Minnesota Public Utilities Commission

Staff Briefing Papers

Part 1 of 2

Meeting Date: March 25 and 27, 2014 ....March 27 - Agenda Item **2

Company: Xcel Energy

Docket No. E002/CN-12-1240

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

Issue(s): Should the Commission adopt the Administrative Law Judge's report? What action should the Commission take regarding the Competitive Resource Acquisition Proposal and Competitive Bids?

Staff: Tricia DeBleeckere / tricia.debleeckere@state.mn.us...................651-201-2254

Relevant Documents

Commission – Order Closing Docket, Establishing new Docket, and Schedule for competitive Resource Acquisition Process...November 21, 2012

(DOCKET 10-825) Commission – Order Approving Plan, Finding Need, Establishing Filing Requirements and Closing Dockets...March 5, 2013

Proposals

Calpine – Other – Expansion Proposal (Trade Secret)..April 15, 2013

Geronimo – Other-Distributed Solar Proposal...April 15, 2013

Geronimo – Other-Appendix A – Completeness Checklist.....................................April 15, 2013

Geronimo – Other-Appendix B – List of Acronyms...April 15, 2013

Geronimo – Other-Appendix C – TS Detailed DEGZ Maps (Trade Secret)	April 15, 2013
Geronimo – Other-Appendix D – TS DEGZ Numbers & Locations (Trade Secret)	April 15, 2013
Geronimo – Other-Appendix E – TS PVSYST Models (Trade Secret)	April 15, 2013
Geronimo – Other-Appendix F – TS Strategist Assumptions (Trade Secret)	April 15, 2013
Geronimo – Other-Appendix G – Typical Solar Array	April 15, 2013
Geronimo – Other-Appendix H – TS Desktop Review (Trade Secret)	April 15, 2013
Geronimo – Other-Appendix I – Emissions Displacement Analysis	April 15, 2013
Geronimo – Other-Appendix J – Form Solar PPA	April 15, 2013
Great River Energy – Proposal (Trade Secret) [1]	October 15, 2013
Invenergy – Other Part 1 of 2 and Part 2 of 2 (2 Parts – Trade Secret)	April 15, 2013
Xcel Energy – Other – Competitive Acquisition Proposal and CN	April 15, 2013
Xcel Energy – Other – Appendix C – Operational and Cost Data	April 15, 2013
Commission – Notice and Order for Hearing	June 21, 2013
Calpine – Testimony – Hibbard Direct – Non-Public	September 27, 2013
Calpine – Testimony – Thornton Direct	September 27, 2013
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Invenergy – Testimony – Ewan Attachment 1-3 Trade Secret (3 Parts)	September 27, 2013
Invenergy – Testimony – Shields Direct and Public Attachments	September 27, 2013
Invenergy – Testimony – Shields Attachments 1-2 Trade Secret (2 Parts)	September 27, 2013
North Dakota – Testimony – Mike Diller (Direct)	September 27, 2013
Xcel Energy – Testimony – Direct of Alders, Ford, Wishart, Savage	September 27, 2013
Xcel Energy – Testimony – Direct of Wishart (Trade Secret)	September 27, 2013
Commission – Order Requiring Notice of Changed Circumstances/Intervention	October 4, 2013
Calpine – Testimony – Hibbard Rebuttal – Non-Public	October 18, 2013
Calpine – Testimony – Thornton Rebuttal	October 18, 2013
Department – Rebuttal – Rakow Rebuttal	October 18, 2013

[1] As the filing indicates, the original public and trade secret filing was made on April 15, 2013 (by the deadline) however, on October 15, 2013 GRE requested the original April 15, 2013 filing be redacted and replaced with the properly labeled public, trade secret and highly sensitive designations.

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III. Statement of the Issues

Should the Commission adopt the Administrative Law Judge's report? What action should the Commission take regarding the Competitive Resource Acquisition Proposal and Competitive Bids?

IV. Background – Procedural History

On March 15, 2011, Northern States Power Company d/b/a Xcel Energy (Xcel) filed a petition for a Certificate of Need to renovate and increase the capacity of its Black Dog Generating Plant. Xcel justified its proposal by arguing that the demand for power in its service area would exceed Xcel's capacities by 2014. Consistent with Commission orders, Xcel proposed soliciting proposals from project developers for alternative means to meet Xcel's anticipated power needs. The Commission assigned the matter to Docket No. E-002/CN-11-184.[2]

On December 7, 2011, Xcel asked to withdraw its Certificate of Need (CN) application, arguing that recent events and new data demonstrated that no new generating capacity would be needed by 2014.[3] Xcel continued to argue that it would need new capacity eventually, and continued to propose soliciting proposals from project developers. But given the significant changes in the record, Xcel argued that the Commission should re-establish the amount of capacity to be acquired, and the schedule for acquiring it.[4]

On November 21, 2012, the Commission issued an order largely adopting Xcel's proposal. The Commission agreed with the need to cancel the Black Dog project, and the need to solicit proposals from project developers based on a revised assessment of Xcel's power needs. Given the degree of change, however, the Commission elected to re-start this solicitation process within the context of a new docket. Consequently the Commission initiated the current docket, but took administrative notice of the record in Docket No. E-002/CN-11-184.[5] And the Commission established a procedural schedule, including the expectation that if the Commission referred this matter to the Office of Administrative Hearings (OAH) for contested case proceedings, that office would return a report and recommendation by October 2013.

On January 30, 2013, the Commission issued its Order Approving Notice Plan, directing Xcel to begin soliciting new proposals from developers.

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[2] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for Approximately 450MW of Incremental Capacity for the Black Dog Generating Plant Repowering Project*, Docket No. E-002/CN-11-184, Xcel Petition (March 15, 2011).

[3] *Id.*, Xcel Motion to Withdraw Application (December 7, 2011).

[4] *Id.*, Xcel Reply Comments (September 6, 2012).

[5] This docket and Docket No. E-002/CN-11-184, Order Closing Docket, Establishing New Docket, and Schedule for Competitive Resource Acquisition Process (November 21, 2012).

On March 5, 2013 in the current docket, the Commission issued an order designating April 15, 2013, as the deadline for developers to file proposals to meet some or all of Xcel's need.[6] On the same day, in the 2011 Integrated Resource Plan (IRP) docket, the Commission issued an order declaring that Xcel had demonstrated the need for an additional 150 megawatts (MW) by 2017, increasing up to 500 MW by 2019:

> **A. Xcel's Resource Plan**
>
> Parties from varying perspectives have now had sufficient opportunity to scrutinize and challenge the data and analysis underlying Xcel's resource plan, and have had the opportunity to share their comments with this Commission. Having reviewed these comments along with the rest of the record, the Commission concludes that Xcel's plan is reliable for planning purposes. Consequently, the Commission will approve it, and will close this docket.
>
> The Environmental Intervenors ask the Commission to refrain from approving the plan until Xcel has further refined it by, for example, considering more recent forecast data. And they argue that approval of Xcel's overall resource plan should not relieve Xcel of the duty to justify the acquisition of any specific resource.
>
> The Commission finds that Xcel has fulfilled the requirements of Minn. Stat. § § 216B.2422 and Minn. R. Chap. 7843 governing resource planning. Moreover, Xcel filed revised forecasting data less than three months ago. Rather that attempting to address the Environmental Intervenors' concerns by ordering a further revision of forecasting data, the Commission will refer these concerns to Xcel's next resource plan that Xcel is due to file in the next 11 months.
>
> Finally, the Commission notes that it is approving Xcel's plan for planning purposes only. This approval does not relieve Xcel from the need to comply with any regulatory review required for any specific resource it might pursue in implementing this plan.
>
> **B. Competitive Resource Acquisition Process**
>
> The current resource planning docket will have a direct bearing on Xcel's competitive bidding process. In particular, the current docket supports the finding that Xcel will need an additional 150 MW in 2017, increasing up to 500 MW by 2019. Moreover, a broad range of resources could contribute to meeting this need, justifying solicitation of a broad range of proposals. In particular, Xcel should invite proposals for meeting all of the forecasted need, or any part of it. Xcel should invite proposals for adding peaking resource, intermediate resources, or a combination of the two. Xcel should invite proposals that rely on building new generators, as well as proposals that rely on existing generators.

[6] This docket, Order Extending Bidding Deadline and Refining Procedural Framework (March 5, 2013).

> Commentors largely agree about the advantages of considering a broad range of potential resources. While the Department recommends that the Commission direct Xcel to seek gas-fueled sources of generation in particular, the Commission is not persuaded of the need to prohibit consideration of other alternatives. Rather, the Commission is willing to rely on the bid evaluation process to identify the best alternatives, regardless of type.
>
> In contrast, parties disagree about the magnitude of Xcel's needs. For example, the Environmental Intervenors and the Large Power Intervenors argue that the 500 MW figure may exceed customer demand. In contrast, Calpine and the Department argue that the 500 MW figure is justified, and may even be too low.
>
> The idea that Xcel will need an additional 500 MW by 2019 is well-supported in the record. Indeed, Xcel had previously argued that it would need up to 600 MW of additional capacity – and Xcel generated this estimate before it cancelled plans to add 118 MW of new capacity to its Prairie Island plant.
>
> For purposes of Xcel's competitive bidding docket, the Commission finds it appropriate to solicit proposals for *an additional* 150 MW in 2017, increasing *up to* 500 MW by 2019. This statement does not preclude Xcel from acquiring more than 150 MW of new resources by 2017. Those choices will be made in the context of the resource acquisition docket, based on the proposals and the evidence adduced in that docket.
>
> Finally, Xcel asks the Commission to identify the magnitude of Xcel's forecasted need in each of the years 2017, 2018, and 2019, on the theory that this information would be useful to potential bidders. In contrast, Calpine and the Department argue that Xcel's figures suggest an unwarranted degree of precision in the forecasting process. Calpine even suggests that the figures could discourage potential bidders by signaling that Xcel has selected need specifications to justify a pre-determined conclusion.
>
> The Commission concludes that the degree of specificity in Xcel's statement of resource need is unnecessary. A statement that Xcel anticipates needing an additional 150 MW by 2017, increasing up to 500 MW in 2019, will suffice to inform potential bidders of the scope of projects that the Commission will be considering.

Regarding solar resources, the Commission's March 5, 2013 Order required the following:[7]

[7] See *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, Docket No. E-002/RP-10-825, Order Approving Plan, Finding Need, Establishing Filing Requirements, and Closing Docket (March 5, 2013).

> In its next resource plan Xcel shall address, in addition to the issues set forth in the Commission's Order Establishing Procedural Schedules and Filing Requirements (November 30, 2012), the following issues:
>
> > a. Solar Energy: Xcel shall report on the expected amount of solar energy on its system, barriers it sees to further solar deployment, and how solar development could contribute to peak demand management, economic development in Minnesota, and meeting Minnesota's renewable energy and environmental mandates and goals.

On April 15, 2013, the Commission received competitive proposals from:

- Calpine Corporation (Calpine),
- Geronimo Energy, LLC (Geronimo),
- Great River Energy (GRE),
- Invenergy Thermal Development, LLC (Invenergy), and
- Xcel.

On May 24, 2013, Minnesota Governor Mark Dayton signed into law Minnesota's Solar Energy Standard (SES).

On July 16, 2013, Xcel filed a petition with the Commission for approval of the acquisition of 600 MW of wind energy and subsequently filed a second petition for the approval of the acquisition of an additional 150 MW.

On October 1, 2013 Xcel filed a notice of changed circumstances (750 MW of wind acquisitions) in both its 2010 IRP docket and the current docket.

In October 2013, public and evidentiary hearings were on the Competitive Resource Acquisition Docket at the Minnesota State Office Building in St. Paul, Minnesota.

On December 13, 2013, the Commission approved Xcel's Petitions to acquire 750 MW of wind generation.

In the current docket, the Administrative Law Judge (ALJ) Recommendations filed on December 31, 2013, recommended that the Commission:

- select the solar bid for 100 MW of solar power, which the ALJ Recommendations conclude would provide Xcel with 71 MW of accredited capacity;
- determine whether additional capacity beyond 71 MW is needed before the end of 2019;
- if additional capacity is needed, select GRE's capacity-only proposal; and
- direct Xcel to undertake Power Purchase Agreement ("PPA") negotiations with the selected offerors.

On February 28, 2013, in Commission Docket E002/M-14-162, Xcel filed a notice of its intent to issue an All-Solar request for proposals (RFP) for 150 MW of solar in order to comply with the new SES and to utilize the full Investment Tax Credit set to expire at the end of 2016. [8]

V. Relevant Law

This case involves several different areas of Minnesota statute and rule. First, Minn. Stat. § 216B.2422 provides that a utility may select resources to meet its projected energy demand through a bidding process approved or established by the Commission. The statute further provides that a Certificate of Need is not required for the resource selected through that process.

In Xcel Energy's 2004 IRP (E002/RP-04-1752) the Commission approved the use of the competitive resource acquisition process. Within the approved process are two tracks:

- Track One to be utilized in instances where Xcel *is not* proposing a competing proposal
- Track Two, to be utilized in instances where Xcel Energy *is* proposing a self-build option

Approval of the acquisition process (and background information) is available in the Commission's May 31, 2006 *Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat.§ 216B.2422, Subd. 5, and Requiring Compliance Filing.*[9] This Order provided that the Track Two process would use the certificate of need framework, or certificate-of-need-like process when Xcel submits a self-build proposal as the certificate of need "decision criteria are clear, comprehensive, directly relevant to resource procurement, and easily transferrable to the resource procurement process." The specifics are further outlined in Xcel's August 28, 2006 Compliance Filing – Resource Acquisition Process, available in E002/RP-04-1752 Docket. The certificate of need criteria are listed in Appendix A to this document.

VI. Background - Xcel's 2010 Integrated Resource Plan

On August 2, 2010, Xcel filed its 2011 resource plan under Minn. Stat. § 216B.2422 and Minn. R. 7843.0400, subps. 1-4, covering the period 2011-2025.

Xcel's 2011 IRP included numerous revisions to its energy and demand forecasts, several changed circumstances, and canceled action plans. Because Xcel's December 2011 Update to the Resource Plan was, in effect, an entirely new resource plan with significantly different projections of need, the parties did not file comments until June 2012. Xcel further revised its need in the Company's August 2012 reply comments.

The Department's initial comments expressed concerns regarding Xcel's forecasts, particularly the Company's permanent downward shift to its energy and demand growth rate as well as the statistical model itself. The Department concluded that Xcel's modeling "is not well designed to

[8] See Commission Docket No. E002/M-14-162 – Xcel Energy Notice of Solar Resource Acquisition Plan, dated February 28, 2014

[9] Commission May 31, 2006 Order Establishing Resource Acquisition Process.

achieve a reasonable forecast."[10] However, the Department developed broad ranges of forecasts, noting that "in the context of resource planning, these issues can be addressed by using the usual ranges of forecasting in capacity expansion models. Therefore, the Department recommends approval of Xcel's energy forecast and the Department's peak demand forecast for planning purposes only."[11]

The Department recommended Xcel obtain 400 to 600 MW of natural gas capacity in 2017-18 and concluded at least half the acquisition should be combined cycle generation. In its reply comments, Xcel agreed with the Department "that 400 to 600 MW is a reasonable target for the Company's resource acquisition process."[12]

On October 22, 2012, in a separate docket, Xcel filed comments proposing to discontinue its plans for a 117 MW uprate in generating capacity at the Prairie Island Nuclear Generating Plant.[13] Emphasizing the urgency to begin a resource acquisition process, the Department requested additional time to assess the effects of the uprate before making a final size, type, and timing determination to be considered in the resource acquisition process. Thus, the final round of modeling in the resource plan was filed by Xcel and the Department in December 2012.

The Commission's November 30, 2012 and March 5, 2013 orders reflect the party positions, and staff does not repeat these here. However, it is staff's view that the Commission's determination of need was not intended to be an exact declaration to prospective bidders. To the contrary, the Commission deliberately did not adopt Xcel's recommendation that the Commission establish the size and timing at 154 MW in 2017, 319 MW in 2018, and 443 in 2019, because exact numbers were too specific.

The Department recommended the Commission "order Xcel to pursue up to 500 MW of natural gas fired (peaking and intermediate) capacity for implementation in the 2017 to 2019 time frame. The specific type of capacity should be determined based upon actual bids submitted in the competitive resource acquisition proceeding."[14] Thus, the Commission's order in the resource plan regarding need was an amalgamation of the recommendations from the Company and the Department. The Commission's intention for coming to a conclusion at all was to establish some structure to the resource acquisition docket, even though the size, type, and timing question was not fully fleshed out. According to the Commission's March 5, 2013 order in the resource plan:

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[10] Department of Commerce, June 12, 2012 Initial Comments, Docket No. 10-825, Xcel Energy Application for 2011-2025 Resource Plan Approval 2011-2025, p. 6.

[11] Ibid.

[12] Xcel Energy, August 13, 2012 reply comments, Docket No. 10-825, Xcel Energy Application for 2011-2025 Resource Plan Approval, p. 6.

[13] Docket No. E-002/CN-08-509, In the Matter of the Application of Xcel Energy for a Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant.

[14] Department of Commerce, January 18, 2013 reply comments, Docket No. 10-825, Xcel Energy Application for 2011-2025 Resource Plan Approval 2011-2025, p. 4

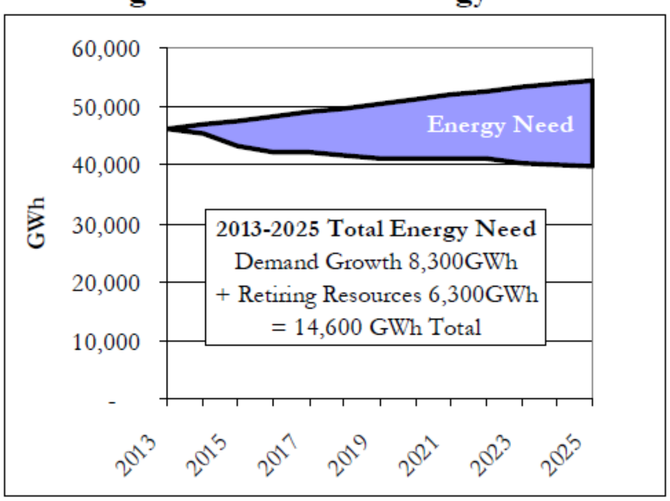
> The Commission concludes that the degree of specificity in Xcel's statement of resource need is unnecessary. A statement that Xcel anticipates needing an additional 150 MW by 2017, increasing up to 500 MW in 2019, will suffice to inform potential bidders of the scope of projects that the Commission will be considering.

2011 IRP Modeling Results

Even though there was lingering dispute over Xcel's base case energy and demand forecasts, the Commission concluded that the range of forecasts in the record supported the need for Xcel to procure additional resources in the 2017-2019 timeframe. Furthermore, the Commission agreed that both peaking and intermediate resources should be considered in the resource acquisition docket.

One modeling result experienced by both the Company and the Department was that the Strategist model was very sensitive to the "type" of resource chosen. The sensitivity analysis resulted in several factors which impacted whether peaking or intermediate generation was preferred, such as the prices assumptions for natural gas and wind and the model's utilization of wholesale energy. However, because Strategist would toggle between peaking and intermediate generation does not mean that Xcel may or may not have a need to acquire energy. As shown in Figure 3, below, the Company's energy need is significant, in large part because of Xcel's plans to retire the coal-fired Black Dog 3 & 4 facilities and retire three smaller peaking resources – Key City, Granite City, and French Island – in addition to expiring purchased power contracts.[15] In fact, as shown in Figure 3 below, the resource plan identified the need for 14,600 GWh of additional energy to meet growing demand and to replace retiring resources.[16] *Figure 3 – 2013-2025 Energy Need from Xcel's 2011-2015 Integrated Resource Plan:*

Figure 3 – 2013-2025 Energy Need

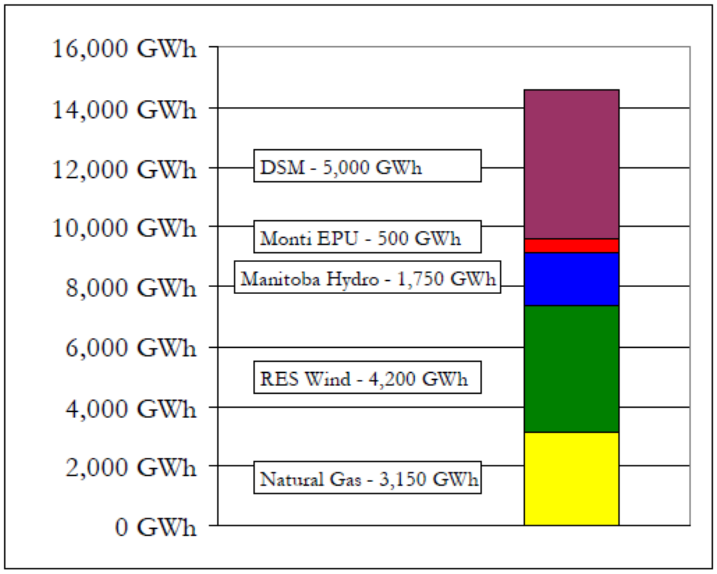


[15] Xcel Energy, July 1, 2013 compliance filing, Fuel Acquisition Plan, Docket No. 10-825, Xcel Energy Application for 2011-2025 Resource Plan Approval, p. 6.

[16] Retirements include the expiration of existing contracts and a loss of 1,529 GWh from the coal-fired Black Dog 3 and 4, which will retire in time to comply with the EPA Mercury and Air Toxics Standards.

Xcel's December 2012 modeling analysis (the final round of IRP analysis) included scenarios which would meet the Renewable Energy Standard (RES) by adding 1,200 MW of wind, achieve 5,000 GWh of Conservation Improvement Program savings, uprate the capability and the Monticello Nuclear Plant, acquire a capacity/energy PPA with Manitoba Hydro, and increase its utilization of natural gas. Xcel's Figure 4 below shows these assumed additions, which represent the Company's strategy to meet its energy requirements, as proposed in its 2011 resource plan.
Figure 4. – 2013-2025 Energy Additions from Xcel's 2011-2025 Integrated Resource Plan Filing:[17]

Figure 4 – 2013-2025 Energy Additions



The 3,150 GWh of energy need supplied by natural gas generation comes from generation at newly constructed plants assumed to be constructed and from higher operating hours at existing facilities. Xcel notes that one reason Strategist toggles between type is because there is a delicate balance between the capital cost versus operating cost characteristics of combined cycle (CC) or combustion turbine (CT) gas units:

> Perhaps the most critical assumptions used in our resource plan modeling are the price of fossil fuels. The cost of fossil fuel implicitly determines the value of renewable generation and energy conservation programs, and the price forecast for natural gas has a significant influence on the selection between low cost peaking units and higher cost, but more fuel efficient, intermediate units.

As the Department noted in their December 2012 comments, an "intermediate plant", in Strategist, can be a gas-fired CC plant, but it could also be gas-fired CT facilities with wind or other energy sources designed to operate more frequently than peaking facilities. According to the Department, "all versions of the Department's modeling show that there are two plans for

[17] Xcel Energy, July 1, 2013 compliance filing, Fuel Acquisition Plan, Docket No. 10-825, Xcel Energy Application for 2011-2025 Resource Plan Approval, p. 8.

providing an intermediate resource that are close in total cost terms." Seven of the top ten plans have one CC unit and one CT unit added in 2017 to 2019. The other three plans all show two CT units added between 2017 and 2019 along with 200 MW of wind.[18]

Sherco Study

On July 1, 2013, Xcel filed its Sherco Life Cycle Management Study to examine the feasibility and cost-effectiveness of continuing to operate, retrofitting, or retiring Sherburne County (Sherco) Generating Station Units 1 and 2. Together, Sherco 1 and 2 provide almost 1,400 MW of capacity and fulfill approximately 20 percent of Xcel's energy requirements. The Sherco study revealed that a number of future environmental regulations could trigger the installation of emissions controls, and the projected costs for those technologies could be similar to scenarios which retire the units.

The Department did not file comments in Xcel's Sherco Study proceeding. However, the Department did evaluate the costs of retiring Sherco in the resource plan. In their June 12, 2012 initial comments, the Department states:

> In summary, shutting down Sherco 1 and 2 would impose significant costs on Xcel's system and require immediate acquisition of significant resources; the typical expansion plan changes from the base case by acquiring over 1,400 MW of additional fossil-fuel resources (largely combined cycle units) combined with an additional 600 to 1,200 MW of wind.[19]

The Commission's order in the Sherco Study proceeding delayed Xcel's 2014 IRP filing date to July 1, 2014.[20] Among other requirements, the Order will require Xcel to study Sherco's retirement "in more detail in Xcel's next resource plan."[21]

2. Xcel shall file its next resource plan by July 1, 2014. As part of that filing, Xcel shall do the following:

> a. Evaluate the feasibility and cost-effectiveness of continuing to operate, retrofitting, repowering, or retiring Sherco Units 1 and 2.
> b. Analyze retiring Sherco Units 1 and 2 in 2020 and thereafter.

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[18] Department of Commerce, December 18, 2012 comments, Docket No. 10-825, Xcel Energy Application for 2011-2025 Resource Plan Approval 2011-2025, p. 11.

[19] Department of Commerce, June 12, 2012 Initial Comments, Docket No. 10-825, Xcel Energy Application for 2011-2025 Resource Plan Approval 2011-2025, p. 26 6

[20] Commission order, Docket 13-368, February 27, 2014.

[21] Ibid.

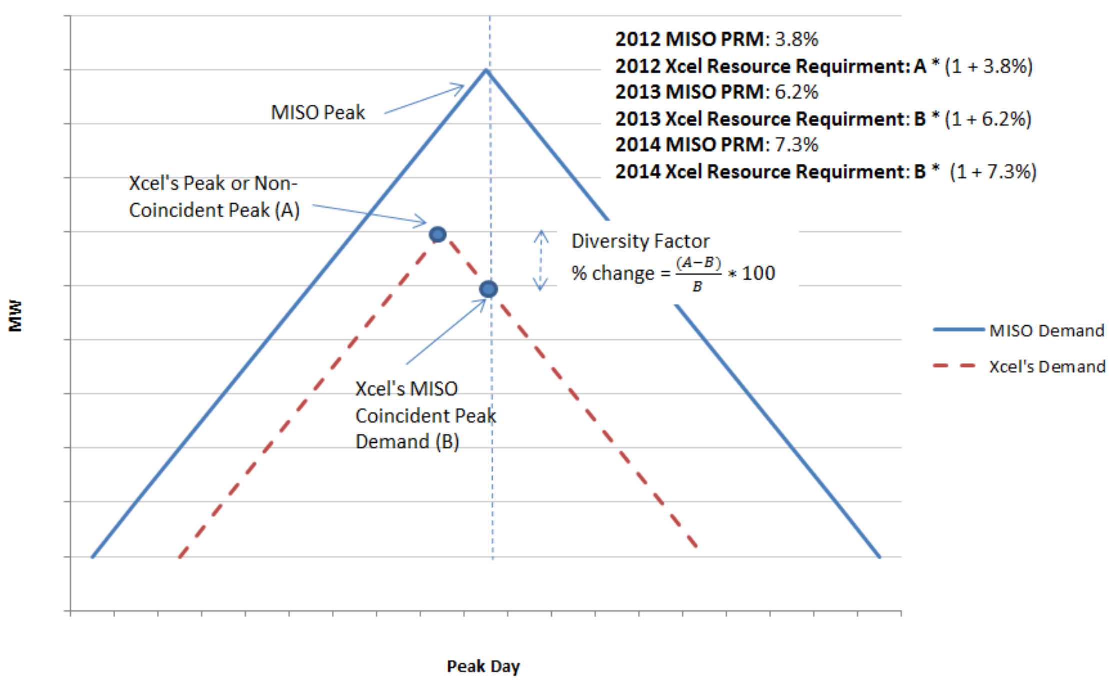
VII. 2013-2014 MISO Planning Reserve Margin Methodology Changes

In 2012, when Xcel's IRP was considered by the Commission, MISO utilities were required to carry planning reserves of approximately 12% of installed capacity (ICAP) above an Load Serving Entity's (LSE's) individual (non-coincident) peak.[22, 23] When this previously used ICAP requirement is translated into the application of unforced capacity value (UCAP), this amounts to a 3.8 % reserve margin on Xcel's peak demand. Staff refers to the 'old' method as the non-coincidental peak method.

For the 2013/2014 planning year, MISO made two modifications to its Resource Adequacy construct per Module E. First, MISO changed its planning reserve margin (PRM) methodology to be based off a utility's coincident peak (instead of the non-coincidental peak). A LSE's coincident peak is the LSE's load at the time of the MISO system wide peak.

Second, MISO changed its 2013/2014 planning reserve margin (UCAP) to 6.2%, however, for the 2014/2015 planning year, MISO modified the PRM (UCAP) from 6.2 to 7.3%. See Figure 1 below for representation of the change.

Figure 1. MISO Reserve Margin Calcuation Changes



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[22] Xcel's 2011-2025 Integrated Resource Plan, pg. 3-18 to 3-19.

[23] This 12% included a system-wide adjustment to account for diversity in the region.

VIII. Competitive Proposals Submitted in this Docket

In this Competitive Resource Acquisition Process (CRP) the following projects were proposed:

- **Calpine**: expand the existing natural-gas-fired Mankato Energy Center combined cycle turbine (CC) by 290 MW of intermediate capacity and 55 MW of peaking capacity (also referred as CCCI);
- **Geronimo**: build up to 100 MW of solar generation using photovoltaic panels, located on up to 20 sites adjacent to substations, ranging from 2 to 10 MW per site,
- **GRE**: two capacity credit proposals to sell Xcel Midcontinent Independent System Operator (MISO) Zone 1 Resource Credits (ZRCs);[24]
- **Invenergy**: two peaking proposals for gas-fired combustion turbines (CT):
  - expand the existing Cannon Falls facility by 179 MW with one CT unit, and
  - build the new 357 MW Hampton Energy Center with two CT units;
- **Xcel**: two peaking proposals for gas-fired combustion turbines
  - build one 215 MW CT unit at the existing Black Dog generating station (Black Dog unit 6); and
  - build two 215 MW (430 MW) CT units at a new site near Hankinson, North Dakota (North Dakota units 1 and 2).

IX. Parties to the Contested Case Proceeding

	Filed Proposal	Filed Testimony	Filed Rebuttal Testimony	Filed Brief	Filed Reply Brief	Filed Exceptions	Filed Reply Exceptions
Calpine	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Department	No	Yes	Yes	Yes	Yes	Yes	Yes
Environmental Intervenors	No	No	No	Yes	No	No	Yes
Geronimo	Yes	Yes	Yes	Yes	Yes	Yes	Yes
GRE	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Invenergy	Yes	Yes	Yes	Yes	Yes	Yes	Yes
ND PSC	No	Yes	No	No	No	No	No
Xcel	Yes	Yes	Yes	Yes	Yes	Yes	Yes

X. Party Positions

A. Xcel Energy

Xcel recommended that the Commission select the Black Dog Unit 6 (BD6) proposal in conjunction with either the Invenergy Cannon Falls proposal or Calpine's Mankato expansion proposal. Xcel argued that that both the Invenergy and Calpine proposals should proceed to the

[24] A ZRC is a credit for resources that count towards MISO's resource adequacy requirements. By selling ZRCs GRE would provide Xcel resources that would count for reliability purposes. However, GRE's proposal would not provide Xcel energy production rights. DOC-DER Ex. 83 at 2 (Rakow Direct).

power purchase agreement (PPA) negotiation phase to determine which one of the two would provide the best value for Xcel's customers. If neither proposal proceeds past the PPA phase, Xcel recommends the Commission select Xcel's Red River Valley Unit 1 proposal in combination with Xcel's Black Dog Unit 6. Xcel also recommended that needs updates be provided by Xcel to the Commission in the Fall of 2014 and 2015 so the Commission can assess if changes (delays or cancellations) in resource implementation should be made.

1. Xcel's Updated Forecast Shows a Reduced System Demand

Xcel introduced updated resource need information (September 2013 Update) into this record to include the most recent evidence on its anticipated need in the 2017-2019 timeframe. Based on the September 2013 Update, Xcel projects a 93 MW capacity deficit in 2017, increasing up to 307 MW in 2019 (see Table 2 – September 2013 – Resource Need Assessment from the Direct Testimony of S. Wishart). This update reflects Xcel's spring 2013 forecast, updated unit capacity ratings, the impact of the solar energy standard (SES), and an updated forecast of load management resources.[25]

Xcel believes the Commission should account for all reasonable circumstances and uncertainty regarding changes to forecasted demand.

Table 2 – September 2013 - Resource Need Assessment

	Resource Plan Docket			September 2013 Update			Change		
	2017	2018	2019	2017	2018	2019	2017	2018	2019
Peak	9,613	9,708	9,799	9,500	9,590	9,676	- 112MW	- 118MW	- 123MW
RM%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	0.0%	0.0%	0.0%
Total Obligation	**9,977**	**10,076**	**10,170**	**9,860**	**9,953**	**10,042**	**- 117MW**	**- 123MW**	**- 128MW**
Resources									
Coal	2,331	2,331	2,331	2,367	2,367	2,367	36	36	36
Nuclear	1,610	1,610	1,610	1,623	1,623	1,623	12	12	12
Gas	3,437	3,424	3,424	3,427	3,416	3,416	(9)	(8)	(8)
Wind, Hydro, Bio	1,280	1,229	1,202	1,238	1,189	1,162	(42)	(40)	(40)
Solar	9	10	11	49	66	83	40	56	72
Load Management	1,157	1,153	1,149	1,063	1,074	1,085	(95)	(79)	(65)
Total Resources	**9,824**	**9,758**	**9,728**	**9,768**	**9,735**	**9,735**	**(57)**	**(23)**	**8**
Long (Short)	**(153)**	**(318)**	**(443)**	**(93)**	**(218)**	**(307)**	**+60MW**	**+100MW**	**+136MW**

[25] The SES is a new requirement of 2013 statutes (Minn. Stat. § 216B.1691, Subd. 2f), and applies only to investor-owned utilities. The SES requires 1.5% of total retail electric sales to come from solar PV by 2020. Certain categories of business customers sales are excluded, and those customers are exempted from paying related costs.

2. *Xcel's Updated Forecast Based on MISO Changes*

Notably, Xcel's September 2013 Update (Table 2, above) did not include changes to MISO's PRM for the 2013/2014 Planning Year (changes discussed above in Section VII). [26] the MISO PRM changes affect Xcel's need as shown by Table 4 from Direct Testimony of S. Wishart.

Table 4 – Impact of MISO's Reserve Margin On Resource Need Assessment

	September 2013 Update			MISO 2013 Reserve Margin Adjustment			2014 Anticipated Reserve Margin		
	2017	**2018**	**2019**	**2017**	**2018**	**2019**	**2017**	**2018**	**2019**
Peak	9,500	9,590	9,676	9,500	9,590	9,676	9,500	9,590	9,676
Coincidence Factor	100%	100%	100%	95%	95%	95%	95%	95%	95%
Coincident Peak	9,500	9,590	9,676	9,025	9,110	9,192	9,025	9,110	9,192
RM%	3.8%	3.8%	3.8%	6.2%	6.2%	6.2%	7.3%	7.3%	7.3%
Total Obligation	**9,860**	**9,953**	**10,042**	**9,585**	**9,675**	**9,762**	**9,684**	**9,775**	**9,863**
Resources									
Coal	2,367	2,367	2,367	2,367	2,367	2,367	2,367	2,367	2,367
Nuclear	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623
Gas	3,427	3,416	3,416	3,427	3,416	3,416	3,427	3,416	3,416
Wind, Hydro, Bio	1,238	1,189	1,162	1,238	1,189	1,162	1,238	1,189	1,162
Solar	49	66	83	49	66	83	49	66	83
Load Management	1,063	1,074	1,085	1,063	1,074	1,085	1,063	1,074	1,085
Total Resources	**9,768**	**9,735**	**9,735**	**9,768**	**9,735**	**9,735**	**9,768**	**9,735**	**9,735**
Long (Short)	**(93)**	**(218)**	**(307)**	**183**	**60**	**(26)**	**84**	**(40)**	**(128)**

Xcel believes it is appropriate to continue this resource acquisition process even in light of the MISO reserve margin changes as the evolving process introduces too much uncertainty at this time – and this should be further reviewed over the next year rather than decided upon in this proceeding.

Xcel argued that it is important to continue to monitor changes in the determination of the resource adequacy in the MISO markets to see if delay or even cancellation of one or more of the selected units may be warranted. Xcel recommended that the Commission require Xcel to file status reports in the Fall of 2014 and 2015 so the Commission can assess if changes in resource implementation should be made. Due to the uncertainty surrounding Xcel's capacity deficit, Xcel explored the option of flexible in-service dates of the Calpine and Invenergy proposals (during Direct Testimony) and believes that PPA negotiations should address the viability of delay and cancellation options for these projects.[27]

Xcel agreed that continuing soft forecasts and the evolving MISO capacity reserve requirements could reduce or eliminate the Xcel's projected need. However, Xcel believes it is prudent to plan

[26] Staff notes that the 3.8 percent reserve margin shown in the table is a UCAP reserve margin, but Xcel's 2011 IRP employed the ICAP method to plan reserves.
[27] See Rakow Rebuttal Testimony – Trade Secret Attachment IRs from Xcel Energy to Calpine and Invenergy Dated Sept.12, 23 and 25 at SR-R-9 at Pg. 1-6.

its system to maintain a reasonable amount of resources above its individual peak demand while acknowledging the changing nature of MISO's resource adequacy construct. Xcel recommends that need updates could be regularly filed with the Commission to strike a balance between deploying new resources while maintaining options if the need decreases. Xcel believes this is especially important in light of the timeliness involved in building power plants. As the provider of last resort, Xcel indicated it was not in their interest to be short – which could happen - Xcel argued, if it doesn't deploy new capacity and the need materializes.

Xcel does not believe that the MW need shown in Table 4, above, should be used to replace the Commission's determination of 500 MW of need by 2019. The year-to-year instability of MISO's reserve margin is not conducive to resource planning, and Xcel noted that MISO has acknowledged the issue of long-term planning criteria and intends to address it in 2014.

For planning purposes, Xcel calculated their average difference between their system's non-coincidental peak and it's MISO's coincidental peak to be 95% (coincidence factor). The 95% was used to project future years' total obligations, as shown above in Table 4.

However, as shown in Table 3-3, below, Xcel's historical diversity factor (or inversely, coincidence factor) has been as low as 0 percent but as high as 14 percent since 2006.[28]

Table 3-3
NSP and MISO Peak Demand

Year	NSP Load at Time of MISO Peak	NSP Peak Load	Difference	Coincidence Factor	Diversity Factor
2005	8,457MW	9,104MW	-647MW	93%	**7%**
2006	9,855MW	9,859MW	-4MW	100%	**0%**
2007	8,184MW	9,473MW	-1,289MW	86%	**14%**
2008	8,678MW	8,694MW	-16MW	100%	**0%**
2009	7,975MW	8,609MW	-634MW	93%	**7%**
2010	8,463MW	9,131MW	-668MW	93%	**7%**
2011	9,621MW	9,623MW	-2MW	100%	**0%**
2012	8,796MW	9,475MW	-679MW	93%	**7%**
				Average	**5%**

A one percent change in the diversity factor results in an approximately 100 MW difference in need, as demonstrated in Table 4, above, by the increase in MISO's 2014 reserve margin from 6.2 to 7.3%. As the Department found during discovery - a variety of diversity factors may be reasonable to use (lower and higher) in this calculation. Further, the Department pointed out that the level of reduced demand (through DSM) that can be achieved at *Xcel's* utility peak may not be as great at the time of the MISO system peak – both factors adding uncertainty to the revised demand numbers Xcel provided in Table 4.

[28] Xcel's Initial Proposal and CN Filing, page 3-7.

3. *Cost Recovery for the Black Dog Unit 6 Proposal*

Xcel provided a specific cost-recovery mechanism for its proposals which utilized elements of the mechanism developed for the Metropolitan Emissions Reduction Project (MERP) in Docket No. E002/M-02-633, which Xcel believes was a successful method of containing capital costs for new generation. This method adjusts the return on equity of a specific unit be adjusted up or down to reflect any difference between the estimated and actual capital costs of the project – for the first five years of rate recovery. Further detail is provided in Xcel's Initial Post-Hearing Brief. However, the Department provided notice to bidders that they were to be held to the costs provided in their proposals (due to the competitive nature of the process), and Xcel, indicated that due to the unique circumstances in this case and the record developed, the Company does not object in principle to the Department's proposed alternative (that bidders be held to the costs proposed in their proposals).[29]

4. *Alternatives Analysis*

Xcel conducted its analysis and concluded that its Black Dog Unit 6 has demonstrated to be the superior proposal, however, noted is not large enough to fulfil the entire need demonstrated in the record and recommended that Invenergy's Cannon Falls (ICT1) proposal and Calpine's Mankato expansion (CCC1) be selected to proceed to PPA negotiations.

5. *Strategist versus Levelized Cost of Energy*

Xcel utilized Strategist to analyze the proposals provided in this competitive process. Xcel believes that Strategist is superior to Calpine's (and Geronimo's) levelized cost of energy (LCOE) analysis for several reasons (Calpine and Geronimo's LCOE results are provided in further detail below in each Party Position section). Xcel believes that an LCOE analysis is only appropriate when comparing very similar resources of the same type where cost is the principal, if not only, distinguishing factor between the resources – which doesn't apply in this proceeding where peaking/intermediate, dispatchable/non-dispatchable, natural gas, solar, and PPA /utility-owned resources are considered.[30] Xcel believes that Strategist is the most appropriate tool to use in this circumstance in that it can examine both the costs of the proposed resources and their widely varying benefits. Xcel argued that a LCOE analysis fails to provide a complete cost-benefit analysis since it only focuses on the various costs of a proposal.

6. *Xcel's Strategist Assumptions and Analysis*

Xcel used a capacity credit range of $5-7 kW-month in order to give addition value to large portfolios (so that larger proposals were not unfairly disadvantaged).[31] Regardless, in Xcel's analysis, the capacity credit did not appear to have a substantial impact on the ranking of

[29] See Ex. 82 (Shaw Rebuttal) at 2-3.

[30] Wishart Rebuttal at 15-16.

[31] A Strategist capacity credits is a monetary value assigned in Strategist to provides value to excess capacity beyond what is needed on the system at any time.

resources. Further, Xcel argued, the Department *did not* use assigned a capacity credit – and its conclusions were similar to those of Xcel.

Regarding generic units, Xcel used internal estimates for the price of generic solar and natural gas additions (generic units are plants added in later years of the model to fill identified needs as other plants retire or PPAs terminate). The generic unit prices Xcel used (which were the same as the Department) for natural gas were higher than the actual proposed prices for natural gas facilities, while the generic solar units were lower priced than the Geronimo bid. Xcel argued that new natural gas generation facilities are typically on greenfield sites and are therefore are usually higher cost than the three recommended (less expensive) proposals which are on brownfield sites. Xcel does not believe there is record evidence to support claims that their generic units were unfairly priced.

Xcel conducted sensitivity (contingency) analyses on the proposals (high and low natural gas prices, cost sensitivities for capacity credits, no new wind scenario, high and low carbon pricing, and the value of a PPA extension). Xcel indicated that the sensitivities had the effects it had expected on each proposal dependent on what sensitivity was applied – but, ultimately the Company believes that the base case was sound and their recommendation (Black Dog 6 plus Calpine Mankato or Invenergy Cannon Falls) remains appropriate.

Direct testimony from Xcel Witness S. Wishart included a table of the Top 20 plans from the sensitivity analysis. Staff shows the top ten plans from Table 9, below.

Staff note: As shown in the table, whether natural gas is priced high or low significantly factors into the relative cost of the packages which include Calpine, because of the different characteristics between combined cycle generation and peaking generation. Also, whether Invenergy's bid includes firm or interruptible gas supply factors heavily into whether Invenergy is included among the least-cost packages.

Table 9 – Strategist Input Sensitivity Tests (PVSC)
Top 20 Plans

	Selected Bids	Base Case	High Gas	Low Gas	Capacity Credit +$1	Capacity Credit - $1	No 750MW Wind	$0 CO2	$9 CO2	$34 CO2	PPA Extension	Invenergy Firm Gas
1	Invenergy Cannon Falls Black Dog 6											
2	Calpine Mankato Black Dog 6	+ $2	($27)	+ $25	($11)	+ $15	($13)	+ $23	+ $14	($18)	($7)	($29)
3	GRE Short Term Red River Valley 1 Black Dog 6	+ $2	+ $2	+ $4	($4)	+ $9	+ $2	+ $3	+ $3	+ $2	+ $28	($29)
4	Invenergy Cannon Falls GRE Short Term Black Dog 6	+ $5	+ $5	+ $4	+ $5	+ $5	+ $4	+ $4	+ $5	+ $5	+ $5	+ $5
5	Black Dog 6 Red River Valley 1	+ $9	+ $8	+ $12	+ $2	+ $15	+ $8	+ $10	+ $9	+ $9	+ $35	($22)
6	Calpine Mankato Black Dog 6	+ $9	($19)	+ $33	($4)	+ $22	($5)	+ $31	+ $22	($10)	+ $1	($22)
7	GRE Short Term Black Dog 6 Red River Valley 1	+ $10	+ $9	+ $12	+ $3	+ $16	+ $10	+ $11	+ $10	+ $10	+ $36	($21)
8	Invenergy Cannon Falls Black Dog 6	+ $11	+ $11	+ $11	+ $11	+ $11	+ $11	+ $11	+ $11	+ $11	+ $11	+ $11
9	Invenergy Cannon Falls GRE Short Term Black Dog 6	+ $13	+ $13	+ $12	+ $13	+ $13	+ $12	+ $12	+ $12	+ $13	+ $13	+ $13
10	GRE Short Term Calpine Mankato Black Dog 6	+ $14	($14)	+ $37	+ $1	+ $27	($0)	+ $36	+ $27	($5)	+ $6	($17)

Xcel's Strategist modeling included detailed emission inputs for every generation system on Xcel's system, included established costs for environmental externalities and forecasted CO_2 compliance – therefore Xcel argued the Strategist model quantified the value of lower emissions from the non-CT projects. Additionally, the natural gas emission profiles are not very different from each other and the overall effect of emissions on the present value of societal costs (PVSC) is relatively small.

Xcel provided that interruptible fuel supply input for the Invenergy Cannon Falls facility. Xcel believes that was an appropriate assumption for a CT unit under the circumstances in this procurement.

Xcel's Strategist results show that the least cost plan is Invenergy's Cannon Falls in 2016 combined with Black Dog Unit 6 in 2018, the second least cost plan is Calpine's Mankato expansion in 2017 with Black Dog Unit 6 in 2019, and the third least cost plan is GRE's short term capacity credits in 2016 with Xcel's Red River Valley 1 in 2018 and Black Dog 6 in 2019.

7. Calpine's Mankato Proposal versus Invenergy's Cannon Falls Proposal

Xcel compared Calpine's CCC1 to Invenergy's ITC1 (Cannon Falls) facility and outlined the reasons it believed the proposals were competitively priced:

1) ICT1 was modeled using an interruptible fuel supply (unlike BD6 or CCC1);
2) CCC1 had higher capacity payments but cheaper energy payments than ICT1;
3) ICT1 was proposed with a 2016 ISD, which added increased net costs for ICT1; and,
4) CCC1's greater capacity delays BD6 to 2019 which creates additional cost savings over ICT1.

Additionally, Xcel argued that the Strategist modeling shows that both Calpine and Invenergy's proposals (and either CC or CT units) have benefits to Xcel's system, which is why they were so closely ranked in Strategist. Xcel does not believe that the Calpine proposal should be imparted greater value due to its proposal (potentially) hedging against future capacity retirements as Calpine claims (see Calpine section below). Xcel indicated it already has two CC units that are under-utilized [during non- peak times] that are available to hedge again any unforeseen retirements. Xcel also noted that both CC and CT have beneficial traits that assist in the integration of renewables and both are viewed as a valuable resource.

Xcel believes that both Calpine's Mankato and Invenergy's Cannon Falls proposals have equivalent overall costs and value based on the information in their bids and therefore both should proceed to the PPA negotiation phase.

8. Xcel's Red River Valley Proposal

Xcel noted that its Red River Valley (RRV) proposal is located on a green-field site and is therefore not as competitively priced as BD6, CCC1 or ICT1. Xcel only recommends the RRV units if neither the CCC1 or ICT1 units are acceptable upon the completion of the PPA negotiation phase.

9. GRE's Capacity Credit Proposal

Xcel does not recommend the GRE's short term capacity credit proposal since the savings derived from GRE's proposals are due only to the delay of the addition of a long-term resource. The modeling shows there are more cost-effective ways to add long-term resources.[32] Xcel's Post-Hearing Brief at 30 provides:

> The value of the delay is determined by comparing the cost of the GRE proposal during the period of delay to the savings incurred by delaying construction of new generation during that same period. The total cost of the GRE contract is larger than the savings derived from shifting the in-service year of Black Dog Unit 6 from 2018 to 2019.[62] Further, the purchase of short-term capacity credits does not result in the creation of new generating capacity for Xcel Energy's system. At this time, the Company supports deployment of additional capacity to ensure that we have enough generation to meet our customers' needs in the mid-to long-term. In short, it is neither reasonable nor prudent to select a short term resource to delay the need to add a long-term resource when doing so costs more than the savings realized by the delay.

[32] Xcel's Post Hearing Brief at 24 and Post Hearing Reply Brief at

10. Geronimo's Proposal (Ranking, S-RECs, Avoided Costs)

Xcel does not recommend Geronimo's solar proposal (GPV) should be selected since it was not included in any of Strategist's 20-top-ranked plans (ranked at 25). A significant portion of benefits from Geronimo's proposal were due to 1) the accredited capacity assigned to the project and 2) the $21.50/ton CO_2 price assumption. Xcel used the accredited capacity based on the accreditation estimate provided by Geronimo. Xcel believes that estimate is higher than the actual credit that projects will receive in the future based on recent analysis conducted by the Company.[33]

Further, Xcel argued that the avoided cost benefits of the CO_2 and other externalities used in modeling will not accrue to ratepayers; therefore, rate impacts would be higher than those represented by the PVSC result.

Xcel also considered the solar renewable energy credit (S-REC) benefit of the solar proposal, but determined that there was no way to substantiate the value of S-RECs in Minnesota at this time. Further, the Geronimo proposal included the S-RECs in its proposed energy price, therefore, once a PPA was signed with Geronimo, Xcel indicated that those S-RECs would be retired and there would be no value to Xcel other than compliance with its solar energy standard. Once retired, there would be no S-RECs available for sale to realize further savings against the PVSC.

Xcel recommended that the Commission require Xcel to issue an all-solar RFP that would identify the lowest cost solar option available for compliance with the SES.[34]

Xcel estimated that (an overestimate of) transmission line losses could account for approximately $10 million benefit (PVSC) for Geronimo's project. Xcel did not account for that benefit in Strategist; however, and argued that the assumed $10 million PVSC was insufficient to overcome the $34 million PVSC difference of the solar proposal.[35]

Xcel does not believe that there is record support of actual avoided transmission costs arising from Geronimo's proposal and contends that Minnesota Statute § 216B.146 does not contemplate that the value of the avoided transmission of a solar facility should be recognized in addition to the costs a utility pays to add the facility to its system. Xcel also provided that the only transmission that is likely to be avoided by the selection of the solar proposal would be the short lines used to interconnect new natural gas plants that would not be needed as a result of the SES. The cost of the interconnection of each bid was included in modeling and the results show that interconnection represents a very small proportion of each natural gas project's total cost. Xcel believes that Geronimo's estimated avoided transmission capacity cost savings ($33m) are greatly exaggerated since they are based on a calculation from MISO's rate of network

[33] Wishart Direct, page 34.

[34] Xcel Post-Hearing Initial Brief at 27.

[35] Wishart Direct, page 35.

integration service (the average cost rate for service) and are not based on the marginal cost for additional transmission capacity.[36]

Last, Xcel believes that the cost premium associated with the Geronimo solar project is not minor and outweighs the renewable energy benefits. Xcel argued that the solar proposal is substantially more expensive that the resources both Xcel and the Department have recommended and the lowest-cost natural gas proposals are in the public interest. Xcel believes it is contrary to the public interest to select a solar proposal to meet one-third of its SES obligations when there is no evidentiary support that it is cost effective in comparison to other solar options that could meet this mandate.

11. Certificate of Need Criteria

Xcel argued that its analysis is consistent with Minn. Stat. § 216B.2422, that the record establishes that the natural gas proposals are in customers' best interest and it would not be cost effective to purchase a renewable energy option. Further, Xcel provided that it cannot assess the reasonableness of Geronimo's project pricing relative to other solar projects as it was the only solar project proposed.

Xcel argued that the Environmental Report prepared on all proposals did not reveal any land use or environmental factor that would be inconsistent with Minnesota's laws and instead, shows that the socioeconomic impacts of the recommended resources are positive. Xcel argued that nothing in the record indicates that any of its recommended projects would fail to comply with relevant state, state and federal agency and local governmental policies, rules, or regulations.

Xcel's Initial and Reply Post-Hearing Briefs further outline additional statutory and rule criteria that have been established for consideration when selecting among resources and how Xcel believes the record addresses those issues.[37] Xcel provided an explanation of how those preferred resources or resources considerations have been considered on a previous, or on-going basis by Xcel (outside the context of this docket), and/or specifically in this record, and why those state preferred resources were not deemed to be reasonable by Xcel for this procurement. Xcel believes it has fully complied with Minnesota law and the certificate of need criteria through its analysis.

12. PPA Negotiations

Xcel provided that every PPA negotiation must allocate some risks that have not been addressed in the information that parties relied upon to commence negotiations and each parties differing performance, financial, and credit characterizations should be considered in making those allocations.

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[36] Xcel Post-Hearing Initial Brief at 29.

[37] Those criteria summarized by Xcel are: the state renewable preference, compliance with the RES statute, consideration of C-BED alternatives, solar energy standards, distributed generation, demand side management, purchased energy, energy efficiency, new transmission, innovated energy projects, and the no–build alternative.

Xcel believes several issues should be discussed further in PPA negotiations, including: schedule (flexibility in ISDs or cancellation), security funds, carbon dioxide emission costs and allowances, capital lease issues, and project-specific issues (ICT1 fuel-oil storage issues, ICT1 transmission costs, the impact of Calpine's below grade investment rating and its ability to meet Xcel's security fund requirements). Xcel believes that a competitive PPA negotiation process is to the benefit of ratepayers, and otherwise, if the Commission designates a clear winner, the winner will have little incentive to accept ratepayer friendly terms. Further, the PPA negotiations phase would not be contrary to the Track Two process that allows four months for Xcel and the vendor to come to terms on a PPA – after which the PPA is brought to the Commission for review and approval.

Xcel has requested the flexibility in the PPA negotiations to permit an delay of the in-service of the Invenergy and Calpine proposals from 2017 to 2018 or 2019, which both Calpine and Invenergy are on record as being amenable to.[38] Xcel would like to negotiate potential *additional* subsequent in-service date changes and negotiations on those price changes would still need to occur. Further, Xcel argued that the option to terminate the PPA raise significant issues in negotiation - if an early termination clause is negotiated (including the timing of the termination) the cost imposed could be significant – and therefore those negotiations would benefit from competition. Xcel noted that the PPA negotiation process would be transparent and the final PPA would be subject to the PPA parties' comments and Commission review and approval.

B. Department of Commerce

1. Demand Forecast and Need

The Department used Xcel's fall 2011 sales forecast for its base case Strategist analysis. However, since that forecast, Xcel has produced additional forecasts, including its spring 2013 forecast. The Department elected to use the fall 2011 forecast for its base Strategist analysis since 1) the Commission's Order initiating the CRP used Xcel's fall 2011 update, 2) the Department has not yet verified the accuracy of Xcel's spring 2013 forecast, and 3) the Department has significant concerns surrounding the accuracy of the spring 2013 forecast.[39]

Xcel's spring 2013 forecast (compared to the fall 2011 forecast) predicts that its customers will use less energy and capacity in the forecast's initial years and its customers will continue to use less energy while making higher demands on Xcel's peak in future years.[40] Thus, Xcel's updated forecast suggests its system load factor – which measures the utilization rate of its generation – is decreasing.

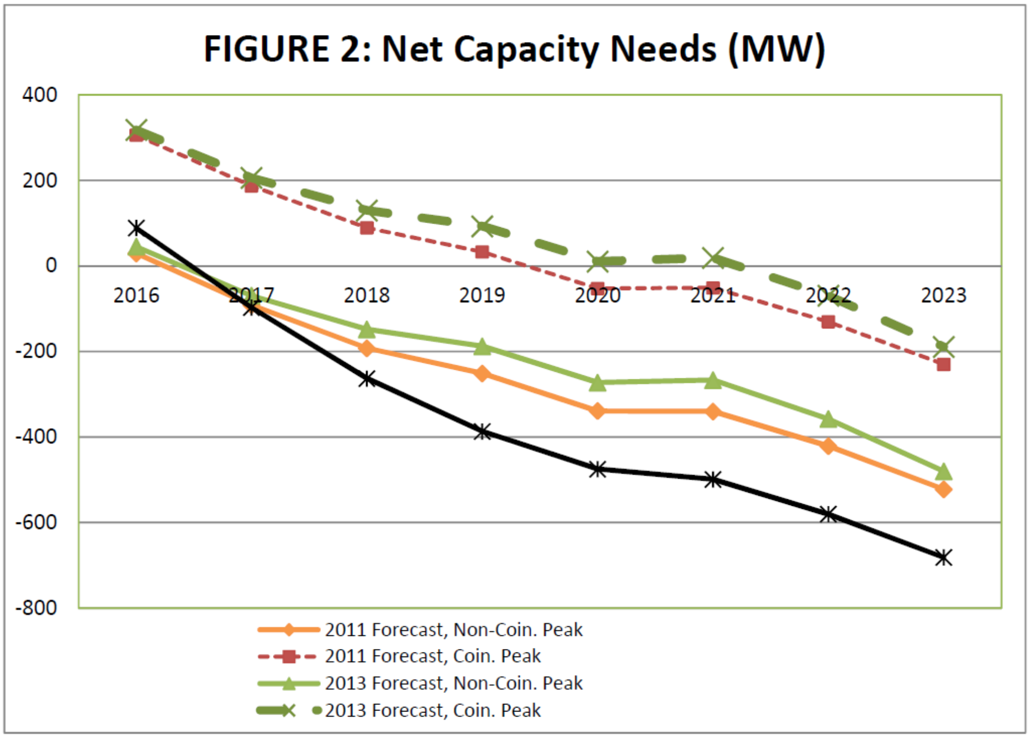
[38] See Rakow Rebuttal Testimony – Trade Secret Attachment IRs from Xcel Energy to Calpine and Invenergy Dated Sept.12, 23 and 25 at SR-R-9 at Pg. 1-6.

[39] Shah Direct at 8-14.

[40] Shah Direct at 8.

The Department witness Sachin Shah identified concerns with Xcel's spring 2013 forecasts, including unresolved questions regarding Xcel's predicted changes in peak demand and the overall load factor of the Xcel system. These issues were not resolved over the courses of this docket.[41] However, Mr. Shah determined that the new forecasts were within the various contingencies the Department modeled in Strategist for this CRP, and, the fall 2011 forecast was a reasonable starting point to begin the analysis.

Figure 2 – Net Capacity Needs (MW) was provided in Direct Testimony of S. Rakow and provides an overview of the range of differing forecasts and the MISO reserve margin calculation methodology impacts on Xcel's capacity deficit. Mr. Shah's testimony indicated that Xcel's forecasts are continually changing and the Department's goal in certificate of need and IRP proceedings of determining a plan that is least-cost across a wide range of forecasts is reasonable and important.[42]



2. Equal Treatment of Proposals

The Department found two key cost assumptions made in the proposals which warranted further review – natural gas fuel costs (for the thermal proposals) and transmission interconnection costs.

[41] *Id.*

[42] Shah Direct at 14.

First, regarding the natural gas fuel supply of the Calpine and Invenergy proposals, both bidders assumed that Xcel would be responsible for all fuel supply and delivery costs without differentiating between reliability and costs associated with firm versus interruptible service. Xcel, in its bid, discussed firm versus interruptible supply, possible constraints on pipeline gas delivery, and pipeline construction. The Department witness Shaw indicated that assuming a firm versus interruptible gas supply is a key cost issue and requested that Xcel provide an analysis in its rebuttal testimony of the benefits and costs of firm versus interruptible gas supply and how Xcel intends to facilitate a gas supply to the bidders' proposed facilities.

Xcel witness Wishart provided the requested analysis in his rebuttal testimony. After reviewing the analysis, the Department concluded that issues regarding firm versus interruptible natural gas supply and associated terms and costs, as well as alternative storage capability and associated costs of the dual fuel (fuel oil backup and fuel oil storage) aspect of Invenergy's proposal, are reasonable issues for negotiated PPAs.[43]

Regardless, the Department used similar (firm) natural gas costs to evaluate all thermal proposals equally in Strategist (through the second round) and used a range of natural gas costs to consider future natural gas price fluctuations.

Second, the Department witness Shaw reviewed costs associated with interconnecting the projects to the transmission system, including the potential for curtailment or congestion charges. Bidders proposed to treat interconnection costs differently, which made initial evaluations of the bids challenging. Shaw informed all bidders that, as far as the Department was concerned, ratepayers should not be at risk for interconnection costs beyond those bid. Calpine provided that it had not included MISO's estimated (up to) $1.5 million cost for upgrades needed to connect the Mankato bid (as the information was pending at the time of application submittal). Those additional costs were then included in Department's Strategist evaluation of the proposals. Xcel stated it did not expect any of the bid proposals to have significant congestion charges, and therefore, congestion charges were not included the Department's Strategist analysis of any bid.

3. *Costs Not Included in Bids*

Generally, Shaw had concerns that Xcel and Invenergy expected ratepayers to be responsible for costs that were not included in their underlying bids. Xcel proposed to pass extra costs to ratepayers by establishment of a rider similar to its Commission approved MERP rider.[44] The Department indicated that it believed that Xcel did not establish the reasonableness of shifting costs to ratepayers in a competitive bidding process, "either as a matter of fairness to other bidders or to ratepayers." Invenergy included $7 million in interconnection costs for its Cannon Falls proposals, but identified a formula to calculate increases or decreases beyond that amount. Again, the Department indicated that Invenergy did not establish the reasonableness of shifting additional costs to ratepayers in a competitive bidding process. The Department indicated it expects that any PPA brought to the Commission for approval would not only have pricing terms consistent with the prices that were used to evaluate the bid, but also would include appropriate

[43] Rakow Rebuttal pg. 4-7.

[44] Docket No. E002/M-02-663.

ratepayer protections – and further, if the pricing terms are not consistent with the analysis used to select the bid or if the PPA does not reasonable protect ratepayers, the Department would recommend modifications to the PPA or rejection.[45]

4. Department's Strategist Analysis

The Department believes that the Strategist model is the most appropriate model to be used to procure resources because Strategist has been used in past Commission proceedings and is superior to the levelized cost of energy (LCOE) alternative for comparing bids which differ in many respects.[46] The Department and Xcel agree that an LCOE analysis is only appropriately used when comparing very similar resources of the same type where cost is the principal, if not only, distinguishing factor. The bids evaluated in the CRP include: peaking and intermediate resources, dispatchable and non-dispatchable resources, and fuel differences such as solar, natural gas or no fuel at all (capacity credits).[47] The Department and Xcel agree the Strategist dispatch simulations provide a more accurate representation of costs and benefits of these various alternatives than an LCOE analysis.

Further, the Strategist model accounts for environmental costs through emission costs inputted for each proposal type – and therefore – externality values, CO_2 internal cost estimates, among other costs, all reward units that are more efficient in terms of environmental impact. Those considerations have been included in the Department's analysis.

The Department 's Strategist analysis consisted of three tiers, 1) the first-round screening, 2) an in-depth analysis and 3) supplemental analysis. The Department modeled all variations of bids that were provided through Direct Testimony.[48]

First Round Screening (Direct Testimony)

For the first-round screening, the Department entered each bidder's proposal information into Strategist. The inputs were then provided to each bidder to review and make corrections if needed. The Department found all combinations of proposals that resulted in less than a 700 MW package.[49] This resulted in 153 combinations of packages, including the base case.[50] The Department then considered 24 different scenarios to evaluate each of the 153 packages for a total of 3,672 Strategist runs.[51]

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[45] Shaw Rebuttal pg. 4-5.

[46] DOC reply brief, p. 35.

[47] *Id.*

[48] Department's Post-Hearing Reply Brief at 33. Discussed later is the potential of delayed ISDs of the Calpine and Invenergy projects.

[49] The DOC-DER used a 700 MW cutoff in lieu of a 500 MW cutoff in order to not artificially limit the outputs due to the large size of some of the proposals.

[50] The base case represented the last Strategist run performed in the IRP docket with relevant updates; see the Department's Post-Hearing Initial Brief at 28-29 for a list of those updates.

[51] Scenarios included combinations of: base forecast versus spring 2013 forecast, 72% versus 50% solar

The 24 different scenarios included the differing combinations of:

- Base (fall 2011) forecast and the spring 2013 forecast
- 72 percent and 50 percent solar accreditation
- Three varying levels of wind acquisition (400/600/800 MW)
- Two MISO planning reserve margin calculations (non-coincidental peak and coincidental peak)

Several scenarios had significant effects on the outcomes. The base case updates (updates necessary since the March 3, 2013 Order) caused the 2017 deficits to remain unchanged but decreased the capacity deficit by 2020 of 135 MW and in 2021 a decrease of 150 MW.

The potential new reserve margin calculation (coincidental peak method) decreased the *peak* demand by between 275-290 MW per year.

Use of the fall 2013 forecast update versus the spring 2013 forecast didn't significantly change outcomes.[52] These results are depicted in Figure 2. in Section IX. B. 1, above.

Strategist Assumptions

The Department used a 2036 end date for each Strategist run, primarily to accurately capture the PVSC of a 20-year PPA and to complete the modeling faster. However, the Department acknowledges the 2036 end date biases against longer-term proposals, such as Xcel's Black Dog Unit 6, which is expected to have a 35 year life.[53]

Dr. Rakow assumed that Xcel (as they typically have done) would conduct their Strategist analysis using a 2050 end date, instead of a 2036 end date, which would provide the Commission with a comparison. Dr. Rakow recommends the Commission consider the benefits of both approaches.

Because the expansion plans run through 2036 (or 2050 in Xcel's case), Strategist will inevitably add generic units at a price set by the modeler. A generic unit's price assumption can impact bid package rankings if the generic price is higher or lower than the proposals submitted. Additionally, packages with a small capacity proposal (in MW) rely more upon generic units to fill in the rest of Xcel's capacity need than packages with a large capacity proposal (in MW).

The Department's base case expansion plan, "the no-build alternative," relied only on generic units to fill Xcel's resource needs, and the assumed costs for these units were the same as those assumed for Xcel's IRP. The thermal bid proposals from Calpine, Invenergy, and Xcel were less

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accreditation, 400/600/800 MW of wind acquisition, and the two MISO PRM methods (coincident and non-coincidental peak methods).

[52] Rakow Direct at 26-27.

[53] Rakow Direct at 28.

expensive than the generic units.[54] Conversely, Geronimo's solar proposal was more expensive than the generic solar units.[55]

While all thermal bids were lower than the generic thermal unit price assumptions, Dr. Rakow maintains that "there is no record basis to conclude that the costs of the generic units are too high.[56] The Department explained that the generic unit cost was determined by the recent market value for the generic units (and provided by Xcel).

The accuracy and reasonableness in costs for generic units is important because the variety of potential projects which can be selected as a result of the assumed costs. If the costs for generic units are too high, smaller capacity packages would be disadvantaged because a small package in combination with a high cost generic unit would result in a higher PVSC for the expansion plan overall. Still, Dr. Rakow did not conclude the cost of generic units was unreasonably high, and the Department favored the approach of making generic units available to Strategist so the model could select whatever combination of generic units was necessary to meet the minimum reliability requirements under various forecasts.[57]

Geronimo's Solar Proposal, the Solar Energy Standard Assumption and Avoided Costs

The Department assumed SES compliance by adding about 290 MW of nameplate solar capacity by 2020. In the first round screening, the Department used two different solar constructs, a 72 percent and a 50 percent solar accreditation, which means 72 percent or 50 percent of the 290 MW by 2020 would be accredited by MISO and therefore be locked into the model as an available resource.

The Department did not include Geronimo's solar proposal as part of the SES in Strategist for several reasons:

- The accredited solar capability which is already assumed would need to be stripped out of the model;
- Geronimo's Proposal should be considered on an equivalent basis for considering the least-cost means to meet Xcel's resource need in the 2017-2019 timeframe;
- An All-Solar competitive bidding process would help ensure that all available solar providers could bid under the SES.

If Geronimo's proposal had been added to meet the SES, it would then require a subtraction of an equivalent amount of capacity (MW), energy (MWh), and costs from the SES units already incorporated – leaving the system unchanged. Under the Department's base case conditions, 72 percent (or 200 MW) of SES-compliant solar was assumed to be accredited by MISO. Replacing the generic solar with Geronimo's proposal would result in the PVSC of the expansion plan being essentially the cost of adding generic resources to meet its identified need (since the solar

[54] Rakow Direct at 30.

[55] *Id*.

[56] Rakow Direct at 31-32.

[57] Rakow Direct, at. 31-33.

proposal would be added then subtracted), which is essentially the base case "no-build alternative."

The Department reasons that separating Geronimo's solar proposal from the SES compliance issue is most consistent with the purpose of the CRP. Xcel issued a request for proposals (RFP) to procure resources to meet a capacity deficit, consistent with the Commission's finding of need in the IRP. Neither Xcel's RFP, nor the Commission's IRP Order, mentions obtaining resources for the SES.

Third, the Department argued that there was no way to determine whether the proposal was a cost-effective way of meeting the SES. The Department is concerned about acquiring half of Xcel's SES requirement without any competing proposals or notice to the public. As such, the Department believes more benefits to ratepayers may arise if the Commission requires Xcel to initiate a second bidding process that is specific to solar resources. The Department suggests that the design of the All-Solar competitive resource process could be decided by the Commission.

In addition to the SES compliance issue, the Department chose not to include any value for solar renewable energy credits (S-RECs). The Department does not believe it is reasonable to assume that Xcel could receive compensation for S-RECs, and resources should be acquired based on the needs of the retail customers.[58]. Not only is the value of an S-REC uncertain, the benefit of any actual benefit to ratepayers is also uncertain because there is no proposed mechanism to accrue benefits from S-RECs. Finally, the Department opposes the assumption of S-REC benefits because Geronimo did not include this benefit as part of its actual bid.

The Department did not include avoided transmission capacity costs in its Strategist analysis for several reasons. Again, the Department noted that Geronimo did not include the benefit in its bid, and any benefits Xcel may receive through a reduction in transmission capacity costs would need to accrue to ratepayers (which are estimated benefits that may not materialize). Geronimo did not provide a mechanism whereby Xcel could recover from Geronimo any difference between the assumed savings and actual benefit ratepayers may receive. Last, Geronimo has already benefitted from the assignment of transmission costs to other bids because those transmission costs were already included in the analysis. It would not be appropriate to include additional avoided transmission capacity costs to Geronimo's bid, if transmission costs are already included in the evaluation of other bids.

The Department did not include transmission line loss savings in its Strategist analysis (again, as it was not provided in Geronimo's bid), but the Department agrees with Xcel that, at most, 9-$10 million in transmission line loss savings (as calculated by Xcel) could be associated with Geronimo's proposal. However, this does not make up for the $34 million PVSC premium associated with Geronimo's project. Further, Geronimo's proposal did not provide any mechanism whereby Xcel could recover from Geronimo any difference between a $9-10 million assumed savings and any actual benefit ratepayers may receive.

[58] DOC Exceptions to the ALJ Recommendations, at p. 16.

The Department's first round screening determined that Geronimo's solar proposal was not a cost-effective way to obtain the 150-500 MW of intermediate and peaking capacity for this CRP. Moreover, it is unreasonable to award a contract for a proposal based simply on the rationale that the solar proposal might fill a need not specified in the original RFP. The Department conceded that if the costs were close, it have been reasonable to consider non-cost factors of differing alternatives (state policy preferences) but the Department argued that is not the case here.

First Round Results

The results of the first round indicated that the package with Xcel's Black Dog CT and Calpine's CC unit was the highest ranked under all 24 scenarios. Beyond the least cost package, the results varied by scenarios (there wasn't a highly robust alternative). Seven packages were chosen for further screening:

1) Black Dog Unit 6 with a 2017 in-service date (BD617) and Calpine's Mankato expansion (CCC1);
2) Invenergy's Cannon Falls expansion (ICT1);
3) Geronimo's Solar Proposal (bundled pricing) – GPV1;
4) Black Unit 6 with a 2019 in-service date (BD619) and CCC1 – the least cost package;
5) ICT1 and BD618 – a package covering needs through 2020;
6) ICT1 and CCC1 – the remaining CT/CC combination remaining; and
7) Base case (no-build).

The first three were selected for further detailed analysis on their own. The least cost package (BD619 and CCC1) was a large package, so Dr. Rakow examined the effects of using smaller packages to cover the deficits for a shorter period of time. Dr. Rakow selected the ICT1 and BD618 based on his focusing on scenario 9 (2011 forecast, 50% solar accreditation, 800 MW of wind and the MISO (new) non-coincidental peak planning reserve margin. Last, Dr. Rakow added the Geronimo proposal to provide the Commission a comparison of alternatives considering Minnesota's renewable preference statutes.

Second Round - Detailed Analysis (Direct Testimony)

The second round, which was a more-detailed analysis that considered various combinations of packages and flexible in-service dates, was conducted using:

- the fall 2011 forecast,
- the non-coincident (utility) peak reliability method,
- 800 MW of wind acquisitions, and
- a 72 percent solar accreditation.

The Department ran many different contingencies on the 7 packages listed above, including: CO_2 reduction per Minn. Statute, the Commission's high and low CO_2 internal cost values, low externality values, high and low wholesale market prices, high and low capital costs, high and low coal costs, high and low natural gas costs, high and low wind accreditation, and high and low forecast of energy and demand.[59]

Two risks were changed for the second round of analysis. First, MISO updated its PRM_{UCAP} from 6.2 percent above Xcel's MISO-coincident peak for the 2013 planning year to 7.3 percent above Xcel's MISO-coincident peak for the 2014 planning year. This change increased the amount of reserve capacity Xcel would be required to have on its system by about 100 MW. Second, the Department became aware of public information that the Xcel-Manitoba Hydro PPA for up to 125 MW may not be available until 2025, or at all, for Xcel's system.[60]

After the second round of analysis, the Department recommended the Commission approve the Black Dog 6 in 2019 and Calpine Mankato Expansion (BD619 with the CCC1) as the least cost package.[61] If the Commission is concerned about the size of the package, the second ranked package is the Calpine proposal alone. This said, the best second package depends heavily on which contingencies are of greatest concern.

Third Round – Supplemental Analysis (Rebuttal Testimony)

In its third round of analysis, the Department evaluated three additional factors:

1. Modeling Invenergy's Cannon Falls project with interruptible natural gas supply;
2. Considering flexible in-service date for Calpine and Invenergy; and
3. Reducing the wind additions from 800 MW to 600 MW.

The assumption of firm natural gas fuel supply disadvantaged Invenergy in the previous round of analysis. Because Invenergy's Cannon Falls project is a CT unit, the Department decided it was reasonable to model the potential for interruptible fuel supply. This modeling choice was not a recommendation of interruptible over firm fuel supplies, however, and the Department noted that additional analysis simply would allow for interruptible fuel be considered in PPA negotiations to reduce costs for ratepayers.

Second, the Department agreed with Xcel that due to demand uncertainties (MISO's PRM, the 125 MW Manitoba Hydro PPA), it would be appropriate to consider flexible in-service dates for the Calpine and Invenergy proposals. Both Calpine and Invenergy provided responses to Xcel information requests (IRs) that provided revised cost and in-service dates to accommodate 2018 and 2019 in-service dates. Neither GRE or Geronimo was asked to or provided delayed in-service dates and revised pricing by the end of Direct Testimony. At that time, the Department did not take a position on the appropriateness of the delayed in-service dates, but developed the information for the Commission's consideration.

[59] Consistent with the Department's analysis of Xcel's most recent resource plan, the Department ran each scenario with the Commission's CO_2 internal cost and externality values removed.

[60] Included as part of the Company's 2011 IRP, Xcel assumes a 125-MW System Power Agreement in 2021, in which Xcel would purchase 125 MW of system capacity (and 450 GWH of incremental energy) year round from May 1, 2021, through April 30, 2025, provided Manitoba Hydro develops its next 1,000 MW hydroelectric project as scheduled and provided Manitoba Hydro does not waive the contract. .

[61] Rakow Direct at 40.

Third, the Department used a 600 MW of wind additions to model the uncertainty surrounding 150 MW of wind generation in the Docket No. E002/M-13-716.[62]

Third Round Results

The combined impact of the fuel supply change (to ICT1 inputs) and the delayed in-service dates (for the CCC1 and ICT1) ultimately didn't change the first ranked package (CCC1 with BD619). However, the previous round second and third ranked packages were displaced (the previous second was CCC1 alone and third was ICT1 with CCC1).

The new second ranked package was ICT1 (as proposed) combined with the Calpine Mankato expansion with a 2019 ISD (CCC1a). The third ranked package was Xcel's Black Dog Unit 6 with a 2017 in-service date (BD617) combined with the new CCC1a. The gap between the first ranked package (CCC1 and BD619) and the second or third ranked packages decreased considerably in this round of analysis.

The change from 800 MW of wind to 600 MW was not shown to be significant.

Due to these results, the Department recommended that it "would be worthwhile for Xcel to pursue negotiations with both Calpine and Invenergy regarding flexibility of in-service dates and use of interruptible natural gas for Invenergy's project."[63] The Department made this recommendation based on sending the least cost projects to the next stage.[64] Ultimately, the Department recommended that the Commission send Calpine's Mankato Project and Invenergy's Cannon Falls project to PPA negotiations and based on those negotiations, the Commission should select the best two of the three (three including Black Dog 6) natural gas projects. Absent differences in the negotiated PPAs, the Department recommends Calpine's project and the Black Dog Unit 6 project with a 2019 in-service date.[65] The Department opposes the selection of the Red River Valley Units 1 and 2 in this proceeding as they weren't least cost alternatives.[66] The Department also did not recommend the GRE capacity credit proposal advance to even the second round of analysis as it was not least cost in the Department's analysis. While GRE proposed additional flexibility in Rebuttal Testimony, the Department only was able to consider variations on proposals through Direct Testimony.[67]

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[62] See MPUC Docket E002/M-13-716, Order Approving Acquisitions with Conditions, December 13, 2013, p. 16. The Commission approved the 150 MW Borders Wind Project but required its approval of any costs that exceed the capped amount or Xcel's plans to terminate the project due to excessive interconnection costs. No filings have been made in this regard.

[63] Department Post-Hearing Initial Brief at 53.

[64] Department Post-Hearing Reply Brief at 34.

[65] Department Post-Hearing Initial Brief at 64.

[66] Department Post-Hearing Initial Brief at 41-43.

[67] Department Post-Hearing Reply Brief at 47.

5. PPA Negotiations

The Department expects that terms such as pricing, in-service dates, firm versus interruptible gas supply, duel fuel capability, and interconnection that are negotiated as part of the PPA process must be consistent with the analysis conducted in this matter.

6. Xcel Status Reports

The Department agrees with Xcel that, given the uncertainty present in this proceeding, it would be appropriate for the Commission to require Xcel to file status reports in the fall of 2014 and 2015.

C. Calpine Corporation

Calpine evaluated all thermal bids and provided a comparison of the thermal bids on a levelized cost of energy (LCOE) basis. Calpine's LCOE analysis showed that its Mankato proposal is the best thermal resource and value for Minnesota ratepayers by a wide margin. Calpine argued that its proposal not only was the best value under its own LCOE analysis, but it was also a top performer under both the Department's and Xcel's Strategist analyses and was *the* top performer under the Department's analysis.

The LCOE metric for each proposal represents the net present value of the expected annual costs, divided by the annual generation over the term of the proposal. Costs include variable and fixed operation and maintenance costs, capital costs, pollution emissions, and the return on investment, and the annual generation uses variable capacity factor inputs (i.e. how many hours a year a unit is assumed to run).

Witness Hibbard concluded the following from Calpine's LCOE analysis:

- Calpine's Mankato proposal offers the lowest LCOE across all gas-fired bids;
- Invenergy's Hampton and Cannon Falls bids are the most expensive gas-fired options; and
- Xcel's Black Dog bid is the lowest cost option among the CT proposals.

Calpine's base case LCOE analysis assumes a 20 percent annual average capacity factor for the Mankato facility, which Witness Hibbard believes is lower than what would actually occur. Calpine notes that, according to Xcel, Xcel's two most efficient CC units (High Bridge and Riverside) operated at a 37 percent and 44 percent capacity factor in 2012, and between 14 percent and 23 percent in 2010 and 2011. Thus, Calpine's assumption of a 20 percent for a CC unit is less than the three year average capacity factor (25 percent) for High Bridge and Riverside over the 2010-2012 period.

With emerging CO_2 and other EPA regulations which could lead to the retirement of baseload coal-fired generation, Calpine believes the Mankato facility capacity factor could be much higher than assumed in the LCOE analysis, thus, providing even greater relative benefits due to its more efficient fuel use.[68]

Calpine believes that CC and CT capacity is an important addition to Xcel's system at this time as the addition of CC capacity provides for several non-price factors that should be considered, including: 1) superior environmental performance (greater fuel efficiency per MWh generated equals less fuel burned and less pollutants), 2) the ability to hedge against future baseload retirements, 3) the ability to support integration of renewables and state environmental goals, and 4) the ability to take advantage of earlier planning and reduce impacts on the environment and host community.

Calpine indicated in its post-hearing brief that sending more than one party to PPA negotiations is unnecessary and could defeat the purpose of the contested case by providing an additional process that allows parties to ignore or discount the record evidence developed in the proceeding.

Other parties criticized the use of a LCOE analysis in this proceeding and argued that the analysis is only useful in scenarios where price is the main, if not only, difference between the resources. Calpine agreed, and indicated that is why they only compared the thermal units in their LCOE analysis. Invenergy argued that the use of the LCOE analysis, and the costs per MWh basis, is inherently biased toward high capacity CC units., Calpine disagrees, and argues the analysis simply showed that CC units are more efficient and will be dispatched more often that CT units. Calpine provided the LCOE analysis as a useful second method to evaluate proposals that should be considered alongside the Strategist modeling.

Calpine further argued that the Department and Xcel's Strategist analysis understated the value of the Calpine proposal by not basing their final recommendations on firm fuel costs for all thermal resources and by not including the costs of selective catalytic reduction technology on the CT resources in the proceeding.

While other parties have argued that CC's typically have higher levels of annual emissions, Calpine countered that is simply because CC's are dispatched by the system more often. When the resources are compared on an emissions per MWh basis, the Calpine expansion would have lower total emissions that the CTs proposed. Further, the Calpine proposal is the only proposal which hedges against future retirements for the Xcel system and the MISO region (as explained in P. Hibbard's Direct Testimony). Last, Calpine argued that the claims that an additional CC unit on Xcel's system is not needed are not supported by the record. Calpine indicated that the record clearly shows that Calpine's project is least cost and asset utilization is incorporated into the modeling of ratepayer impacts - and therefore with the Calpine proposal ratepayers are paying the least amount of money to meet the system's energy needs.[69]

Calpine recommends the Commission direct Xcel to enter into PPA negotiations with Calpine.

[68] Hibbard Direct, at 17.

[69] Hibbard Rebuttal, at 13

D. Geronimo Energy

Geronimo provided that the resources selected in this proceeding must be flexible enough to address the wide range of capacity needs (from 26 MW to 443 MW in 2019). It stated its proposal will provide 71 MW of accredited MISO resource capacity, solar resource credits to meet the SES, provide emission and environmental benefits, and provide avoided costs as a distributed, solar resource.

Criteria to Consider in this Proceeding

Geronimo argued that the Commission must look comprehensively at the record, the Strategist modeling and the certificate of need criteria when making a decision in this proceeding. Geronimo argued that its proposal adequately, reliably and efficiently meets Xcel's range of needs in the 2017-2019 timeframe – and the Commission *must* select this resource first because it is the least cost resource, provides the needed capacity and meets the state's preferences for renewable, distributed and low-emission resources. Geronimo argued its proposal is least cost 1) on a LCOE basis and 2) after appropriately reflecting the recognized benefits of solar in the Strategist modeling. Geronimo argued that Xcel fell short of its burden to explore generating power by means of renewable energy sources.

Additional Benefits of Geronimo's Proposal and the Effect on Strategist Results

Geronimo estimates the solar benefits, which Xcel and the Department erroneously left out of their Strategist modeling, to be on a PVSC basis: $9 million in transmission line losses, $10-38 million in S-REC value, and $33 million in avoided transmission capacity costs) on the Strategist results. Table 2, below, shows Geronimo's proposed adjustments to its Solar Proposal, which Geronimo argues should be made in the PVSC:[70]

[70] Engelking Rebuttal, at 17.

Table 2: Adjustments to PVSC Impact of Geronimo Proposal

	PVSC ($M)		
	Wishart Direct	GE Modified, Low SRECs	GE Modified, High SRECs
Geronimo Solar Project			
Geronimo Energy Payments	$186	$186	$186
Long Term Expansion Plan Difference	($1)	($1)	($1)
Value of SRECS	$0	($10)	($38)
Costs Avoided by Solar			
Avoided Energy	$88	$88	$88
Avoided Capacity	$43	$43	$43
Avoided Emissions	$20	$20	$20
Avoided Line Losses (4%)	$0	$9	$9
Avoided Transmission Capacity	$0	$33	$33
Total Avoided Costs	$151	$193	$193
Total NET PVSC	**$34**	**($17)**	**($46)**

Xcel's analysis shows that the solar proposal is $34 million higher on a PVSC basis than Xcel's modeled least cost plan. Geronimo believes this estimate fails to include quantifiable benefits of Geronimo's Solar Proposal. Accounting for these solar benefits clearly demonstrates Geronimo's Solar Proposal is a least-cost resource, and is $17 and 46 million less expensive than Xcel's Black Dog 6 project (in PVSC terms). Geronimo argued that state law does not require that a resource be least cost in the Strategist model, it requires the utility demonstrate, to the Commission's satisfaction, that the alternative selected is less expensive than the renewable energy resource.

Geronimo believes the distributed generation aspects of its proposal bring significant benefits to Xcel's system and are traits that state law requires the Commission to consider – without setting a cost threshold for those resources. Again, due to the close range of the costs of alternatives in this proceeding, cost alone should not be used to dismiss a distributed generation alternative.

Strategist's Assumptions

Geronimo argued that options Strategist could consider is inherently flawed and biased in favor of selecting large natural gas units. Geronimo provided that four assumptions in particular biased the results toward natural gas:

1. Xcel's modeling assumption that its need was at or near 300 MW;
2. there was a 300 MW minimum threshold for the modeling package selection;
3. Misuse of a capacity credit – a monetary value for excess capacity in year it isn't needed - for large packages (even when Xcel didn't intend to sell excess capacity); and
4. the price Xcel established for generic units was too high.

Higher priced generic natural gas units coupled with an overstated capacity deficit led the resource selection in Strategist to a flawed result based on biased assumptions. Geronimo also contends that Xcel (and the Department) used an unreasonably high generic solar cost, and throughout the proceeding, Xcel argued the Company did not have accurate market information upon which to evaluate solar market prices. Therefore, Geronimo's solar proposal always looked comparably more expensive than the generic solar energy that Xcel assumed for compliance with the SES.

Geronimo's Proposal Price and Risk Minimization

Geronimo argued that its proposal is a fixed cost, unlike the other proposals in this proceeding and, therefore, poses less risk to ratepayers. The solar project is not subject to fluctuations in fuel prices – or the need for backup fuel, as is the case for both the Calpine and Invenergy proposals. Geronimo believes its defined price and minimal ratepayer risk should be considered when comparing the evaluated price of each proposal.

Geronimo argued that the $34 million PVSC difference represents only 0.08% of Xcel's total system cost and, due to the small difference in PVSC of the alternatives in this proceeding, factors other than price should carefully be considered. Geronimo cited the Department's statement that if the solar proposals had been closer under the Department's PVSC analysis then the state policy preferences may have been a consideration – Geronimo questioned how much "closer" than the 0.08% of system costs its proposal would have to be to be considered by the Department.

Geronimo's Proposals and the Certificate of Need Criteria

Geronimo provided a detailed analysis of how its proposal meets the certificate of need criteria – specifically how it provides compatible with the natural and socioeconomic environment, is consistent with federal, state and local rules and policies, meets the state's greenhouse gas reduction policies, and helps Xcel meet the SES. Specifically, Geronimo argued that it is the only alternative that meets Minnesota's renewable and distributed energy preferences and Xcel has not demonstrated that its plans to acquire additional nonrenewable resources are less expensive than plans that include the solar proposal.

Geronimo argued that its proposal is the only proposal to ensure that resources are not overbuilt and ultimately needed. The Commission should select the Geronimo proposal, and if the Commission believes another resource will also be needed based on the 2014 and 2015 updates provided by Xcel, it can determine when that resource should come online. Further, selecting the Geronimo proposal would fill the need identified under all potential forecast scenarios and adds new capacity by 2017 to address Xcel's most immediate need.

Geronimo argued that no party to the proceeding argued that Geronimo could not provide a capacity resource and no one disputed Geronimo's use of MISO's methodology for non-wind intermittent resources to calculate its accredited capacity. Geronimo furthered that there is nothing in the record supporting Xcel's assertion in its Post-Hearing brief that it must add dispatchable resources that can provide energy whenever called upon.

Proposal Selection and PPA Negotiations

Geronimo argued that there are two elements of the proceeding that should not be overlooked, 1) the Commission will select the most prudent resources and 2) the resource selection must be supported by the record.

Under Xcel's recommendation, the Commission would not have the benefit of knowing the price, in-service date, and extent of transmission interconnection costs or other important factors when selecting the best resource. Instead, the Commission would review these details during the final approval of a PPA. Geronimo believes this is grossly inconsistent with the Track Two process and essentially converts the Track Two process into a Track One process. However, with Xcel as a bidder – this leaves too much influence over the final bid selection to Xcel. Geronimo supported the Department's recommendation that the bidders to this proceeding be held to their held to the information submitted in their bids.

Solar Request for Proposal

Geronimo argued that Xcel's recommendation to defer the Geronimo project to an all-solar RFP ignores the Commission's responsibility to consider renewables in this proceeding – and continues Xcel's overall strategy to ignore the bid through the contested case. Geronimo encourages Xcel to move forward with its SES RFP, but that RFP does not excuse Xcel from considering its solar proposal as a capacity resource in this proceeding. Geronimo believes that its proposal is superior to non-renewable alternatives regardless of whether Xcel uses the solar proposal to meet its SES requirements.

E. Great River Energy

GRE argued that their capacity credit proposal, based on the full three years of capacity credits, ranked third in Xcel's Strategist analysis. GRE indicated in their rebuttal testimony that their proposals were not intended to be all or nothing and instead were offered for any, or a combination, of those three years and therefore would qualify as one of the two least-cost resource combination alternatives if the first year of GRE's proposal is not considered (2016/2017).[71] GRE argued that like Xcel's requested of Invenergy and Calpine, it too would be flexible in its in-service date which would provide reduce the cost of its proposal.

GRE stated that in Xcel's analysis, its three-year package was $2.2 million more (on a PVSC basis) than the top ranking plan. GRE's first year proposal cost is approximately $2.2 million, and therefore, if the first year of GRE's plan was excluded it would be equal to the PVSC of the top ranking plan.

Last, GRE objects to the EI's assertion environmental emission costs should be assigned to its proposal. GRE explained that the Commission Orders cited by the EI's pertained to the purchase of output from a generation facility and not to the purchase of capacity credits, as is in this case.

[71] See Section X. A. 6, above, – Table 9 – Strategist Input Sensitivity Tests – Top 20 Plans.

F. Invenergy

Invenergy requests the Commission order the selection of the Cannon Falls Expansion and Hampton projects to meet Xcel's capacity needs identified in the record. Invenergy believes its CT proposals are superior to Calpine's CC proposal because "the need existing in the 2017-2019 time frame is a capacity need, not an energy need."[72] A combined cycle plant, like Calpine's proposal, provides capacity at a significantly higher capacity cost than a CT.[73] Since Xcel forecasts a significantly declining system load factor, as well as the untapped capability at Xcel's existing combined cycle facilities, Calpine overstates the production efficiency benefits of its proposal.

Invenergy also disputes Calpine's reliance on the LCOE method to evaluate bid proposals. Invenergy Witness Norman believes "Calpine witness Hibbard's Levelized Cost of Electricity ("LCOE") analysis is overly simplistic, fundamentally flawed, and produces results that are generally skewed to favor resource units with lower heat rates and higher capacity factors, such as a combined cycle, while eschewing the real risks to (and impacts on) Minnesota customer rates and the broader Xcel system."[74] An LCOE analysis "ignores the fact that combined cycle and peaking resources are used in fundamentally different ways on the system."[75]

Invenergy Witness Norman emphasizes the importance of considering changes to Xcel's system load factor. All else equal, a lower load factor indicates a system where many supply resources will be idle a greater amount of time until higher load conditions occur. Between Xcel's Fall 2011 and 2014 forecasts, Xcel's projection of its system load factor have fallen approximately one percent. Witness Norman calculates the impact of a one percent decrease in load factor amounts to a need for approximately 150 MW of incremental peaking capacity as a result of a declining load factor, holding average energy requirements constant.[76]

Invenergy believes its (~179 MW) CT proposals are superior to Xcel's Black Dog 6 CT proposal because the 215 MW at Black Dog 6 "significantly overshoots the 2017 need for capacity."[77] Ratepayers should not be burdened by excessive costs due to a proposal that is far greater than the identified need. Additionally, "Xcel's Black Dog proposal provides Xcel ratepayers virtually no protection from the risk of cost overruns."[78]

Invenergy also believes Xcel biases the analysis in its favor by adding a replacement facility cost to the end of Invenergy's bid. Xcel evaluates its own project, which is based on a 35-year life. Invenergy's proposal is a 20-year PPA. Because Xcel inserts a replacement facility cost

[72] Invenergy Initial Brief, at 57.

[73] Ewan Rebuttal, at 5.

[74] Norman Rebuttal, at 5-6.

[75] *Id*, at 8.

[76] Norman Rebuttal, at 12-13.

[77] Invenergy Initial Brief, at 58.

[78] *Id*.

assumption at the end of Invenergy's 20-year PPA, Xcel skews the analysis in favor of its own bid. However, Invenergy would propose additional PPA terms that could give Xcel the option to extend the PPA in five year increments at a reduced capacity price. This option was not considered in the modeling. [79]

Invenergy also contends that Xcel's proposed ROE Adjustment Mechanism for cost recovery does not hold Xcel ratepayers harmless in the event of cost overruns. By Commission order, "all bidders should be held to the cost information provided in their bids, which the Commission will evaluate in the course of this contested case proceeding."[80] Xcel's proposal suggests that Xcel would be allowed a reduced ROE in the event of a cost overrun. Invenergy believe "the mechanism proposed still allows Xcel recovery of its capital investment regardless of the degree of cost overrun. The 'mechanism' proposed by Xcel would at best only slightly soften the blow to ratepayers in the event of overruns by offering a modest adjustment to Xcel's allowed return on equity related to its proposed facilities. This mechanism leaves ratepayers with essentially unlimited exposure to the risk of cost overruns."[81]

Invenergy also disputes that "the Department never conducted a detailed analysis of Hampton and never conducted any analysis at all related to the potential of delayed in-service dates at Hampton."[82] The Department concluded that substantial cost savings could arise from delayed in-service dates at Cannon Falls. Since the Cannon Falls expansion and Hampton proposals have similar pricing structures, Invenergy believes the modeling would have likely shown similar cost savings if Hampton had been modeled with flexible in-service dates.

G. North Dakota Advocacy Staff[83]

The North Dakota Public Service Commission Advocacy Staff (NDAS) intervened in this proceeding on behalf of North Dakota ratepayers (who pay approximately 5 percent of Xcel's investments in generation facilities). The NDAS argued that Xcel provides service to four of North Dakota's five largest cities yet none of those cities have generation facilities near them in the event that transmission lines that feed them are disrupted. The NDAS stated that concerns with transmission security are increasing and the most reliable way to mitigate that risk is with local generation, which it believes North Dakota does not have.

North Dakota believes that Xcel has a natural bias to building generation in Minnesota since Minnesota makes up 75 percent of Xcel's overall operation, Xcel is headquartered in Minneapolis and by doing so, it eliminates 75 percent of its risk of recovery. The NDAS believes that Xcel is making some progress to address the lack of jurisdictional inequality (by

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[79] Ewan Rebuttal, at 17.

[80] Commission Order Extending Bidding Deadline and Refining Procedural Framework, March 5, 2013, p. 4

[81] Ewan Rebuttal, at 14.

[82] Invenergy Initial Brief, at 59.

[83] See NDAS Direct Testimony pages 1-8.

way of a recent ND Xcel-owned wind project, a PPA with a ND wind project, and the Hankinson gas turbines proposed in this proceeding) but further equality will only go so far as the Minnesota Commission allows it.

The NDAS argued that price is an important factor to consider in this proceeding; however, the Minnesota Commission should also look at the geographic dispersal of generation and reliability of Xcel's entire system. NDAS believes that if the difference between Hankinson site and the Calpine unit is less than $10 to 20 million, the Hankinson site should be approved and further, the NDAS argued that the addition of another intermediate gas unit would diminish the more efficient use of the existing Xcel intermediate load facilities.

The NDAS argued that Xcel recently purchased 750 MW of wind facilities which should be considered in this proceeding and that the Minnesota Commission does not endorse the Hankinson proposal it should take a wait and see approach due to MISO's new reserve margin, the declining economy and revisit the need in Xcel's next IRP.[84]

H. Environmental Intervenors

The EI's argued that the Commission should clarify that certificate of need criteria apply to this process and any future proceeding that may be conducted under Xcel's competitive procurement framework.

The EI's argued that the Commission must select Geronimo's solar bid since Xcel did not demonstrate that it is not in the public interest and since Minnesota law prohibits the Commission from selecting a non-renewable resource based solely on costs (pursuant to Minn. Stat. 116D.04, subd. 6).[85] The EI's claim that the Department made the policy choice to abandon serious consideration of the only renewable proposal offered in the proceeding based on cost alone. The EI's stated that the Commission must make choices that are historically and functionally legislative in character and whether the record to determine whether it justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy goals – which the EI's indicated

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[84] The NDAS Direct Testimony noted that the NDAS will be arguing before the ND Commission that it should disallow a portion of the new wind acquisitions, so Minnesota's share may be more than the typical 75 percent.

[85] 116D – Environmental Policy, 116D.04 Environmental Impact Statements, Subd. 6.Prohibitions. No state action significantly affecting the quality of the environment shall be allowed, nor shall any permit for natural resources management and development be granted, where such action or permit has caused or is likely to cause pollution, impairment, or destruction of the air, water, land or other natural resources located within the state, so long as there is a feasible and prudent alternative consistent with the reasonable requirements of the public health, safety, and welfare and the state's paramount concern for the protection of its air, water, land and other natural resources from pollution, impairment, or destruction. Economic considerations alone shall not justify such conduct.

include reasonable rates as well as promoting the state's preference for renewables, pollution-free generation, greenhouse gas reduction goals, and the new solar standard.

The EI's argued that the cost difference between the scenarios that include the solar bid versus those that do not are not significant, unlike what the Department contends. The EI's equate the cost difference (without correcting the model's biases) to be a difference in cost of 0.08% over the planning period.[86] Costs which the EI's argued are minute compared to Xcel's total system costs. Last the EI's argued that the modeling analyses are based on an exaggerated view of Xcel's likely capacity need which biased the record in favor of large, non-renewable proposals.

I. Xcel Large Industrials

The Xcel Large Industrials (or XLI) recommends the Commission balance between the risk of under- and over-building in the light of the best information available. XLI references which have changed and points to the decline in the capacity needed on Xcel's system, as a particular example.

XLI stated that, with the record before the Commission it is nearly impossible to determine Xcel's capacity needs in the 2017-2019 timeframe. Therefore, further administrative proceedings are warranted through the next IRP. In the alternative, XLI recommends that:

1. the smallest and least cost selections be made to meet the nearer-term capacity needs,
2. the selection be made for purposes of Minn. Stat. § 216B.2422, subd. 5 (to limit further regulatory proceedings for the project), and,
3. the project approval be contingent on final approval in Xcel's next five-year action plan.

XLI argued that Minnesota's IRP process (absent significant changes in circumstances) can lead to swift and efficient resource acquisitions as shown by several recent cases. However, this proceeding has been subject to continued changing circumstances. XLI doesn't believe that the obsolete 2011 forecast is appropriate to use in this proceeding and cites to the recent Xcel testimony in its most recent rate case that shows a decline in actual sales; XLI argued that declining sales coupled with rising costs will inevitably lead to higher rates and acquiring resources that are not needed for reliability will only exacerbate rate impacts.

XLI highlighted its concerns with MISO's calculation of reserve margins and whether Xcel adequately accounted for solar capacity in the appropriate timeframe in its resource need assessment (Xcel spaced acquisition of the solar resources evenly over the timeframe to comply with the SES instead of timing the acquisitions to meet the expiration of the ITC at the end of 2016.) XLI also questioned the validity of the accreditation factor Xcel used to determine the amount of SES MWs that could be counted towards Xcel's total resource capacity need (see Xcel's Table 4 above – which shows a need for 83 MW by 2019).

XLI argued that it (interested parties) was not allowed to participate and fully develop the record (as XLI was denied intervention by the ALJ) and therefore, the question of Xcel's need by 2019

[86] See EI's Post-Hearing Initial Brief at 7-8.

is undeveloped. XLI further argued that resources were not fully analyzed in light of the potential lower need, that the Department deviated from its position in the 750 MW wind acquisition dockets (regarding when to rely on the 2010 IRP analysis to support the acquisition of resources), and that if the Department analyzed smaller packages, below 700 MW by 2019, the resources recommended in this proceeding may have been different.

XLI took issue with Xcel recommending that the projects to proceed to further negotiations to discuss contract options regarding delay or potential cancellations which leaves behind "the two projects that virtually could not amount to overbuilding and have indicated significant flexibility."[87] XLI recommended that resource selection should be limited to the most immediate and certain needs that can be fully supported by the record. Last, XLI recommends that any resource decision should be based on Xcel's next IRP – which would allow the Commission to make more substantial investment choices on better information, would allow sufficient time to meet the 2017 and 2019 requirements. The Commission should select smaller, more flexible arrangements to meet any near-term needs.

XI. Environmental Report

In the Commission's June 21, 2013 Notice and Order for Hearing, the referred this docket to the Office of Administrative Hearings for a contested case proceeding, and took the following action:

> Regarding the Environmental Report to be prepared by the Department of Commerce's Energy Facilities Permitting Unit (now the Energy Environmental Review and Analysis, or EERA) the Commission:
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> **a.** Granted the EERA's rule variance request and authorized the Department to focus its analysis on the substantially complete alternatives, and on a no-build alternative for each of these alternatives;
> **b.** Requested that the Department prepare an Environmental Report sufficient to meet the requirements outline in Minn. R. 7849, as varied, for all of the substantially complete alternatives;
> **c.** Requested that the Department review Geronimo's solar proposal(s) cumulatively for the up to 31 sites; and
> **d.** Requested that the Department treat the GRE capacity credit proposal as capacity only.

June 24, 2013 DOC DER issued a notice of comment period soliciting comments on the impacts to be evaluated in the environmental report to be prepared for Xcel's Competitive Resource Acquisition proposals. Comments were received until July 10, 2013.

The resource acquisition process required the solicitation of actual proposed alternatives to Xcel Energy's proposed project. The Commission determined that due to the nature of the bidding process, combined with the analysis completed in the IRP docket, the proposed alternatives and a

[87] XLI Post-Hearing Brief/Comments at 16

no-build alternative for each should comprise the scope of alternatives to be evaluated in the ER for this docket.

The ER addressed the impacts identified in Minnesota Rule 7849.1500, subpart 2 (air emissions, visibility impacts, ozone, fuel availability and fuel transportation, electric transmission facilities associated with each proposal, water appropriations, amount and types of wastewater discharges, solid and hazardous wastes, anticipated noise).

Four written comments were received on issues to be evaluated in the ER during the comment period.

Dakota County commented on issues related to potential power plant sites in Dakota County on the Xcel Energy and Invenergy proposals. Comments identified existing and potential soil contamination, waste disposal, and groundwater contamination at the existing Black Dog site identified in Xcel Energy's proposal. The comments also indicated that there was insufficient environmental information on the proposal for the Hampton Energy Center contained in Invenergy's proposal. Dakota County requested that the ER provide "a complete traffic analysis and assessment that is consistent with Environmental Assessment Worksheet documentation requirements."

The Minnesota Center for Environmental Advocacy, Fresh Energy, Izaak Walton League of America – Midwest Office, and Sierra Club (collectively "Environmental Intervenors"), a party to the proceeding, requested that the environmental report address emissions resulting from GRE's proposal.

The Minnesota Chamber of Commerce (Chamber) questioned the need for the acquisition process in the timeframe anticipated.

Mr. Bob Messerich indicated a preference for a more distributed solar option than the one proposed by Geronimo Energy. Mr. Messerich also expressed a preference for solar development in the "built environment," rather than on agricultural or other commercially viable land.

The EERA staff noted that Invenergy filed a public version of its environmental supplement into the record which provided additional environmental information.

Environmental Intervenors' comments reflected on its earlier comments to the Commission recommending that the ER should identify environmental impacts, specifically emissions, of GRE's proposal based on the resource mix identified by GRE. The Commission considered this argument at the time of application acceptance and concluded that the GRE proposal was for capacity only, not energy, and is not tied to specific generators. The Commission's order requested that the Department design its environmental review with the proceeding conclusion in mind.

The Chamber's comments did not address the impacts to be evaluated in the ER, but rather address the need for Xcel Energy to add additional generation in the specified timeframe.

Mr. Messerich’s comments indicate a preference for an alternative that is outside the range of alternatives the Commission will consider.

Staff has reviewed the Environmental Report compiled by the EERA staff and pursuant to Minn. Rule 7849.1800, Subp. 2. recommends that the report and the record created address the issues identified by the Commissioner of the Commerce in its Scoping Decision issued on July 18, 2013.

XII. ALJ Report

The Administrative Law Judge’s report was released on December 31, 2013. Overall, the ALJ concluded that the record is not clear whether there are significant capacity needs on Xcel’s system between 2014 and 2018, but it is clear that Xcel need to add solar energy resources to its system. The ALJ recommended that the Commission use scalable projects (Geronimo’s solar proposal, and if needed, GRE capacity credits) to meet Xcel’s near-term shortfalls through 2019. The ALJ concluded that if the Commission should determine that additional resources are needed by 2019, the decision to procure additional resources could be safely be postponed until after Xcel’s next resource planning process (procurement in 2017, in-service in 2018).

The ALJ found that Geronimo’s proposal is the least cost solution under the analyses used in this proceeding (LCOE and Strategist analyses) when benefits not accounted for in those analyses are considered (avoided costs, societal benefits, statutory preferences). Further, the Geronimo solar proposal has the lowest risk of non-compliance with state and federal laws and regulations and best meets Minnesota’s statutory preferences.

The ALJ made 289 findings and 18 conclusions to arrive at his recommendation. Staff provides a breakdown of the Judge’s findings, parties’ exceptions and staff’s discussion in the section below.

In short, there are many questions that arise from the ALJ’s recommendation and parties, included the Department and Xcel, strongly disagree with the conclusion reached and the facts used to reach that conclusion. The Department and Xcel both strongly recommend that the Commission take a wholly different position than the ALJ. Both the Department and Xcel have serious concerns with the risks that the ALJ’s recommendation may impose on Xcel’s system.

End of Part 1 (Part 1 of 2).