BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY FOR APPROVAL OF COMPETITIVE RESOURCE ACQUISITION PROPOSAL AND CERTIFICATE OF NEED	Docket No. E002/CN-12-1240 OAH Docket No. 8-2500-30760

DIRECT TESTIMONY OF DR. STEVE RAKOW

ON BEHALF OF

THE DIVISION OF ENERGY RESOURCES OF THE MINNESOTA DEPARTMENT OF COMMERCE

SEPTEMBER 27, 2013

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DOCKET NO. E002/CN-12-1240

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I. INTRODUCTION

A. BACKGROUND

Q. Please state your name, business address, and occupation.

A. My name is Dr. Steve Rakow. My business address is 85 Seventh Place East, Suite 500, St. Paul, Minnesota 55101-2198. I am employed as a Public Utilities Rates Analyst with the Minnesota Department of Commerce, Energy Regulation and Planning unit (Department).

Q. What is your educational and professional background?

A. A summary of these items is included as DOC Ex. ___ SR-1 (Rakow Direct).

Q. What are your responsibilities in this proceeding?

A. I am submitting testimony on behalf of the Department that:

- summarizes the alternatives proposed in this proceeding;
- introduces the other witnesses sponsored by the Department;
- presents the criteria used by the Department when making its recommendation;
- provides the Department's cost analysis of the alternatives; and
- summarizes the Department's overall conclusions and recommendations at this time.

B. THE BIDS

Q. Who are the bidders in this proceeding?

A. There are five bidders:

- Calpine Corporation and its affiliate Mankato Energy Center, LLC (Calpine);
- Geronimo Wind Energy, LLC d/b/a Geronimo Energy (Geronimo);
- Great River Energy, a Minnesota cooperative corporation (GRE);
- Invenergy Thermal Development LLC (Invenergy); and
- Northern States Power Company, d/b/a Xcel Energy (Xcel) (collectively, Bidders).

Q. Please summarize the Bidders' proposals.

A. The Bidders proposed the following projects:

- Calpine: expand the existing natural-gas-fired Mankato Energy Center by 290 MW of intermediate capacity and 55 MW of peaking capacity;
- Geronimo: build 100 MW of solar generation using photovoltaic panels, located on up to 31 sites adjacent to substations, ranging from 2 to 10 MW per site;
- GRE: two proposals to sell Xcel Mid-continent Independent System Operator (MISO) Zone 1 Resource Credits (ZRCs);[1]
- Invenergy: two proposals for combustion turbine (CT) capacity:
  - expand the existing Cannon Falls facility with one CT unit; and
  - build a new, Hampton Energy Center with two CT units;

[1] A ZRC is a credit for resources that count towards MISO 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.

- Xcel:
    - build one 215 MW CT unit at the existing Black Dog generating station (Black Dog unit 6); and
    - build two 215 MW CT units at a new site near Hankinson, North Dakota (North Dakota units 1 and 2).

Q. Would a CN be required for proposal(s) selected by the Commission?

A. No, Minnesota Statutes § 216B.2422, subd. 5 (b) states in relevant part: "[I]f an electric power generating plant, as described in section 216B.2421, subdivision 2, clause (1), is selected in a bidding process approved or established by the Commission, a certificate of need proceeding under section 216B.243 is not required." The Minnesota Public Utilities Commission's (Commission) May 31, 2006 *Order Establishing Resource Acquisition Process, Establishing Bidding Process under Minn. Stat. § 216B.2422, subd. 5, and Requiring Compliance Filing* (Docket No. E002/RP-04-1752) approved the bidding process used in this proceeding. Therefore, the Commission-approved bidding process is being used to select proposal(s) that could meet the need identified in Xcel's last resource plan (Docket No. E002/RP-10-825).

C. THE DEPARTMENT'S INVESTIGATION

Q. Please introduce the witnesses sponsored by the Department in this proceeding and summarize the issues on which they will testify.

A. In addition to myself, the Department is sponsoring two other witnesses in this proceeding:

- Mr. Sachin Shah—forecasting and natural gas supply; and
- Mr. Christopher Shaw—transmission, bidder background, and wind acquisition.

II. ANALYSIS

A. ANALYTICAL PROCESS

Q. Please outline the analytical process you used to analyze the cost of the proposals.

A. I used the following process:

1. put data on each proposal into draft Strategist inputs;
2. ran Strategist on the draft proposals to de-bug the inputs;
3. sent the Bidders:
   a. a file with Strategist inputs representing their proposal(s);
   b. a file with Strategist outputs for the proposal showing unit(s) operational and cost data at different levels of output.
   c. a request to obtain feedback (proposed changes or confirmation that proposal is represented correctly).
4. updated the Department's Strategist database;
5. sorted bids into packages to be analyzed;
6. wrote commands to run the proposal packages through Strategist;
7. ran Strategist on the proposal packages and reviewed the outputs;
8. selected a "short list" of packages/bids from the initial runs;

9. put the short list through Strategist contingency analysis (high gas cost, low coal cost, etc.);

10. selected the "winner(s)."

Q. Please identify what you mean by your use of the terms "short list" and "winner" in the description above.

A. I call the analysis of all possible bid packages that were less than 700 MW in size the "first round." By "short list" I mean the bids or packages from the first round that were selected for further analysis in a second round of Strategist runs. The criteria I used to develop the short list was bid packages that were least cost under a variety circumstances or under circumstances that may be of interest to the Commission. By "winners" I mean those bids or packages that were selected for detailed economic analysis. I call this further analysis the "second round."

B. PROPOSAL DEVELOPMENT

Q. How did you place the Bidders' data into Strategist form?

A. Each Bidder completed the Strategist template data form available on Xcel's website as identified in the Department's May 3, 2013 completeness comments. I either input this data directly into Strategist or calculated the required inputs from the Strategist template data. I then ran Strategist several times to remove any obvious errors in the inputs.

Once the proposals were in what I believed to be correct form, I then ran most of the proposals through Strategist under several different system assumptions (the proposals themselves remained the same). From each run I downloaded data regarding how the proposal's unit(s) performed. I then sent each Bidder the data for their proposals. This data allowed the Bidders to see how their unit(s) performed in terms of cost, fuel consumption, pollutants emitted, etc. under a variety of capacity factors. Note that Geronimo's solar unit and GRE's ZRC offer are not dispatchable and will always perform the same in Strategist. Therefore, I sent only one set of outputs to Geronimo and GRE. The Bidders then responded with corrections.

1. Corrections to Inputs for Calpine's Bid

Q. What corrections were made to the Calpine inputs?

A. Calpine's response to Department Information Request No. 5 contained no suggested corrections. However, Calpine did suggest separate treatment for fixed operations and maintenance costs and start charges. This was a helpful suggestion. However, after some experimentation I determined to retain the inputs as initially presented because I could not find a way to adequately model start charges as a variable cost.

Q. Did you make any other changes to the inputs for Calpine's proposal?

A. Yes. Subsequent to the information request to Calpine I noticed that I did not include in the inputs a summer-time decrease in capacity for the Calpine unit. Calpine's proposal contains an estimate of the (lower) summer and (higher) winter capacity. A summer-time capacity de-rating had been included in the inputs for all of the other thermal unit bids.

Q. Why is there a summer-time decrease in capacity?

A. Briefly, many natural gas-fired units have a lower capacity in summer than in winter for accreditation and energy production purposes. Therefore, I added a deration pattern for the Calpine unit. This pattern was based upon Calpine's reported deration amount and the deration patterns used by Xcel for other recently-added units, including Blue Lake 7 and 8, Angus Anson 4, and Calpine's existing unit at the Mankato Energy Center.

Q. Did you consider any other factors stemming from Calpine's response to your request for information?

A. Yes. Calpine's response to Xcel's Information Request No. 3 states, "MISO has estimated the cost of necessary upgrades at $650,000 to $1,500,000 with a final cost to be confirmed upon completion of the facilities study." Therefore, to ensure that Calpine's bid included this cost, I levelized the $1.5 million cost using the 12.17 percent levelized annual revenue requirement (LARR) input used by Xcel in Docket No. E002/CN-12-113.[2] I then calculated a present value of about $1.55 million using the discount rate and decision year used by Strategist.[3] The $1.55 million cost is included in a post-model PVRR adjustment for all scenarios and contingencies evaluating Calpine's proposal.

Q. Does the addition of $1.55 million in costs to Calpine's proposal bias the selection process away from Calpine's proposal?

[2] A LARR is a figure that turns an up-front capital cost into a stream of level, annual payments that are financially equivalent to the up-front cost. The 12.17 percent LARR is the most recent estimate available.
[3] The decision year is the year that all dollars are discounted to by Strategist.

A. No. It is important to ensure that each bid reflects costs as accurately as possible. Such an approach is transparent and fair to all parties. As the Department stated in our July 29, 2013 letter in response to Bidders' varying proposals regarding costs:

> While the Department is aware that some costs, particularly costs related to the facilities necessary to interconnect to the transmission system, can be difficult to estimate, bidders are in the best position to estimate those costs. Further, the competitive bidding is most fair to all bidders and ratepayers if each bid is evaluated based on the total costs that ratepayers will pay. The treatment of interconnection costs noted above proposed by the bidders in the details of their submittals make a fair comparison difficult.
>
> Therefore, consistent with past practices, the Department intends to hold each of the bidders to the prices used to evaluate the bids. This letter is intended to put all parties on notice of the Department's intentions. Parties should not expect that ratepayers will pay for any additional costs that are specific to a particular project beyond those included in each bid. This approach best ensures the integrity of the competitive process. [Footnote omitted]

2. Corrections to Inputs for Geronimo's Bid

Q. What corrections were made to the Geronimo inputs?

A. Geronimo's response to Department Information Request No. 6 reported corrections to the costs reported by Strategist. These corrections were based upon future equipment degradation. Similar inputs were not available for the other proposals. Therefore, rather than put the equipment degradation into Strategist in the base inputs for Geronimo's proposal, I created a separate package that added only Geronimo's proposal with the degraded inputs. This separate package with degradation can be compared to the case with Geronimo's proposal without degradation to obtain an estimate of the overall impact of degradation. The results of adding degradation (specifically, for Scenario 9) are that:

- the expansion plans are identical,
- energy production from Geronimo's unit is decreased, and
- the present value of societal costs (PVSC) increases by about $3.9 million.

That is, there is no change in the expansion plan whether Geronimo's degradation factors are included or not, and no effect on the selection results.

3. Solar Energy Standard and Geronimo's Bid

Q. How did you treat the relationship between the new Solar Energy Standard and Geronimo's proposal?

A. I considered two basic approaches: considering Geronimo to be: 1) part of the new solar energy standard (SES); (see Laws 2013, Chapter 85, Article 10, Section 3—Minnesota Statutes § 216B.1691, subd. 2f) and 2) separate from the SES.

Under the first approach, using the most recent solar cost data available, namely Geronimo's proposal, I would: 1) add Geronimo's proposal and 2) subtract an equivalent amount of MW, MWh, and cost from the SES units. The two changes would offset each other and leave the system unchanged. This approach would result in Xcel's system being priced using only the cost of the generic expansion units since Geronimo's proposal is added and subtracted from Strategist.

The second approach would be to leave the SES units as is and make the Geronimo proposal an addition to Xcel's system beyond the SES. This approach is how the Department treated all other (non-Geronimo) proposals in this case. Under this second approach Xcel's system is evaluated using the cost of Geronimo's proposal as an addition to the cost of generic units at a lower level than if Geronimo's proposal were considered as part of the SES since Xcel's system needs less energy and capacity due to the fact that the SES units are not reduced to reflect the addition of Geronimo. That is, Geronimo's bid would not be used to meet the SES. I decided that the second approach was superior for the reasons I note below.

Q. Please explain why you decided that this second approach would be superior.

A. The main reason is that this approach is consistent with Xcel's request for proposals (RFP), which the Commission approved. That RFP did not mention obtaining resources for the SES; instead, it stated that:

> The Minnesota Public Utilities Commission has opened a Competitive Resource Acquisition proceeding to select new generation resource capacity to meet Xcel Energy's electrical power requirements in the Company's Upper Midwest service area…
>
> The Commission intends to make findings in February 2013 regarding the size, type and timing of the generation resource needed for the Company's Upper Midwest system.

Subsequently, the Commission's *Order Approving Plan, Finding Need, Establishing Filing Requirements, and Closing Docket* (Docket No. E-002/RP-10-825, IRP Order), dated March 5, 2013 making the size, type and timing findings stated:

> 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[s], 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.

Q. Were solar projects precluded from bidding into this RFP?

A. No, there was nothing in the RFP that would have, nor should have, precluded solar projects from bidding in their proposed projects. As such, the Department evaluated Geronimo's bid in this proceeding in the same way as any other bid. Nonetheless, this analysis is less than ideal for several reasons, such as the fact that there is no way to determine whether Geronimo's proposal is a cost effective means of meeting the SES since there are no other proposals to provide solar energy to which the Geronimo bid could be compared.

Q. What was the response to the RFP?

A. This Commission-approved RFP lead to several proposals for the peaking and intermediate need specified by the Commission but did not lead to any solar proposals beyond that provided by Geronimo. That result is not surprising since: 1) the RFP did not mention solar resources, 2) solar resources are currently not as commercially developed as wind proposals, and 3) concurrent with the timing of the decisions noted above, the Minnesota Legislature was discussing what is now the Minnesota SES. Thus, there was a fairly high level of uncertainty about what Minnesota law would become and what the regulatory structure for solar projects would be.

Q. Did the Commission's IRP Order say anything about solar power?

A. Yes, the Commission's Order stated the following in ordering paragraph 4a:

> 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.

This finding highlights the difference in commercial maturity of solar and other projects at this time.

Q. Do you have suggestions for ways to address what is now the Minnesota SES?

A. Yes. Given the difference in the commercial maturity of solar projects compared to other projects, it seems that a more reasonable approach to assess the cost-effectiveness of solar projects would be to direct Xcel to issue a subsequent RFP for solar projects only (an All-Solar RFP, similar to All-Wind RFPs that have been used), at a size and time to be determined in Xcel's next resource plan, which is to be filed in February, 2014. This would allow the RFP to be issued after the solar Effective Load Carrying Capability (ELCC) study is completed, which would give better information regarding the production of solar power compared to Xcel's load. Using this approach would provide better information about Geronimo's bid than is available at this time and would allow Geronimo's bid to be compared on more of an apples-to-apples basis with other solar projects. Finally, this approach would mean that other potential solar bidders would be more widely noticed, allowing better information to be gathered about solar costs and help ensure that the best solar projects are added to Xcel's system.

Q. Nonetheless, what did you observe from your analysis of Geronimo's proposed project in this proceeding?

A. Overall, Geronimo's proposal, as detailed below would not be a reasonable choice (on a cost basis) for the purposes (intermediate and peaking capacity) specified by the Commission, based on information available at this time. Based on this analysis, I conclude that it would not be appropriate to award a contract to a proposal that performs poorly for the identified need on the basis that the proposal might fill a need not specified in the original RFP.

Q. Does your choice of approach mean that you recommend that Geronimo's proposal not be considered as a project that could count towards the SES?

A. No. As suggested above, I recommend that the Commission direct Xcel to establish an RFP for solar projects to meet the SES. At that time, Geronimo certainly could submit another bid.

Q. Notwithstanding the above, is data available to evaluate Geronimo's proposal if it is considered as part of the SES?

A. Yes and no. As discussed above, the results of the ELCC study are not yet available. Further, solar integration costs need to be added. However, other than this information, in scenarios 1 through 24 below, all else that is required to evaluate Geronimo's proposal for purposes of the SES is to look at the results for the package that contains no bids—the base case.

4. Corrections to Inputs for GRE's Bid

Q. What corrections were made to the GRE inputs?

A. During discussions, GRE reported that the Strategist[4] outputs contained an error in cost. I compared the costs of the GRE proposal reported by Strategist to the cost contained in GRE's original proposal. I agreed that the Strategist cost output was in error and that the error was caused by faulty inputs. I worked with GRE to correct the cost inputs.

5. Corrections to Inputs for Invenergy's Bid

Q. What corrections were made to the Invenergy inputs?

A. Invenergy's response to Department Information Request No. 8 indicated three corrections. First, that the Hampton Corners proposal price was incorrect on the input spreadsheet. I corrected this input.

Second, the information request stated that the data sent was created assuming a \$4/MMBtu natural gas price. However, Invenergy's calculations suggested that the actual natural gas costs used in the Strategist runs were above \$6. I reviewed the files sent to Invenergy and concluded that Invenergy was correct. I had not used the indicated (\$4/MMBtu) natural gas price. The Department's assumption did not require any corrections to the Invenergy proposal since the price of natural gas was a background assumption to enable analysis of the inputs and outputs of all proposals rather than as an input to Invenergy's specific proposal to be reviewed. I used the indicated assumptions about natural gas prices for all other bids.

Third, Invenergy was not able to replicate the emissions values, although Invenergy's calculations were within the same magnitude as the amounts in Department Information Request No. 8. I further reviewed the inputs for SO_2, NO_x, CO, and PM_{10}

[4] Strategist is a "capacity expansion model," meaning it determines the set of resources that are the least cost method to meet increases in demand in the future.

emissions for Invenergy's bids. I started by dividing the emissions input provided for Xcel's Black Dog unit 6 by the emissions input (in lbs/MMBtu) provided by Invenergy (both Hampton and Cannon Falls proposals).[5] I then compared the ratios to similar ratios derived from the Strategist outputs. The result was that the ratios were very close. For SO_2, the difference (ratio of bidder provided inputs to ratio of Strategist outputs) was about three percent; for NOx, PM_{10}, and CO the difference was about one percent. Thus, I concluded that Strategist accurately reflected the inputs provided by the bidders.

6. Corrections to Inputs for Xcel's Bid

Q. What corrections were made to the Xcel inputs?

A. Since Xcel has access to Strategist and could create any results desired, I sent to the Company the inputs I proposed to use. Xcel's response to Department Information Request No. 2 did not contain any corrections. However, Xcel later provided a spreadsheet (CAP BASE YEAR REVENUE REQUIREMENT CALCS - 6-20-13.xls) that corrected the base year revenue requirements (capital cost) inputs. I revised Xcel's calculations for Black Dog unit 6—2018 in-service date and Black Dog unit 6—2019 in-service date. Then I used the revised results for the base year revenue requirements for Black Dog unit 6 and North Dakota units 1 and 2.

C. PACKAGE DEVELOPMENT

Q. Did you analyze the proposals separately or in packages with multiple proposals added together?

[5] Both taken from the Strategist input worksheets provided by the bidders.

A. I analyzed the proposals by forcing Strategist to add them to Xcel's system on their own and by forcing Strategist to add the proposals in packages.

Q. How did you determine which packages to analyze?

A. I attempted to include all packages that result in less than 700 MW of nameplate capacity being added to Xcel's system. The Commission's *Order Approving Plan, Finding Need, Establishing Filing Requirements, and Closing Docket* (Docket No. E-002/RP-10-825), dated March 5, 2013 declared that Xcel had demonstrated the need for an additional 500 MW by 2019. Since several of the units in the bids add 200 MW or more, I concluded that a cut off greater than 500 MW was warranted.[6] Also, at the time I established the criteria for selecting packages to be analyzed I did not know whether changes to the model, if any, would increase, decrease, or leave unchanged the analysis underlying the Commission's determination of a 500 MW capacity need. Finally, I concluded that it would be simple to ignore results from packages that turned out to be not needed while it would be rather difficult to go back and increase the number of packages to be analyzed at a later date if more capacity was warranted.

In addition I developed:

- a package that analyzed the alternative pricing provided by Geronimo;
- a package that analyzed degradation of performance for Geronimo; and
- a package that analyzed both degradation and alternative pricing for Geronimo.

[6] For example, the three units in Xcel's proposal could not be included in a single package if a 500 MW cut off was used. Also, Calpine's unit could not be combined with any of the combustion turbine proposals if a 500 MW cut off was used.

Overall my review resulted in a total of 153 packages to be analyzed; including the base case as a "no build" alternative.

D. STRATEGIST BASE CASE DEVELOPMENT

Q. Please explain how you arrived at a base case for Strategist.

A. I started with the Department's most recent Strategist analysis of Xcel's system. Specifically, a file from the December 18, 2012 comments in Docket No. E002/RP-10-825—Scenario 1 (No "Prairie Island uprate" which means no expansion of the Prairie Island nuclear generation units). I updated this file as follows.

1. Re-established Xcel's CT and combined cycle (CC) optional expansion units in the years 2027 and beyond. This was done using the 2011 Strategist database. These units were not needed for the resource plan analysis and had been deleted.
2. Eliminated the optional wind expansion units. The optional wind units were established in order to determine the optimal quantity of wind energy. However, the optimal level of wind energy is not an issue in this proceeding.
3. Re-established Xcel's "hard wired" or "forced" wind expansion units for the years 2012 and beyond to ensure that the existing renewable energy standard (RES) is met in Strategist (data from Xcel's response to Department Information Request No. 1 (referred to as 2013 database). I discuss below how this analysis addresses Xcel's proposed addition of 750 MW of new wind resources proposed in Dockets E002/M-13-603 and E002/M-13-716.

I noted that Xcel's 2011 and 2013 databases have the same number of wind expansion units through 2019. After that the 2013 database has one or two additional wind expansion units each year (except in 2022, when the difference is three units). I considered this difference too small to pursue further for purposes of this analysis, given how far in the future this small difference begins. As is always the case, Xcel's next resource plan will update information to provide another "snapshot in time" of Xcel's system and future needs.

4. Established the new fuel and associated inflation rates required for Xcel's proposed North Dakota units.
5. Removed the Goodhue Wind unit from Xcel's generation portfolio; see the Commission's July 26, 2013 *Order Declining to Extend Certificate of Need, Finding Statutory Violation, Requiring Further Filings, and Giving Notice of Intent to Revoke Site Permit* in Docket Nos. IP6701/CN-09-1186, IP6701/WS-08-1233, IP6701/M-09-1349, and IP6701/M-09-1350.
6. Updated the inputs for the LS Power (Cottage Grove) combined cycle unit per Xcel's 2013 database.
7. Updated the inputs for Xcel's Prairie Island units, largely removing the capacity attributable to the extended power uprate (Docket No. E002/CN-08-509) per Xcel's 2013 database.
8. Updated the wholesale market price inputs per Xcel's 2013 database.
9. Updated the retirement dates for Xcel's Black Dog units 3 and 4 and French Island unit 3 per Xcel's 2013 database.
10. Updated the in-service (repair) date for Xcel's French Island unit 3 per Xcel's 2013 database.

11. Added about 290 MW nameplate capacity, 200 MW accredited capacity, and 490 GWh of solar energy by 2020 to meet the SES. See DOC Ex. ___ SR-2 (Rakow Direct) for the calculation of the SES. For this solar capacity, I modeled:
    a. A capacity factor of about 20 percent based upon data from the National Renewable Energy Laboratory's PVWatts calculator, Geronimo's proposal, and data on solar units Xcel already had in Strategist.
    b. Capacity accreditation of about 72 percent, based upon the December 3, 2012 comments of the Department in Docket No. E002/GR-10-971. I made these changes by adding capacity to solar units already present in the model and increasing these units' energy production. Turned on Xcel's construct for the wholesale energy market to be consistent with the Department's most recent IRP analysis (see Docket No. E015/RP-13-53); previously, the Strategist had been instructed not to consider (i.e., to turn off) the wholesale energy market. Also, it appeared to me that Xcel attempted to attribute air pollutants and associated costs to the market, but mis-specified the inputs; I corrected the apparent mis-specification.
12. Updated the externality values per the Commission's June 5, 2013 *Notice of Updated Environmental Externality Values* (Docket Nos. E999/CI-93-583 and E999/CI-00-1636).
13. Updated the heat rates for the nuclear and generic units per Xcel's 2013 database.
14. Updated the coal, nuclear, biomass, natural gas fuel costs for the existing units per Xcel's 2013 database.

15. Updated the natural gas fuel costs for generic expansion units per Xcel's 2013 database.
16. Updated the monthly pattern for natural gas per Xcel's 2013 database.
17. Updated the variable operations and maintenance costs for certain existing units per Xcel's 2013 database.
18. Updated the wholesale energy market costs per Xcel's 2013 database.

E. FIRST ROUND SET-UP

Q. Please list the scenarios used in the first round of analysis.

A. I ran each of the 153 packages through 24 scenarios for a total of 3,672 runs. The 24 scenarios are defined in DOC Ex. ___ SR-3 (Rakow Direct).

1. Solar Constructs

Q. Please explain the two different solar constructs.

A. The two different solar constructs relate to a 72 percent and a 50 percent solar accreditation by MISO.[7] The phrase "72 percent solar accreditation" means the solar units—the pre-existing units, the capacity added to meet the SES, and Geronimo's proposal—are accredited at about 72 percent for purposes of calculating the reserve margin.[8] The phrase "50 percent solar accreditation" means all solar units are accredited at about 50 percent for purposes of calculating the reserve margin. A 20 percentage point

[7] The Midcontinent Independent System Operator (MISO) accredits generation units according to the amount of capacity that reasonably can be expected from such units.
[8] The reserve margin is a quantity of supply, above the level of the demand forecast, that MISO concludes is necessary to maintain a reliable electrical system.

reduction in accreditation equals about 60 MW of lost capacity accreditation assuming 300 MW nameplate capacity of solar units.

2. Wind Levels and Tie to Wind Dockets

Q. Please explain the three different levels of wind.

A. I refer to 400 MW, 600 MW and 800 MW of wind. The term "400 MW of wind" means the Courtenay and Odell wind units are required to be added in 2015-16 (data on these units was obtained from Xcel in Docket No. E002/M-13-603). Also, 200 MW of wind units are no longer added in 2020 and 100 MW are not added in 2022.[9] The assumption is that two wind projects or 400 MW of wind will be approved by the Commission in Docket No. E002/M-13-603.

The term "600 MW of wind" means the Courtenay, Odell, and Pleasant Valley wind units are required to be added in 2015-16. The assumption is that all three projects (600 MW) will be approved by the Commission in Docket No. E002/M-13-603. Also, 200 MW of wind units are no longer added in 2020 and in 2022 with 100 MW not added in 2024 and 2025 so that the overall quantity of wind energy added remains relatively constant.

The term, "800 MW of wind" means the Courtenay, Odell, and Pleasant Valley wind units and a 200 MW generic wind unit are required to be added in 2015-16.[10] The assumption is that all three projects will be approved by the Commission in Docket No.

[9] Note that the additions and subtractions of wind units are not equal in capacity because 1) the calculation accounts for deletion of the Goodhue Wind unit which was withdrawn by the project proponent, and 2) additions and subtractions were designed to get approximately the same quantity of energy over the period 2012 to 2050.

[10] Note that Strategist generic wind units are 100 MW in size and that two generic units produce about 17 percent more energy than is expected from the unit actually proposed by Xcel in Docket No. E002/M-13-716. There was insufficient time and too little difference (in energy and accredited capacity) to pursue obtaining additional inputs

E002/M-13-603 and a single project will be approved in Docket No. E002/M-13-716, for a total of approximately 800 MW. Also, 200 MW of wind units are no longer added in 2020 and 2022 and 100 MW of wind units are not added in 2024, 2025, and 2026 so that the overall quantity of wind energy added wind remains relatively constant.

Q. In what order are the new wind units added?

A. Since cost analysis of the wind units is beyond the scope of this proceeding, I used alphabetical order for the three units for which I had specific data. The generic unit was added last (to represent the wind unit for which specific data was not yet available).

3. Reliability: Required "Reserve Ratios" for Capacity

Q. Please explain the two peak reliability methods.

A. The term "non-coincident peak" refers to the reliability method used during the analysis of Xcel's last resource plan. Briefly, under this method a 3.79 percent reserve ratio was added to Xcel's forecast of the Company's peak demand (or, peak demand non-coincident with any other entity's peak). Then, resources were required to be added by Strategist so that Xcel had sufficient capacity to cover the Company's peak demand forecast plus required reserves. This was the method used by MISO for the June, 2012 to May, 2013 planning year and in Xcel's most recent resource plan and in Xcel's most recent resource plan.

The term "MISO coincident peak" refers to a new reliability method to be used by MISO for the June, 2013 to May, 2014 planning year. Briefly, the reliability method

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for the proposed unit at this stage of the analysis. However, the actual data for the fourth wind unit was used in subsequent analysis.

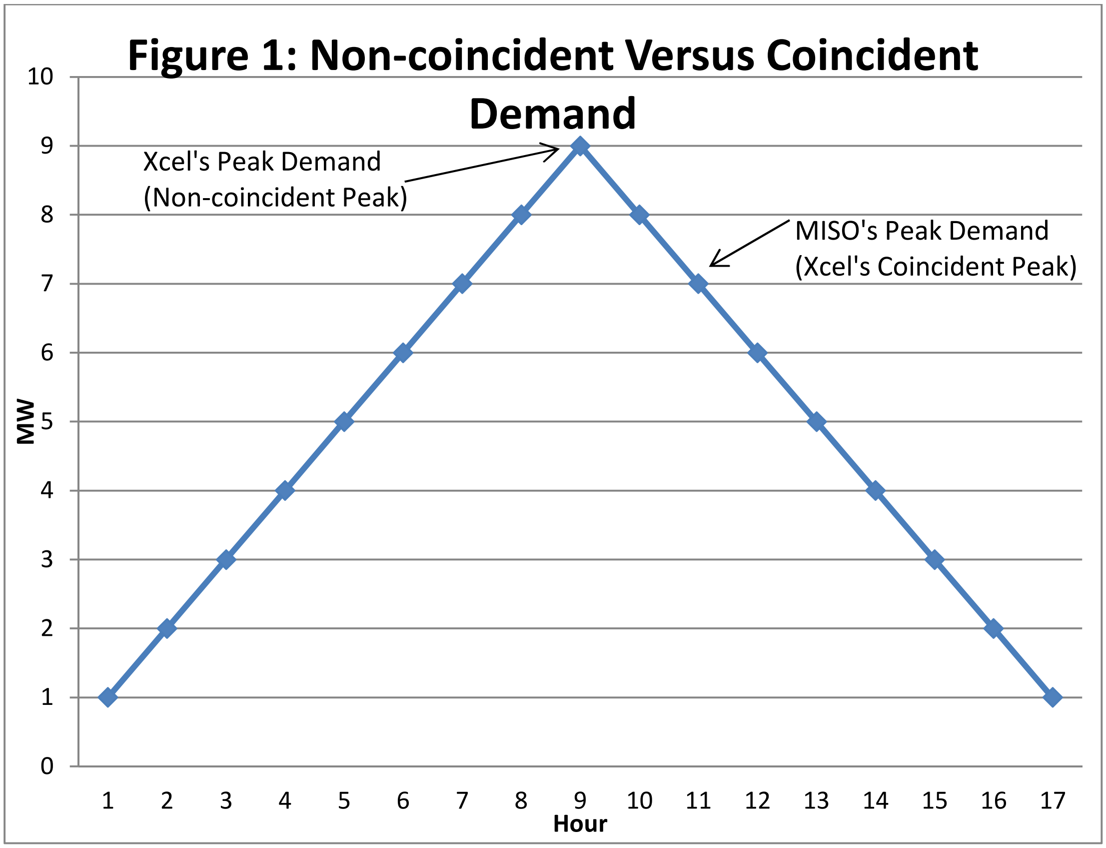
requires that a 6.2 percent reserve ratio be added to Xcel's forecast of its demand at the time of (or coincident with) MISO's peak.[11] The MISO coincident peak demand is determined by discounting the non-coincident peak demand (i.e. the utility's peak demand) by a diversity factor.[12] I developed the diversity factor using Xcel's response to Minnesota Chamber of Commerce Information Request No. 746 in Docket No. E002/GR-12-961 (MCC IR 746). Then, resources are required to be added by Strategist so that Xcel has sufficient capacity to cover the "MISO coincident peak" forecast plus required reserves. Note that Xcel's system is dispatched to meet the Company's forecast of non-coincident (utility) peak demand; the reserve ratio input is calculated to produce the correct quantity of reserves plus coincident peak according to MISO's approach.

Q. Can you provide an example of the difference between non-coincident and coincident peak demand?

A. Yes. Figure 1 shows Xcel's system peak (non-coincident) at hour 9 and Xcel's demand at the time of (or coincident with) MISO's peak at hour 11.

[11] This method is a significant change from the method typically used in resource planning, where the focus is on ensuring that the utility has enough resources to meet the peak demands on its own system, regardless of when MISO's peak occurs. The Department is continuing to examine how to incorporate MISO's changing methods into Minnesota's resource planning process.

[12] For example, if Xcel's demand at the time of (coincident with) MISO's peak is ten percent lower than Xcel's peak demand, then the "diversity factor" would be equal to ten percent.



Q. Please explain why you are using two reliability methods.

A. There are several uncertainties regarding how to best estimate the impact of MISO's proposed new reliability method at this time. One uncertainty is the correct diversity factor to apply to the non-coincident (utility) peak demand to determine the coincident peak demand. MCC IR 746 indicates that a variety of diversity factors would be reasonable.

A second uncertainty is the correct level of demand side management (DSM) to assume. Briefly, at this time it is not clear to me if the full quantity (in MW) of DSM that is assumed available to reduce Xcel's (non-coincident) peak demand is also available to meet Xcel's demand coincident with (at the time of) MISO's peak demand. For example, I reviewed the hourly Saver's Switch interruption data provided by Xcel in annual compliance filings in Docket No. E002/M-01-46. This load management data shows changes in customer usage (demand) from hour to hour that, at times, exceed 100 MW. Thus, the use of two reliability methods is used to determine a reasonable range of capacity needs.

Q. Given the importance of reliability in these models, how should the data be interpreted?

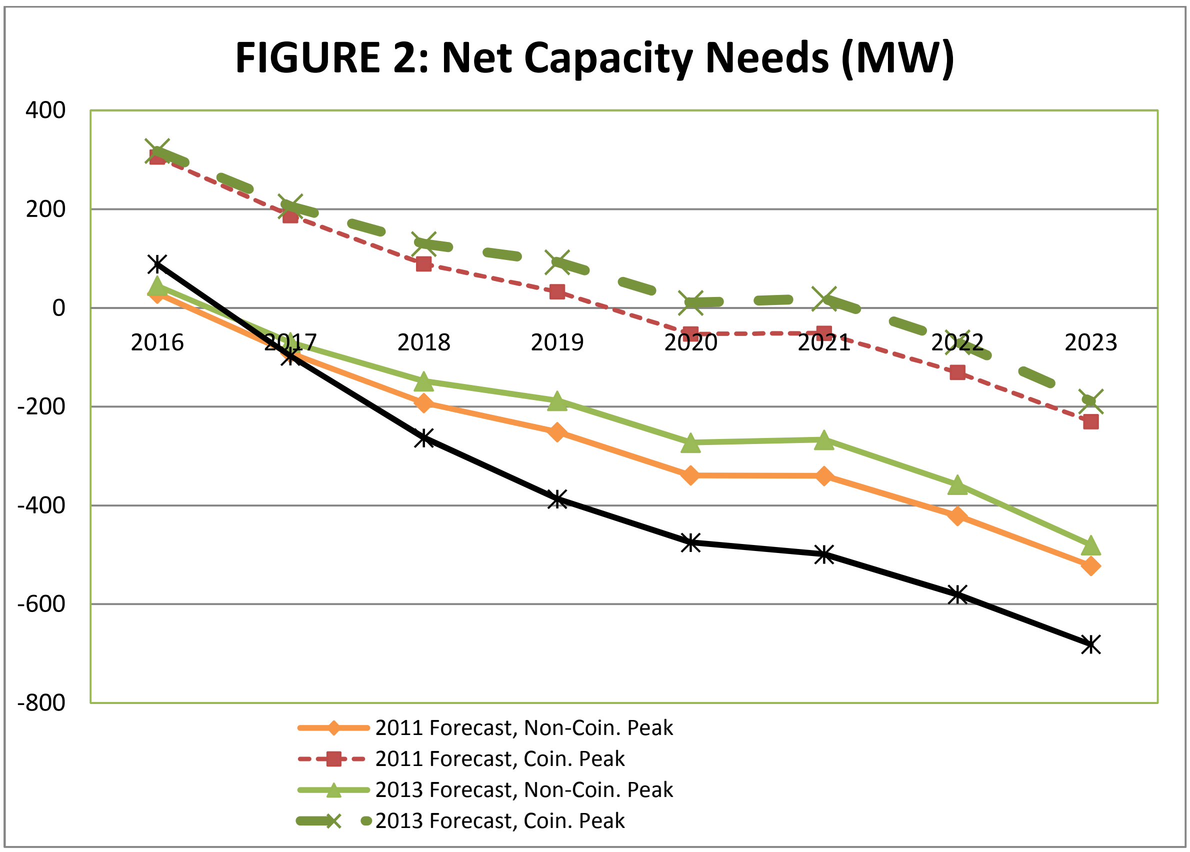
A. Regarding how to interpret the data, my non-coincident (utility) peak demand calculations assume that the forecast reduction (from non-coincident to coincident) is roughly offset by a reduction in DSM capability and the net impact is too small to matter. Thus, the original (non-coincident, utility peak) calculations are assumed to be a reasonable estimate of the coincident (MISO) peak reliability requirement.

On the other hand, my coincident (MISO) peak demand calculations assume that the MW of DSM available does not vary significantly with the conditions that are driving the differences in the coincident and non-coincident demand forecasts. Thus, the reduction of the coincident demand forecast by the original quantity DSM.

Q. What are the differences in Xcel's needs under these various reliability methods?

A. Figure 2 below shows the Company's net capacity surplus/(deficit) before new additions under five different assumptions. Solid lines represent use of the non-coincident peak method; dashed lines represent use of the coincident peak method. Figure 2 resulted from the following process:

- the last Strategist database run by the Department in Xcel's resource plan (Docket No. E002/RP-10-825) was unchanged;
- using the 2011 forecast and non-coincident (utility) peak reliability method;[13]
- using the 2011 forecast and coincident (MISO) peak reliability method;[14]
- using the 2013 forecast and non-coincident (utility) peak reliability method;[15] and
- using the 2013 forecast and coincident (MISO) peak reliability method.[16]



[13] Essentially this is the last Strategist database run by the Department but updated for the list of known modeling changes discussed above.
[14] This is the last Strategist database run by the Department but updated for the list of known modeling changes and the new reliability method.
[15] This is the last Strategist database run by the Department but updated for the list of known modeling changes and the new demand forecast with associated DSM achievements.
[16] This is the last Strategist database run by the Department but updated for the list of known modeling changes, the new reliability method, and the new demand forecast with associated DSM achievements.

Q. What do you observe from this figure?

A. I conclude several things from Figure 2. First, the impact of my model updates can be seen by comparing the "Last IRP model" solid line to the "2011 Forecast, Non-Coin. Peak" solid line. The model changes cause the net capacity deficit to remain relatively unchanged in 2017 but by 2020 the changes reduce the deficit by about 135 MW and by 150 MW in 2021.

Second, the impact of the choice of net demand forecast (2011 or 2013) can be seen by comparing the "2011 Forecast, Non-Coin. Peak" solid line to the "2013 Forecast, Non-Coin. Peak" solid line. The forecast change causes a reduction in net peak demand of between 15 and 70 MW each year.[17] The impact is relatively small in 2016 but gets larger in later years; the impact reaches a peak in 2021 albeit a small peak. Thus, the choice of net forecast does not appear to be significant.

Third, the impact of the choice of reliability method (coincident or non-coincident) can be seen by comparing the "2011 Forecast, Non-Coin. Peak" solid line to the "2011 Forecast, Coin. Peak" dashed line. The reliability method change causes a reduction in net peak demand of between about 275 MW and 290 MW each year.[18] Thus, the uncertainty regarding how to most accurately estimate the impact of the new reliability method on the demand forecast and associated demand-side management resources is significant.

[17] Note that the impact can also be determined by comparing the two coincident peak (dashed) lines, such a comparison would produce approximately the same result.

[18] Note that the impact can also be determined by comparing the 2013 (dashed to solid) lines, such a comparison would produce approximately the same result.

4. End Date Used in Models

Q. Please explain the end date for each model run.

A. Each Strategist analysis, or "run" ends in 2036. The 2036 end date is the approximate end of the proposals for 20-year power purchase agreements coming on-line in 2016 or 2017. Thus, the 2036 end date ensures that the 20 year bids are not penalized to a significant degree by speculation regarding the cost of replacement capacity 20 years in the future.

However, such an end date, even with end effects, likely does not account for the full value of Xcel's bids, which are expected to have a 35 year life. A 2050 end date would allow the full life of Xcel's bids to be analyzed, but that approach would then require the other bids to acquire replacement capacity and energy at the prices assumed in Strategist for the generic units (the costs of generic units are generally higher than the costs of the bids). Both approaches have benefits and costs, but I concluded that the best approach in this case, given the information available, was to use an end-date of 2036.

Q. Are there other factors to consider regarding end dates in the model?

A. Yes, three other factors come to mind on the issue of end dates. One factor is that Xcel has traditionally run Strategist for the full duration available (through 2050); I expect Xcel to follow that approach in this proceeding. Thus, the approach of using 2050 as the end date may be presented to the Commission whether the Department presents it or not. A second factor is that a Strategist run using 2036 as the end date can be completed faster than a Strategist run using 2050 as the end date.[19] In addition, it appeared that a

[19] Strategist runs can take more than a day to complete if a model is particularly complex; moreover, giving the model too many choices could cause Strategist not to be able to "solve" – that is, not to produce reliable results.

Strategist run using 2050 as the end date would require at least some expansion units to be locked in rather than allowing the model to choose the optimal expansion plan.

Q. What do you conclude, based on your assessment of these factors?

A. Based on the information and time available to me in this proceeding, I conclude that using 2036 as the end date is the best approach. Thus, when reviewing the results of my analysis using 2036 as the end date, the Commission should keep in mind that there is extra value in having Xcel's bids on the system for several years beyond the end of the planning period.

5. Relationship between Generic Units and Amount of Capacity in Packages

Q. Are there any considerations to keep in mind when comparing proposals that add significantly different quantities of capacity?

A. Yes. The relationship between the cost of the replacement units and the cost of the proposals is an item to consider. The 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). If the generic units are cheaper than the proposals in this proceeding, then when Strategist is run the small packages will generally look better than large packages because of the more extensive use of the (cheaper) generic units. Similarly, if the generic units are more expensive than the proposals, then when Strategist is run, large packages will tend to look cheaper than smaller packages.

Q. How does the cost of generic units compare to the bid proposals in this proceeding?

A. In general in this case, the generic units are more expensive than the Bidder's proposals. However, some of the Bidders' proposals are more expensive than the generic units. This fact can be seen by comparing the cost of runs with the Bidders' individually to the cost of run of the base case (which only adds generic units); see DOC Ex. ___ SR-4A (Rakow Direct) and DOC Ex. ___ SR-4B (Rakow Direct). The packages with CT or CC proposals are cheaper (resulting in a higher rank) than the base case. However, the opposite is true for Geronimo.

Q. What does this difference suggest to you?

A. Thus, one way to interpret the model results in Geronimo's favor is to consider Geronimo's proposal as part of the SES, thus allowing Geronimo to rely more upon the generic units than would otherwise be the case.

Q. What else do you note about the differences in costs of the generic units and the Bidders' proposals?

A. Overall, if the CT/CC proposals represent a temporary availability of low-cost new units and the cost of the generic units is otherwise accurate, then the bonus given to the proposals with a large quantity of MW (relative to small quantities of MW) is reasonable, all else being equal. However, if the CT/CC proposals are representative of a long run lower cost of new units (meaning the generic units are over-priced), then the bonus given to the proposals with a large quantity of MW may not be reasonable if the bonus is significant since that would mean that proposals with small quantities of MW would be overly penalized.

At this time, absent further information, I assume that the prices of the CT/CC proposals are representative of costs in the long run. Further information will likely become available as utilities build new or replace old generation units. Nonetheless, I examine options to address a potential concern if generic units are overpriced.

Q. How relevant is this issue in this proceeding?

A. I have found this cost influence may be a significant factor in this proceeding as I have evaluated the costs of packages with significant differences in size, type, and timing; this process resulted in a wide variety of potential projects. Thus, if the costs of the generic units are too high, smaller capacity (MW) packages would be disadvantaged.

Q. Is there a way to avoid the issue regarding the relative price of proposals and generic units?

A. Yes, it is possible to "lock in" the expansion plan, meaning that Strategist is forced to accept a certain set of the future expansion units. If that structure is created, then Strategist cannot show a large package as having a lower cost than a smaller package simply due to the addition of fewer generic units being added to the large capacity package than a small capacity package.

Another approach is to run Strategist with expansion units as options but then consider only those proposal packages that cover Xcel's capacity deficit through a certain year, thus limiting the bonus given to large capacity (MW) packages. Under either approach the issue of Strategist analysis being biased towards adding more capacity from the Bidders' proposals (to avoid more expensive generic units) is avoided.

Q. Did you consider locking in the expansion plan?

A. Yes, I did consider that approach but ultimately decided to leave the expansion units as options to be selected. While such an approach would have the advantage just discussed and would greatly reduce Strategist's run time, under this approach Strategist would not be able to adapt to the various sizes of packages by making other changes in the expansion plan. Thus, the cost of each package reported by Strategist would be influenced by how well the package fits with pre-determined expansion plans for many years into the future.

Q. Ultimately, what did you conclude regarding any analytical issues pertaining to the accuracy of the generic units in Strategist?

A. First, as noted above, based on this record alone, there is not a basis to conclude that the costs of the generic units are too high. These costs came from Xcel's most recent resource plan and are intended to represent costs over the planning period rather than costs at a specific time. Nonetheless, if there were a concern about the costs of generic units being too high, then both modeling approaches I discuss above (locking in expansion units or leaving expansion units as options but considering only those packages covering deficits through a particular year or years) have advantages and disadvantages. While there is no clear way to determine which approach is superior, I decided to leave the expansion units as options and considered only those packages covering deficits through the year 2024.

6. Varying Levels of Cost Inputs

Q. Why are there no scenarios with varying costs in the first round?

A. The purpose of the first round of analysis is to reduce the number of potential packages to a manageable number while achieving the overall objectives in this proceeding. Use of a variety of load and capability situations provides a reasonable spectrum of situations to assess the relative performances of the packages at a high level. Thus, varying cost assumptions is not necessary in the first round. Detailed cost analysis of the packages is reserved for the second round of analysis.

F. FIRST ROUND RESULTS

Q. Please provide the results from the first round of your Strategist analysis.

A. Selected model outputs are included in DOC Ex. ___ SR-4A (Rakow Direct) and DOC Ex. ___ SR-4B (Rakow Direct). To assist the reader in reviewing these results, I provide the following list of codes used on these pages:

- BD617—Xcel's Black Dog unit 6, 2017 in-service date;
- BD618—Xcel's Black Dog unit 6, 2018 in-service date;
- BD619—Xcel's Black Dog unit 6, 2019 in-service date;
- CCC1—Calpine Combined Cycle proposal;
- GPV1—Geronimo Solar proposal, "bundled" pricing;

- GPV1 DEGRADE—Geronimo Solar proposal, “bundled” pricing, but performance degrades over time;
- GPV1 FVP—Geronimo Solar proposal, with “Fixed + Variable” pricing;
- GRE1—Great River Energy proposal 1 (the smaller proposal);
- GRE2—Great River Energy proposal 2 (the larger proposal);
- ICT1—Invenergy Combustion Turbine proposal 1 (Cannon Falls);
- ICT2—Invenergy Combustion Turbine proposal 2 (Hampton);
- ND118—Xcel’s North Dakota unit 1, 2018 in-service date;
- ND119—Xcel’s North Dakota unit 1, 2019 in-service date;
- ND218—Xcel’s North Dakota unit 2, 2018 in-service date; and
- ND219—Xcel’s North Dakota unit 2, 2019 in-service date.

Q. How do you interpret these results?

A. I note the following:

- The package with Xcel’s Black Dog CT unit and Calpine’s CC unit is the highest ranked under all 24 scenarios and was an obvious candidate for further analysis. However, this is a rather large package, covering Xcel’s needs for several years. Thus, to allow for greater exploration of alternative approaches, I examined the effects of using smaller packages covering the deficits for a shorter period of time.
- After the least-cost package above, Strategist tends to produce significantly different results in the various scenarios, meaning Strategist doesn’t indicate that there is a highly robust alternative. That result in itself is interesting since it suggests that using the least-cost package above would be a reasonable outcome in this proceeding.

- Focusing on scenario nine and the packages that require a generic unit to be added in 2020, I decided to include a package with Invenergy's Cannon Falls CT unit and Xcel's Black Dog CT unit as well. Finally, considering Minnesota's renewable preference statutes, I included an analysis of Geronimo's proposal to provide the Commission a comparison across a range of cost assumptions. (I discuss above some of the complexities regarding Geronimo's bid and the passage of the SES.)

Q. Please list the packages that are developed further in the Second Round below.

A. I developed the following packages:

1. BD617—Xcel's Black Dog CT proposal, in-service in 2017;
   CCC1—Calpine's Mankato Energy Center expansion proposal;
2. ICT1—Invenergy's Cannon Falls CT expansion proposal;
3. GPV1—Geronimo's solar proposal;
4. BD619 CCC1—the least-cost package, with Black Dog 6 in-service by 2019;
5. ICT1 BD618—a package covering needs through 2020, with Black Dog in-service by 2018;
6. ICT1 CCC1—the only CT/CC combination remaining; and
7. Base Case—a no-build alternative.

The first three packages are simply the proposals from the packages selected for detailed analysis on their own.

Q. Why are there different in-service dates for Xcel's Black Dog unit 6?

A. When considered alone, Black Dog unit 6 needs to be in-service in 2017 to cover the capacity deficit that year. Black Dog unit 6 in-service in 2018 was the actual unit in the package with ICT1 that I selected, use of any other in-service date represent a different package. Black Dog unit 6 in-service in 2019 was the actual unit in the package with CCC1 that is least-cost as noted above.

G. SECOND ROUND SET-UP

Q. What model did you use for the base case in the second round of analysis?

A. For the base case in the second round of analysis I used the 2011 forecast, non-coincident peak reliability method, 800 MW of wind, and 72 percent solar accreditation factor. This is scenario three from the first round of analysis.

Q. Please explain the contingencies you ran on each package selected for inclusion in the second round.

A. In general, I started with the list of contingencies used in the most recent resource plan (Docket No. E015/RP-13-53). I modified that list by removing contingencies not relevant to this proceeding, such as varying wind prices. The resulting list of contingencies includes:

- CO_2 reduction per Minnesota Statutes;
- The Commission's high and low CO_2 internal cost values;
- low externality values;[20]
- high and low wholesale market prices (±25 percent);

[20] The high externality values are included in the base case.

- high and low capital costs (±10 percent);
- high and low coal costs (±20 percent and ±10 percent);
- low natural gas costs (-\$1.50, -\$1.00, -\$0.50)
- high natural gas costs (+\$2.50, +\$2.00, +\$1.50 + \$1.00, and, +\$0.50);
- high and low wind accreditation (±25 percent); and
- high and low forecast of energy and demand (±5 percent and ±2.5 percent).

In addition, similar to what was done for the most recent resource plan, I ran each scenario and contingency a second time with the Commission's CO_2 internal cost and externality values removed.

Q. Did you observe any issues as you tested the effects of the modeling?

A. Yes. During testing of the low wind accreditation, contingency generic units were usually added prior to the proposals being put in-service. Therefore, I forced Strategist to add 100 MW of short term capacity (forced into the supply mix during June, July, and August) in both 2015 and 2016. This approach enabled Strategist to determine whether the packages covered the capacity deficits in the 2017 to 2020 time frame or whether additional long term capacity (from generic units) was needed.

A similar issue appeared in testing the high (+ 5 percent) forecast and mid-high (+ 2.5 percent) forecast contingencies. For the high forecast contingency, I forced Strategist to add 400 MW of short term capacity in 2015 and 500 MW in 2016. For the mid-high forecast contingency, I forced Strategist to add 100 MW of short term capacity in 2015 and 250 MW in 2016. As with the low wind accreditation contingency, this approach enabled Strategist to determine whether the packages covered the capacity deficits in the

2017 to 2020 time frame or whether additional long term capacity (from generic units) was needed.

Q. In the higher forecast contingencies, did you change the level of energy conservation and load management assumed in Strategist?

A. For simplicity of analysis and ease of understanding, I did not change the energy conservation and load management inputs. I note that this approach is how these contingencies are usually performed in resource planning.

Q. Did you make any changes to the Strategist inputs you used in the first round?

A. Yes, at this point I used the data Xcel provided to the Department for the 4th wind project (Border Wind) selected in Xcel's wind RFP proceeding (see Docket Nos. E002/M-13-603 and E002/M-13-716) rather than a generic wind unit. I did so given the results of the Department's analysis in those proceedings that show these wind proposals to be least-cost in every one of the nearly 1,800 Strategist runs in each of those proceedings.

H. SECOND ROUND RESULTS

Q. Please provide the results from the second round of Strategist analysis.

A. Selected outputs are included in DOC Ex. ___ SR-5A (Rakow Direct), DOC Ex. ___ SR-5B (Rakow Direct), and DOC Ex. ___ SR-5C (Rakow Direct). I used the same codes for the second round results as for the first.

Q. Did you consider any additional risks (in addition to those modeled) in reviewing the second round of Strategist outputs?

A. Yes. First, at the September 16, 2013 MISO Loss of Load Expectation Working Group meeting, MISO's presentation provided preliminary results regarding the required capacity reserve ratio for the next year. The preliminary results were that the required reserve ratio was expected to increase by about 1 percentage point. Thus, given a peak demand forecast of about 10,000 MW, each percentage point increase in the reserve ratio requires Xcel to obtain approximately 100 MW of additional accredited capacity.

Second, Xcel's 125 MW power purchase agreement with Manitoba Hydro (see Docket No. E002/M-10-633) includes as one of Manitoba Hydro's conditions precedent, the following:

> …the awarding by [Manitoba Hydro] MH, in MH's sole and absolute discretion, on or before May 1, 2018, the major general civil contract for the civil construction of a new hydraulic electrical generation facility, after all approvals and licenses have been obtained, which generation facility will be designed to have an installed capacity of at least 1000 MW and will have a targeted in-service date of on or before May 1, 2021.

The only new hydraulic electrical generation facility that would have an installed capacity of at least 1,000 MW that I am aware of is the proposed Conawapa generating station to be located in Canada. Regarding Conawapa, Manitoba Hydro's website states "The earliest possible in-service date of the project is 2025." Thus, at this time it appears that Manitoba Hydro will be able to exercise this condition precedent if it desires. If that happens, Xcel may lose access to this resource.

Q. Based on your analysis, what are your observations and which package do you conclude should be approved by the Commission?

A. Depending on the Commission's goal in this proceeding, several options are available. If the overall goal is to minimize costs, as is typically the case, then referring to the information including CO_2 costs, the results clearly demonstrate that the least-cost package is Calpine's proposal combined with Xcel's proposal for a CT unit at the Black Dog site in 2019. The Calpine proposal plus Black Dog in 2019 covers Xcel's capacity deficit to 2023 under the normal forecast and to 2025 and beyond under the mid-low and low forecasts.

If, for some reason the Commission is concerned about the size of the package, the second ranked package (under base case conditions) is Calpine's proposal. However, under certain contingencies either Black Dog in 2017 or Invenergy's proposal plus Calpine's proposal. Thus, the exact ranking would depend upon which contingencies are of greatest concern.

Q. Please provide a summary of the load and capability report[21] for Xcel after these two units Xcel's Black Dog unit in 2017 and Calpine's proposal are added.

A. This information is provided in Table 1 below.

[21] A load and capability report presents a utility's or other system's supply and demand information.

Table 1: Load and Capability After Additions							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Actual Reserve (%)	4.10	5.82	4.76	6.28	5.37	5.54	4.72
Minimum Reserve (%)	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Difference (%)	0.31	2.03	0.97	2.49	1.58	1.75	0.93
Peak Demand (MW)	9,524	9,613	9,708	9,799	9,881	9,963	10,029
Excess Reserves (MW)	29.5	195.1	94.2	244.0	156.1	174.4	93.3

Q. Please provide some context for the size of the excess reserves noted above.

A. There are several comparison points:

- the difference in solar accreditation (50 percent versus 72 percent) is about 60 MW;
- a one percent increase in required reserves equals about 90 MW to 100 MW; and
- the spring 2013 forecast is lower than the fall 2011 forecast (both net of conservation) by 80 MW to 125 MW between 2017 and 2022.

I also note that a number of Xcel's resources are aging, which may result in the need to replace those facilities. Further, the economy in Minnesota is still in recovery mode, meaning that demand is expected to increase as the economy improves.

Thus, overall, I conclude that the level of excess reserves shown in Table 1 is reasonable.

I. OTHER ISSUES

Q. Do you have any additional analysis?

A. Yes, the issue of promotional activities has been raised in other certificate of need dockets. It is necessary to ensure that Xcel does not benefit by promoting an increase in electric load while imposing on ratepayers the costs of that increase. For example, the Department's January 28, 2013 comments in Docket No. E002, ET2/CN-11-826 stated:

> The Department notes that the *Direct Testimony and Schedules of Allen D. Krug* (Krug Direct) in Docket No. E002/GR-12-961 proposes a new Business Incentive and Sustainability (BIS) Rider:
>
> The proposed BIS Rider authorizes fixed discounts over a five-year period to new loads in excess of 350 kW (either from a new customer or from incremental new load from an existing customer)…

The Krug Direct clearly distinguishes the newly proposed BIS Rider from similar existing rates:

> The statutes authorizing the Competitive Service Rider and Area Development Rider are specialized legislative provisions designed to address two specific needs for discounted rates. The BIS Rider addresses a different, broader need to incent new business load and associated new investment.

The BIS Rider is clearly a promotional practice designed to create increases in demand for energy. Since the BIS Rider is not in place at this time, it cannot have contributed to the demand for energy addressed by this proceeding. However, if the BIS Rider is approved in the future it likely will qualify as a promotional practice. In turn, the Department may recommend that the Commission approve future CN petitions with conditions designed to ensure that the Company does not benefit financially from the promotional practices while imposing costs on others through the CN process.

III. RECOMMENDATION

Q. Please provide your recommendations.

A. I recommend that the Commission approve Calpine's proposal and Xcel's proposal for a unit at the Black Dog site with a 2019 in-service date. I also recommend that the Commission consider requiring Xcel to issue an all solar RFP in consideration with other information that is known in the context of Xcel's next IRP, due February 2014.

Q. Does this conclude your testimony?

A. Yes.