

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA**

IN THE MATTER OF THE APPLICATION
OF NORTHERN STATES POWER
COMPANY FOR AN ADVANCE
DETERMINATION OF PRUDENCE FOR A
POWER PURCHASE AGREEMENT WITH
MANKATO ENERGY CENTER, LLC FOR
APPROXIMATELY 345 MW OF
COMBINED-CYCLE NATURAL GAS
GENERATION

Case No. PU-15-_____

APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE

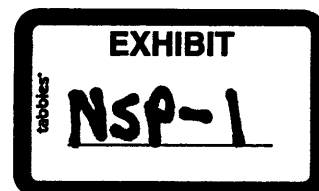
I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, respectfully submits this Application to the North Dakota Public Service Commission for an Advance Determination of Prudence (ADP) for 345 MW of capacity and associated energy to be added to the NSP System¹ through a 20-year power purchase agreement with Mankato Energy Center, LLC, an affiliate of Calpine Corporation (the Calpine Project PPA).

The Calpine Project's capacity and associated energy will be acquired from a new combined-cycle, natural-gas unit added to Calpine's existing 375 MW Mankato Energy Center located in Mankato, Minnesota, from which the Company purchases capacity and associated energy through an existing 20-year PPA. This application is made pursuant to N.D.C.C. § 49-05-16, the Settlement Agreement in Case No. PU-07-776, the Company's commitments in Case No. PU-12-59, and the Settlement Agreement in Case No. PU-12-813, *et. al.*

Our proposed resource addition to the NSP System will help meet a potential need of 150-500 MW on our system in the 2017-2019 time period that was identified in our 2010 Resource Plan. To meet the need, we are proposing to add three new resources:

¹ The NSP System is comprised of generation, transmission, distribution and associated assets, designed to serve our approximately 1.8 million customers across five states: North Dakota, South Dakota, Minnesota, Wisconsin and Michigan. The Company plans, implements and operates the NSP System on an integrated basis, taking into account the needs of all of our customers and addressing the legal and policy requirements of all of our jurisdictions.



**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

(1) the Calpine Project PPA, which is the subject of this Application; (2) Black Dog Unit 6, a 215 MW (nameplate) combustion turbine for which we have already received an ADP from the Commission in Case No. PU-13-194; (3) and the up-to-100 MW (nameplate) distributed solar generation PPA proposed by an affiliate of Geronimo Energy (Geronimo Solar PPA).

As discussed in this Application, we have determined that this portfolio of projects is a reasonable and prudent set of resources to meet the capacity need. As the Commission is aware, the Company initially proposed that our need be met with the addition of up to three new 215 MW natural gas combustion turbine (CT) units, with one of the CTs located at our existing Black Dog plant (Black Dog Unit 6), in Burnsville, Minnesota, and the other two CTs (Red River Valley Units 1 and 2) located at a new plant to be constructed near Hankinson, North Dakota, in the Red River Valley.² The Commission found these additions to be prudent and an ADP was granted for each of these resources.³

We acknowledged in Case No. PU-13-194, however, that it was not certain that the three proposed units reviewed in that Case would actually be constructed as we were also evaluating capacity proposals that were submitted in the Minnesota Public Utilities Commission's (MPUC) Competitive Acquisition Process (CAP) proceedings.⁴ In the CAP Docket (which is a mandatory process for Xcel Energy in Minnesota), the Company evaluated: (1) Black Dog Unit 6; (2) the Red River Valley Units; (3) the Calpine Project; (4) the Geronimo Solar Project; (5) a 150 MW combustion turbine project proposed by Invenergy to expand its existing Cannon Falls, Minnesota facility (Invenergy Project); and (6) a system purchase from Great River Energy.

In evaluating these resource options in the CAP Docket, our analysis showed that Black Dog Unit 6 in conjunction with either the Calpine Project or the Invenergy

² *In the Matter of the Application of Northern States Power Company for an Advance Determination of Prudence for Three Natural Gas Combustion Turbine Generators*, Case No. PU-13-194 (Gas CT Case), Application for Advance Determination of Prudence (Gas CT ADP) at 1-2.

³ The Commission granted the ADPs in its February 26, 2014 *Order Adopting Settlement* that resolved issues in a number of matters, including the Gas CT Case.

⁴ *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need*, Docket E-002/CN-12-1240, *In the Matter of a Draft Purchase Power Agreement with Geronimo Wind Energy, LLC, d/b/a Geronimo Energy, LLC*, Docket No. E-002/M-14-788, and *In the Matter of Draft Power Purchase Agreements with Calpine Corporation and Invenergy Thermal Development, and Proposed Price Terms for Black Dog Unit 6*, Docket No. E-002/M-14-789, ORDER APPROVING POWER PURCHASE AGREEMENT WITH CALPINE, APPROVING POWER PURCHASE AGREEMENT WITH GERONIMO AND APPROVING PRICE TERMS WITH XCEL, (Feb. 5, 2015)(February 2015 CAP Order). The CAP Docket is discussed in the Gas CT Case, Supplemental Testimony of James R. Alders (Alders Supp. Testimony) (Nov. 12, 2013) at 12.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

Project were least-cost options to fill the identified need.⁵ With respect to our evaluation in the CAP Docket, which utilizes externality values required under Minnesota's resource evaluation process, our analysis demonstrated that the combination of Black Dog Unit 6 with the Calpine Project PPA, or the combination of Black Dog Unit 6 with the Invenergy Project PPA had less societal costs.⁶ However, evaluation of other resource options presented in the CAP Docket suggested other benefits could be derived with a larger resource portfolio consisting of the Geronimo Solar PPA in addition to Black Dog Unit 6 and the Calpine Project PPA.

Ultimately, we concluded that the Calpine Project PPA is a prudent and cost-effective resource to add to our system to meet our identified potential need because it provides the flexibility of a combined cycle unit at a reasonable cost. And when it is paired with the other resources we have selected – Black Dog Unit 6 and the Geronimo Solar PPA – it provides additional diversity of resources on our system to meet our customers' needs at an overall reasonable cost.

Specifically, the addition of the combined-cycle natural gas capacity and associated energy of the Calpine Project PPA at this time provides the following strategic benefits:

- Competitive pricing that adds capacity to an existing site and provides strategic benefits to the overall system.
- Additional flexible capacity and lower priced energy that will help to ensure our supply portfolio does not fall short in the event that we experience a rebound in load growth in the coming years.
- Intermediate capacity to support and balance the significant and growing levels of intermittent renewable generation on the system.
- Enhanced flexibility to address the known retirements of existing intermediate and baseload generation during the planning horizon.
- Hedging against emerging environmental regulations that make it increasingly likely the Company's older coal resources will need to be replaced in part with natural gas generation.

The Company recognizes that this ADP replaces the Red River Valley Units - which were found to be a prudent investment by the Commission - with a resource that is, in part, the result of Minnesota's resource selection process. This Application and

⁵ Gas CT Case, Alders Supp. Testimony at 10-11.

⁶ Gas CT Case, Alders Supp. Testimony, Schedule 2 (Wishart Direct) at 23, and Table 5 at 26.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

supporting testimony will demonstrate the prudence of this resource addition in lieu of moving forward with the Red River Valley Units.

In support of this Application, the Company provides the Direct Testimony of Company Witnesses Ms. Laura McCarten, Mr. Paul B. Johnson, and Mr. Kurtis J. Haeger. Ms. McCarten's Direct Testimony provides additional information with respect to the CAP process, the selected resource, and the benefits of adding capacity at this time. Ms. McCarten also describes the issues raised in the Company's last rate case regarding the divergent energy policies among some of the states in which the Company provides electric service. Mr. Johnson provides information regarding the Strategist modeling supporting this filing. Mr. Haeger discusses the factors that affect the Company's forecasting of its need, as well as the considerations that impacted the Company's determination that the Calpine Project PPA, as well as the Geronimo Solar PPA and Black Dog Unit 6, are the appropriate resources to add to our system in light of the Company's down-stream capacity needs. Mr. Haeger also discusses the "Restack concept" embodied in our recent rate case Settlement Agreement, and how the Restack could be utilized in this proceeding.

The remainder of this Application will provide:

- Description of the Applicant;
- Communications and Service;
- Standard of Review;
- Determination of Need;
- Resource Selection Processes;
- Calpine Project PPA;
- Prudence of Calpine Project PPA; and
- Conclusion.

II. DESCRIPTION OF APPLICANT

Xcel Energy is a Minnesota corporation duly authorized to conduct business in the State of North Dakota as a foreign corporation. The Company conducts business in the State of North Dakota as a public utility subject to the jurisdiction and regulation of the Commission pursuant to Title 49 of the North Dakota Century Code. The name and address of Xcel Energy is:

Northern States Power (NSP) Company,
a Minnesota corporation
414 Nicollet Mall
Minneapolis, Minnesota 55401

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

Xcel Energy also operates in North Dakota from the following address:
Northern States Power (NSP) Company,
a Minnesota corporation
2302 Great Northern Drive
Fargo, North Dakota 58102

The Company's Certificate of Incorporation with amendments and Certificate of Authority were filed with the Commission on September 30, 2009 and October 12, 2009, respectively, in Case No. PU-09-664. Current Certificates of Good Standing issued by the North Dakota and Minnesota Secretaries of State were filed in the same docket on January 13, 2014, and are incorporated herein by reference.

Xcel Energy has service territory in five upper Midwest states including North Dakota. We presently serve over 112,000 retail electric customers in and around Fargo, Grand Forks, and Minot, North Dakota. We own approximately 304 miles of transmission lines and 19 substations in North Dakota.

III. COMMUNICATIONS AND SERVICE

We respectfully request that the following person be placed on the Commission's official service list for all official communications in this case:

David H. Sederquist	Tiffany Hughes
Senior Consultant, Regulation and Finance	Records Specialist
Xcel Energy Services Inc.	Xcel Energy Services Inc.
2302 Great Northern Drive	414 Nicollet Mall, 7th Floor
Fargo, ND 58102	Minneapolis, MN 55401

IV. STANDARD OF REVIEW

North Dakota Century Code Section 49-05-16 (1)(d) authorizes the Commission to issue an ADP if it "determines that the resource addition is prudent." Section 49-05-16 (7) further provides that "[t]here is a rebuttable presumption that a resource addition located in the state is prudent."

This standard is similar to the "honestly and prudently invested" standard that the Commission uses for ratemaking. *See* N.D.C.C. § 49-06-02. The general prudence standard calls for determining whether the utility action was reasonable at the time it was taken under all relevant circumstances. *See* Charles F. Philips, Jr., *The Regulation of*

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

Public Utilities – Theory and Practice at 292 (Public Utility Reports 1988); *see also* David. J. Muchow, William A. Mogel, *Energy Law and Transactions* at § 4.02[3][b] (2009). Under N.D.C.C. § 49-05-16 (1), the Commission may issue an order approving the prudence of a proposed project if four conditions are met:

1. The public utility files with its application a projection of costs to the date of the anticipated commercial operation of the resource addition;
2. The public utility files with its application a fee in the amount of one hundred seventy-five thousand dollars;
3. The commission provides notice and holds a hearing, if appropriate, in accordance with section 49-02-02; and
4. The commission determine that the resource addition is prudent. For facilities located or to be located in this state the commission, in determining whether the resource addition is prudent, shall consider the benefits of having the resource addition located in this state.

V. DETERMINATION OF NEED

A. Forecasting Need

The assessment of whether there is a resource need is based on three primary factors: the Company's peak demand forecast; its reserve margins; and the maximum generation capability of its existing resources. In other words, we determine the need to add capacity to our system based on the requirement that we at all times (1) meet our customers' demand for electricity (peak demand); (2) ensure an adequate margin of excess capacity to reliably do so (reserve margins); and (3) have adequate capacity from the resources we have available to meet customer demand while maintaining our reserve margin.

In addition to analyzing peak demand in our forecasts, we also forecast our total annual energy requirements (sales plus transmission losses), including the impacts of Demand-Side Management . By doing so, we can assess not only our capacity needs but also the type of resource that will best address our energy needs. This analysis is necessary to determine if a baseload, intermediate or peaking resource addition will be the most appropriate type of resource to add to the system to address energy as well as capacity needs.

As part of our resource planning efforts, we develop forecasts of these variables to determine if there is a need to add more resources to our system in the future as well

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

as what types of resources to add. As time goes on, forecasts can and do change and changing economic conditions impact the level and timing of the need.

Consequently, it is important to recognize that forecasts are essentially predictions of potential future circumstances based on a specific set of assumptions at a particular point in time.

Building electric generation is an expensive and time-consuming endeavor that must be planned well in advance in order to complete construction to match the anticipated need. Consequently, we must rely on our forecasts to determine if we have a need to add capacity to our system, recognizing that our forecasts may change over the long lead times inherent in generation development. To avoid the “analysis paralysis” that can be inherent in trying to forecast an uncertain and ever-changing future, we must at some point establish a need and then begin the long-lead-time process of selecting resources, obtaining regulatory approvals, and permitting and developing the generation resources.

In general, we first determine if there is a system capacity need as part of the forecasting process utilized in our resource planning efforts. We then update that forecast to provide the best available information to our regulators as we begin the process to obtain regulatory input regarding which resources to select to meet that need. These forecasts, taken together, form the basis for our subsequent decisions on how to proceed rather than become stuck due to the “analysis paralysis” described above. As regulatory processes are ongoing, we may update our forecasts several times to determine if our initial analyses continue to demonstrate the appropriateness to add resources to our system based on the updated information.

1. Fall 2011 Forecast

In this Case, the forecast used to establish the capacity need of 150-500 MW was the Company’s updated Fall 2011 Forecast. The Fall 2011 Forecast updated the forecasting analysis in our 2010 resource plan, which first identified our capacity need. Mr. Haeger further describes in his Direct Testimony the forecast needs identified in our 2010 Resource Plan proceedings, the updates we made to that forecast, and the effects of the economic circumstances in that timeframe on our forecast.

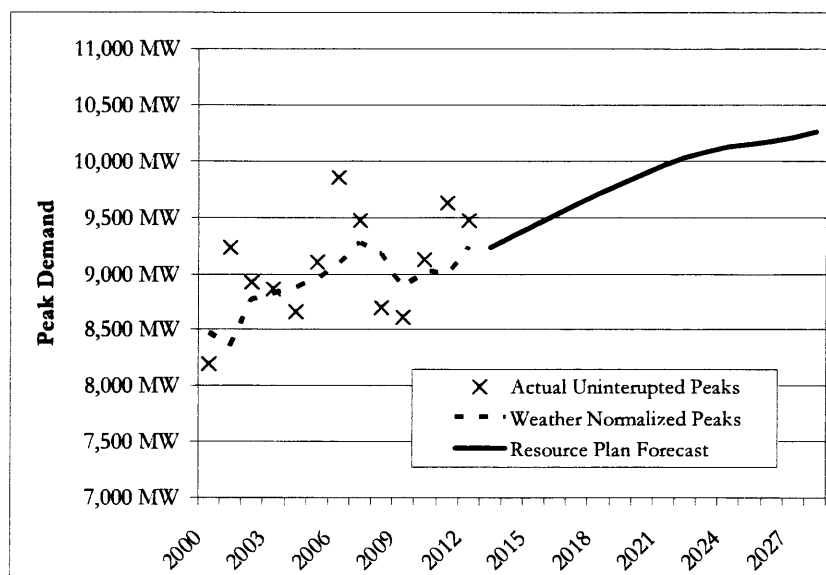
The Fall 2011 Forecast (augmented with information through our Spring 2013 forecast) was the most up-to-date information available when the Company began the regulatory approval processes in North Dakota and Minnesota for the selection of appropriate resources to meet the identified need. This is the forecast underlying our analysis in the Gas CT Case, and we advised that it was prudent to plan to meet the

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

identified need in the Fall 2011 Forecast because “this ensures adequate generating capacity under all reasonable circumstances,” while also pointing out that “[a]t the same time, our proposal provides flexibility to adjust the timing of the CT generator additions.”⁷ While subsequent forecasts have indicated a lower need in 2017-2019, we concluded it was appropriate to rely upon the Fall 2011 Forecast in our analysis and subsequent applications to provide consistency through the many reviews of our resource selections.

Figure 1 provides the Fall 2011 Forecast’s peak demands. As shown in Figure 1, from 2013 through 2020, the average rate of growth in our peak demand forecast is 1.0 percent.

**Figure 1:
NSP Historic and Forecasted Peak Demand**

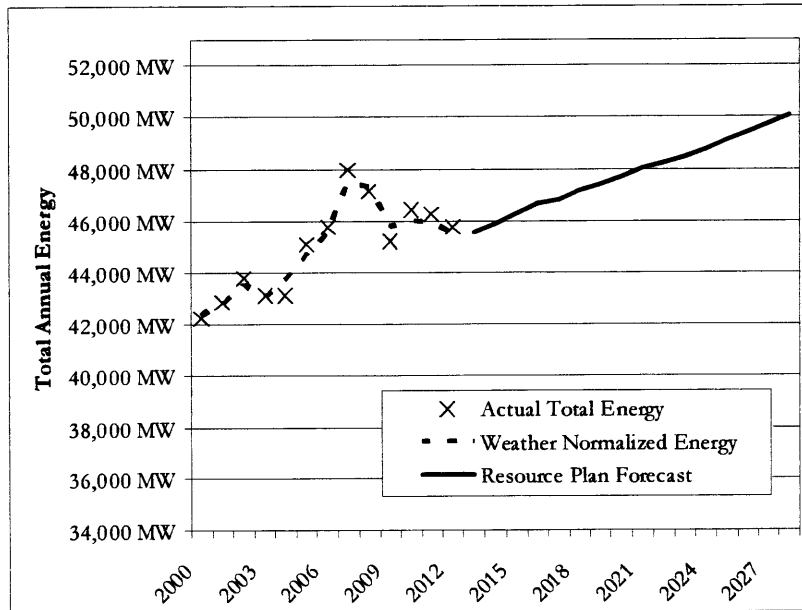


Our total annual energy forecast is shown in Figure 2. The Fall 2011 Forecast assumed an average growth rate from 2013 to 2020 of 0.7 percent.

⁷ Gas CT ADP at 18.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

**Figure 2:
NSP Historic and Forecasts Total Annual Energy**



Our Fall 2011 Forecast also took into consideration the reserve margin calculations specified by Midcontinent Independent System Operator, Inc., (MISO) using the criteria applicable at the time. MISO calculates the reserve margin percentage based on loss of load expectation (LOLE) studies that calculate how high the reserve margin must be to ensure that load will not have to be curtailed any more often than once in every 10 years. Comparing the load forecast plus reserve margin to the capacity ratings of Xcel Energy-owned resources plus purchased power, our system's forecasted capacity need is around 500 MW by 2019-2020 as shown in Table 1 below.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

**Table 1:
System Capacity Need
(Fall 2011 Forecast)**

	2015	2016	2017	2018	2019	2020
Peak Forecast	9,428	9,524	9,613	9,708	9,799	9,881
<u>x 1+RM%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>
= Total Obligation	9,786	9,885	9,977	10,076	10,170	10,255
<u>Resources</u>	2015	2016	2017	2018	2019	2020
Coal	2,331	2,331	2,331	2,331	2,331	2,331
Nuclear	1,610	1,610	1,610	1,610	1,610	1,610
Gas	3,476	3,534	3,437	3,424	3,424	3,424
Renewable	1,288	1,289	1,287	1,238	1,212	1,213
Other	92	-	-	-	-	-
<u>Load Management*</u>	<u>1,145</u>	<u>1,153</u>	<u>1,157</u>	<u>1,153</u>	<u>1,149</u>	<u>1,145</u>
Total	9,943	9,917	9,823	9,757	9,727	9,724
Long (Short)	157	32	(154)	(319)	(443)	(532)

* Includes reserves

Our Fall 2011 forecast identified a capacity need of 154 MW in 2017, growing to 532 MW in 2020.

2. Subsequent Forecast Updates

Since developing our Fall 2011 Forecast, we have updated our demand forecast several times: in the Spring of 2012, in the Fall of 2012, in the Spring of 2013, and in 2014 as depicted in Figure 3 below. As described in Mr. Haeger's Direct Testimony, this is a normal part of planning, but as a result, it is necessary to decide which forecast is the most prudent to use to make a resource addition to avoid the risk that "analysis paralysis" prevents the Company from timely meeting need as it materializes.

Most recently, the Company prepared a new forecast to support our recently-filed 2015 Resource Plan.⁸ The most recent forecast suggests weakening demand and the possibility that the Company will not need to add additional capacity to its system until approximately 2024. This suggests the Company could delay adding resources to

⁸ Case No. PU-15-019.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

its system at this time. However, in light of the various reviews and applications of our Fall 2011 Forecast with respect to resource options and related timing, we are not relying on the forecast in the 2015 Resource Plan filing to support the need in this case.

B. Forecast Uncertainty

As described in greater detail in Mr. Haeger's Direct Testimony, peak demand forecasts are dependent on underlying assumptions regarding economic growth. If the assumptions change, the forecast will change. And if actual circumstances do not match the assumptions used, actual results will be different than the forecast results.

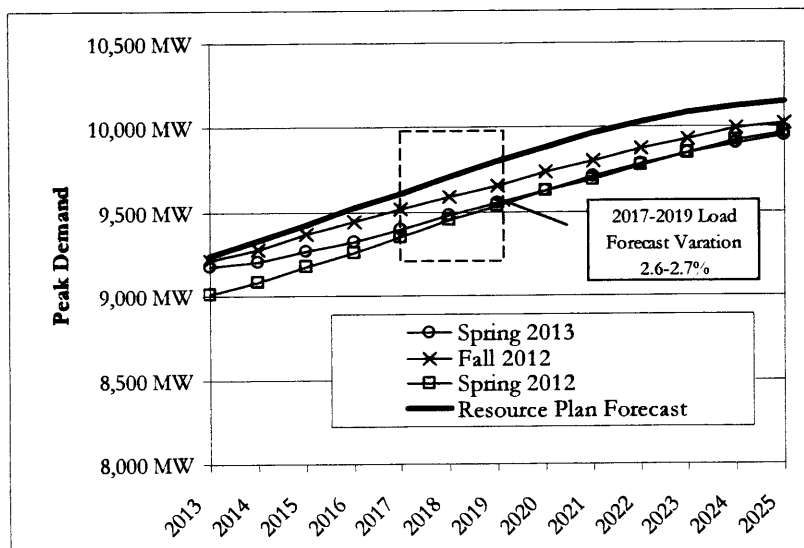
These assumptions can change dramatically with the ups and downs of the economy. It has been difficult to predict what kind of economic conditions will result from the uneven recovery across the region from the 2008 recession. And it continues to be difficult to predict what impact current circumstances, such as the recent drop in oil prices, may have on our load growth. The Company's varying forecasts over the course of its resource planning process supports taking a conservative approach to ensure sufficient available generation to serve our customers' requirements under all reasonable circumstances.

Relatively small changes in economic growth rate assumptions can have a significant impact on the amount of needed resources. With a nearly 10,000 MW integrated system, a demand forecast change of only a few percent result in estimates varying by several hundred MWs. The variation in our load forecast occurs within a relatively tight range, however, and the amount of the variation is relatively small in the context of our total system peak demand.

As noted above, since the Fall of 2011 when our last resource plan analysis was completed, the Company has updated its forecast several times. The total variation in forecasts has been about 250 MW, or 2.6 percent, in the 2017–2019 timeframe. Figure 3 shows the peak demand forecast changes.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

**Figure 3:
Variation in Peak Demand Forecasts**

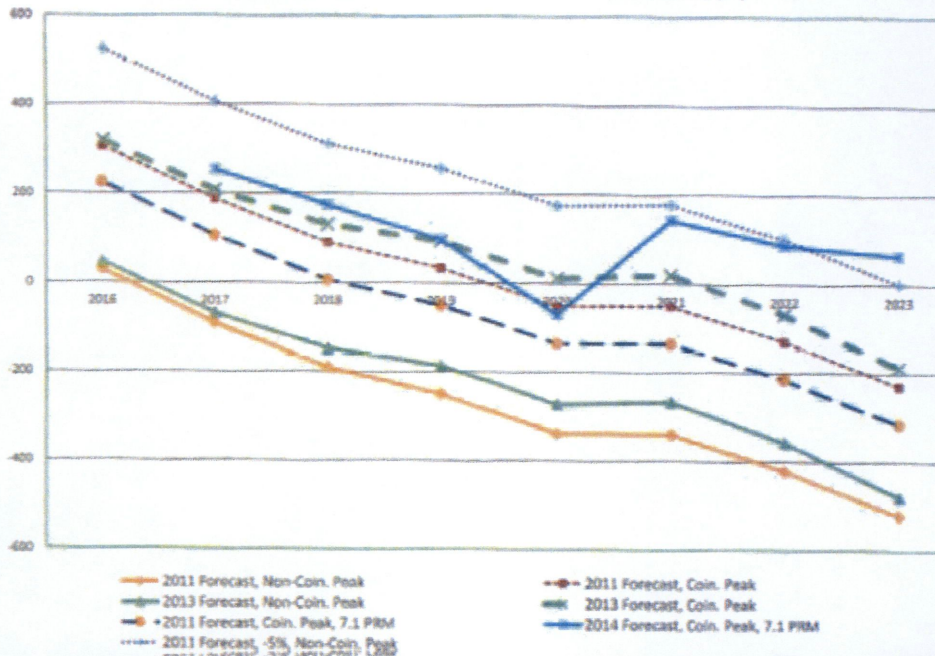


These relatively small variations in our forecasts are primarily a reflection of the inherent uncertainty in forecasting, and we do not believe there is currently any indication of a definitive change in the future peak demand of our customers.

Figure 4 below, which includes a series of recent demand forecasts arising during our 2010 Resource Plan proceedings, illustrates the forecasting uncertainty and the potential that very small changes could result in a material swing in the required amount of capacity.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

**Figure 4:
Impact of Coincident and Non-Coincident Peak Methodologies on
Resource Plan Need Forecasts**



Source: Department of Commerce, Docket No. E002/CN-12-1240 (Dec. 10, 2014)

C. Implications of Forecast Variability

Xcel Energy generally takes a conservative approach to evaluating resource needs to ensure the Company has adequate resources to satisfy our obligation to serve under all reasonable circumstances. Forecast demand fluctuates over time, and sometimes significantly, based on small changes in economic indicators. Because resource decisions are made in the midst of this type of fluctuation, we must balance the cost of new generation against the risk of falling short or exposing our customers to too much market risk. In reaching that balance, we believe it is appropriate to plan for a range of outcomes. While this may sometimes mean that available capacity will exceed the identified need for a short period of time, this is preferable to incurring a shortfall of capacity. Further, this conservative planning approach insulates our customers from over-reliance on the MISO market due to routine variations in the availability of system resources.

The variability in our forecasts since the Fall 2011 Forecast, which established our baseline resource need, indicates that the NSP System could be in deficit between 2017 and 2024. Even our current forecast (used in the 2015 Resource Plan) shows

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

that our capacity position in 2019 and 2020 is very near a deficit and any uptick in demand would put us in the position of needing to acquire market capacity.

The variability in our forecasts also indicates some uncertainty with respect to the size and timing of our capacity need. Consequently, the question is not if but when to make resource additions, and of what size and type. Answering these questions must also take into account known changes to our system in the out-years of our planning horizon to ensure we have sufficient capacity to address retiring generation, expiring PPAs, and other known issues that will affect our generation fleet.

While delaying making any resource decision until the actual timing and size of a capacity need is certain would limit the rate impacts of adding resources to our system, the drawback of this course of action is that it could require us to make the ultimate decision to add resources very near to the time they are needed. This could limit the opportunity to examine different options, since the urgency to meet an imminent capacity deficit will likely outweigh cost considerations in deciding which resource to select. Thus, we could be price takers in the marketplace as a result of the decision to add resources being made close to the timing of the need. Delaying a decision for more certainty may even put us in a position where we cannot construct the needed resources in time to meet the need. This could lead to us being short on capacity and subject us to uncertain and volatile short term capacity market prices to obtain the significant amounts of capacity necessary to meet the needs of the large, integrated NSP System.

Another course of action is to act conservatively in the face of uncertainty and make resource additions as a need is forecasted and have those additions be of a size and type to address the need in a way that also positions us well for the future. This approach is premised on the assumption that it is better for a utility to be long than short on capacity, since the utility has the obligation to serve all of its customers' needs under all reasonable circumstances and must have resources available to meet those needs. The benefits to this approach are that it provides the time needed to make resource decisions through the use of competitive processes to help bring down the cost of these resources. Additionally, it avoids exposing the Company - and ultimately customers - to short-term capacity markets and the price uncertainty inherent with such markets. The drawbacks to this approach are that it could lead to a system that is overbuilt in the short term, with the consonant cost impacts to customers.

We recognize that these two paths sit on opposite ends of the resource planning spectrum and that the most prudent approach to adding capacity to the NSP System

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

lies somewhere in the middle. Mr. Haeger provides additional discussion in his Direct Testimony with respect to balancing uncertainty and reliability. This ADP Application presents the difficult question of where along this spectrum is the appropriate point at which to make a resource decision. We believe our Application demonstrates the prudence of making resource additions now in spite of forecast uncertainty, which includes a recent forecast update that shows a slacking of demand.

VI. RESOURCE SELECTION PROCESSES

The Company, along with its affiliate Northern States Power Company, a Wisconsin corporation, jointly plan for and operate the integrated NSP System. The NSP System serves over 1.8 million retail electric customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. Because customers in these five states are served by the same system, we have been able to achieve significant economies of scale that provide benefits to all of our customers in all of the states we serve. We have been able successfully planning for and managing the integrated NSP System to meet all of our customers' needs for almost 100 years.

Each of the States in which we provide electric service has different regulatory constructs and oversight regimes. Two of the States in which we provide service – North Dakota and Minnesota – require a form of preapproval for the resources we select. The other states we serve generally determine the prudence of a resource addition when we seek to include those costs in rates through a rate case.⁹ This Application is a result of the input provided by the Commission and MPUC through their respective pre-approval processes.

A. Applicable Preapproval Processes

We provide a brief description of the relevant pre-approval processes that resulted in this Application. Ms. McCarten provides further discussion of these processes in her Direct Testimony.

⁹ Resource review in South Dakota is handled through a prudence review when the utility files a rate case that proposes adding the resource to rate base. In Wisconsin and Michigan, the addition of new resources is subject to FERC-filed interchange agreements that the Xcel Energy operating companies in those States have with the Company.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

1. North Dakota ADP Process

In North Dakota, when the Company seeks to acquire a resource for our system it will file an ADP Application to obtain the Commission's approval before the acquisition is made.¹⁰

In the Settlement Agreement of our 2007 North Dakota rate case,¹¹ the Company agreed to a series of process changes that, among other things, requires Xcel Energy to apply for an ADP from the Commission for any resource addition to the NSP System of 50 MW and larger. Prior to this time, the Company had no obligation in North Dakota to seek pre-approval of its resource additions. And, before the ADP process became law, the prudence of the Company's resource additions was subject to an after-the-fact prudence review in a rate case or a Fuel Cost Recovery (FCR) proceeding.

Our ADP filing obligation for larger additions was further refined in Case No. PU-12-59 to address Commission concerns about the timing of ADP filings. In that case we committed to coordinating our ADP applications with the timing of the Minnesota process. In Case No. PU-12-813, our most recent rate case, we again refined our ADP obligations through a settlement that provides that the Company may not recover the costs of any PPAs through the FCR rider without an ADP being granted by the Commission for any resource addition over 50 MW.¹²

Taken together, the Company views these obligations as creating a required resource pre-approval process in North Dakota that (i) defines the timing requirements for filing for Commission approval, and (ii) results in a Commission prudence determination that is binding for the resource as if it were reviewed in a rate case.

¹⁰ In her Direct Testimony accompanying this Application, Ms. McCarten discusses in more detail the history of the Company's obligations and practices with respect to seeking Commission approval for the addition of resources to the NSP System.

¹¹ Case No. PU-07-776.

¹² The Company notes that the Calpine Project PPA is structured in such a way that the Company makes separate payments for both capacity and energy. As a result, this PPA will be somewhat different than other recent PPAs we have brought to the Commission. Traditionally, capacity payments are included in base rates as part of a rate case and the energy payments would be included in our FCR calculations. As described in Ms. McCarten's Direct Testimony, if this rate treatment is implemented, any base rate impact will occur in 2018 or 2019, which is after the expiration of the rate plan that was agreed to as part of our last rate case.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

2. Minnesota CAP Process

In Minnesota, resource acquisitions are reviewed in a two-step process. First, resource needs are determined through Minnesota's resource planning proceedings before the MPUC.¹³ Second, the Company initiates a MPUC-designed acquisition process to obtain approval of adding the resource to meet the need.

Pursuant to Minn. Stat. § 216B.2422, subd. 5, the MPUC is empowered to establish a competitive bidding process under which a utility acquires a resource to meet a need identified in the resource planning process. Xcel Energy is subject to the MPUC's competitive process.¹⁴ The competitive bidding process that the MPUC has established for Xcel Energy is composed of two separate methodologies: "Track 1" and "Track 2."

The "Track 1" process is used in the circumstance where Xcel Energy is not seeking to construct the resource itself. That process provides that we use a competitive Request for Proposals (RFP) process. This is intended to ensure that the Company probes the market for the most cost-effective and appropriate proposals available. Since its implementation, the Track 1 process has been the primary method we have used to procure new resources, and we have entered into numerous PPAs with third-party vendors for generation selected through RFPs.

The "Track 2" process applies when the Company seeks to meet its identified resource need with a Company-owned, self-build project. The Track 2 process involves soliciting and evaluating alternative competitive proposals to the resource proposed by the Company. This is intended to ensure that the Company probes the market for resource proposals from independent power producers that may be more cost effective than the Company's self-build proposal.¹⁵

The Track 2 CAP consists of the following steps:

¹³ Minn. Stat. § 216B.2422. Resource review in South Dakota is handled through a prudence review when the utility files a rate case that proposes adding the resource to rate base.

¹⁴ *In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2004 Resource Plan*, Docket No. E002/RP-0-1752, ORDER ESTABLISHING RESOURCE ACQUISITION PROCESS, ESTABLISHING BIDDING PROCESS UNDER MINN. STAT. § 216B.2422, SUBD. 5, AND REQUIRING COMPLIANCE FILING at 6-7 (May 31, 2006) (2006 CAP Order).

¹⁵ While the Track 2 process for a self-build resource proposal by the Company has been in place since the Commission's 2006 CAP Order, the process has not been used prior to the current CAP Docket. The Company therefore had no previous experience with the complexities of selecting a resource pursuant to the Track 2 process before the current CAP docket was initiated by the MPUC.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

- The MPUC identifies the resource need to be addressed in the competitive acquisition process through its resource planning order, which establishes parameters around size, type and timing;
- The Company submits its proposal with the information required in Minnesota rules and statutes governing certificate of need applications;
- On the same date the Company files its proposal, interested competitors provide their proposals in similar certificate-of-need-like detail, including proposed contract terms;
- After the MPUC determines that the proposal filings are adequate, a contested case is conducted before an administrative law judge. At the end of the hearing process the administrative law judge provides findings and recommendations to the MPUC;
- The MPUC considers the developed record, issues its resource selection, and grants any associated certificates of need; and
- In the event the MPUC selects a power provider proposal rather than the Company's self-build proposal, the Company and selected power provider have four months to negotiate a PPA and bring it back to the Commission for approval.

B. Outcomes of the North Dakota and Minnesota Approval Processes

We provide a brief description of the outcomes of the pre-approval processes that resulted in this Application. Mr. Haeger provides a further discussion of the results of the Minnesota process with respect to the Calpine Project PPA, the Geronimo PPA, and Black Dog Unit 6 in his Direct Testimony.

1. North Dakota

In the Gas CT Case, the Company sought an ADP from the Commission for our proposal to meet a capacity need of 150-500 MW by adding Black Dog Unit 6 and Red River Valley Units 1 and 2 to our system. As we described in our in our Gas CT ADP, the Company was simultaneously seeking approval from the MPUC for Black Dog Unit 6 and the Red River Valley Units under the CAP proceedings, which Xcel Energy was required to do under the Minnesota Track 2 process. We made our application at that time consistent with our commitment in Case No. PU-12-59 that we would apply for an ADP from the Commission at the same time we sought approval for a resource from the MPUC.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

In the course of the Commission's consideration of whether to grant our ADP request, we explained that whether or when the Black Dog and Red River Valley Units might be constructed was not clear due to potential fluctuations in forecast demand, and to the Minnesota Track 2 process which might identify other competitive proposals from independent power producers as more appropriate than our proposed units.

After discovery and a hearing before the Commission, a settlement was reached between the Company and Advocacy Staff that the Commission adopted. The settlement summarizes the substantive and procedural factors that led to the Commission granting ADPs for Black Dog Unit 6 and the Red River Valley Units:

As part of the Gas CT Cases, the Company proposed to construct two gas combustion turbines (CT) near Hankinson, North Dakota known as Red River Valley Unit 1 and Red River Valley Unit 2 to meet an identified capacity resource need in the 2017-2019 time frame. The record in the Gas CT Cases also reflects the fact that the Company may choose some alternative resource to meet that need instead of one or both of the proposed North Dakota based CTs. In light of the record in the Gas Cases, the Parties acknowledge that the Gas Cases identified the interest of the Commission in ensuring that the Company develops generation closer to its loads in North Dakota. The Parties further acknowledge that the record in the Gas CT Cases reflects the fact that diversifying the location of the Company's generation mix and locating generation closer to the Company's North Dakota loads provides some benefits to the Company's North Dakota customers as well as all of the other customers served by the Company.

In recognition of the fact that the Company's proposal to construct and own North Dakota based generation to meet its 2017-2019 resource need may not be implemented, but to obtain the benefits of North Dakota based generation identified in the Gas CT Cases, the Company hereby commits to develop up to 400 MW of thermal generation resources in North Dakota no later than 2036, consistent with the principles of orderly development of resources, the principle of least-cost development as provided in N.D. Admin. Code § 69-09-02-33, and general concepts of prudent resource planning to meet incremental additional resource needs that may arise in that time frame. In furtherance of the foregoing sentence, and not in limitation thereof, development of North Dakota based generation must be cost effective taking into account the benefits of locating generation nearer to North

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

Dakota loads and the benefits of geographic diversity of generation when compared to other alternatives.¹⁶

2. Minnesota

The Company's proposal to build Black Dog Unit 6 and the Red River Valley Units to meet its capacity need triggered the Track 2 process used in the MPUC's CAP docket. Proposals from Calpine, Invenergy, Geronimo Energy, and Great River Energy were also submitted in the CAP docket to compete with the Company's Gas CT proposals.

The MPUC selected three capacity resources to meet the up to 500 MW of capacity need identified in our Fall 2011 Forecast:

Resource (Nameplate Capacity)	Accredited Capacity	In-Service Date	Technology
Geronimo Solar Project (up to 100 MW)	Up to 71 MW	2016	Distributed Solar
Calpine Project (345 MW)	278 MW	2018 or 2019	Combined-Cycle Thermal
Black Dog Unit 6 (215 MW)	207 MW	2019	Combustion Turbine Thermal

In its May 23, 2014 Order explaining its resource selections, the MPUC focused on the importance of ensuring that adequate capacity is in place for the Company to meet all of its customers' requirements. Recognizing that the record contained a variety of forecasts and predictions of evolving MISO capacity requirements the Company must meet, the MPUC concluded that the resulting uncertainty warranted selecting resources that delivered enough capacity to avoid a potential shortfall in its ability to meet customer demand. The MPUC determined in these circumstances it was most appropriate to rely upon the Fall 2011 Forecast that had been fully analyzed in the resource planning proceeding, which showed the Company needed up to 500 MW of new capacity by 2019.¹⁷

¹⁶ Revised Second Amended Comprehensive Settlement, Section II.B (pages 17-18, emphasis added), which is attached to the Commission's Order Adopting Settlement granting the ADPs sought in the Gas CT Case.

¹⁷ The MPUC also noted that various laws and policies that influence resource planning further supported its finding that we should add generation to our system in the 2017-19 timeframe. These policies include state and federal environmental requirements, Minnesota's solar and wind energy requirements, and MISO's reserve margin requirements.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

The MPUC found that Geronimo's distributed solar generation proposal not only met a portion of the Company's capacity need, but had the added benefit of promoting beneficial environmental and socioeconomic policies set forth in state statute. The Commission also concluded that the record clearly demonstrated that Black Dog Unit 6, Calpine's proposed combined cycle unit, and Invenergy's proposed combustion turbine unit had comparable merits, and that one or more of these three proposed gas units was needed to meet the Company's capacity need. The MPUC ordered the Company to refine its estimate of the costs for Black Dog Unit 6, and negotiate PPAs for both the Calpine and Invenergy projects, so that the Commission could then determine which of these resources should be selected to meet the Company's need. Based on its review of the PPAs the Company negotiated with Calpine and Invenergy, the MPUC selected Black Dog Unit 6 and the Calpine Project PPA to meet our need.

In its February 5, 2015 CAP Order, the MPUC reaffirmed these selections and approved the Calpine Project PPA. It also ordered the Company to execute the Calpine Project PPA that is being considered in a separate Case.

C. Implications of North Dakota and Minnesota Outcomes

The North Dakota and Minnesota pre-approval processes have resulted in divergent outcomes that require the Company to make difficult choices as to its next steps.

- The North Dakota process resulted in Commission approval of the Company's proposal to add three gas CTs (about 620 MW accredited capacity) to our system, with the flexibility to implement that proposal consistent with our need materializing.
- The Minnesota process resulted in a selection of only one of our proposed gas CTs in combination with the Calpine Project's combined-cycle capacity and the Geronimo Solar Project (about 556 MW accredited capacity), which provides different types of benefits to our system given a conservative assessment of our need.

While the two States' processes result in around 600 MWs of new capacity, the profile and potential timing of the added generation differs. The benefits of the Calpine Project PPA are such that we respectfully request that the Commission conclude that it is a prudent resource selection. The Company believes that adding this resource to the integrated system provides a prudent path forward in light of forecast variability; the need for flexibility in responding to upcoming retirements of intermediate and baseload resources from our system; the significant uncertainty of the impacts of potential environmental regulations on our generation fleet; the overall cost of

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

acquiring new resources in the future; evolving market conditions; and our commitment to construct up to 400 MW of thermal generation near our eastern North Dakota loads by 2036 to increase reliability in the region.

We recognize, however, that the Commission may disagree with our concurrence with the MPUC's policy choice to conservatively assess our need, and with its selection of resource additions based on this conservative assessment and Minnesota energy policies. The Commission may determine that the decision to avoid the risk of a shortfall due to the inherent uncertainty in forecasting demand is not a choice that comports with its least-cost resource planning approach.

As the Commission knows, the Restack is being developed to address just such a situation. At a high-level, adding a resource to the Restack will ensure that the Company's North Dakota customers pay a reasonable cost for the used and useful capacity and energy of any resource addition that the Company makes. As the Commission is aware, we are currently negotiating a Restack agreement with Staff consistent with the Settlement Agreement in Case No. PU-12-813. Should the Commission not deem the Calpine Project PPA prudent, we believe that this resource could be included in that agreement. Of course, the drawback of such an approach is that the Company is unable to recover its full cost of the resource. Mr. Haeger discusses in his Direct Testimony the implications of Commission denial of an ADP for this resource on our Restack efforts.

VII. CALPINE PROJECT PPA

This section provides information on the Calpine Project and the terms of the PPA with the Company. We provide the Calpine Project PPA as Trade Secret Exhibit___(KJH-1), Schedule 2 , and discuss its terms below.

A. General Description

The Mankato Energy Center is located in Mankato, Minnesota. Calpine's 345 MW combined cycle unit will add approximately 278 MW of accredited capacity to the existing 375 MW (nameplate) Mankato Energy Center. The new CC unit will be located on the same site and incorporated into the existing footprint of Mankato Energy Center's existing CC unit.

Calpine's affiliate and the Company entered into a 20-year PPA with a kW-month price for capacity and MWh price for energy. The proposed capacity and energy

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

prices escalate annually after the first year of operation. We anticipate that the new CC will achieve commercial operation in 2018 or 2019.

The payment and other terms in the PPA generally mirror the same terms in the Company's existing Mankato Energy Center PPA with Calpine. By using the existing Mankato Energy Center PPA payment provisions in the new Calpine Project PPA, the administrative burden associated with using two different payment calculations and billing processes for the two PPAs was avoided. It also avoids the risk that unforeseen differences in the payments made and received under different calculation formulas for the two PPAs could have unintended consequences on how the parties choose to schedule, operate, and properly calculate payments for each facility.

We expect that, unless this resource addition is subject to the Restack, we would seek to include the capacity costs of the Calpine Project PPA in base rates in the appropriate rate case, and collect the energy costs of the PPA through our FCR rider.

B. Risk Allocation

The new Calpine Project PPA addresses risks in the following areas:

Potential for Delay/Termination. The Company negotiated options to delay or terminate its PPA in the event future circumstances warrant exercising the options. The Company may delay the facility's COD from 2018 to 2019 subject to the increased capacity and energy prices associated with the new COD, and must also pay for Calpine's demobilization and re-mobilization costs. The Company may also terminate the PPA, paying Calpine for its unrecovered costs, as well as a breakage fee in addition to the unrecovered costs. Total termination fees could be substantial as shown in Trade Secret Exhibit___(KJH-1), Schedule 2.

Transmission Interconnection Costs. The PPA reflects Calpine's proposal that the Company pay for all transmission costs to interconnect the Calpine Project to the grid. Calpine estimated that these costs could run from \$650,000 to \$1.5 million, and the Company has agreed to accept the risk of such costs.

Capacity Accreditation Risk. It appears there are transmission network upgrades that must be made before MISO can accredit the expansion capacity as a Capacity Resource available to the Company, and the completion schedule for these upgrades is beyond Calpine's control. The Company agreed to Calpine's proposal that it may elect to delay COD by one year upon timely notice to the Company that Calpine cannot achieve accreditation by COD. This allows the Company to obtain the

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

capacity credit it needs for the year the PPA is delayed from another source, although the cost of the capacity credit will be subject to the prevailing market conditions. Absent such timely notice, Calpine must achieve accreditation by COD, and failure to do so is an Event of Default subject to specific cure provisions designed to keep the Company whole in all events.

Environmental Risk. Calpine proposed that the Company be liable for all costs resulting from future regulation of all types of emissions. The Company strongly objected to its customers incurring these unknowable costs, and Calpine accepted the Company's position that it will only accept conditional risks from the regulation of carbon emissions, consistent with the carbon emissions provision in the Company's model PPA form used to guide negotiations.

Financial Risk. The Calpine Project PPA establishes a pre-COD and post-COD security fund to protect the Company generally from the range of financial risks associated with the PPA. The Company also negotiated a provision requiring Calpine to obtain a subordinated mortgage on the facility upon its completion for the benefit of the Company.

Construction/Operational Risk. The Company negotiated the payment of liquidated damages for each day that Calpine fails to meet COD for the new CC unit due to reasons other than its failure to achieve MISO accreditation of the unit as a Capacity Resource. In addition, the PPA includes other protective measures such as specific performance, step-in rights, actual damages, and termination. The Company also accepted Calpine's proposal that it be allowed to provide energy from an alternative generation source post COD in the event more than 50 MW of the capacity of the new CC unit becomes unavailable due to a forced outage. This holds the Company harmless from a shortfall in meeting its energy needs in the face of a significant outage of the unit

Adding the expansion capacity to the NSP System in June 2018 would result in the addition of approximately [TRADE SECRET BEGINS TRADE SECRET ENDS] of revenue requirements in 2018 and [TRADE SECRET BEGINS TRADE SECRET ENDS] in 2019.

C. Conditions Precedent

The Calpine Project PPA contains a number of conditions to the parties' performance under the contract. These conditions precedent are important to ensure that the parties appropriately manage their risks and implementation. There are certain risks

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

that are beyond a party's reasonable control and which must be addressed for the project to go forward. Such risks include obtaining required governmental permits and approvals, obtaining required third-party contracts that are necessary for the project to be completed, and obtaining internal approvals of regulatory revisions of the PPA's terms. The PPA provides a mechanism for terminating the PPA if a required condition precedent fails to be obtained.

Calpine must satisfy a number of conditions in order to be obligated to perform under the PPA. These conditions include obtaining an air permit, a site permit and interconnection agreement, and approval of the final PPA by the Calpine Board of Directors after all regulatory approvals have been received, all by specified dates. In the Company's experience, these conditions and the timelines for their completion are typical of the conditions we would expect.

The Company has one important condition precedent. The Company must obtain timely approval of the PPA from this Commission. The Company's obligation is to seek an approval order from the Commission no later than 15 business days after the execution of the PPA, or the Company shall be deemed to have waived its right to seek such approval. The PPA provides that the Company may terminate the PPA if it has not received the requested approval from the Commission by April 1, 2015, but can delay the April 1 deadline to July 1, 2015 with the consequence that the PPA's commercial operation date is delayed until 2019.¹⁸

VIII. PRUDENCE OF THE CALPINE PROJECT PPA

The Company respectfully requests that the Commission find our proposed purchase of the 345 MW Calpine Project PPA to be prudent under the circumstances. The PPA (i) provides capacity that meets our identified need; (ii) is reasonably priced for the benefits provided; and (iii) provides qualitative benefits with respect to anticipated environmental regulation and the retirement of existing baseload and intermediate generation at the end of our current planning period that are not provided by a simple-cycle combustion turbine.

A. Calpine Project PPA Meets Capacity Need

Xcel Energy acknowledges that our recent 2015 Resource Plan filing shows a modest capacity surplus in the 2017-2019 timeframe. Nevertheless, we believe the selection

¹⁸ Trade Secret Attachment A, Calpine Project PPA at Section 6.1.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

of this resource at this time is prudent and in the best interest of all of our customers on our integrated system.

As described above, even small changes in forecast demand can have a significant result on our supply requirements. If forecast demand changes by even one or two percent, it could wipe out any excess capacity and expose us to the MISO capacity market at a time when a number of baseload capacity resources are being retired, raising the potential for higher prices or even a capacity shortfall.

The Company's current supply portfolio shows a modest amount of excess capacity (between 1 and 2.5%) from 2015 through 2018 and virtually no excess capacity on a system-wide basis in 2019 and 2020. In 2021, the system then regains a small amount of excess capacity by increasing our current Manitoba Hydro purchase with anticipated new capacity that is under development. In 2024, however, we again show a system deficit of 234 MW. This load balance profile suggests that we are at risk of capacity deficits beginning in 2019 and 2020 if our projected loads change by even a very small amount. Indeed, even the 0.5 to 2.5 percent excess capacity shown on our assumed supply portfolio is modest given that normal forecast variability can result in demand swings of 200 MW (2 percent) or more.

The 2015 Resource Plan data suggests that we are at risk of capacity shortfalls (both on a system-wide and North Dakota allocated share basis) in 2019-2020 due to small changes in customer loads. The normal variability we have experienced between load projections and actual results in recent years indicates it is appropriate to acquire additional generation as a hedge. While we recognize that we could potentially purchase short-term capacity from the MISO voluntary capacity market at then-prevailing rates for any capacity shortfall, we must also consider that existing and proposed retirements of baseload units in the MISO footprint may result in a shortfall of capacity across the footprint leading to higher capacity prices in the MISO voluntary short-term capacity market. Prudent planning includes balancing the risk of exposure to the capacity market in the next five years against the cost of building additional capacity in the 2019/2020 time-frame, which will be necessary by 2024 in any event.

We also included a scenario in our 2015 Resource Plan analysis which reflects all of our currently contemplated resources. This includes: (1) the 98 MW creditable capacity (187 MW nameplate) of the solar portfolio which is the subject of Case No. PU-14-810; (2) the 278 MW creditable capacity (345 MW nameplate) of the Calpine Project PPA; (3) the up-to 71 MW creditable capacity (100 MW nameplate) of the Geronimo Solar PPA; (4) the 207 creditable capacity of the Black Dog 6

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

combustion turbine unit (215 MW nameplate); (5) a new short-term (four-year) 75 MW capacity exchange with Manitoba Hydro; and (6) additional resources contemplated in our 2015 Resource Plan.¹⁹ If all of this contemplated new generation is deployed, it will result in a system surplus in the 2019-2020 timeframe of about 6 to 7 percent (550 MW in 2019 and 685 MW in 2020) and address our resource need in 2024.

The following Table 2 provides a summary of the analysis on a system-wide basis:

**Table 2:
System Capacity Forecast (MW)
(2014 Forecast)**

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Long/(Short) (existing system)	177	142	242	91	8	0	231	182	163	(234)
Resources Approved by the MPUC	-	-	-	71 ³	278 ⁴ 71 ³	207 ⁵ 278 ⁴ 71 ³	556 ⁶	556 ⁶	556 ⁶	556 ⁶
Proposed Additional Resources	-	73 ¹	73 ¹	98 ² 73 ¹	98 ² 73 ¹	98 ²	98 ²	98 ²	98 ²	98 ²
Resources in the 2016 IRP Preferred Plan	-	-	-	-	-	-	89	89	118	171
Aggregate Additional Resources	-	73	73	243	551	684	773	773	803	855
Long/(Short) Position (assumes all additions)	177	216	315	334	529	685	1,004	956	965	621
Notes	1- Manitoba Hydro 75 MW additional capacity exchange (four years). 2- 187 MW Solar portfolio (98 MW accreditation) 3- Geronimo Solar Project PPA (2016 in-service; 2018 MISO accreditation) 4- Calpine Project PPA 5- Black Dog Unit 6 6- Geronimo PPA + Calpine Project PPA + Black Dog Unit 6									

We prepared a similar analysis showing the same information on a North Dakota load-allocated basis. The following Table 3 provides the output of that analysis:

¹⁹ Please note, we expect to file for approval for the Manitoba Hydro contract from the Commission in the next several months. Because it is a short-term purchase, approval by the MPUC is not required.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

**Table 3:
North Dakota Allocated System Capacity Forecast (MW)
(2014 Forecast)**

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ND as a Percentage of NSP System	4.94	4.99	5.01	5.05	5.08	5.13	5.19	5.22	5.34	5.38
Long/(Short) (existing system)	9	7	7	5	0	0	12	10	9	(13)
ND Allocation of Additional Resources	-	4	4	12	28	35	40	40	43	46
Long/(Short) (assumes all additions)	9	11	11	17	28	35	52	50	52	33

This shows that on a North Dakota allocated basis, there is no excess capacity in 2019 and 2020. While the number increases again in 2021 due to the addition of new capacity from Manitoba Hydro, it is appropriate to plan the system to include additional capacity that addresses the 2019 and 2020 ‘pinch point’ and remains available in 2024 when we begin to experience forecasted capacity deficits.

B. Analysis of Costs and Customer Impacts of Calpine Project PPA

1. Strategist Analysis of Resource Proposals Submitted in CAP Docket

To ensure that sufficient resources were evaluated to cover the high end of potential capacity needs identified in our Fall 2011 Forecast and adopted by the MPUC, the Company modeled portfolios consisting of different combinations of the resource proposals submitted in the CAP docket that ranged from 358 MW to 636 MW.²⁰ The Company’s proposal was to add a single CT unit at its Black Dog plant in 2017, 2018, or 2019, and two CT units at a new Red River Valley plant site near Hankinson, North Dakota in 2018 and 2019.²¹

The Company examined the cost effectiveness of peaking and intermediate natural gas generation in developing our proposal. The peaking resources were modeled as dispatchable units with heat rate curves that reflect the units' efficiency at various generation levels. Each unit's maximum capacity was modeled as approximately 230

²⁰ Gas CT Case, Alders Supp. Testimony, Schedule 2 (Wishart Direct) at 10-11.

²¹ Gas CT ADP at 2.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

MW in the winter and 215 MW in the summer. The fuel costs were based on the forecasted costs of natural gas at the Ventura hub, with transportation cost adders included to reflect the expected cost at each of the sites. A scenario to reflect a large natural gas, combined-cycle unit was also run through the Strategist model. Natural gas, combined -cycle generators have higher capital expenditures for construction, but are more fuel efficient when generating.

Based on our Strategist modeling, the Company determined Black Dog Unit 6 was the most cost-effective option as evidenced by the fact that it is included in each of the top 20 resource plans identified in the Company's Strategist analysis.²² We recognize that the Minnesota analysis includes consideration of societal costs that are not considered in the Commission's analysis. The most cost-effective plans identified by Strategist consisted of combinations that included Black Dog Unit 6 being deployed in conjunction with either the Calpine Project or the Invenergy Cannon Falls project.²³ Our modeling did not conclude that the Geronimo Solar Project was a least-cost resource.

As the Commission is aware, we held our proposed Red River Valley Unit 1 in reserve in case the PPAs negotiated with Calpine and Invenergy were not successful. The PPA negotiations were successful, however, and since our analysis showed that the Calpine Project PPA is more reasonable on a Present Value Societal Cost (PVSC) basis than the Red River Valley Units, we continue to believe it is a reasonable choice to hold development of the Red River Valley Units (or some other up-to-400 MW thermal plant(s) in North Dakota) to a future time, consistent with our commitment in the Rate Case Settlement.

2. Strategist Analysis of Calpine Project Using North Dakota Resource Planning Assumptions

We used the Strategist resource planning model again to evaluate our resource selection consistent with the requirements of this Commission. We used the same assumptions and forecast information as we did in the CAP docket but express our modeling results as Present Value of Revenue Requirements (PVRR), consistent with North Dakota law.²⁴ Table 4 provides the results of this analysis.

²² Gas CT Case, Alders Supp. Testimony, Schedule 2 (Wishart Direct) at 26, Table 5.

²³ Gas CT Case, Alders Supp. Testimony, Schedule 2 (Wishart Direct) at 23.

²⁴ PVRR excludes any assumptions regarding the future cost of CO₂ or externalities.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

**Table 4:
Incremental PVRR from Base Case (\$millions)**

Scenarios	Base	2012 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions
Base Case using ND Assumptions	\$0	\$0	\$0	\$0	\$0	\$0
Add Calpine PPA	(\$11)	(\$22)	\$10	(\$40)	(\$74)	(\$27)

In addition, to provide a basis of comparison for the Commission's consideration, we have evaluated the overall cost of the proposed thermal generation we now intend to add to our system against the cost of adding the three gas CTs to the system, as we originally proposed to the North Dakota and Minnesota Commissions. We provide below the cost of adding Black Dog Unit 6 and the Calpine Project PPA to our system versus the cost of adding Black Dog Unit 6 in combination with the Red River Valley Units using both the Minnesota PVSC and North Dakota assumptions. This provides the Commission with a comparison of the outcome of the Minnesota CAP Docket and the North Dakota Gas CT Case. Table 5 below provides this cost comparison:

**Table 5:
PVSC v. PVRR of Portfolios (\$millions)**

Resource Combination	2013-2050 PVSC (\$millions)	2013-2050 PVRR with ND Assumptions (\$millions)
Calpine PPA + Black Dog 6	\$45,368	\$39,180
Black Dog 6 + RRV 1&2	\$45,404	\$39,198
Cost/(Savings) of Calpine PPA + Black Dog 6	(\$36)	(\$18)

Our cost analysis shows that the acquisition of the 485 MW combination of Black Dog Unit 6 (207 MW accredited capacity) and Calpine Project PPA (278 MW accredited capacity) is less expensive on both a PVRR and PVSC basis than the 621 MW combination of Black Dog Unit 6 and the two Red River Valley Units (207 MW accredited capacity each). This raises the issue whether the additional \$18 million cost associated with the extra 136 MW provided by the combination of the Black Dog and Red River Valley CTs presents more value than the combination of Black Dog Unit 6 with the Calpine Project PPA. The Company believes it does not. As discussed in more detail below, the addition of 278 MW of combined cycle capacity to our system through the Calpine Project PPA provides the Company significant operational flexibility as it faces the loss of intermediate and baseload

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

capacity over the next decade as a result of retiring generation units and expiring PPAs.

3. Cost Impact of Calpine Project PPA

As demonstrated above, the selection of Calpine Project PPA was a reasonable and prudent decision based on the alternatives available to us. However, we recognize that taking a conservative approach to the Company's resource needs also requires an analysis of the cost impact of the Calpine Project PPA on our customers so that the benefits and the burdens of undertaking this project can be appropriately evaluated by the Commission. To do this, we used the 2014 load forecast and resource availability assumptions included in our 2015 Resource Plan recently filed with the Commission, which is our most recent load forecast update.

As the Commission knows, Strategist simulates the operation of the NSP System and estimates the total cost of energy over the life of the project on a present value basis. We also use the model to test results under a range of input assumptions. To assess the impact on customer costs, we simulated the operation of the NSP System with and without the addition of the Calpine Project PPA. For purposes of this analysis we considered the PPA in isolation rather than in combination with the other proposed new generators. To provide context for our overall resource decisions, we provide in the next section a similar analysis of all the generation selected in the MPUC's CAP proceeding to meet our capacity need.

MISO generally dispatches combined cycle intermediate load units on an economic basis during peak to support and balance baseload units and intermittent resources. The energy produced by an economically dispatched CC unit generally displaces a similar amount of more expensive energy that would have been produced by the Company or otherwise purchased elsewhere. The Strategist analysis identifies a displacement of the approximately 18,300,000 MWh of more expensive generation, which accounts for the differences in the cost of system operations with and without the Calpine Project PPA.

Our analysis estimates that the overall system cost of energy with the Calpine Project PPA added to our system (on a PVRB basis without considering any costs associated with CO₂ emissions or externalities) is \$11 million lower than it would be without the this resource being on our system.

We also conducted various "sensitivity tests" to evaluate how the Calpine Project PPA will affect system costs under different circumstances. The sensitivities analyzed

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

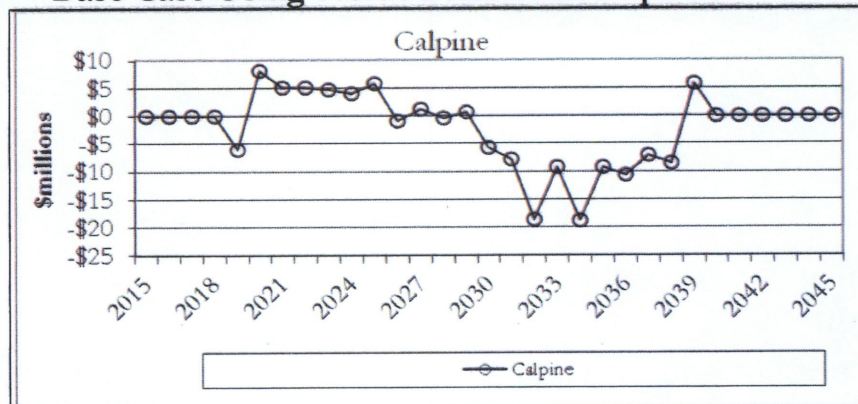
include the effect on system costs if one assumes (i) the Fall 2011 Forecast of capacity need (i.e., a need of 150-500 MWs in the 2017-2019 timeframe), (ii) no MISO market purchases available to supplement system resources (Markets Off), and (iii) higher and lower gas costs. As Table 6 below shows, our economic analysis indicates that the addition of the Calpine Project PPA reduces system costs for all sensitivities except when the price of gas is low.

**Table 6:
Total System Cost With/Without Calpine Project PPA**

Changes in PVRR Cost (\$millions)	Base Case Using ND Assumptions	2012 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions
Base Case Using ND Assumptions	\$44,949	\$49,279	\$41,260	\$50,050	\$45,957	\$51,971
Base Case Using ND Assumptions with Calpine Project PPA	\$44,937	\$49,257	41,271	\$50,010	\$45,883	\$51,944
Net Cost/(Savings)		(\$22)	\$10	(\$40)	(\$74)	(\$27)

Figure 5 below illustrates the year-over-year annual net costs or savings of the Calpine Project PPA during its 20-year life, which results in the net \$11 million savings identified in the table above. Except in 2019, the cost of energy over the first 10 years of the PPA does not offset its capacity cost, while energy savings in the second 10 years of the PPA more than offset its capacity cost to achieve the overall net savings of \$11 million over the PPA’s 20-year term.

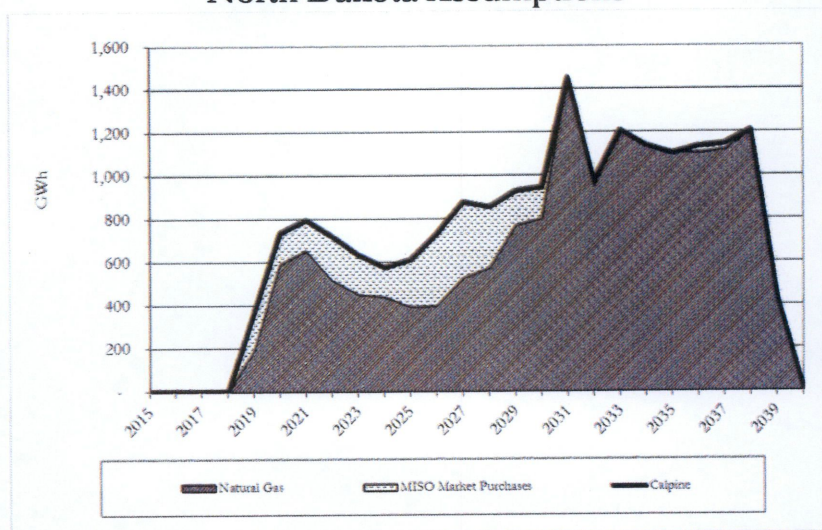
**Figure 5:
Annual Net System Costs (Savings) with Calpine Project PPA Compared to Base Case Using North Dakota Assumptions**



**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

Figure 6 below illustrates the results of the Strategist dispatch simulations for the Base Case using North Dakota assumptions (i.e., a “Markets On” scenario with no additional renewable generation and no externalities or carbon cost). In this scenario Strategist may choose to purchase market energy to meet system needs. Over the 20-year term of the PPA, approximately 87 percent of the Calpine Project PPA’s generation displaces other natural gas generation, and 13 percent displaces market energy.

**Figure 6:
Calpine Project PPA – Displaced Energy for Base Case Using
North Dakota Assumptions**



While the Calpine Project PPA represents the addition of a CC unit to our system, the customer rate impacts of the addition will be mitigated when spread across the entire NSP System because the System is so large. As shown in Table 7 below, our Strategist dispatch simulation forecasts for most years shows the rate impact of the Calpine Project PPA (energy and capacity costs) is significantly offset by avoiding higher priced fossil fuel energy and market energy purchases.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

**Table 7:
Calpine Project PPA Impacts
(¢/kWh)**

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Base Rates	0.000	0.000	0.000	0.000¢	0.041	0.070	0.071	0.072	0.0730	0.0730	0.074
Fuel Clause	0.000	0.000	0.000	0.000	0.036	0.077	0.088	0.080	0.073	0.069	0.074
Avoided Fuel/Mkt Purchases	0.000	0.000	0.000	0.000	-0.091	-0.129	-0.148	-0.140	-0.134	-0.133	-0.135

As shown in Table 8 below, the initial net rate impact of the Calpine Project PPA is estimated to be 0.014¢ per kWh in 2019, rising to 0.019¢ per kWh in 2020, and then dropping to and staying at or below 0.012¢ per kWh through 2024 before rising back up to 0.014¢ per kWh again in 2025.

**Table 8:
Calpine Project PPA Net Rate Impacts (10 Years)**

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
0.000¢/ kWh	0.000¢/ kWh	0.000¢/ kWh	0.014¢/ kWh	0.019¢/ kWh	0.012¢/ kWh	0.012¢/ kWh	0.011¢/ kWh	0.009¢/ kWh	0.014¢/ kWh

4. Qualitative Analysis of Benefits of Calpine Project PPA

As mentioned, the Calpine Project PPA will displace other generation sources that serve the NSP System. Through this displacement of generation, the Calpine PPA provides qualitative benefits in the form of hedging against the early retirement of baseload and intermediate capacity from the Company's system sooner than is currently anticipated. The PPA's displacement of fossil based generation also provides a hedge against future environmental regulation, such as new carbon rules and any associated costs applied to generation with carbon emissions.

a. Retiring baseload and intermediate capacity

We are entering a period of significant evolution of the NSP System. Although we have built a strong foundation of a diverse and cost effective resource mix, our resource additions should be viewed through the lens of significant change to that mix in the out-years of the Calpine Project PPA and beyond.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

From 2015-2030, the NSP System will experience significant reductions in energy resources due to power contracts expiring without extension or renewal. Several potential key changes include:

- 2023-Blue Lake Units 1-4 cease operation (153 MW)
- 2025-Manitoba Hydro contracts expire (850 MW)
- 2026-Cottage Grove Combined Cycle Energy Center contract expires (262 MW)
- 2027-Mankato Combined Cycle Energy Center contract expires (357 MW)

Further, our resource additions should be viewed in the context of the potential retirement of our three baseload nuclear units, along with the potential end of Sherco Units 1 and 2, which suggest that a significant proportion of our baseload generation may be retired within 15 to 20 years. These five generating units have been the backbone of the NSP System for many years and have formed the foundation to provide low cost and highly reliable service to our customers.

With respect to Sherco, there is the possibility that Unit 1 may be retired as early as 2025, and we have included modeling in our 2015 Resource Plan to identify system requirements in the case that occurs. The addition of the Calpine PPA is a hedge against that possibility. Current technology suggests that natural gas combined cycle units, along with additional renewable energy, will be the likely candidates to replace the energy and capacity these units have provided. As a result of the large potential exposure to add natural gas to our system in the 2025 to 2035 timeframe, the Company must attempt to minimize this exposure going into that timeframe. The addition of the Calpine PPA in 2019 helps mitigate the Company's exposure to this risk, allowing for greater flexibility to respond when our backbone baseload plants are retired.

First, the Calpine PPA locks in very competitive pricing for natural gas combined cycle generation for the next twenty years. Second, this competitively priced capacity resource is capable of intermediate and baseload operation, offering a flexible option to conservatively address the uncertainty of our forecasted capacity need. In addition, the Calpine Project PPA is capable of significant energy production that enhances system flexibility for a variety of system outcomes. Having this operational flexibility and available capacity could become valuable if, for example, Sherco Unit 1 or 2 are retired during the next 20 years due to increased environmental compliance costs.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

b. Emerging environmental regulation

We have pursued a strategy of shifting our resource portfolio toward lower-emission options while maintaining our focus on fuel diversity, affordability and reliability. However, we continue to experience significant uncertainty surrounding environmental regulation, which contributes to potential impacts to the NSP System beyond just the resource need that is being addressed by the Calpine Project PPA.

Probably the biggest – and most uncertain – factor is the EPA’s existing source green house gases (GHG) performance standard, known as the Clean Power Plan or Section 111(d) Rules, which Environmental Protection Agency (EPA) expects to finalize in mid-summer 2015. The final rule is likely to face legal challenges which, depending whether or not the rule is stayed during litigation, may affect the timeline for state plan development. If the Rule is not stayed, each state will draft plans and submit them to EPA by 2016 to 2018, for approval by EPA one year later. Compliance will begin in 2020.

While much remains unknown, it seems clear that the Rule will:

- Put increasing pressure on coal plants, possibly resulting in reduced utilization levels or additional retirements;
- Likely increase generation from existing and new natural gas plants; and
- Push us to continue adding renewable energy resources, and increasing energy efficiency efforts and associated investments.

The addition of the Calpine Project PPA hedges against these likely outcomes. It constitutes intermediate capacity that can step in to support the NSP System due to impacts any future environmental regulation may have on our key generating facilities, including our baseload coal units at the Sherburne County Generating Station and our Allen S. King Plant.

C. Analysis of Full Resource Portfolio (Calpine, Geronimo, Black Dog)

To provide context for the Commission’s evaluation of our ADP request, we conducted additional analysis for the Commission’s consideration. In this Section we provide modeling results that identify the costs of various combinations of the three resources we propose to acquire: Black Dog Unit 6, the Calpine Project PPA, and the Geronimo Solar PPA.²⁵ These three facilities are all part of the Company’s selections

²⁵ Since the Commission has already granted an ADP for Black Dog Unit 6, the analysis provided here is only intended to inform the Commission’s consideration of this ADP application.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

to meet our identified capacity need. In the aggregate, these three projects reflect our proposed construction initiative of new generation in the 2016-2019 timeframe.

Tables 9 and 10 below present the PVRR results of the specified combinations of resources, and the results of the same sensitivity tests that we conducted for the Calpine Project PPA.

**Table 9:
PVRR Results (\$millions)**

Scenarios	Base	2011 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions (PVSC)
Base case using ND Assumptions	\$44,949	\$49,279	\$41,260	\$50,050	\$45,957	\$51,971
Add Geronimo Solar PPA	\$45,011	\$49,350	\$41,336	\$50,094	\$46,006	\$52,005
Add Calpine Mankato CC PPA	\$44,937	\$49,257	\$41,271	\$50,010	\$45,883	\$51,944
Add Black Dog 6	\$44,836	\$49,162	\$41,159	\$49,923	\$45,825	\$51,868
Add Geronimo & Calpine	\$45,012	\$49,328	\$41,358	\$50,070	\$45,947	\$51,992
Add Calpine & BD6	\$44,842	\$49,155	\$41,186	\$49,902	\$45,767	\$51,849
Add Geronimo & Calpine & Black Dog 6	\$44,929	\$49,219	\$41,286	\$49,974	\$45,842	\$51,908

**Table 10:
Incremental PVRR from Base Case (\$millions)**

Scenarios	Base	2011 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions
Base case using ND Assumptions	\$0	\$0	\$0	\$0	\$0	\$0
Add Geronimo Solar PPA	\$62	\$71	\$76	\$44	\$49	\$35
Add Calpine Mankato CC PPA	(\$11)	(\$22)	\$10	(\$40)	(\$74)	(\$27)
Add Black Dog 6 CT	(\$112)	(\$118)	(\$101)	(\$127)	(\$132)	(\$103)
Add Geronimo & Calpine	\$63	\$48	\$98	\$20	(\$10)	\$21
Add Calpine & Black Dog 6	(\$107)	(\$124)	(\$74)	(\$147)	(\$190)	(\$122)
Add Geronimo & Calpine & Black Dog 6	(\$20)	(\$60)	\$26	(\$76)	(\$115)	(\$63)

Notably, the addition of the Calpine Project PPA together with Black Dog Unit 6 provides the most PVRR savings of the combinations analyzed. Further, the Geronimo Solar PPA in combination with the Calpine Project PPA and Black Dog Unit 6 provides a net reduction in the PVRR in all scenarios except the low gas case. Figure 7 below shows the aggregate impact of the Geronimo Solar PPA, the Calpine Project PPA, and Black Dog Unit 6.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

**Figure 7:
Annual Net Costs (Savings) (without CO2)
Compared to Base Case using ND Assumptions**

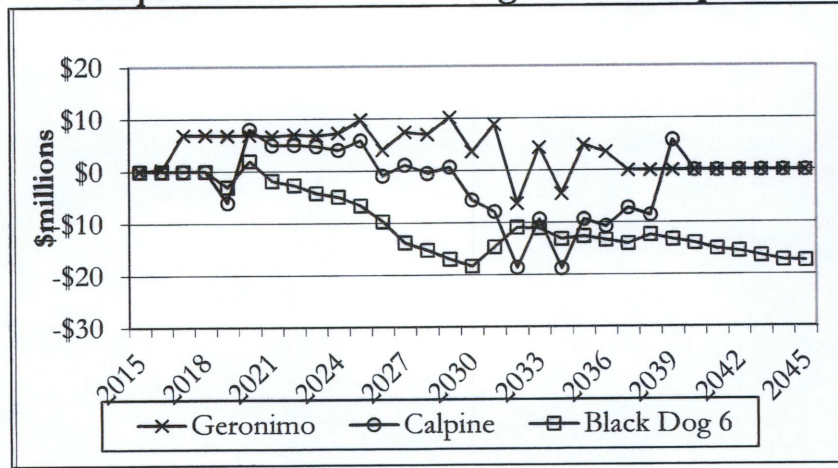
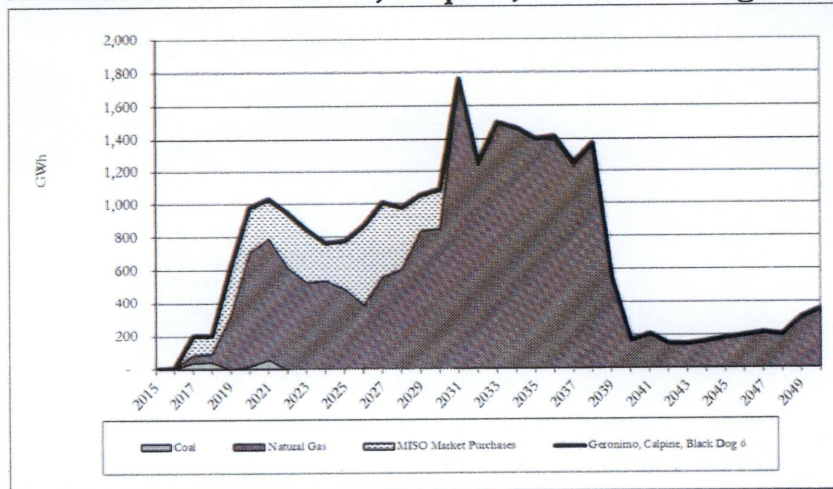


Figure 8 below illustrates the results of the Strategist dispatch simulations for the Base Case using North Dakota assumptions (i.e., a “Markets On” scenario with no additional renewable generation). In this scenario Strategist may choose to purchase market energy to meet system need. Approximately 85 percent of the aggregate generation displaces natural gas-based generation, 16 percent displaces market energy, with coal generation output having a net increase of 1 percent.

**Figure 8:
Strategist Simulations - Displaced Energy Base Case Using ND Assumptions
for combination of Geronimo, Calpine, and Black Dog 6 Projects**



As shown, the overall impact of adding all three resources on the operation of the NSP System is displaced natural gas generation.

**PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED**

Table 11 below shows the rate impact of the various combinations.

**Table 11:
Annual Rate Impact Analysis**

GERONIMO	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.017¢/kWh	0.023¢/kWh
CALPINE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.014¢/kWh)	0.019¢/kWh	0.012¢/kWh	0.012¢/kWh	0.011¢/kWh	0.009¢/kWh	0.014¢/kWh
BLACK DOG 6	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.007¢/kWh)	0.005¢/kWh	(0.004¢/kWh)	(0.006¢/kWh)	(0.010¢/kWh)	(0.011¢/kWh)	(0.015¢/kWh)
GERONIMO + CALPINE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.003¢/kWh	0.035¢/kWh	0.027¢/kWh	0.028¢/kWh	0.026¢/kWh	0.032¢/kWh	0.023¢/kWh
CALPINE + BLACK DOG 6	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.021¢/kWh)	0.018¢/kWh	0.025¢/kWh	0.019¢/kWh	0.009¢/kWh	0.006¢/kWh	0.003¢/kWh
GERONIMO + CALPINE + BLACK DOG 6	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.006¢/kWh	0.034¢/kWh	0.035¢/kWh	0.046¢/kWh	0.036¢/kWh	0.021¢/kWh	0.016¢/kWh

IX. CONCLUSION

In conclusion, the Company respectfully requests that the Commission grant an advance determination of prudence for the Company's acquisition of the capacity and energy of the 20-year Calpine Project PPA as an appropriate resource for the Company's integrated system. In the alternative, and if the Commission finds that purchasing this capacity is not in our North Dakota customers' best interest, the Company requests that this purchase be found to be appropriate and eligible for inclusion and proxy pricing in the Restack.