MINNESOTA DEPARTMENT OF COMMERCE

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October 23, 2014 **PUBLIC DOCUMENT**

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **PUBLIC Comments of the Minnesota Department of Commerce-Division of Energy Resources**
Docket Nos. E002/CN-12-1240, E002/M-14-788 and E002/M-14-789

Dear Dr. Haar:

Attached are the **PUBLIC** comments of the Minnesota Department of Commerce-Division of Energy Resources (Department) in the following matters:

- In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process,
- In the Matter of a Draft Purchase Power Agreement with Geronimo Wind Energy, LLC, d/b/a Geronimo Energy, LLC, and
- In the Matter of Draft Purchase Power Agreements with Calpine Corporation and Invenergy Thermal Development and Proposed Price Terms for Black Dog Unit 6.

Theses petitions were filed on September 23, 2014 by:

James R. Alders
Strategy Consultant
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401

The Department provides its analysis of Xcel's proposal and the draft power purchase agreements and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ CHRISTOPHER SHAW
Rates Analyst

/lt
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

PUBLIC DOCUMENT

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

PUBLIC COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NOS. E002/CN-12-1240, E002/M-14-788 and E002/M-14-789

I. BACKGROUND

On May 23, 2014, the Minnesota Public Utilities Commission (Commission) issued its *Order Directing Xcel to Negotiate Draft Agreements with Selected Parties* in Docket No. E002/CN-12-1240. The Commission required that:

A. Xcel shall negotiate a draft power purchase agreement with Geronimo Wind Energy, LLC, d/b/a Geronimo Energy, LLC, and submit the agreement for Commission review to ensure that the negotiated terms are consistent with the public interest.

B. Xcel shall negotiate draft power purchase agreements with Calpine Corporation and Invenergy Thermal Development, LLC, and shall develop price terms for Black Dog Unit 6. Xcel shall then submit the agreements and terms for Commission review to determine which of these project(s), if any, best addresses Xcel's overall system needs identified in this record and in the Commission's Order Approving Plan, Finding Need, Establishing Filing Requirements, and Closing Docket (March 5, 2013) issued in Docket No. E-002/RP-10-825, *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*.[1]

In addition, the Commission required that:

> Xcel shall file status updates in October 2014 and October 2015 on any changes in Xcel's resource needs, including needs resulting from changes in MISO's reserve requirements.[2]

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[1] ORDER DIRECTING XCEL TO NEGOTIATE DRAFT AGREEMENTS WITH SELECTED PARTIES at 36, Docket No. E002/CN-12-1240, May 23, 2014.
[2] Id. at 37.

On September 23, 2014, Xcel Energy (Xcel or the Company) filed its Compliance filing in Docket No. E002/CN-12-1240 (competitive acquisition process or CAP proceeding). While Xcel provided draft power purchase agreements (PPAs) with Aurora Distributed Solar, LLC (Aurora or Geronimo), Mankato Energy Center II, LLC (Calpine), Invenergy Cannon Falls II, LLC (Invenergy) and price terms for Black Dog Unit 6 (Black Dog), Xcel did not request approval of any proposed project(s) at this time. Instead, Xcel requested that the Commission delay action on all proposals and instead allow the Company to work with thermal bidders, and on its Black Dog 6 proposal, to update terms and pricing that reflects in-service timing in the 2019-2021 timeframe and consider the Aurora proposal with the solar PPAs from its solar request for proposals (RFP) process when determining which PPAs are in the public interest.

The Minnesota Department of Commerce, Division of Energy Resources (Department or DOC), submits its comments on Xcel's proposals and the draft PPAs below.

II. ANALYSIS

A. XCEL'S UPDATED RESOURCE NEED ASSESSMENT

1. Peak Demand Forecast

Xcel stated that while the Company has seen stronger-than-expected sales, as evidenced in its pending rate case,[3] the Company's most recent demand forecast was adjusted slightly

[3] Rebuttal Testimony of Xcel Witness Jannell E Marks in Docket No. E002/GR-13-868:

Q. WHAT ARE THE KEY DRIVERS FOR THE DIFFERENCES BETWEEN THE UPDATED FORECAST AND THE INITIAL FORECAST?

A. The primary driver of the increased sales and customer count forecast is actual results for January through May 2014. Through May, weather-normalized actual sales are 142,811 MWh higher and average customer counts are 4,144 customers higher than the Initial Forecast.
… In addition to the higher-than-expected actual results for January through May, updates to the economic forecast also are contributing to the changes in the sales forecast.

Xcel Ex. 40 at 5 (Marks Rebuttal)

Q. PLEASE DESCRIBE THE CHANGES TO THE ECONOMIC FORECAST THAT WAS [sic] USED TO DEVELOP THE UPDATED FORECAST.

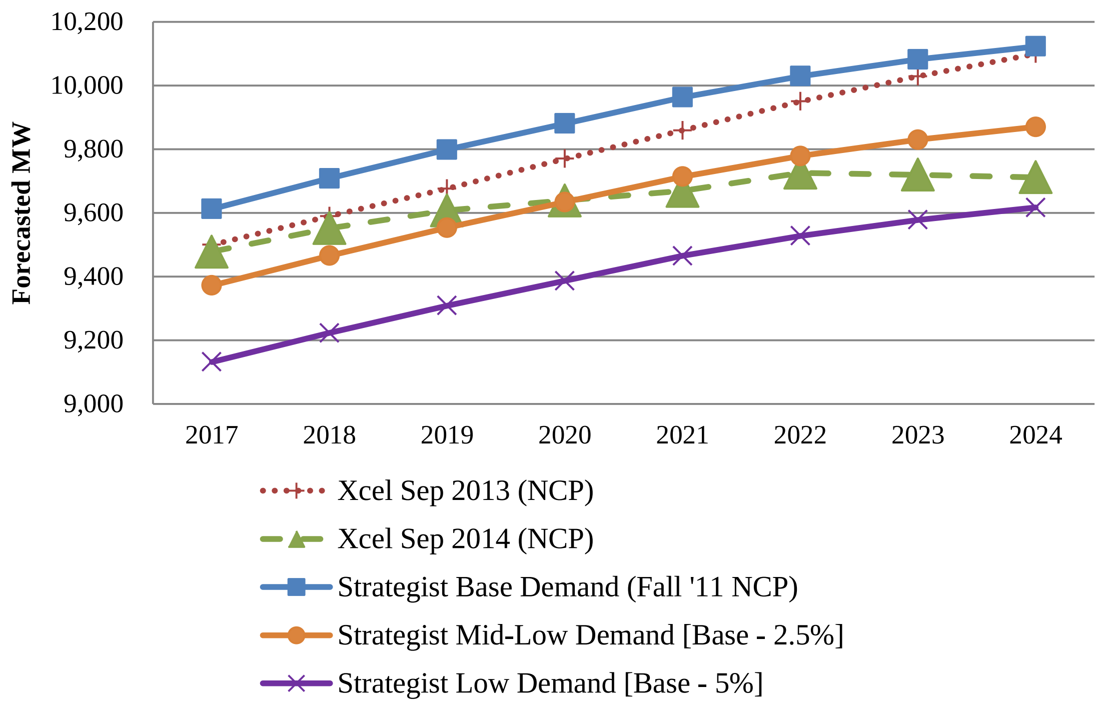
A. The most significant changes can be seen in the forecasts of households and total employment for the Minneapolis-St. Paul metropolitan area. The forecast of households is an input into the forecast for Residential customer counts, and the forecast of total employment is an input into the forecast for Small Commercial and Industrial sales. The 2014 forecast for each of these economic series is 3 percent higher than the original forecast used to develop the sales forecast presented in my Direct Testimony. Not only is the 2014 forecast higher, but each series shows fairly significant changes over the past four to five years as compared to the original data used in the Company's Initial Forecast.

Xcel Ex. 40 at 6 (Marks Rebuttal)

Q. WHAT IS THE SIGNIFICANCE OF THE CHANGES TO THESE ECONOMIC FORECASTS?

A. Actual Residential customer counts have been higher than forecast, and the upward revision to the household data used to develop the customer forecast indicates that a key driver of the under-forecasting of customer counts has been a household series that historically understated actual households, and subsequently under-forecasted households for the test downward.[4] In its most recent demand forecast, Xcel projected an average annual growth rate of less than 0.6 percent as compared to its September 2013 forecast, which projected average annual growth rate of 0.9 percent. Table 1, below, shows Xcel's September 2014 forecast, its September 2013 forecast, its Fall 2011 forecast, which was a foundation for the DOC in its analysis in the CAP proceeding, and two low forecast contingencies analyzed by the DOC as part of the Strategist analysis in the CAP proceeding.[5]

Figure 1: Non-coincident Peak Demand Forecasts



The information in Figure 1 above confirms the importance of using a range of forecasts in analyzing resource plans and in proceeding such as the CAP. As shown in Figure 1, above, Xcel's most recent forecast remains within the band of demand forecasts analyzed by the DOC through 2024. Analysis of Xcel's updated forecast would require a significant amount of time. Further given that Xcel's recent sales increases exceeded Xcel's sales forecasts, the DOC has some concerns about the accuracy of Xcel's forecast of lower demand. Moreover, the DOC noted in its Direct Testimony in this proceeding a number of concerns

> year. Similarly, weather-normalized actual Small Commercial and Industrial sales have been higher than forecast, and this also can be attributed to an understatement of historical employment levels, which led to an under-forecast of test year employment.

Xcel Ex. 40 at 7 (Marks Rebuttal)

[4] Xcel Compliance at 5.

[5] The forecasts shown in the above graph differ slightly from those shown in Figure 3 in DOC Witness Sachin Shah's Direct Testimony. Mr. Shah presented forecasts before a DSM adjustment whereas Figure 1 above shows the forecasts after the DSM adjustment, consistent with the forecast as presented by Xcel on page 5 of its Compliance filing.

regarding Xcel's September 2013 forecast, which Xcel was not able to explain. Mr. Shah concluded, overall, that:

> The fundamental goal in certificate of need and resource planning proceedings is not to establish a plan that is least cost under a single forecast but for the plan to be least cost across a wide range of forecasts. Given this goal, the concerns I discuss above, the Commission's decision not to require continual updating of forecasts in the 2010 IRP (*i.e.,* that the need was based on using the fall 2011 forecast), and the fact that the spring 2013 forecast is within the 5 percent contingency modeled, I conclude that Department Witness Dr. Steve Rakow's use of the fall 2011 forecast as a starting point to begin his analysis of assessing the bids is reasonable.[6]

Given that Xcel's most recent forecast would not materially affect the need for capacity resources in the 2017-2019 timeframe and remains within the band of demand forecasts analyzed by the DOC through 2024, the DOC concludes that there is no need to reopen the Commission's March 13, 2013 Order in this proceeding to reflect Xcel's most recent forecast.

2. *MISO Reserve Margin Requirements*

Planning for a reliable electric system requires estimating the amount of generation and transmission resources that will be available at all times to meet the varying levels of demand for electricity. Thus in order to ensure the sufficient resources are available to serve load, utilities use a planning reserve margin (PRM). The Midcontinent Independent System Operator's (MISO) January 2014 Business Practice Manual for Resource Adequacy stated at page 12 that:

> Planning Reserve Margins (PRMs) must be sufficient to cover:
>
> - Planned maintenance;
> - Unplanned or forced outages of generating equipment;
> - Deratings in the capability of Generation resources and Demand Response Resources;
> - System effects due to reasonably anticipated variations in weather; and
> - Load Forecast Uncertainty.

PRMs have varied over time. MISO performs the analysis annually to establish the PRMs for each Load Serving Entity (LSE) in the MISO Region and publishes the results by November 1st preceding the applicable planning year.

[6] Direct Testimony of Sachin Shah at 14, Docket No. E002/CN-12-1240. Mr. Shah's Direct Testimony at 8-14 is included as Attachment A for ease of reference.

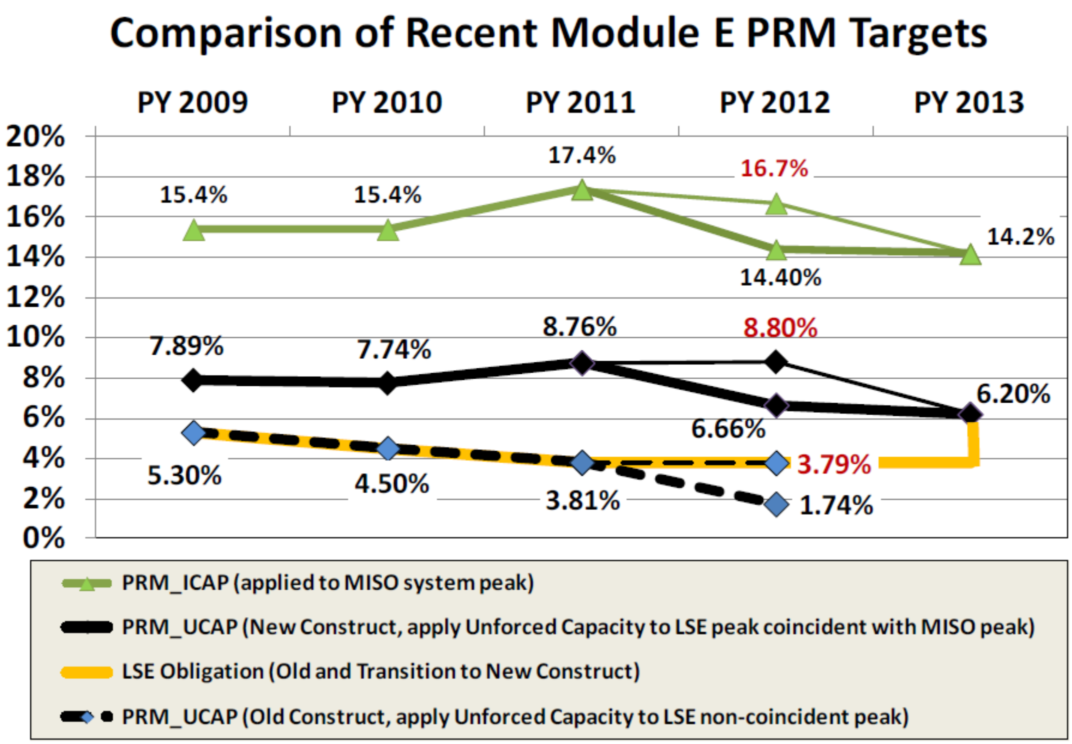
Xcel stated that in the time since the hearing in the CAP proceeding, it has gained more confidence in the use of a coincidence factor to calculate the Company's reserve margin.[7] Specifically, Xcel stated that MISO accepted Xcel's recent calculation of a 5 percent coincidence factor.[8]

Prior to 2013, Planning Reserve Margins (PRM) included a diversity factor, which reflected the differences in timing of peak demand on utilities' systems.[9] Thus, for the 2012/2013 planning year, a 4.61% diversity factor was incorporated into the established PRM of 3.79% to be applied to LSEs' non-coincident peaks.[10]

In the CAP proceeding, 2013 was the first time the coincident peak method was used. This method does not apply a PRM to the utility's peak ("non-coincident peak"); instead, the PRM is applied to the demand on the utility's system at the time of *MISO's* peak ("coincident peak"). As this method was new at the time of testimony in the CAP proceeding, the DOC analyzed Xcel's capacity needs using both coincident and non-coincident peaks. The DOC applied a 3.79% PRM to the non-coincident peak and a 6.2% PRM to the coincident peak with a 5% diversity factor. Table 2, below, shows the planning reserve margins used by the DOC in the CAP proceeding.[11]

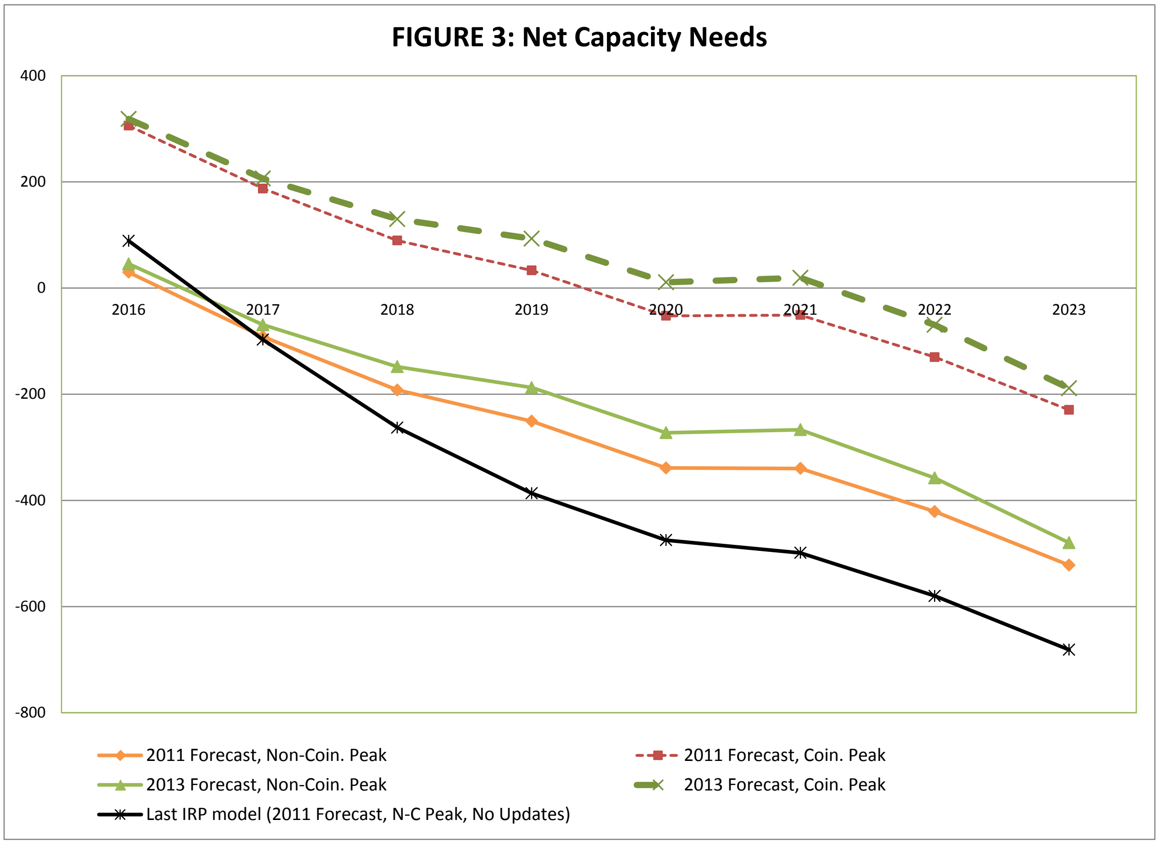
[7] Id. at 5.
[8] Id. at 6.
[9] The amount of demand on a utility's system at the time of peak demand on MISO's overall system is the utility's coincident peak, whereas the peak demand on the utility's system overall is called the utility's non-coincident peak. If the peak demand on a utility's system happens at the same time as MISO's peak (an unlikely occurrence), then the utility's peak is fully coincident and equals its non-coincident peak.
[10] MISO 2012 LOLE Study Report at 4, https://www.misoenergy.org/Library/Repository/Study/LOLE/2012%20LOLE%20Study%20Report.pdf
[11] MISO 2013 LOLE Study Report at 12, https://www.misoenergy.org/Library/Repository/Study/LOLE/2013%20LOLE%20Study%20Report.pdf

Figure 2:



The DOC notes that for 2014, the PRM increased from 6.2% to 7.3%. Dr. Stephen Rakow analyzed Xcel's capacity needs so that Xcel had sufficient capacity to cover the Company's peak demand forecast plus required reserves under both the coincident and non-coincident peak methodologies as shown in Figure 2 (reproduced below as Figure 3) of his Direct Testimony:[12]

[12] Rakow Direct at 26, Docket No. E002/CN-12-1240.



Comparing the different results of the net capacity needs under the coincident peak and the non-coincident peak methodologies in Figure 3 shows the effects of both the differences in calculation methodologies and the differences in the PRMs in 2012 and 2013. A much smaller impact is shown by the difference in net capacity needs under the 2011 and 2013 forecasts.

Figure 3, shows that, under the coincident peak methodology, the need for capacity additions is postponed by three years, from 2017 until 2020. However, as noted above, the PRM for the 2012/2013 planning year included a 4.61% diversity factor. Xcel's estimated diversity factor of 5% is similar to the diversity factor previously applied to all MISO load. Thus, while the Department has expressed concern regarding the appropriate calculation of a diversity factor to be applied in a coincident peak calculation,[13] for Xcel in this proceeding, use of either the coincident or non-coincident peak methods would produce very similar results. In other words, use of the coincident peak method would have little impact on Xcel's capacity needs, given the facts in this proceeding. Thus, the difference in net capacity needs under the coincident and non-coincident peak methodologies shown in Figure 3, are mostly due to the different reserve margins applied using each method. [14]

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[13] For example, Otter Tail Power's integrated resource plan, Docket No. E017/RP-13-961.
[14] As noted above, and shown in Figure 2, the DOC applied the 3.79% PRM used for planning year 2012 to its non-coincident peak calculation and the 6.2% PRM used for planning year 2013 to its coincident peak calculation. However, the 3.79% PRM for 2012 was temporarily adjusted upward from 1.74%, according to MISO in its MISO 2013 LOLE Study Report at 13:

In calculating its updated capacity need, Xcel applied MISO's most recent annual update to the PRM of 7.1% for 2015. Thus, as compared to the DOC's coincident peak calculation, the use of a 7.1% PRM *increases* Xcel's capacity need. As shown in Figure 2, above, PRMs have fluctuated up and down due a variety of circumstances present in each annual loss of load expectation (LOLE) study that MISO uses to calculate the annual PRMs.

Figure 4 below includes Xcel's capacity needs based on a 7.1% PRM as well as its most recent forecast. The effect of the 7.1% PRM is reflected in the difference between the dashed blue/orange circle line and the dotted red line, showing that capacity would be needed a year or two sooner under the 7.1% PRM than under the lower PRM. Xcel's most recent demand forecast (2014) is shown by the solid teal star line

FIGURE 4: Updated Net Capacity Needs

The adjustment was made only in planning year 2012 due to concern over the credibility of the new equivalent and that Forced Outage Rates may not have been appropriate for peak-time situations. Subsequently, in June 2012, MISO confirmed that Forced Outage Rates are reflective of peak times and the conservative adjustment indicated by the 'detour path' red-font values need not be continued.

Had the Department used the lower 1.74% PRM in its non-coincident peak calculation, the results under both methods would have been similar. Thus, the differences in Figure 3 can primarily be attributed to changes in reserve margins.

The upper-most dotted purple line, which reflects the lower bound of the 2011 forecast based on a non-coincident peak, represents the lowest capacity need explicitly modeled. Thus, as can be seen in Figure 4, incorporating Xcel's updated forecast and PRM assumption produces capacity needs within the bounds of the analyses in the docket in the 2017-2022 timeframe. After 2021, the capacity needs move toward the edge of the lowest capacity need modeled.

3. Existing Generation Capacity

The remaining portion of the difference between Figure 4 above, and Xcel's net resource supply shown on page 9 of its compliance filing, is due to differences in the existing supply capacity. Table 1, below, shows the difference between the supply capacity modeled in Strategist and the supply capacity shown on page 9 of Xcel's compliance filing.

Table 1: Differences in Supply Resources (in Proceeding and Compliance Filing)

	2017	2018	2019	2020	2021	2022	2023	2024
Spring 2013 Forecasted Resources	9,791	9,805	9,855	9,867	9,966	9,969	9,930	9,863
Xcel 2014 Resources	9,897	9,892	9,872	9,736	9,979	9,981	9,953	9,720
Difference	**106**	**87**	**17**	**(131)**	**13**	**12**	**23**	**(143)**
Fall 2011 Forecasted Resources	9,885	9,884	9,919	9,916	10,001	9,988	9,942	9,876
Xcel 2014 Resources	9,897	9,892	9,872	9,736	9,979	9,981	9,953	9,720
Difference	**12**	**8**	**(47)**	**(180)**	**(22)**	**(7)**	**11**	**(156)**

The Department is aware of at least the following regarding the model used in this proceeding and in Xcel's compliance filing:

- the Department included 290 MW[15] of solar in its model and Xcel included 150 MW of solar in its compliance filing;[16]
- the Department and Xcel excluded the capacity of Black Dog units 3 and 4 beginning in 2015[17] and Key City beginning in 2017;[18]
- in determining the capacity value for Sherco 3 and Black Dog 5/2, Xcel used a 5-year average instead of the 2014/2015 planning year 3-year average UCAP values used by MISO; [19] and

[15] One-third was added in each year 2017-2019.
[16] PUC IR 5.
[17] MPUC Notice, Black Dog Units 3 and 4 Retirement, Docket No. E002/RP-10-825, October 15, 2014.
[18] DOC IR 2 included as Attachment B.

- additional minor differences are likely due to updated UCAP values.

However, it is not clear what accounts for the larger differences in 2020 and 2024; they may be due to the expiration of power purchase contracts or another easily identifiable change. The Department requests that Xcel explain in reply comments what accounts for the decrease in supply capacity in 2020 and 2024. Regardless of whether Xcel is able to identify what change may account for the differences in 2020 and 2024, the Department requests that Xcel provide a unit-by-unit list of all capacity included in its updated available resources calculation.

Figure 5, below, is the same as Figure 4, but uses Xcel's updated supply capacity with its September 2014 forecast.

FIGURE 5: Updated Net Capacity Needs with Updated Supply Resources

The Department concludes that the record in the proceeding continues to provide a reasonable basis for the Commission to require Xcel to add capacity to its system, consistent with the Commission's March 13, 2013 Order in this proceeding. Moving forward, PRMs, demand forecasts, available generator capacity, and thus overall capacity needs will continue to change. This proceeding, like all resource planning and acquisition proceedings, involves an evaluation of needs and alternatives under numerous possible

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[19] DOC IR 3 included as Attachment C. Xcel state that this change was intended to better predict the long term capacity value of these resources and added approximately 100 MW to Xcel's expected capacity supply. The DOC notes that its modeling included a capacity of 246.4 MW for Black Dog 5/2 and 496.2 MW for Sherco 3.

futures or contingencies. Figure 5 shows only a few of the numerous possible futures analyzed by the DOC in this case.

Overall, based on Figure 5 above, the Department concludes that Xcel should add capacity to its system by no later than 2018.

4. Possible Short-Term Capacity Additions

Xcel stated that during PPA negotiations it became apparent that, due to the passage of time, bidders were no longer able to meet a 2017 in-service date.[20] Therefore, Xcel investigated short-term capacity options. Xcel discussed two possible short-term capacity additions in its compliance filing: Manitoba Hydro and Blue Lake.

a. Manitoba Hydro

Currently, one of Xcel's agreements with Manitoba Hydro provides for 350 MW of generation from Manitoba Hydro in the summer in exchange for 350 MW of generation to Manitoba Hydro in the winter. Xcel stated that the Company is currently in discussion with Manitoba Hydro to increase its diversity exchange by approximately 75 MW. Xcel stated that it is in continuing discussions with Manitoba Hydro, but that it contemplates this capacity could cover years 2016-2019.

The DOC notes that, currently, MISO accredits resources on an annual basis. Therefore, the Department request that, in reply comments, Xcel clarify whether it anticipates that both Manitoba Hydro and Xcel could receive capacity credit for the additional 75 MW, whether Xcel anticipates that MISO will move to a seasonal construct, or what other options Xcel anticipates will be available to ensure that it would be able to claim the full capacity credit for this resource if needed.

b. Blue Lake

Xcel stated that it had previously assumed that four older peaking units, Blue Lake 1-4, with a combined capacity of 157 MW, would be retired in 2019.[21] Xcel stated that the Company could accomplish a short extension to their operating life, to 2023, with minimal, if any, increase in current fixed and variable O&M.

The DOC notes that its modeling, which includes generation based on the modeling done in Xcel's 2010 IRP and provided by the Company, includes capacity from Blue Lake 1-4 through 2030.[22] Thus, the Department recommends that the Company clarify, in reply

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[20] Xcel Compliance at 9.
[21] Xcel Compliance at 10.
[22] The Department reviewed the following FSV files provided by the Company:

File:	NSP CAP CON BASE CASE.FSV
Provided in:	Reply to IR 1, E002/CN-12-1240
Provided on:	May 20, 2013
B L 1-4:	In L&C beyond 2025

comments, what past resource assessments included the retirement of Blue Lake 1-4 in 2019, whether Xcel's Resource Need Assessment table on page 9 of its Compliance Filing includes Blue Lake 1-4 after 2019, and whether the modeling Xcel conducted in this proceeding included Blue Lake 1-4 after 2019.

5. Summary of Xcel's Updated Resource Need Assessment

Xcel stated that, due to its updated resource need assessment, there is a high probability that it will have adequate generation through 2018 and 2019 and perhaps through 2023. Therefore, the Company requested that it be allowed to return to bidders for renewed discussions regarding the timing of these resources. Specifically, the Company requested that it be allowed to "work with bidders to refresh their proposals to reflect potential in-service dates in the 2019-2021 timeframe, as well as options to delay or cancel."[23]

As noted above, the Department continues to have concerns regarding Xcel's forecast. However, as also noted, the DOC evaluated varying levels of forecasted demand in analyzing Xcel's resource needs. The reduced forecast scenarios analyzed by the DOC reduced both capacity and energy forecasts. In addition, the DOC evaluated delayed in-service dates of several packages of bids. As DOC Witness Dr. Rakow noted in his Rebuttal Testimony, delayed in-service dates would result in reduced costs:

> The analysis indicates that the potential for flexible in-service dates for ICT1 significantly reduces the difference between packages with ICT1 deferred and the packages with ICT1's original in-service date—by about $50 to $55 million PVSC under base case conditions; see DOC Ex. ___ SR-R-11A (Rakow Rebuttal).
> The analysis also indicates that the potential for flexible in-service dates for CCC1 has a small impact on the overall PVSC. The difference between packages with CCC1 deferred and the packages with CCC1's original in-service date is only about $5 to $12 million PVSC under base case conditions; see DOC Ex. ___ SR-11A (Rakow Rebuttal).[24]

Table 2 below shows the PVSCs of bid packages with delayed in-service dates and lower level of demand and energy. Scenarios with delayed in-service dates are shaded grey. The

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File: DOC-DER IR-133 Att A NON-PUBLIC_NSP - IRP UPDATE - BASE CASE.FSV
Provided in: Reply to IR 133, E002/RP-10-825
Provided on: December 2, 2011
B L 1-4: In L&C beyond 2025

File: NSP - 2010RP - BASE - BASE.FSV
Provided in: Reply to IR 10, E002/RP-10-825
Provided on: September 13, 2010
B L 1-4: In L&C beyond 2025

[23] Xcel Compliance at 11.
[24] Rakow Rebuttal Testimony at 11, Docket No. E002/CN-12-1240.

lowest PVSC of packages in each forecast contingency is in bold; the lowest single project's PVSC under each forecast is in bold italics.

Table 2: Selected Delayed In-Service Date and Reduced Forecast Scenarios (PVSC)

	Base Forecast	Mid-Low Forecast - 2.5%	Low Forecast - 5%	Scenario #
Interruptible Gas (Invenergy)				
Black Dog 2017 and Calpine 2019	**$41,258,564**	**$40,145,956**	$39,064,212	41
Black Dog 2017 and Invenergy 2019	$41,280,804	$40,164,740	**$39,047,572**	43
Invenergy 2016 and Calpine 2019	$41,310,372	$40,179,328	$39,084,200	45
Calpine 2017 and Invenergy 2019	$41,270,568	$40,157,360	$39,089,008	47
Black Dog 2019 and Calpine 2017	$41,263,483	$40,151,467	$39,072,079	33
Black Dog 2018 and Invenergy 2016	$41,299,021	$40,160,593	$39,067,529	37a
Geronimo 2016	$41,423,488	$40,249,608	$39,121,180	25
Black Dog 2017	$41,326,470	$40,178,734	$39,075,954	27
Calpine 2017	***$41,315,664***	$40,197,444	$39,103,384	29
Invenergy 2016	$41,381,884	***$40,175,872***	***$39,072,568***	31
Invenergy 2016 and Calpine 2017	$41,287,152	$40,182,260	$39,089,596	35a
Firm Gas				
Black Dog 2018 and Invenergy 2016	$41,334,589	$40,196,845	$39,103,705	37
Invenergy 2016	$41,381,884	$40,211,528	$39,107,792	31
Invenergy 2016 and Calpine 2017	$41,322,652	$40,218,196	$39,125,080	35

Thus, under scenarios with lower forecasts, the Invenergy project becomes more cost-effective when a non-firm gas supply is assumed. This issue is discussed further below.

In conclusion, based on the above discussion, and in particular Figure 5, the Department concludes that capacity should be added to Xcel's system no later than 2018. While there may be benefits to delaying the acquisition of the proposed projects, projects should not be delayed absent a credible short-term capacity addition available as a bridge from at least 2018, if not earlier. While the DOC has requested more information from Xcel in reply comments regarding possible short-term capacity additions, as of this time, Xcel has not provided a credible short-term capacity addition to ensure that it has sufficient capacity resources allowing for a further delay in the in-service dates of the proposed projects.

B. DRAFT PPAs

As noted above, Xcel did not request approval of any proposed projects at this time. Instead, Xcel requests that the Commission delay action on all proposals and instead allow the Company to work with thermal bidders, and on its Black Dog 6 proposal, to update terms and pricing that reflect in-service timing in the 2019-2021 timeframe and to consider the Aurora proposal with the solar PPAs from its solar RFP process when determining which PPAs are in the public interest. As noted above, the Department concludes that, absent a credible short-term capacity addition, such a delay would not be reasonable. Thus, the Department provides its review of the draft PPAs below.

In analyzing whether a proposed PPA is in the best interest of Xcel's ratepayers, the Department typically considers the following:

- The proposed price to be paid by Xcel; and
- Whether Xcel's ratepayers would be appropriately protected from the financial and operational risks of the proposed project.

In addition, the Department reviewed:

- Transmission Interconnection Risk;
- Capacity Accreditation Risk; and
- Environmental Risk.

In this case, when considering the term of the PPA, the Commission stated that:

A. Calpine, Geronimo, Invenergy, and Xcel shall be held to the prices and terms used to evaluate each bid for the purpose of cost recovery from Xcel ratepayers. Ratepayers must not be put at risk for costs that are higher than bid or for benefits assumed in bids that do not materialize. If actual costs are lower than bid, the bidders should be allowed to keep those savings.

B. The agreements must provide terms that sufficiently protect ratepayers from risks associated with the non-deliverability of accredited capacity and/or energy from the project(s) as proposed.

C. The Commission is unlikely to find it reasonable for Xcel to enter into an agreement in which negotiated terms shift risk or unknown costs to ratepayers.

D. Delay and cancellation provisions are appropriate considerations for power purchase agreement negotiations.[25]

These considerations, enumerated by the Commission, are discussed below. The Department's discussions of the three PPAs follow a similar structure for ease of comparison.

1. *Calpine Mankato Energy Center Expansion*

   a. *The Price of the PPA*

[25] ORDER DIRECTING XCEL TO NEGOTIATE DRAFT AGREEMENTS WITH SELECTED PARTIES at 36, Docket No. E002/CN-12-1240, May 23, 2014.

The Department reviewed the draft Calpine PPA price terms for consistency with the pricing term used to evaluate Calpine's bid. Calpine's bid included the following terms:

[TRADE SECRET DATA HAS BEEN EXCISED]

These and additional terms can be found in Appendix B of Calpine's Initial Proposal in the CAP proceeding. Later in the CAP proceeding, at the request of Xcel, Calpine provide updated pricing information for 2018 and 2019 Commercial Operation Dates (CODs) that were incorporated into analyses conducted by both Xcel and the Department. For a 2018 COD, the capacity price started at [TRADE SECRET DATA HAS BEEN EXCISED]; for a 2019 COD, the capacity price started at [TRADE SECRET DATA HAS BEEN EXCISED]. All other terms remained the same.

Xcel stated that the 2017 COD could not be met for two reasons: (1) the timing of the construction of the required transmission network upgrades for the facility's interconnection to be unconditional; and (2) the likely timing of the Commission's review and approval of the PPAs in this proceeding. Therefore, parties negotiated a June 1, 2018 COD.

In addition, the price terms were changed from those bid to mirror the same terms in the existing Mankato Energy Center PPA. This change added a dispatchability payment that was not included in Calpine's bid. The change slightly increases the total expected capacity payments to Calpine. The expected impact is shown in the response to DOC IR 72 includes as Attachment D.

As shown in Attachment D, the capacity price for a 2018 COD begins at [TRADE SECRET DATA HAS BEEN EXCISED] which matches the bid.[26] The dispatchability payment is [TRADE SECRET DATA HAS BEEN EXCISED] and was not included in the bid.

As the Department noted above, the Commission's Order states that:

> Calpine, Geronimo, Invenergy, and Xcel shall be held to the prices and terms used to evaluate each bid for the purpose of cost recovery from Xcel ratepayers. Ratepayers must not be put at risk for costs that are higher than bid or for benefits assumed in bids that do not materialize. If actual costs are lower than bid, the bidders should be allowed to keep those savings.

[26] Attachment A of draft Calpine PPA.

Thus, the Department concludes that the dispatchability payment is an unreasonable addition to the draft Calpine PPA.

b. Financial Risks

There are two main financial risks that may have negative impacts on Xcel's ratepayers. They are:

- A seller default and termination of the PPA before the expiration of the contract period, and

- Entitlement by a lender or other party, as a result of the seller's failure to pay debt, to take over the project and terminate the PPA.

Under these events, Xcel may be forced to find more costly replacement power when the PPA is terminated. Article 11 of the proposed PPA describes the Security Fund required to be established by the seller to account for Replacement Energy in the event of bankruptcy and other potential damages caused by the seller. The Security Fund will total **[TRADE SECRET DATA HAS BEEN EXCISED]** and is to be established by a letter of credit, by depositing the funds in an escrow account or by a parent company guaranty. Article 12 of the PPA includes events which would constitute seller's default, thus allowing the Company, among other remedies, to draw on the security fund. Article 11 of the PPA also requires Calpine to obtain a subordinated mortgage on the proposed facility for the benefit of Xcel.

After reviewing these features in the PPAs, the Department concludes that Xcel's ratepayers would be reasonably protected from the financial risks discussed above.

c. Operational Risk

As is typically true of PPAs, the operational risks are the risks that the project will not be built and operated as expected. These risks include a delay in the COD, a complete shutdown, or a partial shutdown of the project due to technical problems. In the case of a partial shutdown, ratepayers must be assured that their payments for the capacity are reduced accordingly.

The PPA includes specific features that would protect both Xcel and its ratepayers from the operational risks discussed above. These features include the security fund, as discussed above, and payments only for the actual net capability of the proposed facility. Failure to meet the COD, other than failure to achieve MISO accreditation as discussed below, is an event of default under the PPA. In addition, the PPA includes other protective measures such as specific performance, step-in rights, actual damages, and termination of the PPA.

After reviewing these features in the PPA, the Department concludes that, except for the accreditation issue discussed further below, Xcel's ratepayers would be reasonably protected under the proposed terms of the PPA from the operational risks discussed above.

d. Transmission Interconnection Risk

In evaluating the Calpine proposal in Strategist, the Department included $1.5 million in potential transmission interconnection costs. During the proceeding, the Department made clear that it did not view proposals that place unknown financial risks on ratepayers to be reasonable. Further, as noted above, the Commission stated that:

> The Commission is unlikely to find it reasonable for Xcel to enter into an agreement in which negotiated terms shift risk or unknown costs to ratepayers.

Despite this directive from the Commission, the draft PPA with Calpine places the risk for additional interconnection costs on Xcel and its ratepayers. According to Xcel, the Company sought to limit its exposure to this risk, but Calpine would not agree. In response to a Department Information Request, the Company indicated that it did not know the likelihood or extent to which interconnection costs may exceed $1.5 million.[27] As the treatment of interconnection costs places an unknown cost on Xcel ratepayers, the Department concludes that this portion of the draft PPA is unreasonable.

e. Capacity Accreditation Risk

In response to Commission IR 8, Xcel stated that:

> Under the current MISO generator interconnection and resource adequacy requirements, generators with [a] conditional Generator Interconnection Agreement (GIA) will not be eligible for capacity accreditation until all upgrades required under the project's GIA are complete and in-service. Over the past several years GIAs for projects located in the Minnesota area have been conditional upon the completion of various MISO Multi-Value Projects including the North LaCrosse to Madison 345 kV line[1]. This means that generating projects with conditional GIAs will not be eligible to qualify as capacity resources until the 2019/2020 planning year assuming the North LaCrosse to Madison line is completed as presently scheduled for the end of 2018. MISO is aware of this concern and is working with its stakeholder to identify ways for conditional GIAs to qualify as capacity resources prior to the 2019/2020 planning year. [Citation Omitted.]

Due to the difficulty in obtaining capacity accreditation under current MISO requirements until significant upgrades are completed, Article 10.6 of the draft PPA includes a provision that would allow Calpine to delay the COD by one year if it is unable to obtain a "Full Interconnection Agreement." The Department's interpretation of Article 10.6(E) is that

[27] DOC IR 70 included as Attachment E.

Calpine may also delay the COD in subsequent years if it is unable to obtain a Full Interconnection Agreement; thus, ratepayers would bear the cost of any capacity payments necessary during the delay period regardless of the length of delay and would also bear the cost pf replacement power since Xcel is currently allowed to pass all such costs on to ratepayers through the fuel clause adjustment. The Department requests that the Company confirm the Department's understanding in reply comments. The Department also requests that Xcel provide further explanation of the status of any resolution of this issue at MISO.

f. Environmental Risk

Article 20.2 of the draft PPA places the risk of carbon dioxide regulation on the Company, unless limits are placed on specific facilities. Regarding the risk of future regulation of other types of emissions, the PPA requires that Xcel and Calpine cooperate to find a mutually agreeable response and mitigation measures. The Department notes that costs of complying with CO_2 regulations, along with certain estimated externalities, were modeled in the Strategist analysis in this proceeding. As a result, the Department concludes that Article 20.2 appears to be reasonable at this time. If the Commission approves a PPA with Calpine, the Department would recommend that the Commission require Xcel to keep the Commission informed about any such response and mitigation measures in the future.

2. Invenergy Cannon Falls Expansion

a. The Price of the PPA

The Department reviewed the draft Invenergy PPA price terms for consistency with the pricing term used to evaluate Invenergy's bid. Invenergy's bid included the following terms:

[TRADE SECRET DATA HAS BEEN EXCISED]

As with Calpine, Xcel stated that a 2016 or 2017 COD could not be met for two reasons: (1) the timing of the construction of the required transmission network upgrades for the facility's interconnection to be unconditional; and (2) the likely timing of the Commission's review and approval of the PPAs in this proceeding. Therefore, parties negotiated a June 1, 2018 COD.

In addition, because of the two-year delay in the COD, Invenergy is no longer planning on using the 179 MW combustion turbine (CT) it had in stock, and now plans to add a new 209 MW GE Turbine 7FA.05 at its Cannon Falls facility.

For a 2018 COD, the capacity price in the draft PPA is **[TRADE SECRET DATA HAS BEEN EXCISED]** than the 2016 COD bid price and will be inflated each year by the Gross Domestic Product Implicit Price Deflator (GDPIPD).[28] The capacity price in the draft PPA matches the capacity price provided by Invenergy during the course of this proceeding for a 2018 COD.[29] Payments for dispatchability and variable O&M remain the same as bid.[30]

During the proceeding, there was discussion on whether Invenergy's proposal should be evaluated using firm or interruptible gas.[31] Section 5.3(C) of the draft PPA with Invenergy provided that Xcel has the option of obtaining and providing firm gas or non-firm gas transportation service to deliver natural gas fuel to Invenergy.

Currently, MISO does not require generators to have a firm fuel supply to qualify as a planning resource and does not differentiate between resources with firm fuel contracts and those with non-firm fuel contracts for capacity accreditation. Rather, planning resources are accredited according to verification testing results and generator performance consistent with MISO's Business Practices Manuel on Resource Adequacy. However, in response to concerns of the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC) and other MISO stakeholders regarding the increasing reliance on natural gas for electric generation, MISO formed the Electric and Natural Gas Coordination Task Force (ENGCTF). As noted on the MISO website:

> The ENGCTF provides a forum for electric and natural gas industry experts and interested MISO stakeholders to identify challenges and develop recommendations to comply with regulatory deadlines, investigate market impacts, and manage on-going operations with an increasing reliance upon natural gas while ensuring the reliability of the electric system.[32]

The Department notes that the issue of whether firm gas supply should be required for gas-fired generator to receive capacity accreditation is an issue the ENGCTF has considered. Recently, an issue summary paper consider by the ENGCTF stated that:

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[28] Exhibit A of Draft Invenergy PPA.
[29] Information Request Xcel-029, Supplement DOC Ex. __ SR-R-9.
[30] Exhibit A of Draft Invenergy PPA.
[31] From Dr. Rakow's Rebuttal Testimony at page 7:

> Q. Would there be a negative effect on electric reliability if interruptible gas supplies were used at the Invenergy project?
>
> A. That is an issue that will need to be explored during negotiations. However, I obtained preliminary information from Xcel. Assuming that lack of firm natural gas would be a larger problem in winter than in summer, I requested additional information from Xcel regarding Xcel's winter load and capability situation in Department Information Request No. 67; see DOC Ex. ___ SR-R-8 (Rakow Rebuttal). This information confirms that it is worth exploring the use of interruptible natural gas supplies for the Invenergy project.

[32] https://www.misoenergy.org/StakeholderCenter/CommitteesWorkGroupsTaskForces/ENGCTF/Pages/home.aspx

> While until the winter vortex of January 2014, generation owners were adequately served with interruptible service levels; going forward, the expectation is that firm service will be necessary to maintain our expected level of reliability at least for the winter season.[33]

Thus, whether firm gas supplies will be required at some point for natural gas generators appears to be an ongoing question and concern at MISO. Xcel noted that, during the course of negotiations, Invenergy proposed to increase fuel oil storage at the proposed Cannon Falls Expansion by 50 percent at no cost to Xcel. The increase would allow the entire site to maintain its current fuel oil run capability of 28 hours after the addition of the proposed expansion. However, Xcel did not offer additional explanation regarding its choice of firm or interruptible gas supplies for the proposed project nor the risks associated with using interruptible gas from an operations perspective or from a MISO capacity accreditation perspective. As noted above in Table 2, whether an interruptible or firm gas supply is used affects the cost-competitiveness of the Invenergy proposal. Thus, the Department requests that Xcel explain in reply comments whether it would expect to obtain firm or interruptible gas supplies for the Cannon Falls expansion.

b. Financial Risks

As noted above, there are two main financial risks that may have negative impacts on Xcel's ratepayers. They are:

- A seller default and termination of the PPA before the expiration of the contract period, and

- Entitlement by a lender or other party, as a result of the seller's failure to pay debt, to take over the project and terminate the PPA.

Under these events, Xcel may be forced to find more costly replacement power when the PPA is terminated. Article 11 of the proposed PPA with Invenergy describes the Security Fund required to be established by the seller to account for Replacement Energy in the event of bankruptcy and other potential damages caused by the seller. The pre-COD Security Fund will total **[TRADE SECRET DATA HAS BEEN EXCISED]** and the post-COD the Security Fund will total **[TRADE SECRET DATA HAS BEEN EXCISED]**.[34] Article 11 of the draft PPA states that the security fund is to be established by a letter of credit, by depositing the funds in an escrow account or by guaranty. Article 12 of the PPA includes events which would constitute seller's default and allow the Company, among other remedies, to draw on the security fund.

After reviewing these features in the PPAs, the Department concludes that Xcel's ratepayers would be reasonably protected from the financial risks discussed above.

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[33] https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=185009
[34] Exhibit A of Draft Invenergy PPA.

c. Operational Risk

As is typically true of PPAs, the operational risks are the risks that the project will not be built and operated as expected. These risks include a delay in the COD, a complete shutdown, or a partial shutdown of the project due to technical problems. In the case of a partial shutdown, ratepayers must be assured that their payments for the capacity are reduced accordingly.

The PPA includes specific features that protect both Xcel and its ratepayers from the operational risks discussed above. These features include the security fund discussed above, along with capacity payments only for the actual net capability of the proposed facility. Failure to meet the COD, other than failure to achieve MISO accreditation as discussed below, is an event of default under the PPA. In addition, the PPA includes other protective measures such as specific performance, step-in rights, actual damages, and termination.

After reviewing these features in the PPA, the Department concludes that, except for the accreditation issue, Xcel's ratepayers would be reasonably protected under the proposed terms of the PPA from the operational risks discussed above.

d. Transmission Interconnection Risk

As noted above, in its bid Invenergy proposed a mechanism for recovering transmission interconnection costs above those included in the bid through an adjustment in the Monthly Capacity Payment. Invenergy removed the interconnection cost adjustment from the draft PPA and, thus, Xcel ratepayers would no longer be exposed to an unknown transmission interconnection cost risk under the draft PPA with Invenergy.

e. Capacity Accreditation Risk

Xcel's response to Commission IR 8, indicated above, also applies to Invenergy's draft PPA. As with the draft Calpine PPA, due to the difficulty in obtaining capacity accreditation under current MISO requirement until significant upgrades are completed, Article 10.6 of the draft PPA includes a provision that would allow Invenergy to delay the COD by one year if it is unable to obtain accreditation of the proposed Cannon Falls expansion. The Department's interpretation of Article 10.6(E) is that Invenergy may also delay the COD in subsequent years if it is unable to obtain a Full Interconnection Agreement and thus ratepayers would bear the cost of any capacity payments necessary during the delay period regardless of the length of delay, along with replacement power costs. The Department requests that the Company confirm the Department's understanding in reply comments and further explanation of the status of any resolution to this issue at MISO.

f. Environmental Risk

Article 20.2 of the draft PPA places the risk of carbon dioxide regulation on the Company, unless limits are placed on specific facilities. The Department concludes that this provision is reasonable since it reflects the modeling assumptions in this proceeding.

3. Aurora Project

a. The Price of the PPA

The Department reviewed the draft Geronimo PPA price terms for consistency with the pricing term used to evaluate Geronimo's bid. Geronimo's bid included the following terms:

[TRADE SECRET DATA HAS BEEN EXCISED]
- Maximum Capacity – 100 MW[35]

The COD in the draft PPA is December 1, 2016 to ensure that the project will qualify for the 30 percent investment tax credit (ITC). The draft PPA is based on the Company's newly developed Model Solar PPA. The pricing in the draft PPA matches the bundled per-MWh capacity/energy price payment structure proposed in Geronimo's bid.[36] The maximum nameplate capacity under the draft PPA is 100 MW.

b. Financial Risks

Again, there are two main financial risks that may have negative impacts on Xcel's ratepayers. They are:

- A seller default and termination of the PPA before the expiration of the contract period, and

- Entitlement by a lender or other party, as a result of the seller's failure to pay debt, to take over the project and terminate the PPA.

Under these events, Xcel may be forced to find replacement power that would be more costly if the PPA is terminated when replacement power costs are higher than in the PPA. Article 11 of the proposed PPA describes the Security Fund required to be established by the seller to account for Replacement Energy in the event of bankruptcy and other potential damages caused by the seller. The pre-COD Security Fund will total [TRADE SECRET DATA HAS BEEN EXCISED] and the post-COD the Security Fund will total

[35] Geronimo Initial Petition at F-1.
[36] Geronimo Draft PPA at Exhibit J.

[TRADE SECRET DATA HAS BEEN EXCISED].[37] Article 11 of the draft PPA states that the security fund is to be established by a letter of credit, by depositing the funds in an escrow account or by guaranty. Article 12 of the PPA includes events which would constitute seller's default and allow the Company, among other remedies, to draw on the security fund. After reviewing these features in the PPAs, the Department concludes that Xcel's ratepayers would be reasonably protected from the financial risks discussed above.

c. Operational Risk

As is typically true of PPAs, the operational risks are the risks that the project would not be built and operated as expected. These risks include a delay in the COD, a complete shutdown, or a partial shutdown of the project due to technical problems. In the case of a partial shutdown, ratepayers must be assured that their payments for the capacity are reduced accordingly.

The PPA includes specific features that would protect both Xcel and its ratepayers from the operational risks discussed above. In addition to the security fund discussed above, the draft PPA contains a mechanism whereby payments would be offset due to Geronimo's failure to obtain 71 percent accreditation of its nameplate capacity. Instead of a mechanism whereby a portion of the payment to Geronimo is for capacity, Section 10.6 of the draft PPA provides that Geronimo would pay the Company liquidated damages of **[TRADE SECRET DATA HAS BEEN EXCISED]** for each month that the Accredited Capacity Shortfall exists. According to Xcel:

> Section 10.6 of the Aurora PPA is designed to compensate the Company should Geronimo's project be accredited by MISO for less than 71 percent of nameplate capacity, subject to adjustment in the event MISO changes the solar resource capacity accreditation methodology/calculations that Geronimo relied upon in the contested case proceeding. The damage amount established for an accreditation shortfall is based on a proxy of actual capacity costs.[38]

In addition, failure to provide sufficient capacity by the COD would entitle Xcel to damages under Sections 3.1(E) and 3.1(F) of the draft Aurora PPA. Section 3.1(F) provides a scale of damage payments that escalates more, the further the aggregate MW level Geronimo achieves is below 100 MW. In addition, the PPA includes other protective measures such a specific performance, step-in rights, actual damages, and termination.

The Department concludes that the liquidated damages proposed in the draft PPA for any Accredited Capacity shortfall **[TRADE SECRET DATA HAS BEEN EXCISED].** The DOC notes that the Commission ordered that proposed

[37] Exhibit A of Draft Invenergy PPA.
[38] DOC IR 4 included as Attachment F.

PPAs "must provide terms that sufficiently protect ratepayers from risks associated with the non-deliverability of accredited capacity." Thus, subject to a determination by the Commission that the proposed terms adequately protect ratepayers from this risk, the Department concludes that Xcel's ratepayers would be reasonably protected under the proposed terms of the PPA from the operational risks discussed above.

d. Transmission Interconnection Risk

None of the phases of the Aurora project would interconnect to the transmission system. Geronimo bears all distribution interconnection costs. Thus, the Department concludes that this issue is reasonably resolved.

e. Capacity Accreditation Risk

As noted above, the parties negotiated a scale of damage payments if Geronimo fails to achieve 100 MW of capacity by the COD or if Geronimo fails to obtain 71 percent accreditation of it nameplate capacity. Please see the discussion above under Operational Risks.

f. Environmental Risk

Xcel will own all environmental and renewable energy credits. The Department concludes that this structure is reasonable.

g. Curtailment Risk

Section 8.2 of the draft Geronimo PPA provides for payments for curtailments directed by the Company. Section 8.2(D) describes "Non-Compensable Curtailments" and includes emergencies declared by the Distribution Authority which is Xcel. The Department requests that Xcel explain the risk that it will incur compensable curtailment payments.

C. XCEL'S BLACK DOG 6 PROPOSAL

Xcel stated that, like the other bidders, Xcel is no longer able to meet a 2017 in-service date. The Company stated that its capital cost estimates for 2018 and 2019 have not changed, but that to meet a 2018 in-service date it will have to make a commitment for major equipment soon. Xcel proposes that, if its project is selected, the capital cost estimates presented in its initial filing for a 2018 or 2019 in-service date provide the basis for costs recovery. If the actual capital cost of Black Dog 6 is higher than the estimate presented, Xcel proposes that only the estimate and allowance for funds used during construction (AFUDC) would be placed in rate base. If the actual cost of the project is less than the estimate, Xcel proposes that the full capital cost estimate along with AFUDC associated with actual incurred costs would be put in rate base.

Regarding transmission interconnection, Xcel states that only minor modifications to the existing 115 kV switchyard will be required and that no upgrades to the 115 kV transmission system will be required. Further Xcel states that:

> The Company is planning on utilizing the existing Interconnection Rights assigned to Black Dog Units 3 and 4 for Black Dog Unit 6. The Company will be submitting an Attachment Y Notification for decommissioning and retirement of Black Dog Units 3 and 4 to MISO effective April of 2015. The Company will also submit a MISO Attachment X Generator Interconnection Request for Black Dog Unit 6 along with the Attachment Y Notification. Submitting the Attachment X request and Attachment Y notifications together will, in accordance with Section 38.2.7 of the MISO Tariff, allow the Company to retain the Black Dog interconnection rights upon successful completion of the interconnection procedures in Attachment X. The Company believes that we will be able to execute what should be an unconditional GIA early in 2016 following completion of all studies.[39]

Thus, as the proposed Black Dog Unit 6 would use existing transmission rights, unlike Calpine and Invenergy, Xcel does not have to wait for transmission upgrades to be completed before obtaining capacity accreditation. The proposed Black Dog Unit 6 would be able to receive capacity accreditation in time for a 2018 COD.

D. COST RECOVERY

The DOC notes that Xcel did not request approval of a recovery mechanism in its compliance filing. The Commission may wish to make a determination on whether energy-related charges for the thermal PPAs may be recoverable through the fuel clause under Minnesota Rules 7825.2500 or under Minn. Stat. §216B.1645, subd. 2 for the Aurora project. Further the Commission may wish to determine whether Minn. Stat. §216B.1691, subd. 2f applies such that some Xcel customers may not have the costs of the Aurora PPA included in their rates.

IV. RECOMMENDATION

The Department recommends that in reply comments Xcel:

- Explain what may account for the decrease in supply capacity in 2020, 2021 and 2024 and provide a unit-by-unit list of all capacity included in its updated available resources calculation;
- Clarify whether it anticipates that both Manitoba Hydro and Xcel could receive capacity credit for the additional 75 MW, whether Xcel anticipates MISO will move to a seasonal construct, or what other options Xcel anticipates will be available to ensure that Xcel would be able to claim the full capacity credit for this resource if needed;

[39] Commission IR 8.

- Clarify what past resource assessments included the retirement of Blue Lake 1-4 in 2019, whether Xcel's Resource Need Assessment table on page 9 of its Compliance Filing includes Blue Lake 1-4 after 2019, and whether the modeling Xcel conducted in this proceeding includes Blue Lake 1-4 after 2019;
- Confirm the Department's interpretation of Article 10.6(E) of the Calpine and Invenergy draft PPAs that Calpine and Invenergy may also delay the COD in subsequent years if they are unable to obtain capacity accreditation of their proposals and thus ratepayers would bear the cost of any capacity payments along with replacement power costs necessary during the delay period regardless of the length of delay;
- Provide further explanation on the status of any resolution at MISO to the inability of Calpine and Invenergy to obtain capacity accreditation until significant transmission upgrades, such and the LaCrosse to Madison line, are completed;
- Explain whether Xcel would expect to obtain firm or interruptible gas supplies for Invenergy's proposed Cannon Falls expansion; and
- Explain the risk that Xcel would incur compensable curtailments under the draft Geronimo PPA.

/lt

Q. Please explain the two different forecasts: the fall 2011 update and the spring 2013 forecast.

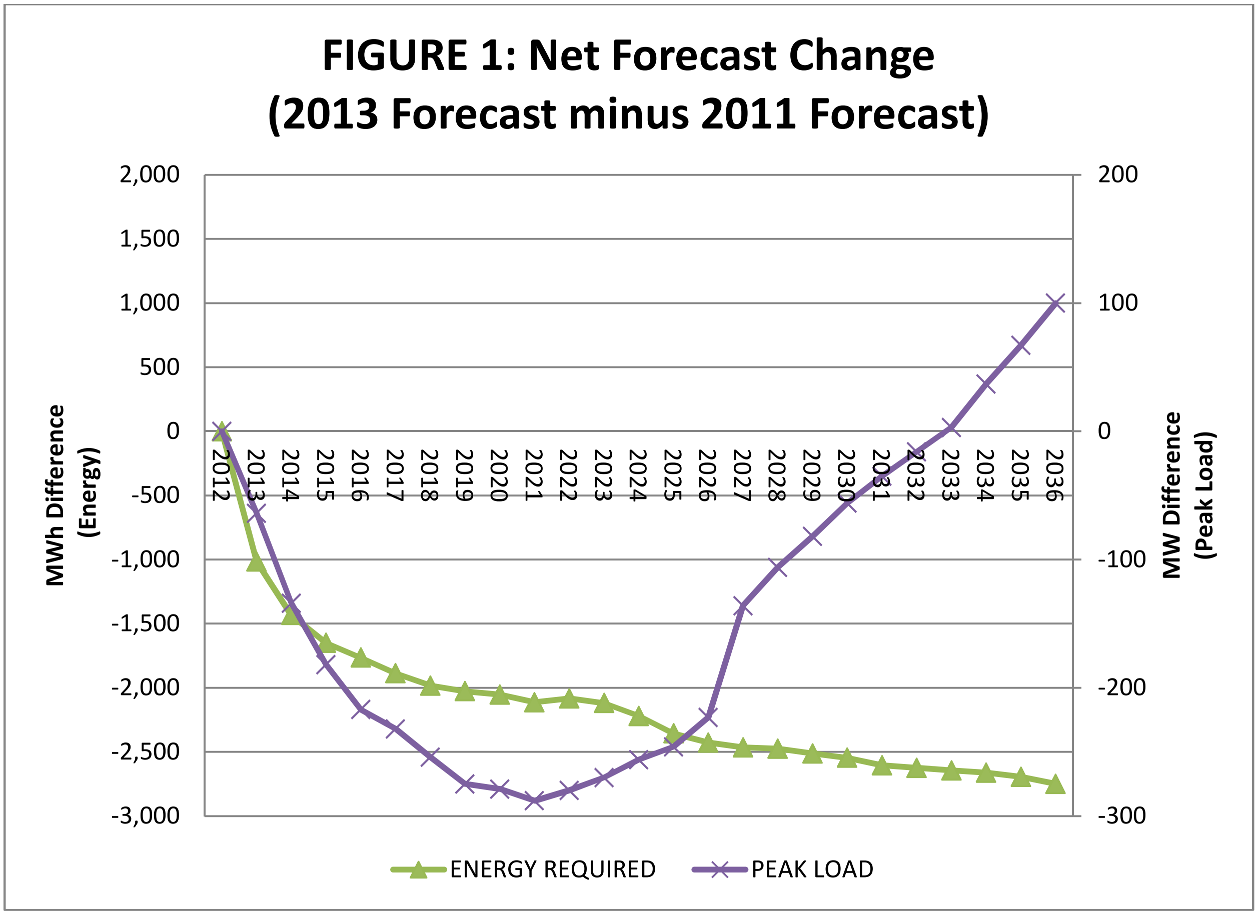
A. The term "base forecast" refers to the fall 2011 update in the most recent resource plan (Docket No. E002/RP-10-825) while "spring 2013 forecast" means the forecast presented in Xcel's petition in Docket No. E002/RP-13-368.

Data for the spring 2013 forecast was obtained from Xcel's response to Department of Commerce Information Request No. 1 in Docket No. E002/RP-13-368. A comparison of the peak demand and energy forecasts is shown in Figure 1 below. In Figure 1, a positive number means the spring 2013 forecast estimates a higher need than indicated by the fall 2011 update; a negative number means the spring 2013 forecast is for a lower need.

Q. What are your observations about the forecasts?

A. I note that, overall, the spring 2013 forecast predicts a lower energy need than the fall 2011 forecast and a lower peak load than the fall 2011 forecast, net of conservation.[1] However, the difference in peak load between the spring 2013 forecast and the fall 2011 forecast is large in the early years ranging from a 64 MW difference in 2013 to a high of 288 MW difference in 2021 and gradually declines to a difference of 223 MW by 2023; it is 136 MW or less from 2027 and on.

[1] Note that direct load control is treated separately from conservation in Strategist as constructed by Xcel. The amount of direct load control input to Strategist is lower in the 2013 model than in the 2011 model by between 20 and 105 MW. Generally, the difference is large in the early years and declines; it is 25 MW or less from 2022 and on.



Thus, one of my concerns is the different patterns in these two vintages of forecast as presented by Xcel. In particular:

- Why the differences in the two forecasts of peak demand that Xcel prepared a year and a half apart – from fall 2011 to spring 2013 – follows a U-shaped pattern over the forecasted period?
- Why Xcel's spring 2013 forecast predicts that energy sales will be consistently lower over the forecast period, while Xcel's spring 2013 forecast predicts that peak load will decline and then grow to be slightly higher than estimated in the fall 2011 forecast.

- These changes in peak and energy forecasts, together, mean that Xcel predicts a significant change in the overall load factor of its system.[2] Specifically, Xcel's prediction that customers will use less energy overall while making higher demands on Xcel's peak means that Xcel predicts that its load factor will decrease significantly over time, with customers demanding ever more from Xcel's peak while using less energy overall. What is the basis for this prediction?

Q. What information did Xcel provide about the changes in its sales forecast?

A. The Company's response to Department Information Request No. 9 provides detailed information on the various changes in methodology, models and the data Xcel used in the various vintages of its forecasts. This response is included as DOC Exhibit ___ at (SS-2) (Shah Direct).

Q. What does Xcel's response tell you about the changes to the Company's sales forecast from fall 2011 to spring 2013?

A. Some of the changes are interesting. For example, the Company stated the following in its response:

> <u>Prices</u>
>
> The Fall 2011 forecast included an electric price forecast for Minnesota and North Dakota based on the U.S. Wholesale Price Index for electricity.

[2] The load factor measures how much customers use a utility's system over the course of a year relative to the size of the system; the higher the load factor, the more customers use a utility's system throughout the year, whereas a low load factor means that customers make less use of a utility's system over the year. For example, industrial customers tend to have a higher load factor than a residential customer since, unlike residential customers, industrial customers tend to use about the same amount of energy throughout a day and throughout the year.

> The Spring 2012 forecast included an electric price forecast for North Dakota based on the U.S. Wholesale Price Index for electricity and an electric price forecast for Minnesota based on the Company's Strategist model.
>
> The Fall 2012 and Spring 2013 forecasts included an electric price forecast for Minnesota and North Dakota based on the Company's Strategist model.

Q. Please explain the significance of the excerpt above.

A. The spring 2013 forecast uses Strategist outputs to create the electric price variable. However, to produce outputs, Strategist needs a demand and energy forecast input. Thus, Xcel would presumably use an old vintage of forecast as an input into Strategist, run Strategist and get the price variable output, then in turn, put these price outputs into the new forecast inputs and create a new demand and energy forecast and put that new forecast into Strategist to run for the IRP.

Overall, this approach seems rather odd. In any case, below I discuss my overall conclusions about the forecasts used in this proceeding.

Q. Do you have any additional observations to address concerns that may arise regarding the latest vintage of Xcel's forecast, namely the spring 2013 forecast?

A. Yes I have one additional set of observations. Figures 2 and 3 below compare the spring 2013 forecast to the fall 2011 forecast, along with contingencies of 2.5 percent and 5 percent that Dr. Rakow uses in his analysis.

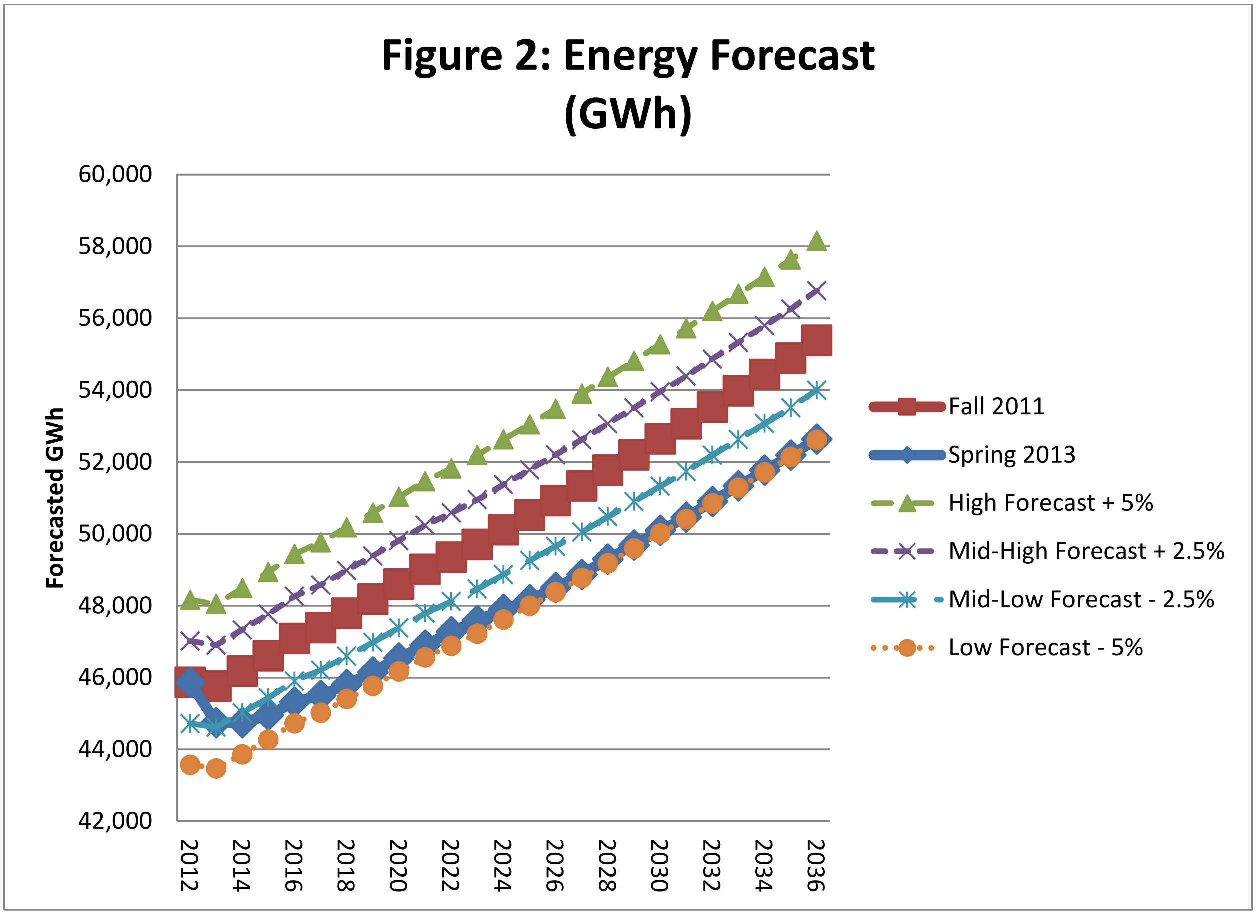
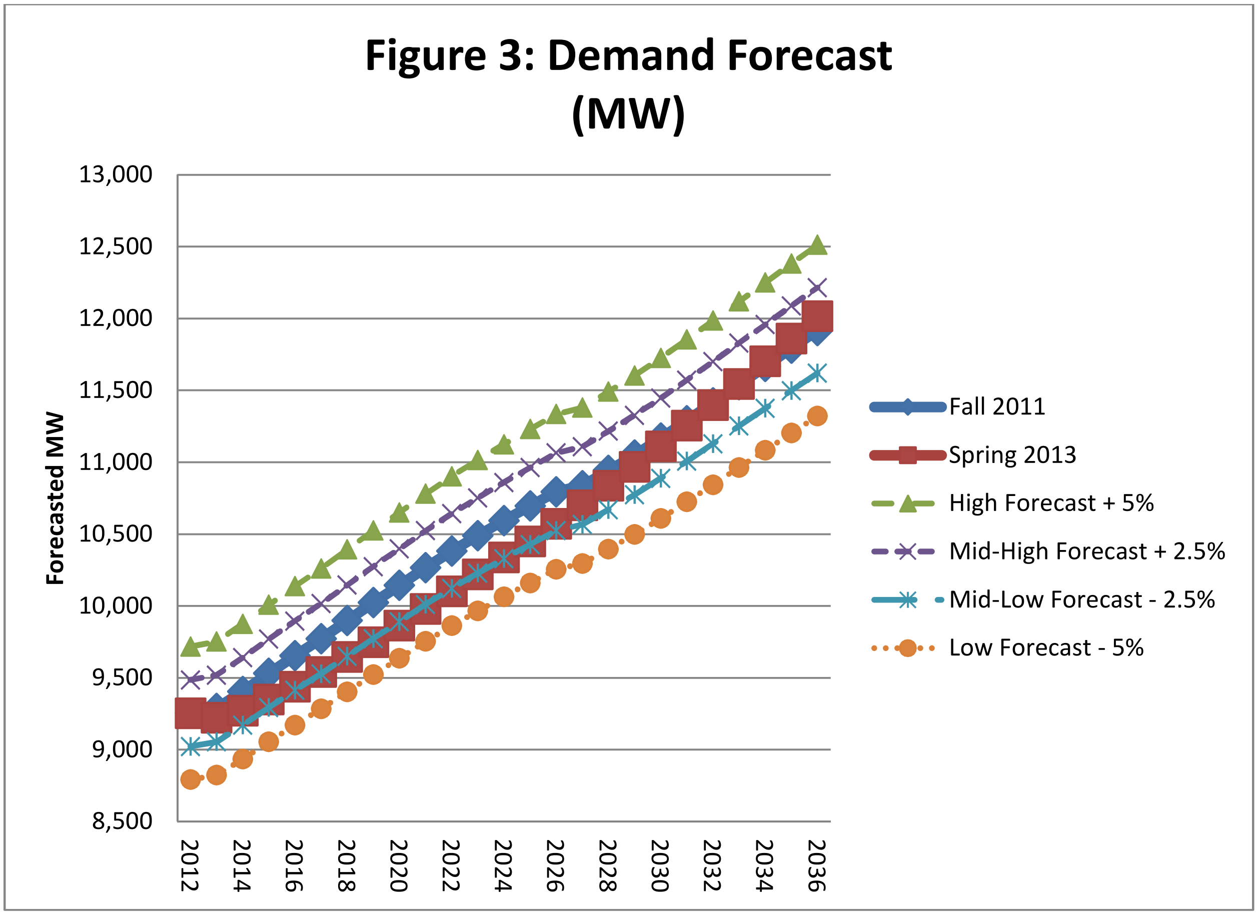


Figure 2: Energy Forecast
(GWh)
Forecasted GWh
60,000
58,000
56,000
54,000
52,000
50,000
48,000
46,000
44,000
42,000
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Fall 2011
Spring 2013
High Forecast + 5%
Mid-High Forecast + 2.5%
Mid-Low Forecast - 2.5%
Low Forecast - 5%



Q. What do you observe from Figures 2 and 3?

A. While the energy portion of the spring 2013 forecast is barely within the range indicated by the low forecast (-5 percent contingency) for the period of approximately 2015 to 2036, demand for this same period is within the mid-low forecast (-2.5 percent contingency) and very close to the fall 2011 forecast in the later years (i.e., approximately equal to the fall 2011 forecast in later years. Nonetheless, these Figures show that, overall, the 2013 spring forecasts (both demand and energy) are within the various contingencies modeled by Department Witness Dr. Steve Rakow, based on the fall 2011 forecast.

Q. Based on this information, what do you conclude?

A. As mentioned above, the fundamental goal in certificate of need and resource planning proceedings is not to establish a plan that is least cost under a single forecast but for the plan to be least cost across a wide range of forecasts. Given this goal, the concerns I discuss above, the Commission's decision not to require continual updating of forecasts in the 2010 IRP (i.e. that the need was based on using the fall 2011 forecast), and the fact that the spring 2013 forecast is within the 5 percent contingency modeled, I conclude that Department Witness Dr. Steve Rakow's use of the fall 2011 forecast as a starting point to begin his analysis of assessing the bids is reasonable.

V. NATURAL GAS SUPPLY, DELIVERY AND COSTS

Q. Please identify Xcel Energy's proposal.

A. Xcel's proposal consists of three 215 MW combustion turbine (CT) peaking units with one unit proposed to be placed at the Company's existing Black Dog plant in Burnsville, Minnesota and the other two units at a site in the Red River Valley near Hankinson, North Dakota. The Company on page 1-11 of its Application and Proposal states the following with respect to the CT unit proposed to be placed at the Black Dog site:

> The unit will be fueled entirely by natural gas. Center Point Energy currently serves the Plant site. We plan to secure additional natural gas supply through a competitive process beginning in early 2014. We anticipate that the successful bidder may need to replace the existing pipeline serving the plant with a new higher pressure natural gas line from the Cedar Town Border station to the plant.

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Xcel Energy
Docket No.: E002/M-14-788, E002/M-14-789
Response To: Department of Commerce Information Request No. 2
Requestor: Chris Shaw
Date Received: October 10, 2014

<u>Question:</u>

Was the retirement of the Key City plant included in Xcel's resource need assessment on page 9 of its October 2 filing? If not, how will the Key City retirement affect Xcel's capacity need?

<u>Response:</u>

Yes. The retirement of the Key City plant was incorporated in our resource need assessment included in our September 23, 2014 and October 2, 2014 filings.

Preparer: Mary Morrison
Title: Resource Planning Analyst
Department: Resource Planning and Bidding
Telephone: 612.330.5862
Date: October 20, 2014

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Xcel Energy
Docket No.: E002/M-14-788, E002/M-14-789
Response To: Department of Commerce Information Request No. 3
Requestor: Chris Shaw
Date Received: October 10, 2014

Question:

On pages 7 and 8 of its October 2 filing, Xcel indicates that it used a value based on the 5-year median for the capacity of Sherco 3 and Black Dog 5-2 instead of the 3-year average used by MISO. Please show the effect on Xcel's expected capacity using current UCAP values for Sherco and Black Dog.

Response:

The table below shows a comparison of MISO 3-Year Average and a 5-Year Median UCAP calculation for Black Dog 5/2, all Sherco units, and the NSP fleet

Unit	2014-15 Planning Year 3-Year Average UCAP (MW)	5-Year Median UCAP (MW)
Black Dog 5/2	189[1]	247
Sherco 1	695	694
Sherco 2	676	667
Sherco 3	491[2]	515
NSP Fleet[3]	6,893	6,998

Notes:
1 – The 2012 outage at Black Dog 5/2 has impacted the current MISO 3-Year Average UCAP rating; this will impair the MISO UCAP value through the 2016-2017 planning year.
2 – Following the extended outage of Sherco 3, MISO accredits the unit with a Class Average EFORd factor. This average is based on units of similar size and generation type within the MISO system. The Class Average will impact the unit through the 2015-2016 planning year. Prior to this outage, Sherco 3 maintained an EFORd of less than 3% in non-outage years.
3 – NSP Fleet includes all NSP owned generating units.

Preparer:	Mary Morrison
Title:	Resource Planning Analyst
Department:	Resource Planning and Bidding
Telephone:	612.330.5862
Date:	October 20, 2014

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Xcel Energy			
Docket No.:	E002/CN-12-1240		
Response To:	Department of Commerce	Information Request No.	70
Requestor:	Chris Shaw		
Date Received:	October 10, 2014		

<u>Question:</u>

Is Xcel able to estimate a maximum cost for Calpine's transmission interconnection cost? Has Xcel assessed the likelihood the costs beyond the $1.5 million estimated could be incurred? When will Xcel and Calpine know with certainty what final interconnection costs will be?

<u>Response:</u>

The Company does not have any additional information regarding the Calpine Mankato Energy Center Expansion project's interconnection costs or the likelihood that the costs will exceed $1.5 million. MISO has posted an update on the status of the Calpine project (*identified as* **[TRADE SECRET BEGINS TRADE SECRET ENDS]** *)* with the meeting materials for the MISO Interconnection Process Task Force Meeting scheduled for October 17, 2014.[1] The update indicated that the System Impact Studies for **[TRADE SECRET BEGINS TRADE SECRET ENDS]** are complete and the study report will be published by the end of October. The System Impact Study Report will provide the transmission upgrades required for the interconnection along with a planning level estimate of their costs. The interconnection costs will not become official until all Facility Studies are completed for any required upgrades.

This information marked as Trade Secret Information is per the terms of the October 1, 2013 Fifth Prehearing Order in this matter, and the Trade Secret Information is

[1] Generator Interconnection DPP Studies Update for *October 17, 2014 MISO Interconnection Process Task Force Meeting. File name: 20141017 IPTF Item 02 DPP Study located at:* *https://www.misoenergy.org/Events/Pages/IPTF20141017.aspx*

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only being served on those persons who are authorized by this Order to review this information.

Preparer:	Randall L. Oye
Title:	Analyst, Transmission Access
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Telephone:	612-330-2886
Date:	October 20, 2014

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Xcel Energy			
Docket No.:	E002/CN-12-1240		
Response To:	Department of Commerce	Information Request No.	72
Requestor:	Chris Shaw		
Date Received:	October 10, 2014		

Question:

Please provide an analysis which shows the expected payments for the Calpine proposal under the pricing terms as bid compared to the pricing terms, including the dispatchability payment, as presented in the draft PPA.

Response:

We provide the requested analysis requested as Attachment A to this response.

Attachment A contains pricing specific to the Calpine proposal. This information is Trade Secret Information per the terms of the October 1, 2013 Fifth Prehearing Order in this matter, and is only being served on those persons who are authorized by this Order to review this information.

Preparer:	Jeanette Schuck
Title:	Purchased Power Analyst
Department:	Purchased Power
Telephone:	303.571.7428
Date:	October 20, 2014

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Capacity (Net Capability) - KW:

Original Bid

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Capacity Rate $/KW-Mo.																								

Annual Fixed Payments:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Est. Capacity Payment																								
Total Annual Fixed Charges:																								

Updated Bid

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Capacity Rate $/KW-Mo.																									
Dispatchability Payment - $/kW-Mo.																									

Capacity Payment Factors:	
Assumed DAF:	
On Peak (June-Sept)	
Off Peak (Oct-May)	

Annual Fixed Payments:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Est. Capacity Payment																									
Est. Dispatchability Payment																									
Total Annual Fixed Charges:																									

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Xcel Energy			
Docket No.:	E002/M-14-788, E002/M-14-789		
Response To:	Department of Commerce	Information Request No.	4
Requestor:	Chris Shaw		
Date Received:	October 10, 2014		

Question:

Please provide the basis for the damages amount due to Accredited Capacity Shortfall as provided in Article 10.6 of the PPA with Aurora. Please explain how this damage provision compares to the capacity payment terms in the draft PPAs for the thermal projects.

Response:

Section 10.6 of the Aurora PPA is designed to compensate the Company should Geronimo's project be accredited by MISO for less than 71 percent of nameplate capacity, subject to adjustment in the event MISO changes the solar resource capacity accreditation methodology/calculations that Geronimo relied upon in the contested case proceeding. The damage amount established for an accreditation shortfall is based on a proxy of actual capacity costs.

The accredited capacity risk in the thermal PPAs is different. The risk was not *how much* accredited capacity the Calpine and Invenergy facilities would each achieve under current MISO accreditation calculations for thermal resources, but rather *when* the facilities' capacity would be accredited by MISO, given the uncertainty surrounding the timing of their interconnection to the grid. As a result, Section 10.6 of the thermal PPAs requires Calpine and Invenergy to affirmatively declare when the Company can commit to MISO that it will provide the accredited capacity of their respective facilities into the MISO market. In the event Calpine or Invenergy fail to deliver the accredited capacity after such a declaration to the Company, Section 10.6 specifies that they must pay the Company damages equal to the costs the Company incurs for the replacement accredited capacity it must provide to MISO.

Preparer:	Jeffrey C. Klein / Jessica L. Collins
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Department:	Purchased Power / Purchased Power
Telephone:	303.571.2732 / 303.571.7740
Date:	October 20, 2014

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Comments

Docket No. **E002/CN-12-1240, E002/M-14-788 and E002/M-14-789**

Dated this 23rd day of October 2014

/s/Sharon Ferguson

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