing zones.

In addition, as noted above, the Company's Fargo and Grand Forks load pockets are largely adjacent to OTP and Minnkota's transmission facilities respectively. In the scenario where a North Dakota-specific pricing zone is implemented, there is a risk that OTP or Minnkota may take the position NSPD cannot serve these load pockets

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[17] Note that the MISO Tariff has specific requirements for developing pricing zones, including the necessity of the utility creating an LBA as a condition of joining MISO. This could be challenging for NSPD since the three load pockets all currently reside within the LBA of other utilities. As a result, the feasibility of this scenario would need to be carefully investigated prior to implementation.

[18] Similar to Scenario 3, above, replacing NSPD on the GRE JPZ agreement would require consent of all parties thereto and to the extent this scenario results in cost shifts, it may be challenging to obtain the required consents.

[19] Note that FERC approval would be required for the transfer of facilities to NSPD, the creation of an NSPD pricing zone under the MISO Tariff, and any coordinating agreements between NSPD and NSPM.

using NSPD's own zonal facilities and claim NSPD is dependent upon OTP or Minnkota's facilities in those areas. OTP could argue that NSPD should be required to join the OTP pricing zone or seek to create an OTP/NSPD JPZ reflecting OTP's greater transmission investment in these areas, rather than remain part of the NSP pricing zone. We have no estimate at this time for the magnitude of the potential cost shift associated with this risk.

Another issue with this scenario is that the basis upon which MISO charges are allocated would change. In the current circumstances, MISO administrative and other charges are allocated across the integrated NSP System based on the jurisdictional load-ratio share of the System with North Dakota customers responsible for about five percent of those charges.

In this Legal Separation scenario, however, North Dakota customers will be responsible for 100 percent of the costs attributable to providing service to North Dakota. These include certain costs subsumed by the NSP System today related to support for the sub-regional network in North Dakota. Further, to the extent that unusual or unforeseen charges are attributed to the North Dakota jurisdiction, such costs would not be shared across the larger NSP System. Thus, if a network reservation to serve the new North Dakota jurisdiction created a seams cost with SPP or Minnkota, such a cost would be attributable only to NSPD and would not be spread to the larger NSP System. Alternatively, if NSPD were required to install new network transmission facilities because of load growth or new generation interconnections, the costs would not be shared in the manner they are today.

Given the number of potential impacts to development of this scenario and the range of costs associated with certain risks of this scenario, we have not attempted a specific cost evaluation. In our judgment, we anticipate a minimum transmission cost increase for NSPD of $5 million annually compared with regulatory alignment in order to effectuate the arrangements that would support this scenario. In addition, this scenario would be dependent upon rearranging transmission contracts throughout the region and obtaining numerous third-party consents and approvals, none of which could be assured.

D. Additional Costs and Risks in Separation Scenarios

Legal Separation of North Dakota from the integrated NSP System may have additional impacts relating to the allocation of transmission-related costs. While these issues may not apply in all scenarios, there is the potential for unexpected results.

1. Example 1: Risk of SPP Seams Cost

A utility located at the seam between MISO and SPP may have two transmission sources to support a network transmission reservation – one source interconnecting to MISO and one interconnecting to SPP. If the MISO source experiences an outage, service would be provided solely through the SPP source for the duration of the outage. Such use of the SPP interconnection source could result in temporarily "leaning on" the SPP system, a layman's term for an insufficient contract path as contemplated in the MISO/SPP JOA.

Generally, MISO has taken the position that a scenario like this is not grounds for contract path insufficiency and that the RTOs can and should provide mutual aid to each other during such contingencies without compensation for such transmission usage. SPP, however, has taken the position that the JOA does not require providing mutual aid of this type. Rather, SPP generally takes the position that the contingent outage scenario can create contract path insufficiency and hence an obligation for the load serving utility to purchase SPP transmission service. SPP has maintained in the past that if this scenario occurs there must be a payment for transmission service to establish contract path, pursuant to Section 5.2 of the JOA. SPP maintains that the concept of mutual aid encourages free riding and should be discouraged.

This divergent view of seams management could create a situation where the utility (i.e., NSPD) is required either to pay SPP for transmission service (pancaked rates), or penalties (under the JOA) when the contract path is exceeded, or invest in new transmission facilities to reinforce the system to ensure that the system is adequate to obviate the need for mutual aid. All three options would come at a currently-unknown cost to NSPD that would not be shared with the remainder of the NSP System.

The issue of pancaked rates between MISO and SPP is currently being reviewed in a FERC proceeding involving OTP. In *Southwest Power Pool, Inc.*, FERC Docket No. ER16-209, SPP filed a transmission rate for a new SPP transmission-owning member, Central Power Electric Cooperative, Inc. (Central). Central's transmission facilities are interconnected with OTP's facilities at the seam between SPP and MISO.

OTP protested, arguing the arrangement would undermine OTP's existing rights and cause pancaked rates for transmission uses where OTP had not borne pancaked rates previously. Both the MPUC and NDPSC intervened in the case.[20]

FERC accepted the SPP filing but recognized the potential for pancaked rates and set the matter for settlement judge procedures to address this and other issues. In its December 30, 2015, *Order Accepting Tariff Revisions Implementing Formula Rates and Establishing Hearing and Settlement Judge Procedures*,[21] FERC accepted SPP's proposed tariff, subject to refund, and required the parties to attempt to resolve their differences through FERC's established settlement procedures. As it pertains to OTP's protest, FERC ruled that:

> to the extent that Otter Tail has facilities that are highly integrated with facilities in the expanded SPP transmission system as a result of joint planning and ownership, and is concerned that the integration of Central Power into SPP will introduce duplicative or pancaked rates that did not previously exist for use of such jointly planned and owned facilities, Otter Tail may address in the hearing and settlement judge procedures whether any provision is needed in its service agreement with SPP to mitigate such impacts in order to ensure just and reasonable rates.[22]

This FERC matter is ongoing and remains unresolved. Regardless of the outcome, it raises important questions for consideration applicable to NSPD in a separation scenario, as the risk of incurring pancaked transmission rates in the future would impose costs on NSPD's customers.[23]

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[20] The MPUC intervened, opposing Central's proposal and expressing concerns about the cost impacts to OTP ratepayers. The NDPSC intervened and commented on the filing.

[21] *Sw Power Pool, Inc.*, 153 FERC ¶ 61,367 (2015).

[22] 153 FERC ¶ 61,367 at P 47 (2015).

[23] FERC has stated that seams charges from one regional transmission organization (SPP) to another (MISO) are permitted and are consistent with FERC precedent and that pancaking of transmission rates is permitted where the utility is using the transmission facilities within both regional organizations. *Sw Power Pool, Inc.*, 155 FERC ¶ 61,259 at P 29 (June 16, 2016) (citing *Sw Power Pool, Inc.*, 153 FERC ¶ 61,051 at P 52 ("[T]hese separate 'inter-RTO' transmission charges are consistent with Commission precedent, which allows RTOs to

Under current circumstances, any seams costs incurred affecting delivery to loads in North Dakota are allocated to the entire NSP System, meaning that the North Dakota jurisdiction is allocated about 5.3 percent of the cost. If the Company's North Dakota transmission system is separated into a distinct NSPD operating company, such costs incurred to support transmission to North Dakota customers would be assessed only to NSPD.

2. *Example 2: Minnkota Costs*

NSP's load pocket in the Grand Forks/East Grand Forks area is supported by transmission assets owned by Minnkota via the GFA NSPM has with Minnkota. Power is transmitted from Fargo across the Minnkota system contract path to customers in the Grand Forks area pursuant to a GFA.[24] This area of northeastern North Dakota (and far northwestern Minnesota) lies predominantly within Minnkota's retail service territory.

As Minnkota is not a member of MISO, it is not bound by the MISO Tariff; and as a cooperative, Minnkota is not subject to FERC jurisdiction. As a result, maintaining this GFA and contract path to serve the Grand Forks area is an important factor in providing transmission delivery to our customers in North Dakota. If this GFA is terminated or is found to be inapplicable to future circumstances in a Legal Separation scenario, NSPD would potentially need to obtain alternative transmission capacity. While it is likely NSPD could obtain a transmission reservation under the MISO Tariff to serve this load pocket, MISO could determine that network upgrades are required to provide the service. The cost and schedule for system upgrades necessary to support such a reservation are currently unknown.

Because of the presence of GFAs with Minnkota, NSPM is able to obtain transmission service for these customers under the MISO Tariff and GFA without incurring any additional charges for using Minnkota's facilities. In the future, if the GFA with Minnkota is terminated or found to no longer be applicable in a separation scenario, additional payments may be demanded by Minnkota for use of its

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collect transmission charges from a load-serving entity for every transmission system that the load-serving entity uses.")) (citing *Cal. Indep. Sys. Operator Corp.*, 147 FERC ¶ 61,231 at P 155 (2014)("As a matter of policy, the Commission generally has not required the elimination of inter-RTO rate pancaking, but has required the elimination of intra-RTO rate pancaking.")).

[24] *North Dakota – Western Minnesota 230 kV Facilities Coordinating Agreement* (MISO Attachment P No. 317).

transmission facilities. If this scenario occurred today affecting delivery to loads in North Dakota, any cost imposed by Minnkota would be allocated to the entire NSP System, meaning that the North Dakota jurisdiction would be allocated about 5.3 percent of the cost. If North Dakota transmission is separated into a distinct NSPD operating company, such costs incurred to support transmission to North Dakota customers would be assessed only to NSPD and its customers.

As noted, in a transmission separation scenario, the Company believes it should be allowed to assign the relevant GFAs to NSPD to allow the North Dakota operating company to retain the benefits of those agreements, including the GFAs with Minnkota. However, that outcome would ultimately be determined by negotiations with Minnkota and be subject to FERC approval, and cannot be guaranteed.

E. Conclusion

Separating the Company's North Dakota operations from the overall NSP System in some form raises issues for consideration regarding how transmission service will be provided. Different scenarios raise different issues, costs, and risks. If separation is ultimately the desired outcome, how separation impacts transmission service will need to be taken into account.

RTF High-Level Revenue Requirement Impact-North Dakota

Revenue Requirement Impact ($ in millions) **2020 Test Period**

	Alloc	ND Jur	Res	Commercial Non Demand	C&I Demand	Ltg
Pseudo-Separation Differences						
Biomass	E8760	(6.6)	(2.3)	(0.4)	(3.9)	(0.0)
CBED Wind	E8760	(2.3)	(0.8)	(0.1)	(1.4)	(0.0)
Solar	E8760 & D10C	(1.2)	(0.4)	(0.1)	(0.7)	(0.0)
Replacement cost for Biomass, CBED Wind, Solar	E8760 & D10C	3.1	1.0	0.2	1.8	0.0
New wind net of fuel savings	E8760 & D10C	4.1	1.4	0.2	2.4	0.0
Sherco 1 & 2 Retirements	E8760 & D10C	(1.3)	(0.5)	(0.1)	(0.8)	(0.0)
Additional Acctg & IT	A&G	0.1	0.0	0.0	0.0	0.0
Total-Pseudo-Separation		(4.1)	(1.4)	(0.2)	(2.4)	(0.0)
Legal Separation Differences						
Pseudo-Separation Differences except A&G		(4.2)	(1.5)	(0.2)	(2.5)	(0.0)
Additional A&G	A&G	2.0	0.8	0.1	1.1	0.0
Financing difference	Labor	1.0	0.4	0.1	0.5	0.0
Service Co Allocations	A&G	3.0	1.0	0.2	1.8	0.0
Transmission	D10T	5.0	1.7	0.3	3.0	0.0
Transaction Costs	A&G	1.0	0.4	0.1	0.5	0.0
Total-Legal Seperation		7.8	2.8	0.5	4.4	0.1
Estimated Bill Impacts						
Pseudo-Seperation						
Annual kHh Sales		2,309,682,896	812,242,938	122,259,235	1,356,166,305	19,014,418
Impact per kWh			-$0.0017711	-$0.0019191	-$0.0017924	-$0.0014408
Average Annual kWh per Month per Customer			842	1,137	28,784	783
Average Monthly Bill Impact			**-$1.49**	**-$2.18**	**-$51.59**	**-$1.13**
Legal Seperation						
Annual kHh Sales		2,309,682,896	812,242,938	122,259,235	1,356,166,305	19,014,418
Impact per kWh			$0.0034523	$0.0040549	$0.0032808	$0.0033888
Average Annual kWh per Month per Customer			842	1,137	28,784	783
Average Monthly Bill Impact			**$2.91**	**$4.61**	**$94.44**	**$2.65**

RTF High-Level Revenue Requirement Impact-Minnesota

Revenue Requirement Impact ($ in millions)		**2020 Test Period**				
	Alloc	MN Jur	Res	Commercial Non Demand	C&I Demand	Ltg
Main RTF Differences						
Biomass	E8760	5.1	1.5	0.2	3.4	0.0
CBED Wind	E8760	1.8	0.5	0.1	1.2	0.0
Solar	E8760 & D10S	0.9	0.3	0.0	0.6	0.0
Replacement cost for Biomass, CBED Wind, Solar	E8760	(2.4)	(0.7)	(0.1)	(1.6)	(0.0)
New wind net of fuel savings	E8760 & D10S	(3.2)	(0.9)	(0.1)	(2.1)	(0.0)
Sherco 1 & 2 Retirements	E8760 & D10S	1.0	0.3	0.0	0.7	0.0
Additional Acctg & IT	A&G	0.7	0.3	0.0	0.4	0.0
Total-Pseudo-Separation		4.0	1.2	0.1	2.6	0.0
Legal Separation Differences						
Pseudo-Separation Differences except A&G		3.2	1.0	0.1	2.1	0.0
Additional A&G	A&G	0.0	0.0	0.0	0.0	0.0
Financing difference	Labor	0.0	0.0	0.0	0.0	0.0
Service Co Allocations	A&G	(2.3)	(0.7)	(0.1)	(1.5)	(0.0)
Transmission	D10S	(3.9)	(1.3)	(0.1)	(2.4)	0.0
Transaction Costs	A&G	1.0	0.3	0.0	0.7	0.0
Total		(1.9)	(0.8)	(0.1)	(1.1)	0.0
Estimated Bill Impacts						
Pseudo-Seperation						
Annual kHh Sales		30,680,751,285	8,558,594,266	930,970,250	21,013,565,407	177,621,362
Impact per kWh			$0.000144	$0.000148	$0.000123	$0.000099
Average kWh per Month per Customer			630	893	37,099	545
Average Monthly Bill Impact			**$0.09**	**$0.13**	**$4.55**	**$0.05**
Legal Seperation						
Annual kHh Sales		30,680,751,285	8,558,594,266	930,970,250	21,013,565,407	177,621,362
Impact per kWh			-$0.000096	-$0.000089	-$0.000050	$0.000062
Average kWh per Month per Customer			630	893	37,099	545
Average Monthly Bill Impact			**-$0.06**	**-$0.08**	**-$1.86**	**$0.03**