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Minnesota Department of Commerce

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September 9, 2013 **PUBLIC DOCUMENT**

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

RE: **Public Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket Nos. E002/M-13-603 and E002/M-13-716

Dear Dr. Haar:

Attached are the **PUBLIC** comments of the Minnesota Department of Commerce, Division of Energy Resources, in the following matter:

Petition of Northern States Power Company d/b/a Xcel Energy for Approval of the Acquisition of 600 MW of Wind Generation; and

Petition of Northern States Power Company d/b/a Xcel Energy for Approval of the Acquisition of 150 MW of Wind Generation.

Theses petitions were filed on July 16, 2013 and August 9, 2013, respectively, by:

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

The Department recommends **approval** of the proposed petition and is available to answer any questions the Commission may have.

Sincerely,

/s/ CHRISTOPHER SHAW
Rates Analyst

/s/ CRAIG ADDONIZIO
Financial Analyst

CS/CA/jl
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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

DOCKET NOS. E002/M-13-603 AND E002-M-13-716

I. BACKGROUND

On July 16, 2013, Xcel Energy (Xcel or the Company) petitioned the Minnesota Public Utilities Commission (Commission) for approval of the acquisition of 600 MW of wind generation (Petition or, together with Xcel's August 9 filing in Docket No. E002/M-13-716, Petitions).

On July 25, 2013 the Commission issued a *Notice of Comment Period on Procedural and Statutory Issues Related to Xcel's Petition* (Procedural Notice) and a *Notice of Comment Period on the Merits of Xcel's Petition* in Docket No. E002/M-13-603.

On August 8, 2013, the Minnesota Department of Commerce, Division of Energy Resources (Department), Xcel, Geronimo Energy (Geronimo), Ecos Energy (Ecos), and the Minnesota Chamber of Commerce (Chamber) submitted comments in response to the Commission's Procedural Notice.

Sorgo Fuels (Sorgo) submitted comments to the Commission regarding Xcel's Petitions on July 24, July 25, July 26, August 7, August 10, August 16, August 26, September 3, and September 4 2013.

On August 9, 2013 Xcel filed a petition requesting approval of an additional 150 MW of wind generation in Docket E002/M-13-716.

On August 13, 2013, Ecos submitted reply comments regarding the Procedural Notice, petitioned to intervene and requested a contested case.

On August 16, 2013, Ecos submitted supplemental reply comments and a motion to consolidate Dockets E002/M-13-603 and E002/M-13-716.

On August 19, 2013, the Commission issued its *Notice of Comment Period of the Merits of Xcel's Petition* in Docket No. E002/M-13-716.

On August 23, 2013, Geronimo submitted its objection to Ecos' petition to intervene.

On August 28, Ecos submitted comments and requested a contested case.

On August 29, 2013, , the Department submitted a request to extend the deadline for comments and reply comments by 10 days. As the Department suggested in its August 8 comments, this extension was necessary to provide the Commission with a complete and thorough analysis of Xcel's proposal.

On September 4, 2013 the Commission met to consider the procedural questions in these dockets. The Commission declined to send these dockets to a contested case proceedings or consolidate these dockets with any other ongoing proceedings. The Commission granted Ecos' petition for intervention only in these wind dockets.

On September 4, 2013, the Commission also granted the Department's request to extend the deadline for comments by 10 days and reply comments correspondingly.

The Department submits its comments on the merits of Xcel's proposals below.

II. SUMMARY OF PROPOSED PROJECTS

In it Petitions, Xcel proposed to acquire a total of 750 MW of nameplate wind generation from four wind farms through two Power Purchase Agreements (PPAs) and two Purchase and Sale Agreements (PSAs). Each proposed project is briefly summarized below:

A. ODELL

The proposed Odell wind farm (Odell) would have a nameplate capacity of 200 MW and be located near Mountain Lake, Minnesota. Odell would be developed, owned and operated by Geronimo. Xcel would purchase the output of Odell under the terms of a 20-year PPA. Xcel expects Odell to begin operating in late 2015. The levelized cost of energy purchased over the term of the PPA is **[TRADE SECRET DATA HAS BEEN EXCISED].**

B. COURTENAY

The proposed Courtenay wind farm (Courtenay) would have a nameplate capacity of 200 MW and be located near Jamestown, North Dakota. Courtenay would be developed, owned and operated by Geronimo. Xcel would purchase the output of Courtenay under the terms of a 20-year PPA. Xcel expects Courtenay to begin operating prior to September 2015. The levelized cost of energy purchased over the term of the PPA is **[TRADE SECRET DATA HAS BEEN EXCISED].**

C. PLEASANT VALLEY

The proposed Pleasant Valley wind farm (Pleasant Valley) would have a nameplate capacity of 200 MW and be located near Austin, Minnesota. Pleasant Valley would be developed by RES America and transferred to Xcel once construction is completed. Xcel expects Pleasant Valley to begin operating by October 2015. The estimated capital cost of Pleasant Valley is **[TRADE SECRET DATA HAS BEEN EXCISED]** resulting in a levelized cost of electricity generated from Pleasant Valley of **[TRADE SECRET DATA HAS BEEN EXCISED]** assuming a 25-year project life.

D. BORDER WINDS

The proposed Border Winds wind farm (Borders Winds) would have a nameplate capacity of 150 MW and be located in northeastern Rolette County, North Dakota. Border Winds would be developed by RES America and transferred to Xcel once construction is completed. Xcel expects Border Winds to begin operating in late 2015. The estimated capital cost of Border Winds is **[TRADE SECRET DATA HAS BEEN EXCISED]** resulting in a levelized cost of electricity generated from Pleasant Valley of **[TRADE SECRET DATA HAS BEEN EXCISED]** assuming a 25-year project life. The levelized cost includes **[TRADE SECRET DATA HAS BEEN EXCISED]** of network upgrade costs associated with Border Winds.

III. ANALYSIS

A. CONSISTENCY WITH XCEL'S 2010 INTEGRATED RESOURCE PLAN (IRP)

As discussed in the Department's August 8, 2013 procedural comments in Docket No. E002/M-13-603, the Department concludes the Xcel's proposed wind additions are not inconsistent with the analysis conducted in its 2010 IRP. The Department stated:

> In analyzing Xcel's 2010 IRP the Department used a cost of \$65/MWh in its base case for wind generation. The Department then analyzed the impact of changes in the cost of wind on Xcel's capacity expansion plan by studying wind costs in \$5/MWh

increments between $35 and $80. The Department concluded that additions of new wind generation were only cost effective if the cost was below $50/MWh. At the time of the Department's analysis of Xcel's 2010 IRP, Xcel's most recent wind acquisition, while below $50/MWh, was in the $40 to $50/MWh range.[1] In addition, the Department had reviewed numerous wind projects in the 2010-2011 timeframe that had prices both above and below $50/MWh.[2] Thus the Department's analysis focused on the identification of a break-even point for additions of new wind units.

The Department recommended that Xcel pursue 100 MW to 200 MW of wind in 2015-2016 if the price was $50/MWh or less. That amount was determined after the Department removed all of the forced wind units and had 200 MW optional units available every other year starting in 2014.[3] When the cost of wind was lower than $50/MWh, the capacity expansion model added as much wind as was allowed in the model.

The Department did not explore the effects on the timing of wind additions in the event a significant amount of low cost wind was available in the near-term. Thus, as the Department's analysis indicated that the capacity expansion model would add as much wind as allowed when priced below $50, Xcel's proposal is likely consistent with the modeling conducted in the IRP. That is, it is likely that the model would have added more than 200 MW in the near-term if wind was priced below $30/MWh (as the bids Xcel received were priced) and if the model was allowed to add more [than] 200 MW every other year. However, as that scenario was considered unlikely at the time of the analysis, neither the Department nor Xcel explored that scenario. Thus, while the Department concludes that Xcel's proposal is not inconsistent with the IRP, Xcel should not rely on the analysis in the 2010 IRP to support its acquisition of the specific resources requested in the instant docket. This approach is consistent with the Commission's 2010 IRP Order which approved the IRP for planning purposes only and is also consistent with Xcel's filing in the instant docket.

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[1] See Docket No. E002/M-11-713.
[2] See Docket Nos. E001/M-10-312, E015/M-11-234, E002/M-09-1349.
[3] Department Comments at 11 (June 12, 2012), Docket No E002/RP-10-825.

Thus, while the IRP is not inconsistent with Xcel's proposal, it alone does not provide a complete basis to determine that the wind resources proposed to be acquired are part of a least-cost expansion plan.

B. CAPACITY EXPANSION MODELING

1. Introduction

As the 2010 IRP could not be relied upon as showing a need for 750 MW in the 2015 time-frame, both Xcel and the Department conducted additional capacity expansion modeling in order to evaluate whether the proposed additions are part of a least-cost expansion plan. To evaluate the cost-effectiveness of Xcel's proposed wind additions, the Department used the Strategist capacity-expansion model to examine numerous scenarios. This is the same type of analysis the Department conducts in IRPs.

2. Base Case

The Department did not begin with the base file provided by Xcel in this Docket for several reasons. First, since an evaluation of various capacity additions to Xcel's system is occurring in Docket E002/CN-12-1240, both models should be consistent in the base assumptions used. Second, the Department had already reviewed the base case in Xcel's 2010 resource plan and updated it as discussed below for our analysis in Docket E002/CN-12-1240. Beginning the review process with a new base model would raise questions and could lead to inconsistent results in these proceedings. Third, by beginning with the base model from the resource plan, the Department is able to assess the accuracy of Xcel's model by developing its own base model rather than relying on a review of the base model provided by Xcel.

The Department began its analysis using the most recent Strategist analysis the Department used for Xcel's system. Specifically, the Department began with the Scenario 1 (No Prairie Island uprate) file from our December 18, 2012 comments in Xcel's most recent resource plan, Docket No. E002/RP-10-825 (the 2010 IRP Docket). The Department updated the file as follows.

1. Re-established Xcel's combustion turbine (CT) and combined cycle (CC) optional expansion units in the years 2027 through 2050. (Because these units were not needed for the analysis in resource plan proceeding the Department deleted those units in the 2010 IRP docket.)

2. Eliminated the optional wind expansion units that the Department used in the IRP proceeding to determine the optimal quantity of wind energy. The optimal level of wind energy is not an issue in this proceeding; the focus is on the cost-effectiveness of the specific wind resource proposed to be acquired.

3. Re-established "hard wired" or "forced" wind expansion units only as needed to ensure that the Minnesota Renewable Energy Standard (RES) is met in Strategist (data from Xcel's latest Strategist database). No generic wind expansion units are added before 2020. This configuration allows for a comparison of the effect of adding the proposed projects on Xcel's system.

4. Removed the Goodhue Wind unit from Xcel's generation portfolio.[4]

5. 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).

6. Updated the retirement dates for Xcel's Black Dog units 3 and 4 and French Island unit 3.

7. Updated the in-service (repair) date for Xcel's French Island unit 3.

8. Added about 290 MW and 520 GWh of solar energy during 2017 to 2019 growing to about 300 MW and 550 GWh by 2030. This addition is done to meet the solar energy standard (SES). See Attachment A for the calculation of the SES.

    a. A capacity factor of about 20 percent was assumed based upon data from the National Renewable Energy Laboratory's PVWatts calculator, Geronimo's bid, and data on solar units Xcel already had in Strategist.

    b. Capacity accreditation is assumed to be about 72%, based upon the December 3, 2012 comments of the Department in Docket No. E002/GR-10-971.

    c. These changes were made by adding capacity to solar units already present in the model and increasing these units' energy production.

9. Turned on Xcel's construct for the wholesale energy market to allow a limited use of the wholesale market; previously the Department had turned off the wholesale energy market completely. This change is consistent with guidance from the Commission and with the Department's most recent IRP analyses.[5]

In addition to the changes listed above, the Department updated the model based on a brief review of Xcel's base case for the July 1, 2013 *Life Cycle Management Study for Sherburne County (Sherco) Generating Station Units 1 and 2*[6] and the base case used by Xcel in this docket.

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[4] 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.

[5] For example, see page 37 of the Department's June 3, 2013 comments in Docket No. E015/RP-13-53.

[6] See Department Information Request No. 1 in Docket No. E002/RP-13-368.

Specifically, the Department reviewed the following items that would directly impact unit dispatch and the load and capability of Xcel's existing fleet:

- Thermal unit heat rates;
- Annual fuel costs;
- Wholesale market costs;
- Thermal unit variable operation and maintenance (O&M) costs;
- Thermal unit maximum capacity; and
- Percent firm for thermal units.[7]

Based on this review the following inputs were updated:

- Heat rates for nuclear and generic units;
- Fuel prices for coal, nuclear, biomass, and natural gas (natural gas prices are set at about $4/MMBtu in 2013 and are escalated through the planning period for a levelized cost of about $6/MMBtu. This amount is consistent with current market prices for natural gas);
- Seasonality for natural gas prices (price variation across months);
- Price of wholesale market energy; and
- Variable O&M for Sherco and the generic units.

All of the changes listed above are the same changes made to the base case for evaluation of the bids in Docket No. E002/CN-12-1240 (Capacity request for proposals, RFP). Thus, as noted at the Commission's September 4, 2013 agenda meeting, the Department used the same base case in this Docket as will be used as the basis for its Direct Testimony in Docket No. E002/CN-12-1240.

Given the updates to the Department's base model discussed above, the Department notes that a major difference in the base models used by Xcel and Department is the demand and energy forecast. The Department's base model uses the 2011 forecast that was the basis for our analysis in Xcel 2010 IRP. Xcel used a spring 2013 forecast in its analysis. However, the Department evaluated the proposed wind additions under both the 2011 and 2013 forecasts as well as a scenario assuming that there is no growth in sales, which is less than the sales forecast used in either the Department's or Xcel's base case.

3. Wind Units

The Odell and Courtenay proposals are modeled using dollar-per-MWh costs that correspond to each of the proposed PPAs. Pleasant Valley and Borders Wind are modeled using a projected revenue requirement for each project. Xcel does not expect the proposed wind resources to receive capacity accreditation until 2021 when significant transmission investments are

[7] Percent firm is the portion of a unit's maximum capacity that is counted for purposes of required reserves.

completed.[8] Therefore, the proposed resources are modeled without any accredited capacity until 2021. Starting in 2021, a 13.3% accredited capacity value is used, which is consistent with the most recent MISO analysis of the effective load carrying capability of wind facilities.

Costs associated with congestion and line losses are included by using a dispatch model, which forecasts hourly prices at individual pricing nodes. Specifically, Xcel used MISO's 2012 Promod model to forecast the difference in locational marginal prices (LMP) between: 1) the nodes at each proposed generator and 2) Xcel load. The difference in price is attributed to line losses and congestion.

Integration costs are based on the 2006 Minnesota Wind Integration study. Xcel updated the 2006 study costs by using a cost of natural gas of $4/MMBtu to be closer to the current cost of gas. The 2006 Minnesota Wind Integration Study used a natural gas cost of $9/MMBtu. The Department did not update the integration costs from the 2006 Minnesota Wind Integration Study and thus used costs that are higher those used by Xcel. However, even the costs used by Xcel are likely overstating the incremental costs of ancillary services for the proposed wind additions as current prices for ancillary service are low.[9] Thus, these approaches regarding wind integration costs are conservative and make it more difficult for the proposed wind projects to be cost-effective.

The wind profile used in the capacity model is based on historical wind generation. Strategist uses an hourly wind profile for a representative week for each month of the year.

4. Scenarios

The Department ran scenarios to ensure that decisions regarding the acquisition of any additional wind do not improperly affect the concurrent proceeding in Docket No. E002/CN-12-1240 regarding capacity additions. Specifically, the Department analyzed whether the cost-effectiveness of wind was dependent on the decisions to be made in the Capacity RFP proceeding. The Department attempted to run scenarios using all possible packages of capacity addition in Docket E002/CN-12-1240 that result in less than 700 MW of nameplate capacity being added to Xcel's system with different combinations of wind. This approach is consistent with the Department's analysis in Docket No. E002/CN-12-1240.[10]

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[8] See DOC Attachment B (Xcel Response to DOC IR 1).

[9] See DOC Attachment C (Xcel Response to DOC IR 2).

[10] 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, the Department concluded that a cut off greater than 500 MW was warranted to examine. For example, the three units in Xcel's bid could not be included in a single package if a 500 MW cut off were used. Also, Calpine's unit could not be combined with any of the combustion turbine bids if a 500 MW cut off were used. Thus, the Department expanded its analysis to address practical effects of the bids that were actually submitted.

The Department compiled 153 different combinations of capacity addition combinations. The different combinations are shown in Attachment D. The Department then ran several scenarios that were most likely to show wind additions as less cost effective, again to use a conservative approach in this analysis. Specifically, the Department reduced the capacity factor of each unit, used a \$0 CO_2 cost, reduced gas commodity costs, used Xcel's 2013 forecast, and used no load growth. The Department then ran the following scenarios on each of the 153 different capacity combinations:

Scenario 1: 153 capacity combinations + 0 MW of wind through 2020
Scenario 2: 153 capacity combinations + Odell and Courtenay
Scenario 3: 153 capacity combinations + Odell, Courtenay, and Pleasant Valley
Scenario 4: 153 capacity combinations + all 4 wind projects (750 MW)
Scenario 5: 153 capacity combinations + all 4 wind projects + 10% reduction in energy output from each wind addition.
Scenario 6: 153 capacity combinations + spring 2013 forecast w/ 0 MW of wind additions through 2020
Scenario 7: 153 capacity combinations + spring 2013 forecast w/ all four wind projects
Scenario 8: 153 capacity combinations + \$1.50 reduction in gas cost w/ 0 MW of wind additions through 2020
Scenario 9: 153 capacity combinations + \$1.50 reduction in gas cost w/ all four wind projects
Scenario 10: 153 capacity combinations + \$0 CO_2 w/ 0 MW of wind additions through 2020
Scenario 11: 153 capacity combinations + \$0 CO_2 w/ all four wind projects
Scenario 12: 153 capacity combinations + no load growth w/ 0 MW of wind additions through 2020
Scenario 13: 153 capacity combinations + no load growth w all four wind projects.

Thus, the Department ran 1,859 different Strategist runs to evaluate the cost effectiveness of Xcel's proposed wind additions. These scenarios allow for cost comparisons of adding the proposed wind versus not adding the proposed wind. Under every scenario the wind additions are cost-effective. Further, adding all four proposed projects results in a lower present value societal cost (PVSC) than adding only some of the projects, as shown in a comparison of Scenarios 1-4. The net reductions in PVSCs for each scenario modeled by the Department are shown in Appendix D.

As every scenario showed the addition of the full 750 MW of wind proposed by Xcel to be cost-effective, the Commission's decisions in the Capacity RFP docket will have no bearing on the cost effectiveness of the wind additions. That is, regardless of the Commission's determination in the Capacity RFP, the addition of the full 750 MW of wind is a cost effective resource addition to Xcel's system.

Table 1 presents a summary of the PVSCs. The savings are as compared to not adding the proposed wind projects. Each scenario listed in Table 1 below was run using 153 different capacity combinations. The maximum and minimum savings of the 153 different options modeled are shown in Table 1. As noted above, complete results are attached as Attachment D.

Table 1:
Range of Net PVSC Savings (000s Difference from No Wind Additions)

	Maximum	**Minimum**
Add Odell and Courtenay	($376,604)	($265,524)
Add Odell, Courtenay, and Pleasant Valley	($648,428)	($529,220)
Add All Wind	($821,836)	($653,780)
Add All Wind w/ 10% reduced output	($754,868)	($589,996)
Add All Wind w/ Spring 2013 forecast	($802,344)	($634,944)
Add All Wind w/$1.50 reduced gas cost	($720,996)	($609,312)
Add All Wind w/ $0 CO2	($677,700)	($519,468)
Add All Wind w/ No Growth	($788,452)	($724,976)

As noted above, the Department modeled scenarios that were most likely to make wind additions less cost effective. As every scenario modeled by the Department resulted in PVSC savings, the Department concludes that all four of the proposed projects would be cost effective additions to Xcel's system.

C. COMPLIANCE WITH THE RES

The RES requires Xcel to supply 30 percent of its Minnesota customers' energy from renewable sources by 2020; 25 of the 30 percent must be generated from wind, and the remaining 5 percent may be generated by other eligible technologies. The Department confirmed Xcel's calculations found on pages 11-12 of the application in Docket No. E002/M-13-603 and pages 8-9 of the application in Docket No. E002/M-13-716 as based on the Company's updated load forecast. Based on the updated forecast, the addition of the proposed 750 MW would extend Xcel's compliance with the RES by about four years, to 2023. The Department also calculated Xcel's compliance with RES under the 2011 forecast. Using the higher 2011 load forecast, Xcel's compliance with the RES would also be extend by about four years through 2020.[11] Therefore, the Department concludes the addition of all four wind projects would allow Xcel to continue to comply with the RES for a longer period, in a cost-effective manner.

[11] The Department's calculation using the 2011 forecast is shown in Attachment E.

D. RESOURCE SELECTION PROCESS

1. Summary of Process

Xcel selected the four proposed wind projects through a competitive bidding process. As discussed in the Department's August 8, 2013 Comments in Docket No. E002/M-13-603, the five-year action plan from Xcel's 2010 IRP Docket included the solicitation of proposals for up to 200 MW of wind-powered generation. Consistent with that action plan, on February 4, 2013, Xcel made a filing in its 2010 IRP Docket notifying the Commission of its intent to issue an RFP for approximately 200 MW of wind generation.

On February 18, 2013, Xcel issued its RFP through a variety of mediums, including trade press and industry-related websites.[12] The RFP was open to wind projects of any size up to 200 MW and of various structures (i.e. community-based energy development (C-BED) projects, power purchase agreements and ownership structures). The RFP generated 57 projects representing approximately 6,300 MW of distinct resources.[13] Many of the projects were offered with multiple transaction structures, giving Xcel nearly 200 individual proposals to consider.[14] The Company received proposals for wind projects in six states, with levelized prices ranging from **[TRADE SECRET DATA HAS BEEN EXCISED]** and sizes ranging from **[TRADE SECRET DATA HAS BEEN EXCISED]**.

In the first phase of its analysis of the bids received, the Company performed an initial screening of all of the proposals based on the Company's estimate of each project's levelized cost. Xcel calculated the levelized cost of each proposal with a PPA structure using energy pricing data provided in the bid. For proposals with ownership structures (PSAs), Xcel developed estimates of annual O&M expenses and ongoing capital expenditures, and used these estimates, along with other cost data provided in the bids, to determine the annual revenue requirements for each proposal. Xcel used the estimated annual revenue requirements, along with estimates of energy production, to calculate the estimated levelized cost of each PSA proposal.

Xcel then ranked all proposals by estimated levelized cost, and based on these rankings, chose to pursue proposals with levelized costs of $29/MWh or lower.[15] Sixteen proposals representing fourteen projects fell below the $29/MWh threshold, including five PPA proposals and eleven PSA proposals.

The second phase of Xcel's review of the bids consisted of limited due diligence reviews of the sixteen proposals. Xcel's due diligence reviews of the five PPA proposals considered, among other factors:

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[12] See page 12 of Xcel's 13-603 Petition. See also page 3-1 of Attachment D to Xcel's 13-603 Petition.
[13] See page 13 Xcel's 13-603 Petition.
[14] See Appendix A of Attachment D to Xcel's 13-603 Petition.
[15] See Xcel's 13-603 Petition, Attachment E.

- experience and creditworthiness of the bidders,
- transmission interconnection status of the project,
- development schedules,
- permitting, and
- O&M plans.[16]

After this additional review, Xcel selected two PPA proposals to move forward into detailed due diligence and "closed door" negotiations.

Xcel's due diligence reviews of the eleven PSA proposals that fell under the $29/MWh threshold considered, among other factors:

- transmission interconnection status,
- network upgrade costs,
- energy production profile,
- turbine availability, and
- site control.[17]

From this review, Xcel selected five of the eleven PSA proposals to move forward into detailed due diligence and "closed door" negotiations. The Department notes that two of the five PSA proposals that reached this stage also had associated PPA proposals selected for detailed due diligence and "closed door" negotiations.[18] Xcel then separated these five proposals into three tiers to differentiate their relative attractiveness. The proposed Pleasant Valley Project was alone in the first tier, while the other four projects were divided among the second and third tiers.[19] Ultimately, Xcel selected two PSA proposals for further consideration and negotiations.

In the third phase of its analysis, Xcel used Strategist to analyze the impacts and cost effectiveness of the proposed projects, and concluded that all four projects offered significant cost savings to customers. Xcel also hired an outside consultant, V-bar, to conduct analyses of site-specific wind data for the two surviving PSA projects.

2. Analysis of Xcel's RFP Process

i. Project Selection

The Department concludes that Xcel's general RFP process was reasonable due to the use of the robust competitive bidding process, the general attention to cost, and examination of the expected ability of the projects to move forward in a timely manner at the costs proposed in the

[16] See Xcel's 13-603 Petition, Attachment D, page I-2 for a more detailed list of the factors evaluated.
[17] See Xcel's 13-603 Petition, Attachment D, pages 3-6, I-3, and J-2 for more details regarding the factors evaluated.
[18] See Xcel's 13-603 Petition, Attachment D, pages 3-6.
[19] See Xcel's 13-603 Petition, page 14.

bids. Further, the Department is convinced that the selected proposals will be cost-effective for ratepayers barring unforeseen, extreme circumstances. The Department notes, however, that the four selected wind proposals do not represent the four least expensive proposals available, per Attachment E of Xcel's 13-603 Petition. In supplemented Information Request 5, the Department asked Xcel to explain its reasons for rejecting the projects which had a lower levelized price than one or more of the selected projects, as shown in Xcel's Attachment E. In its response, Xcel provided the following information regarding the rejected projects:[20]

Table 2: Xcel's Reasons for Rejecting Specific Proposals

Project #	Primary Basis for Not Selecting
[TRADE SECRET DATA BEGINS	
TRADE SECRET DATA ENDS]	

The Department concludes, based on these reasons, that Xcel's decisions to eliminate these projects from consideration were reasonable, based on the same reasonableness factors that the Department applied to Xcel's approach overall. The Department notes that the factors described in Table 2 would affect all proposals associated with each project. That is, regardless of whether the project would be purchased under a PPA or PSA the above factors would apply.

Additionally, the Department notes that Xcel's Attachment E presents a range of levelized costs for each project, and the final levelized cost estimate for each of the four selected projects is higher than the low end of the levelized cost ranges presented in Xcel's Attachment E. As a result, the Department was concerned that rejected *proposals* associated with selected *projects* may have been more cost effective than the selected proposals. Thus, the Department asked Xcel to provide further explanation of the ranges presented in Attachment E, as well as the differences between the levelized cost estimates developed in the first phase of Xcel's review of the RFP responses and the final levelized cost estimates presented in the two Petitions. With respect to the ranges presented in Attachment E, Xcel explained that:[21]

> The range of levelized costs for each project per Attachment E represents the lowest cost and highest cost options where a bidder submitted multiple proposals for the same project. As an example, Geronimo submitted PPA, ownership or combination PPA/ownership proposals with numerous variations in size, turbine type and price structure for most of their projects. We calculated

[20] See DOC Attachment F (Xcel Supplemental Response to DOC IR 5).
[21] See DOC Attachment F.

> the levelized cost for each option offered and presented results as a range per Attachment E. As it relates to Geronimo's Courtenay project, the lowest cost option came in at **[TRADE SECRET DATA HAS BEEN EXCISED]** and the highest cost option was priced at **[TRADE SECRET DATA HAS BEEN EXCISED]**. All other options offered for the Courtenay project fell within the range of **[TRADE SECRET DATA HAS BEEN EXCISED]**.

With respect to the differences between the levelized cost estimates developed in the first phase of Xcel's review of the RFP responses and the final levelized cost estimates presented in the two Petitions, Xcel provided the following information:[22]

Table 3: Xcel's Reasons for Differences in Initial and Final Cost Estimates

Project	Proposal Selected	$/MWh Initial Screen	$/MWh Final	Main Driver
		[Begin Trade Secret…	**[Begin Trade Secret…**	**[Begin Trade Secret…**
Courtenay	200 MW PPA Escalating Price			
Odell	200 MW PPA Escalating Price			
Pleasant Valley	200 MW Build / Transfer			
Border	150 MW Build/Transfer			
		…End Trade Secret]	**…End Trade Secret]**	**…End Trade Secret]**

As noted by Xcel in these two responses, based on the first phase of Xcel's review, the least expensive proposal associated with the Courtenay project had a levelized cost of **[TRADE SECRET DATA HAS BEEN EXCISED].** However, the initial levelized cost estimate of the Courtenay proposal that was ultimately selected was **[TRADE SECRET DATA HAS BEEN EXCISED]**, and the final estimated levelized cost for Courtenay presented in the 13-603 Petition was **[TRADE SECRET DATA HAS BEEN EXCISED]**. In a telephone conversation with a

[22] See DOC Attachment F.

Company representative, Xcel explained that in negotiations with the developer of the Courtenay project, a number of terms and conditions originating from different proposals were discussed and that the proposal ultimately selected was, in Xcel's opinion, the best option for ratepayers, given potential effects of those terms and conditions on ratepayers. Based on this description, the Department concludes that Xcel reasonably evaluated the proposals associated with the selected projects, and notes that any differences between, for example, the lowest cost Courtenay proposal and the proposal which was ultimately selected are likely to be minor. The selection of particular projects is largely where the benefits to ratepayers are determined, rather than the selection of one PPA pricing structure proposal versus another for the same project.

Regarding the differences between the final levelized cost estimates presented in the two Petitions relative to the levelized cost estimates presented in Attachment E, the Department concludes that it is likely that the levelized cost of any proposal would have experienced some type of uplift similar to that shown above based on further fleshing out of proposals. The differences observed are the result of more conservative modeling by Xcel or the back-and-forth nature of the negotiation process. Thus, the Department concludes that the differences are reasonable.

In addition, the Department notes that, consistent with the Commission's Order in Docket No. E002/RP-04-1752, Xcel retained an independent auditor to evaluate Xcel's RFP process. The auditor's report is included as Attachment D of Xcel's initial filing in Docket No. E002/M-13-603.

ii. Transaction Structure

Additionally, the Department had concerns regarding Xcel's method of comparing PPA proposals to PSA proposals. The Department notes that Commission Orders in the past Dockets have set approximate allocation targets for Xcel's overall portfolio of renewable generation which should be acquired via independent power producers, C-BED projects, and utility-owned resources.[23] The Department notes, however, that the Commission has clearly stated its desire that Xcel evaluate renewable projects on an equal basis, and that ratepayers should not be forced to bear needless costs incurred solely to maintain a preset target allocation. In the context of the instant Dockets, the Department was concerned that Xcel might be paying a premium for one transaction structure in order to maintain a certain balance of PPA versus utility-owned generation.

As noted above, at least two projects had both a PPA proposal and a PSA proposal that survived at least part-way through the second phase of Xcel's review process. Because only two PPA proposals survived Xcel's screening process to that point and two PPA proposals were selected, it seems clear that both the Odell and Courtenay projects, at some point during the process, appeared to be attractive options as both PPAs and PSAs. In its response to Information Request

[23] See, for example, the Commission's June 19, 2009 *ORDER APPROVING TARGET PORTFOLIO ALLOCATION WITHIN XCEL'S RENEWABLE ENERGY PLAN* in Docket No. E002/M-07-1558.

5, part b, Xcel stated that as negotiations progressed on the PPA and PSA proposals, the developers "became less interested in negotiating terms and conditions acceptable for a build/transfer transaction."[24] In other words, the decision to pursue PPAs rather than PSAs was driven more by the developer than the Company. Further, the final levelized cost estimates for the four selected wind projects are tightly clustered, and thus it does not appear that Xcel is paying a premium for one type of transaction structure over the other. Thus the Department concludes that Xcel's proposed mix of PPA and PSA projects is reasonable.

E. CONSIDERATION OF C-BED PROPOSALS

Minn. Stat. §216B.1612, subd. 5(a) states:

> A utility subject to section 216B.1691 that needs to construct new generation, or purchase the output from new generation, as part of its plan to satisfy its good faith objective and standard under that section must take reasonable steps to determine if one or more C-BED projects are available that meet the utility's cost and reliability requirements, applying standard reliability criteria, to fulfill some or all of the identified need at minimal impact to customer rates.
>
> Nothing in this section shall be construed to obligate a utility to enter into a power purchase agreement under a C-BED tariff developed under this section.

As noted above, Xcel received proposals for 57 projects totaling 6,300 MW of wind resources in response to its RFP. Through its initial screening process, Xcel identified 14 projects that had a levelized cost of $29/MWh or lower for further evaluation. While several projects claimed to qualify as C-BED, no C-BED projects had a levelized cost below $29/MWh.

Xcel's last IRP noted that 18 percent of its nameplate wind capacity was C-BED.[25] Since 2007, Xcel has issued three C-BED-only RFPs. It its March 29, 2010 reply comments in Docket Nos. IP6830/CN-09-1186, E002/M-09-1349, E002/M-09-1350, and E002/M-07-1558, the Department expressed concern that it was difficult to evaluate whether a particular C-BED project has a "minimal impact to customer rates" if a C-BED-only RFP were used to select the C-BED resources. The Department suggested that the best way to ensure the most cost-effective resources were acquired is to allow for a comparison of C-BED and non-C-BED projects by comparing C-BED and non-C-BED bids in an all-source bid process. That is what Xcel did in this case.

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[24] See Attachment F.
[25] Application of Xcel Energy, Table 5.2, Docket No. E002/RP-10-825.

In response to the Department's concerns, Order Point 2 of the Commission's April 28, 2010 ORDER APPROVING POWER PURCHASE AGREEMENTS, APPROVING CONTRACT AMENDMENTS, AND REQUIRING FURTHER FILINGS required that:

> Within 60 days of the date of this order, Xcel Energy shall make a filing in docket E-002/M-07-1558, which deals with it Renewable Energy Plan, outlining it plans for complying with the June 19, 2009 order in that case. The filing shall outline Company plans to use competitive bidding or an equally rigorous process to select future renewable resources in a manner the permits meaningful price comparison, promotes thoughtful weighing of competing policy objectives, and ensures cost-effectiveness. The filing shall also discuss the Company's intentions for balancing the policy objectives set forth in Minn. Stat. § 216B.1691, subd. 10 and Minn. Stat. § 216B.1612, subd. 5.

Xcel submitted a compliance filing on June 28, 2010 which stated that:

> We believe a fully competitive bidding process for new renewable generation will allow us to fully evaluate the cost, size, timing, ownership, and geography issues that need to be balanced in the selection of the next increment of wind generation.

Xcel further stated that an all-source RFP would "ensure that C-BED projects will be objectively compared to bids of other ownership structures, which will ensure minimal impact on customer rates related to any C-BED projects selected."

Like Xcel's 2010 wind RFP, the RFP at issue in this docket was also an all-source RFP. Xcel considered PPAs, build-transfer arrangement, C-BED proposals, and combinations of different arrangements. C-BED projects were thus objectively compared to bids of other ownership structures. No C-BED project had a low enough price to make the short list of 14 projects for further evaluation. Thus, the Department concludes that, through this RFP, Xcel appropriately considered C-BED projects, and appropriately declined to pursue any C-BED projects as the additional costs associated with the C-BED proposals would not be in the best interests of ratepayers. That is, Xcel took reasonable steps to examine C-BED projects and appropriately considered cost factors in its decision not to pursue C-BED projects further in its selection process.

F. ADDITIONAL TERMS OF THE PPAs

1. Protection of Xcel's Ratepayers from Financial and Operational Risks

As is generally true of electric generators, there are risks that Odell and Courtenay will not be able to provide the electric service as specified in the PPAs. An appropriate PPA should protect Xcel's ratepayers from such risks. The risks of non-performance can be classified into two categories:

- Financial risks, and
- Operations risk.

The Department discusses these risks below.

a. Financial Risks

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

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

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

Under these events, Xcel may be forced to find more costly replacement power when the PPA is terminated. Further, under both events, the projects may be terminated and, therefore, put Xcel's compliance with various wind legislative and Commission Order requirements in question.

Regarding these issues, the Department notes that the terms of both the Odell and Courtney PPAs are similar to the terms of the Prairie Rose PPA approved by the Commission in Docket No. E002/M-11-713. Article 11 of each PPA describes the Security Fund required to be established by the seller to account for Replacement Energy in the event of bankruptcy and other potential damages caused by the seller. The Security Fund will total **[TRADE SECRET DATA HAS BEEN EXCISED]** and is to be established either by a letter of credit or by depositing the funds in an escrow account. Article 12 of the PPA includes events which constitute seller's default and include: seller's dissolution or liquidation, assignment of the PPA or any rights under the PPA for the benefit of creditors, bankruptcy, sale of energy to a third party, fraud, abandonment, failure to establish the security fund, failure to deliver energy pursuant to the terms of the PPA, or any other material breach.

The Department also notes that each PPA assigns the Renewable Energy Credits (RECs) associated with each project to Xcel and that any revenues, including revenues from the sale of

RECs, associated with the addition of the PRW resource should be credited to ratepayers through the fuel clause.

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

b. Operational Risks

As is typically true of PPAs, the operational risks are the risks that the wind projects will not be built and operated as expected. These risks include a complete shutdown or a partial shutdown of the project due to technical problems. In the case of a partial shutdown, ratepayers must be assured that their payments for the wind energy are reduced accordingly. In the case of a complete shutdown, once again Xcel may face the risk of non-compliance with the various legislative wind requirements, and may need to find what is likely to be more expensive replacement power.

The PPAs included specific features that protect both Xcel and its ratepayers from the operational risks discussed above. These features include the security fund discussed above, and payments only for net energy actually delivered to Xcel (except for curtailment issues discussed by the Department below).

Article 19 of the PPAs include restrictions on the transfer of the PPA. The PPAs also included provisions allowing Xcel to access the facility to read meters and to be present any time meters are inspected or tested and a provision to allow Xcel to assume control and operation of the project in the event of seller's default. Finally, the PPAs specify the amount of time the seller has to cure an event of default. Failure to cure constitutes an event of default and allows Xcel to terminate the contract and draw on the Security Fund to compensate for any losses caused by seller's default.

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

2. Curtailment Provisions

For wind power, payments for curtailed energy may be necessary to maintain financial viability of the wind project.

In principle, Xcel must pay for the curtailed energy only if the curtailments are initiated by Xcel, when the seller is able to produce and deliver wind energy. Xcel does not make curtailment payments in other circumstances. If, after including these payments, the price is still reasonable, curtailment payments should be approved. Below is a detailed discussion of the curtailment issue.

Section 8.2 of the PPAs contains provisions to ensure that the projects will continue to receive payments for energy that would have been generated during any period of compensable curtailment.

The PPAs define compensable and non-compensable curtailments. Non-compensable curtailments are, in essence, curtailments resulting from: emergency, *force majeure*, seller's failure to obtain the necessary permits, or failure of the seller's equipment.

Voluntary curtailments are curtailments for reasons other than non-compensable events. In essence, voluntary curtailments are the result of Xcel's refusal to accept delivery for reasons other than non-compensable events, such as curtailments due to lack of transmission service or low load conditions that require curtailment for stability purposes and may be directed by the MISO.

The Department notes that the curtailment provisions in the PPA are similar to the curtailment provision in the PPA between Xcel and other wind projects.

However, for Odell, Xcel identified that the project would have a higher-than-normal curtailment risk until several upgrades to the transmission system are placed in-service. Xcel has mitigated this risk by including terms in the PPA that specify that Geronimo will not be compensated for curtailments imposed by MISO until the transmission upgrades are completed.

The PPA's proposed payments per MWh for voluntary curtailment are the same as the PPA's price plus the amount of lost Production Tax Credits (PTC) and any other tax benefits that would have been received by the seller, absent the curtailment.

The Department has consistently reviewed proposed wind projects for curtailment risk. The Department notes that the voluntary curtailments are necessary to maintain the integrity of the transmission system. Further, as noted above, both Xcel and the Department conducted Strategist modeling that included a significant amount of curtailment and the project remained cost-effective. The Department modeled a reduction in output of 10 percent, whereas Xcel's historical experience from May 2012 to April 2013 was at 1.4 percent. In addition, as the Department did not allow for any excess energy to be sold into the MISO market, all energy output must be delivered to Xcel load which results in a higher amount of curtailed energy than would likely be experienced in practice.

As in past proceedings, the Department recommends that Xcel report in its monthly fuel clause filings and annual automatic adjustment filings (AAA) the amount of any curtailment payments. The Department reviews those filings and reserves the right to make recommendations regarding the appropriateness of any curtailment payment beyond a reasonable level.

G. ADDITIONAL TERMS OF THE PSAs

For the Pleasant Valley and Borders Wind proposal, the Department notes that the operational risk shifts to Xcel upon transfer of the projects. Xcel will be responsible for all operation and maintenance costs after the projects are transferred and will be compensated for that risk through its overall rate of return. Thus, the risks associated with the PSAs are development risks.

For Odell and Pleasant Valley, the risk of qualifying for the PTC lies with the developer. For Pleasant Valley and Borders Wind, the PTC risk is addressed by the proposed PSAs in several ways. First, RES Americas is required to provide certification that each project was under construction as defined by the Internal Revenue Service (IRS), **[TRADE SECRET DATA HAS BEEN EXCISED].** Second, the PSAs contain extensive provisions that require RES Americas and Xcel to seek to challenge any adverse ruling by the IRS that would not allow the projects to qualify for the PTC. In addition, Xcel may **[TRADE SECRET DATA HAS BEEN EXCISED].**

Regarding risks associated with siting, the projects must develop avian and bat protection plans to avoid and minimize adverse effects to avian and bat species. **[TRADE SECRET DATA HAS BEEN EXCISED].**

Finally, the Department notes that by purchasing a turn-key project, Xcel mitigates construction risks as RES Americas must complete construction before the Company purchase of the proposed projects.

H. TRANSMISSION RISK

Under the proposals for the Odell and Courtenay projects, Geronimo will absorb the generation interconnection risk as part of the PPA. Further discussion of the interconnection status for each project can be found on pages 22-23 of Xcel's Petition.

For the Pleasant Valley project, RES Americas obtained an Optional Interconnection Study from MISO that provides support for the **[TRADE SECRET DATA HAS BEEN EXCISED]** of interconnection costs that RES Americas included in the purchase price. Xcel states that some risk of additional costs remains since the MISO study process is not yet complete. Consequently, **[TRADE SECRET DATA HAS BEEN EXCISED].** To account for this uncertainty, Xcel included an additional **[TRADE SECRET DATA HAS BEEN EXCISED]** contingency in the estimate of the project's capital costs used in both the Strategist analysis and the levelized-cost evaluation of the bids. Since Xcel relied on that level of costs for its analysis of the proposed project, any costs beyond the**[TRADE SECRET DATA HAS BEEN EXCISED]** contingency should not be recovered from ratepayers unless Xcel can adequately justify such cost recovery. In addition, when Xcel submits a filing for recovery of costs associated with Pleasant Valley, Xcel should clearly identify the final amount of total interconnection costs and provide documentation and a justification for the total amount proposed to be included in rates.

For the Border Winds project, significant uncertainty regarding network upgrade costs exists. Preliminary study work indicated potential network upgrades approaching $50 million in costs. In order to deal with this risk, the PSA provides that if the Shared Interconnection Costs, which includes the network upgrade costs, exceed **[[TRADE SECRET DATA HAS BEEN EXCISED]**, Xcel can terminate the contract unless RES Americas agrees to absorb the excess transmission costs. The Department concludes that the PSA terms provide a reasonable way for Xcel to deal with the transmission interconnection risk. As with Pleasant Valley, when Xcel submits a filing for recovery of costs associated with Border Winds, Xcel should clearly identify the final amount of total interconnection costs and provide documentation and a justification for the total amount proposed to be included in rates. If Shared Interconnection Costs exceed **[TRADE SECRET DATA HAS BEEN EXCISED]** any additional amount should not be recovered from ratepayers unless Xcel can adequately justify such cost recovery.

I. CN EXEMPTION FOR ODELL

Geronimo and Xcel requests an exemption from the Certificate of Need Statute for the Odell project under Minn. Stat. §216.243, subd. 9. Subdivision 9 provides:

> This section does not apply to a wind energy conversion system or a solar electric generation facility that is intended to be used to meet the obligations of section 216B.1691; provided that, after notice and comment, the commission determines that the facility is a reasonable and prudent approach to meeting a utility's obligations under that section. When making this determination, the commission must consider:
>
> (1) the size of the facility relative to a utility's total need for renewable resources;
> (2) alternative approaches for supplying the renewable energy to be supplied by the proposed facility;
> (3) the facility's ability to promote economic development, as required under section 216B.1691, subdivision 9;
> (4) the facility's ability to maintain electric system reliability;
> (5) impacts on ratepayers; and
> (6) other criteria as the commission may determine are relevant.

Regarding this provision, Xcel's need for additional renewable resources and the costs of the proposed facilities along with the consideration of other renewable resources in the bids submitted to Xcel are discussed above. In its August 8, 2013, Initial Procedural Comments, Geronimo discussed a number of potential economic benefits to the local community, including hiring construction workers, using local contractors, hiring full time local employees and generating direct payments to local governments. MISO's interconnection process ensures that Odell will be connected to the grid in a safe and reliable manner. Finally, as discussed above, the addition of the proposed wind projects would result in a reduction in PVSC versus not adding the proposed project. Thus, the Department concludes that Odell in exempt for the CN requirements under Minn. Stat. §216.243, subd. 9.

J. APPLICATION OF MINN. STAT. § 216B.50

The Department noted in its August 8, 2013 procedural comments that we believed that Minn. Stat. § 216B.50 applied to the Pleasant Valley project. The Department also noted that we would fully analyze whether the acquisition of the Pleasant Valley project is in the public interest regardless of whether or not Minn. Stat. § 216B.50 applies. Based on the above analysis, the Department concludes that the acquisition of the Pleasant Valley and Borders Winds projects would be in the public interest and that granting Xcel request variance to Minn. R. 7825.1400 (A)-(J) would be appropriate.

K. COST RECOVERY

In addition to requesting approval of the proposed projects under Minn. Stat. § 216B.1645, subd. 1, Xcel requested that the Commission find that the costs associated with the Odell and Courtenay projects are eligible for recovery through the fuel clause mechanism under Minn. Stat. § 216B.1645, subd. 2. Since the Department concludes that the addition of Odell and Courtenay are reasonable and prudent additions to Xcel's resources portfolio and that the generation can count toward Xcel's compliance with the RES, the Department concludes that the costs of each project are recoverable through the fuel clause. To recover costs associated with Pleasant Valley and Border Winds, Xcel must file for recovery through Xcel's renewable rider under Minn. Stat. § 216B.1645, subd. 2a or as part of a general rate case. The Department notes that we will use the estimates of the annual revenue requirement for Pleasant Valley and Border Winds to evaluate the reasonableness of Xcel's requested costs recovery for those projects, as discussed above.

IV. RECOMMENDATION

The Department recommends that the Commission:

- Approve Xcel's proposed acquisition of the Odell, Courtney, Pleasant Valley, and Border Winds projects,
- Approve the PPAs for Odell and Courtney as eligible for recovery through the Company's fuel clause,
- Find, if Minn. Stat. § 216B.50 applies, that the purchase of the Pleasant Valley and Border Winds projects are in the public interest,
- Find that the Odell project is exempt for a certificate of need under Minn. Stat. §216.243, subd. 9,

- Require that Xcel report in its monthly fuel clause filings and AAA filings the date and duration of any curtailment event, the amount of any curtailment payment for Odell and Courtney, and an explanation of the reasons for any curtailment,
- Require that, when Xcel submits a filing for recovery of costs associated with Pleasant Valley or Border Winds, Xcel must clearly identify the final amount of total interconnection costs and provide documentation and justification for the total amount proposed to be included in rates, and
- Prohibit Xcel from recovering any amount above the contingency costs for Pleasant Valley and Border Wind, unless Xcel can fully justify requiring ratepayers to pay for any such cost.

/jl

DOC Calculation of Xcel Solar Requirement

Year	System (MWh)	Minnesota	% Minn.
2012	43,579,392	32,294,407	74.1%
2013	43,941,668	32,503,578	74.0%
2014	44,446,901	32,846,647	73.9%
2015	44,744,330	33,032,802	73.8%
2016	45,166,313	33,335,380	73.8%
2017	45,421,276	33,467,243	73.7%
2018	45,816,836	33,722,546	73.6%
2019	46,132,477	33,927,415	73.5%
2020	46,660,598	34,308,552	73.5%
2021	46,973,827	34,485,092	73.4%
2022	47,372,237	34,750,229	73.4%
2023	47,705,141	34,971,889	73.3%
2024	48,256,821	35,396,709	73.4%
Average			73.6%

Year	Energy Requirements (GWH)	Minn. Energy Req. (GWh)	Solar %	Minn Solar Req (GWh)	MW @ 20% Cap. Fact
2012	45,757	33,698	0.0%	-	-
2013	45,569	33,559	0.0%	-	-
2014	45,901	33,804	0.0%	-	-
2015	46,243	34,056	0.0%	-	-
2016	46,628	34,339	0.0%	-	-
2017	46,838	34,494	0.0%	-	-
2018	47,137	34,714	0.0%	-	-
2019	47,416	34,920	0.0%	-	-
2020	47,720	35,143	1.5%	527.2	301
2021	48,020	35,365	1.5%	530.5	303
2022	48,236	35,523	1.5%	532.9	304
2023	48,466	35,693	1.5%	535.4	306
2024	48,747	35,900	1.5%	538.5	307
2025	49,060	36,130	1.5%	542.0	309
2026	49,404	36,384	1.5%	545.8	312
2027	49,738	36,630	1.5%	549.4	314
2028	50,089	36,888	1.5%	553.3	316
2029	50,430	37,139	1.5%	557.1	318
2030	50,792	37,406	1.5%	561.1	320
2031	51,141	37,663	1.5%	564.9	322
2032	51,529	37,949	1.5%	569.2	325
2033	51,919	38,236	1.5%	573.5	327
2034	52,310	38,524	1.5%	577.9	330
2035	52,696	38,808	1.5%	582.1	332
2036	53,139	39,134	1.5%	587.0	335
2037	53,583	39,461	1.5%	591.9	338
2038	54,022	39,785	1.5%	596.8	341
2039	54,471	40,115	1.5%	601.7	343
2040	54,954	40,471	1.5%	607.1	346
2041	55,387	40,790	1.5%	611.8	349
2042	55,844	41,126	1.5%	616.9	352
2043	56,299	41,462	1.5%	621.9	355
2044	56,755	41,797	1.5%	627.0	358
2045	57,199	42,125	1.5%	631.9	361
2046	57,652	42,458	1.5%	636.9	364
2047	58,103	42,790	1.5%	641.9	366
2048	58,555	43,123	1.5%	646.8	369
2049	59,007	43,456	1.5%	651.8	372
2050	59,458	43,788	1.5%	656.8	375

20% Cap. Fact http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/US/Minnesota/Minneapolis.html

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E002/M-13-603		
Response To:	Department of Commerce	Information Request No.	001
Requestor:	Christopher Shaw		
Date Received:	August 9, 2013		

Question:

Please explain why Xcel does not expect each wind project to receive a capacity accreditation until 2021. Please explain what transmission upgrades are necessary in order for each project to receive a capacity accreditation. In addition, please explain the risk of curtailment before and after the projects are able to receive a capacity accreditation in 2021.

Response:

The 600 MW of wind generation will become eligible to obtain Capacity Accreditation from MISO when the project has: 1) obtained unconditional Network Resource Interconnection Service (NRIS) through the Generation Interconnection Process; or 2) obtained unconditional Energy Resource Interconnection Service (ERIS) through the Generation Interconnection Process along with Network Integration Transmission Service (NITS) through the Transmission Service Process.[1]

Unconditional NRIS or ERIS is granted when all network upgrades identified in the Generation Interconnection System Impact Studies are completed and placed in service. System Impact Study results for the Odell, Courtenay and Pleasant Valley projects (Wind Projects) are not available at this time. However, the results of System Impact Studies performed for earlier generation projects have identified MISO Multi-Value Projects (MVP) as required network upgrades – which means the MVPs will likely also be required for the Wind Projects.

We summarize the expected timing for the required MVP facilities identified in earlier System Impact Studies, or that the Company believes will be identified in the Wind Project MISO studies, in the following table:

---

[1] The Company has not submitted Transmission Service Requests (TSR) for these projects at this time. The decision to seek firm transmission service will likely be determined following completion of the MISO System Impact Deliverability Study. The Company may elect not to seek firm transmission service for a Wind Project if the MISO deliverability study indicates that the project will qualify for NRIS.

MVP Project Name	Transmission Owner	Expected In-Service Timing*
Pleasant Prairie-Zion Energy Center 345 kV line	American Transmission Company	Late 2013
North LaCrosse-North Madison-Cardinal - Spring Green - Dubuque area 345 kV lines	American Transmission Company, Xcel Energy, ITC Midwest	End 2020
Lakefield Jct. - Winnebago - Winco - Kossuth County & O'Brien County - Kossuth County - Webster 345 kV lines	MidAmerica Energy, ITC Midwest	End 2016
Winco to Hazleton 345 kV line	MidAmerica Energy, ITC Midwest	End 2015
Ellendale to Big Stone South 345 kV line	Ottertail Power Company, Montana Dakota Utilities	End 2019
Big Stone South to Brookings 345 kV line	Ottertail Power Company, Xcel Energy	End 2017
Brookings - Southeast Twin Cities 345 kV line	Xcel Energy, Great River Energy	Early 2015

* Note: Expected In-Service timing is based on the MISO 2012 MTEP, and are subject to change.

The last MVP project expected to be completed – the North LaCrosse to Madison to Dubuque area 345 kV lines – is scheduled to go into service at the end of 2020. We expect that our proposed Wind Projects will also be conditional on this MVP and, therefore, would not be able to obtain Capacity Accreditation until June 2021.[2]

The Wind Projects will be allowed to interconnect and inject power into the transmission grid prior to obtaining unconditional NRIS or ERIS. The amount of injection allowed, and subsequently the amount of curtailment, will be determined by system conditions at the time.

We do not believe that the Wind Projects will have a high curtailment risk because of Power Purchase Agreement terms negotiated by the Company that assign certain curtailment costs to Geronimo, the location of the projects, and the ongoing transmission improvements (including MVP) planned for the area.[3]

The Wind Projects are scheduled to go into service in the 2015 timeframe. At this time several major MVP (and other) transmission facilities will be in-service or will be going into service that will have a major positive impact on curtailment risk. The Pleasant Prairie-Zion Energy Center 345 kV line, the Brookings-Southeast Twin Cities 345 kV line and the Winco to Hazleton 345 kV line will all be going into service in this

[2] Under MISO's annual resource adequacy construct, capacity accreditation cannot be obtained until the resource qualifies for an entire June through May resource adequacy planning year.
[3] The PPAs signed with Geronimo Energy, the owner of the Courtenay and Odell wind farms, requires that Geronimo take all curtailment risk until the projects obtain unconditional NRIS or ERIS.

this timeframe. In addition, the Lakefield Jct.-Winnebago-Winco-Kossuth County and O'Brien County - Kossuth County - Webster 345 kV lines will be going into service in 2016.

Preparer:	Randall L. Oye
Title:	Transmission Access Analyst
Department:	Market Operations
Telephone:	612-330-2886
Date:	August 19, 2013

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E002/M-13-603		
Response To:	Department of Commerce	Information Request No.	002
Requestor:	Christopher Shaw		
Date Received:	August 9, 2013		

Question:
Please explain how Xcel incurs charges related to wind integration, including whether charges are incurred for ancillary services and revenue sufficiency guarantee (RSG) charges. Please explain whether Xcel's historical experience regarding actual integration charges incurred is consistent with the integration charges determined in the 2006 Minnesota Wind Integration Study and the integration charges used in the Strategist model in this proceeding.

Response:
The Company may incur charges for both ancillary services and RSG charges. RSG charges are associated with specific wind farms and can be tracked directly. However the primary cost component identified in the 2006 Minnesota Wind Integration Study are the incremental ancillary services that need to be maintained in order to support wind. These ancillary service costs cannot be tracked directly. Rather, MISO sets a market wide requirement for spinning and supplemental reserves on a daily basis. The total reserve requirement does not identify how much is due to wind and how much is due to other factors. Therefore it is not possible to precisely determine if the actual wind integration costs are consistent with those in the study and those used in the Strategist modeling in this proceeding.

To account for this lack of precision, we apply conservative Strategist assumptions that allow for a large amount of operating reserves and RSG charges. Based on current prices for ancillary services and the incremental ancillary services requirements identified in the 2006 Study, the total 2016 integration cost would be approximately $0.84 million. In comparison, the Strategist analysis used a conservative assumption of $5.5 million. Attachment A to this response illustrates these calculations.

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Date:	August 19, 2013

Northern States Power Company

2006 Wind Integration Study - Table 18 - Page 41

Reserve	Category MW	Base %	15% MW	Wind %	20% MW	Wind %	25% MW	Wind %
Regulating	137	0.65%	149	0.71%	153	0.73%	157	0.75%
Spinning	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Non-Spin	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Load Following	100	0.48%	110	0.52%	114	0.54%	124	0.59%
Operating Reserve Margin	152	0.73%	310	1.48%	408	1.94%	538	2.56%
Total Operating Reserves	1049	5.00%	1229	5.86%	1335	6.36%	1479	7.05%

2012 MISO State of the Market Report - Page 30

Average Ancillary Services Costs

Regulating	$8.88/MWh
Spinning	$2.74/MWh
Supplemental	$1.58/MWh

Incremental Opperating Reserves

15% to 20% Incremental Operating Reserves Based on Table 18

	NSP Peak	Regulating	Spinning	Non-Spin	Load Following	Operating Reserve Margin
2016	9,334 MW	2 MW	0 MW	0 MW	2 MW	43 MW
2017	9,411 MW	2 MW	0 MW	0 MW	2 MW	43 MW
2018	9,500 MW	2 MW	0 MW	0 MW	2 MW	44 MW
2019	9,590 MW	2 MW	0 MW	0 MW	2 MW	44 MW
2020	9,676 MW	2 MW	0 MW	0 MW	2 MW	45 MW
2021	9,770 MW	2 MW	0 MW	0 MW	2 MW	45 MW
2022	9,859 MW	2 MW	0 MW	0 MW	2 MW	45 MW
2023	9,950 MW	2 MW	0 MW	0 MW	2 MW	46 MW
2024	10,029 MW	2 MW	0 MW	0 MW	2 MW	46 MW
2025	10,100 MW	2 MW	0 MW	0 MW	2 MW	46 MW
2026	10,151 MW	2 MW	0 MW	0 MW	2 MW	47 MW
2027	10,208 MW	2 MW	0 MW	0 MW	2 MW	47 MW
2028	10,266 MW	2 MW	0 MW	0 MW	2 MW	47 MW
2029	10,326 MW	2 MW	0 MW	.0 MW	2 MW	47 MW
2030	10,380 MW	2 MW	0 MW	0 MW	2 MW	48 MW
2031	10,449 MW	2 MW	0 MW	0 MW	2 MW	48 MW
2032	10,518 MW	2 MW	0 MW	0 MW	2 MW	48 MW
2033	10,587 MW	2 MW	0 MW	0 MW	2 MW	49 MW
2034	10,664 MW	2 MW	0 MW	0 MW	2 MW	49 MW
2035	10,758 MW	2 MW	0 MW	0 MW	2 MW	49 MW

Ancilliary Services Costs

Ancillary Service Prices Based On MISO State of Market Report, escalated at inflation

	Regulating	Spinning	Supplemental
2016	$9.73/MWh	$3.00/MWh	$1.73/MWh
2017	$9.95/MWh	$3.07/MWh	$1.77/MWh
2018	$10.18/MWh	$3.14/MWh	$1.81/MWh
2019	$10.41/MWh	$3.21/MWh	$1.85/MWh
2020	$10.65/MWh	$3.29/MWh	$1.90/MWh
2021	$10.90/MWh	$3.36/MWh	$1.94/MWh
2022	$11.15/MWh	$3.44/MWh	$1.98/MWh
2023	$11.40/MWh	$3.52/MWh	$2.03/MWh
2024	$11.67/MWh	$3.60/MWh	$2.08/MWh
2025	$11.93/MWh	$3.68/MWh	$2.12/MWh
2026	$12.21/MWh	$3.77/MWh	$2.17/MWh
2027	$12.49/MWh	$3.85/MWh	$2.22/MWh
2028	$12.78/MWh	$3.94/MWh	$2.27/MWh
2029	$13.07/MWh	$4.03/MWh	$2.33/MWh
2030	$13.37/MWh	$4.13/MWh	$2.38/MWh
2031	$13.68/MWh	$4.22/MWh	$2.43/MWh
2032	$13.99/MWh	$4.32/MWh	$2.49/MWh
2033	$14.32/MWh	$4.42/MWh	$2.55/MWh
2034	$14.64/MWh	$4.52/MWh	$2.61/MWh
2035	$14.98/MWh	$4.62/MWh	$2.67/MWh

Total Cost

Non-Spin, Load Following, and Operating Reserve Margin priced at Supplemental

	Regulating	Spinning	Non-Spin	Load Following	Operating Reserve Margin	Total	Total Integration Costs Included in Strategist ($000)
2016	$159,038	$0	$0	$28,297	$650,837	$838,172	$5,476
2017	$164,038	$0	$0	$29,187	$671,299	$864,523	$5,731
2018	$169,406	$0	$0	$30,142	$693,269	$892,818	$6,146
2019	$174,941	$0	$0	$31,127	$715,919	$921,986	$6,610
2020	$180,563	$0	$0	$32,127	$738,927	$951,618	$7,041
2021	$186,510	$0	$0	$33,185	$763,262	$982,957	$7,351
2022	$192,556	$0	$0	$34,261	$788,006	$1,014,823	$7,672
2023	$198,795	$0	$0	$35,371	$813,539	$1,047,706	$8,197
2024	$204,988	$0	$0	$36,473	$838,880	$1,080,341	$8,489
2025	$211,182	$0	$0	$37,575	$864,227	$1,112,984	$8,753
2026	$217,134	$0	$0	$38,634	$888,586	$1,144,354	$9,013
2027	$223,373	$0	$0	$39,744	$914,118	$1,177,236	$9,215
2028	$229,805	$0	$0	$40,889	$940,442	$1,211,136	$9,440
2029	$236,462	$0	$0	$42,073	$967,685	$1,246,220	$9,695
2030	$243,169	$0	$0	$43,266	$995,129	$1,281,565	$9,924
2031	$250,410	$0	$0	$44,555	$1,024,762	$1,319,726	$10,107
2032	$257,858	$0	$0	$45,880	$1,055,243	$1,358,981	$10,352
2033	$265,535	$0	$0	$47,246	$1,086,661	$1,399,442	$10,568
2034	$273,607	$0	$0	$48,682	$1,119,693	$1,441,983	$10,810
2035	$282,361	$0	$0	$50,240	$1,155,518	$1,488,119	$10,108

Net PVSC Savings (000s Difference from No Wind Additions)

	Scenario 1 (No Wind)	Scenario 2 (Add 400 MW Wind)	Scenario 3 (Add 600 MW Wind)	Scenario 4 (Add 750 Wind)	Scenario 5 (Low Cap. Factor + All Wind)	Scenario 6 (Spring 2013 Forcast + No Wind)	Scenario 7 (Spring 2013 Forecast + All Wind)	Scenario 8 (Low Gas + No Wind)	Scenario 9 (Low Gas + All Wind)	Scenario 10 ($0 CO2 + No Wind)	Scenario 11 ($0 CO2 + All Wind)	Scenario 12 (No Growth + No Wind)	Scenario 13 (No Growth + All Wind)
BASE CASE	$0	($375,760)	($642,436)	($813,024)	($748,652)	$0	($770,444)	$0	($711,120)	$0	($647,316)	$0	($762,468)
BD617	$0	($296,492)	($563,168)	($733,756)	($669,384)	$0	($711,516)	$0	($654,024)	$0	($581,056)	$0	($760,156)
BD618 GRE1	$0	($372,744)	($639,256)	($815,200)	($749,556)	$0	($774,044)	$0	($709,644)	$0	($657,032)	$0	($761,680)
BD617 GRE1	$0	($312,656)	($579,912)	($750,424)	($686,256)	$0	($720,376)	$0	($669,716)	$0	($596,756)	$0	($760,696)
BD619 GRE2	$0	($372,280)	($639,188)	($815,560)	($749,372)	$0	($774,952)	$0	($709,964)	$0	($657,784)	$0	($762,536)
BD618 GRE2	$0	($372,364)	($639,000)	($815,252)	($749,312)	$0	($774,380)	$0	($709,724)	$0	($657,252)	$0	($761,588)
BD617 GRE2	$0	($320,296)	($587,780)	($758,528)	($693,956)	$0	($729,304)	$0	($676,988)	$0	($604,252)	$0	($760,380)
ICT1 GPV1	$0	($313,612)	($583,116)	($753,224)	($689,440)	$0	($721,972)	$0	($660,392)	$0	($610,284)	$0	($763,604)
GRE1 GPV1 ICT1	$0	($322,052)	($591,876)	($762,000)	($698,120)	$0	($730,948)	$0	($668,432)	$0	($618,492)	$0	($763,580)
GRE2 GPV1 ICT1	$0	($329,204)	($599,672)	($770,036)	($706,088)	$0	($731,340)	$0	($675,728)	$0	($625,796)	$0	($763,876)
CCC1	$0	($358,092)	($624,648)	($713,192)	($648,820)	$0	($694,720)	$0	($653,056)	$0	($572,252)	$0	($771,188)
GRE1 CCC1	$0	($358,688)	($625,504)	($730,024)	($665,856)	$0	($703,356)	$0	($668,540)	$0	($587,796)	$0	($771,636)
GRE2 CCC1	$0	($358,056)	($625,032)	($737,936)	($673,364)	$0	($712,320)	$0	($675,836)	$0	($595,188)	$0	($771,236)
BD618 GPV1	$0	($357,424)	($613,780)	($799,752)	($722,736)	$0	($753,588)	$0	($694,808)	$0	($649,916)	$0	($754,272)
BD617 GPV1	$0	($284,568)	($554,072)	($724,180)	($660,396)	$0	($690,744)	$0	($643,828)	$0	($581,596)	$0	($730,892)
GRE1 GPV1 BD619	$0	($358,612)	($614,916)	($801,240)	($724,116)	$0	($754,428)	$0	($695,912)	$0	($651,420)	$0	($755,336)
GRE1 GPV1 BD618	$0	($360,248)	($616,852)	($803,584)	($726,128)	$0	($753,680)	$0	($699,668)	$0	($647,688)	$0	($754,336)
GRE1 GPV1 BD617	$0	($292,580)	($562,404)	($732,528)	($668,648)	$0	($699,756)	$0	($651,700)	$0	($589,572)	$0	($730,824)
GRE2 GPV1 BD619	$0	($360,352)	($617,832)	($804,704)	($727,152)	$0	($754,532)	$0	($700,380)	$0	($648,716)	$0	($755,400)
GRE2 GPV1 BD618	$0	($360,140)	($617,160)	($803,964)	($726,452)	$0	($753,820)	$0	($700,072)	$0	($648,064)	$0	($754,580)
GRE2 GPV1 BD617	$0	($300,300)	($570,768)	($741,132)	($677,184)	$0	($700,160)	$0	($659,580)	$0	($597,344)	$0	($731,224)
ICT2	$0	($374,464)	($633,552)	($812,076)	($741,496)	$0	($802,260)	$0	($712,752)	$0	($635,472)	$0	($733,420)
GRE1 ICT2	$0	($375,448)	($634,576)	($812,760)	($742,204)	$0	($802,344)	$0	($713,216)	$0	($635,660)	$0	($733,968)
GRE2 ICT2	$0	($375,104)	($633,884)	($812,516)	($741,972)	$0	($802,264)	$0	($712,804)	$0	($635,636)	$0	($733,904)
BD617 ICT2	$0	($325,780)	($584,868)	($763,392)	($692,812)	$0	($747,324)	$0	($683,184)	$0	($584,908)	$0	($734,196)
CCC1 GPV1	$0	($372,240)	($647,416)	($721,644)	($657,860)	$0	($672,856)	$0	($664,148)	$0	($589,632)	$0	($742,968)
BD619 ICT1	$0	($335,684)	($602,028)	($777,324)	($711,456)	$0	($744,916)	$0	($688,604)	$0	($614,368)	$0	($771,480)
BD618 ICT1	$0	($346,076)	($612,008)	($788,188)	($722,180)	$0	($743,904)	$0	($700,180)	$0	($627,444)	$0	($770,416)
GRE1 GPV1 CCC1	$0	($372,688)	($647,904)	($730,480)	($666,600)	$0	($681,812)	$0	($672,012)	$0	($597,600)	$0	($742,868)
GRE1 ICT1 BD619	$0	($355,120)	($621,620)	($797,692)	($731,964)	$0	($753,668)	$0	($708,764)	$0	($636,236)	$0	($771,648)
BD617 ICT1	$0	($287,876)	($554,552)	($725,140)	($660,768)	$0	($694,736)	$0	($660,496)	$0	($568,264)	$0	($770,132)
GRE1 ICT1 BD618	$0	($362,820)	($629,332)	($805,276)	($739,632)	$0	($757,420)	$0	($715,756)	$0	($643,200)	$0	($770,656)
GRE2 GPV1 CCC1	$0	($372,812)	($648,428)	($739,244)	($675,296)	$0	($682,156)	$0	($679,708)	$0	($605,344)	$0	($743,316)
GRE1 ICT2 BD617	$0	($326,744)	($585,872)	($764,056)	($693,500)	$0	($747,060)	$0	($683,640)	$0	($585,084)	$0	($734,700)
GRE1 ICT1 BD617	$0	($304,204)	($571,460)	($741,972)	($677,804)	$0	($703,596)	$0	($676,208)	$0	($584,020)	$0	($770,072)
GRE2 ICT1 BD619	$0	($362,532)	($629,440)	($805,812)	($739,624)	$0	($758,592)	$0	($716,008)	$0	($643,796)	$0	($771,644)
GRE2 ICT1 BD618	$0	($362,396)	($629,032)	($805,284)	($739,344)	$0	($757,812)	$0	($715,760)	$0	($643,480)	$0	($770,616)
GRE2 ICT2 BD617	$0	($326,540)	($585,320)	($763,952)	($693,408)	$0	($747,504)	$0	($683,392)	$0	($585,184)	$0	($734,572)
GRE2 ICT1 BD617	$0	($312,204)	($579,688)	($750,436)	($685,864)	$0	($712,380)	$0	($683,508)	$0	($591,456)	$0	($770,084)
ND119 ND219 GRE2	$0	($367,092)	($635,504)	($821,836)	($754,868)	$0	($776,032)	$0	($717,688)	$0	($677,700)	$0	($746,908)
ND118 ND218 GRE1	$0	($367,468)	($633,560)	($820,180)	($754,448)	$0	($774,728)	$0	($716,244)	$0	($677,256)	$0	($742,132)
BD617 ND118	$0	($311,728)	($569,536)	($750,296)	($683,636)	$0	($712,756)	$0	($664,892)	$0	($602,404)	$0	($742,868)

BD618 ND118 GRE1	$0	($367,492)	($633,652)	($821,472)	($753,588)	[redacted]	$0	($776,372)	[redacted]	$0	($718,172)	[redacted]	$0	($676,816)	[redacted]	$0	($739,784)
ICT2 GPV1	$0	($345,660)	($606,848)	($777,256)	($713,608)	[redacted]	$0	($782,372)	[redacted]	$0	($680,144)	[redacted]	$0	($624,620)	[redacted]	$0	($746,528)
ND118 ND218 GRE2	$0	($367,144)	($633,300)	($820,224)	($754,124)	[redacted]	$0	($775,140)	[redacted]	$0	($716,232)	[redacted]	$0	($677,368)	[redacted]	$0	($742,188)
BD617 ND118 GRE1	$0	($328,056)	($586,772)	($767,036)	($700,900)	[redacted]	$0	($723,564)	[redacted]	$0	($680,324)	[redacted]	$0	($617,984)	[redacted]	$0	($743,404)
GRE1 GPV1 ICT2	$0	($345,428)	($606,388)	($777,644)	($714,080)	[redacted]	$0	($782,300)	[redacted]	$0	($680,216)	[redacted]	$0	($624,636)	[redacted]	$0	($746,580)
BD618 ND118 GRE2	$0	($367,172)	($633,384)	($821,436)	($753,292)	[redacted]	$0	($776,792)	[redacted]	$0	($718,088)	[redacted]	$0	($676,824)	[redacted]	$0	($739,580)
BD617 ND118 GRE2	$0	($327,664)	($586,428)	($767,044)	($700,600)	[redacted]	$0	($723,948)	[redacted]	$0	($680,212)	[redacted]	$0	($618,076)	[redacted]	$0	($742,872)
GRE2 GPV1 ICT2	$0	($345,692)	($606,764)	($778,112)	($714,328)	[redacted]	$0	($782,652)	[redacted]	$0	($680,480)	[redacted]	$0	($624,964)	[redacted]	$0	($746,712)
BD619 CCC1	$0	($367,812)	($625,284)	($708,800)	($642,932)	[redacted]	$0	($709,568)	[redacted]	$0	($645,072)	[redacted]	$0	($565,404)	[redacted]	$0	($761,912)
BD618 CCC1	$0	($367,412)	($624,864)	($731,248)	($665,240)	[redacted]	$0	($709,304)	[redacted]	$0	($662,124)	[redacted]	$0	($585,452)	[redacted]	$0	($761,248)
BD617 CCC1	$0	($311,196)	($577,752)	($666,296)	($601,924)	[redacted]	$0	($658,012)	[redacted]	$0	($622,076)	[redacted]	$0	($525,452)	[redacted]	$0	($759,544)
GRE1 CCC1 BD619	$0	($368,452)	($626,216)	($740,564)	($674,836)	[redacted]	$0	($718,164)	[redacted]	$0	($670,352)	[redacted]	$0	($593,744)	[redacted]	$0	($762,376)
GRE1 CCC1 BD618	$0	($368,192)	($625,904)	($748,528)	($682,884)	[redacted]	$0	($722,620)	[redacted]	$0	($677,620)	[redacted]	$0	($601,140)	[redacted]	$0	($761,640)
GRE1 CCC1 BD617	$0	($312,032)	($578,848)	($683,368)	($619,200)	[redacted]	$0	($666,700)	[redacted]	$0	($637,800)	[redacted]	$0	($541,244)	[redacted]	$0	($760,008)
GRE2 CCC1 BD619	$0	($367,700)	($625,632)	($748,448)	($682,260)	[redacted]	$0	($723,140)	[redacted]	$0	($677,548)	[redacted]	$0	($601,024)	[redacted]	$0	($761,944)
GRE2 CCC1 BD618	$0	($367,560)	($625,432)	($748,432)	($682,492)	[redacted]	$0	($722,828)	[redacted]	$0	($677,548)	[redacted]	$0	($601,180)	[redacted]	$0	($761,488)
GRE2 CCC1 BD617	$0	($311,380)	($578,356)	($691,260)	($626,688)	[redacted]	$0	($675,628)	[redacted]	$0	($644,992)	[redacted]	$0	($548,532)	[redacted]	$0	($759,928)
ICT1 CCC1	$0	($345,992)	($612,548)	($701,092)	($636,720)	[redacted]	$0	($680,928)	[redacted]	$0	($649,012)	[redacted]	$0	($561,312)	[redacted]	$0	($785,164)
GRE1 ICT1 CCC1	$0	($346,804)	($613,620)	($718,140)	($653,972)	[redacted]	$0	($689,680)	[redacted]	$0	($664,672)	[redacted]	$0	($577,100)	[redacted]	$0	($785,456)
GRE2 ICT1 CCC1	$0	($346,556)	($613,532)	($726,436)	($661,864)	[redacted]	$0	($698,768)	[redacted]	$0	($672,052)	[redacted]	$0	($584,676)	[redacted]	$0	($785,408)
GPV1 ICT1 CCC1	$0	($366,200)	($641,376)	($715,604)	($651,820)	[redacted]	$0	($670,404)	[redacted]	$0	($661,008)	[redacted]	$0	($588,980)	[redacted]	$0	($753,672)
GPV1 ICT1 BD619	$0	($336,204)	($592,224)	($778,484)	($701,412)	[redacted]	$0	($723,124)	[redacted]	$0	($685,432)	[redacted]	$0	($626,820)	[redacted]	$0	($776,276)
GRE1 ICT1 GPV1 CCC1	$0	($366,112)	($641,328)	($723,904)	($660,024)	[redacted]	$0	($679,284)	[redacted]	$0	($668,876)	[redacted]	$0	($597,020)	[redacted]	$0	($753,448)
GPV1 ICT1 BD618	$0	($335,240)	($591,596)	($777,568)	($700,552)	[redacted]	$0	($742,512)	[redacted]	$0	($684,776)	[redacted]	$0	($625,832)	[redacted]	$0	($775,312)
BD619 ICT2	$0	($372,700)	($637,340)	($815,952)	($751,892)	[redacted]	$0	($771,372)	[redacted]	$0	($720,516)	[redacted]	$0	($648,308)	[redacted]	$0	($725,772)
BD618 ICT2	$0	($372,420)	($637,008)	($815,356)	($751,340)	[redacted]	$0	($770,584)	[redacted]	$0	($719,824)	[redacted]	$0	($647,364)	[redacted]	$0	($724,976)
GPV1 ICT2 BD617	$0	($306,568)	($567,756)	($738,164)	($674,516)	[redacted]	$0	($755,340)	[redacted]	$0	($656,100)	[redacted]	$0	($587,068)	[redacted]	$0	($749,608)
GPV1 ICT1 BD617	$0	($272,448)	($541,952)	($712,060)	($648,276)	[redacted]	$0	($678,728)	[redacted]	$0	($640,204)	[redacted]	$0	($567,936)	[redacted]	$0	($753,292)
GRE2 ICT1 GPV1 CCC1	$0	($366,356)	($641,972)	($732,788)	($668,840)	[redacted]	$0	($679,792)	[redacted]	$0	($676,488)	[redacted]	$0	($604,720)	[redacted]	$0	($753,948)
GRE1 ICT2 BD619	$0	($373,684)	($638,416)	($816,664)	($752,648)	[redacted]	$0	($771,448)	[redacted]	$0	($720,996)	[redacted]	$0	($648,516)	[redacted]	$0	($726,304)
GRE1 ICT2 BD618	$0	($373,056)	($637,772)	($816,036)	($752,088)	[redacted]	$0	($770,340)	[redacted]	$0	($720,272)	[redacted]	$0	($647,540)	[redacted]	$0	($725,360)
GRE1 ND119 ND219 GPV1	$0	($368,720)	($629,228)	($816,308)	($748,048)	[redacted]	$0	($779,424)	[redacted]	$0	($708,380)	[redacted]	$0	($658,492)	[redacted]	$0	($745,356)
ND118 ND218 GPV1	$0	($369,368)	($622,992)	($808,628)	($741,280)	[redacted]	$0	($778,208)	[redacted]	$0	($704,504)	[redacted]	$0	($653,224)	[redacted]	$0	($745,404)
GRE2 ICT2 BD619	$0	($373,500)	($637,744)	($816,496)	($752,496)	[redacted]	$0	($771,356)	[redacted]	$0	($720,652)	[redacted]	$0	($648,524)	[redacted]	$0	($726,220)
GRE2 ICT2 BD618	$0	($372,948)	($637,500)	($815,984)	($752,068)	[redacted]	$0	($770,800)	[redacted]	$0	($720,068)	[redacted]	$0	($647,672)	[redacted]	$0	($725,280)
GRE2 ND119 ND219 GPV1	$0	($368,772)	($632,476)	($819,492)	($750,324)	[redacted]	$0	($779,548)	[redacted]	$0	($711,116)	[redacted]	$0	($662,580)	[redacted]	$0	($745,548)
BD618 ND118 GPV1	$0	($368,972)	($622,444)	($811,296)	($743,908)	[redacted]	$0	($777,592)	[redacted]	$0	($706,180)	[redacted]	$0	($653,688)	[redacted]	$0	($746,232)
GRE1 ND118 ND218 GPV1	$0	($369,612)	($625,680)	($811,956)	($743,024)	[redacted]	$0	($778,332)	[redacted]	$0	($708,104)	[redacted]	$0	($657,788)	[redacted]	$0	($745,396)
BD617 ND118 GPV1	$0	($308,580)	($562,896)	($752,008)	($675,828)	[redacted]	$0	($718,392)	[redacted]	$0	($668,668)	[redacted]	$0	($594,616)	[redacted]	$0	($743,768)
ICT1 ICT2	$0	($346,912)	($606,000)	($784,524)	($713,944)	[redacted]	$0	($783,764)	[redacted]	$0	($697,208)	[redacted]	$0	($610,472)	[redacted]	$0	($753,268)
GRE1 GPV1 BD618 ND118	$0	($369,532)	($626,176)	($815,052)	($746,640)	[redacted]	$0	($777,680)	[redacted]	$0	($710,016)	[redacted]	$0	($657,876)	[redacted]	$0	($746,252)
GRE2 ND118 ND218 GPV1	$0	($369,608)	($625,916)	($812,436)	($743,384)	[redacted]	$0	($778,484)	[redacted]	$0	($708,312)	[redacted]	$0	($658,052)	[redacted]	$0	($745,588)
GRE1 GPV1 BD617 ND118	$0	($318,732)	($572,968)	($762,968)	($686,472)	[redacted]	$0	($718,520)	[redacted]	$0	($679,284)	[redacted]	$0	($599,248)	[redacted]	$0	($743,724)
GRE1 ICT2 ICT1	$0	($347,940)	($607,068)	($785,252)	($714,696)	[redacted]	$0	($783,760)	[redacted]	$0	($697,676)	[redacted]	$0	($610,684)	[redacted]	$0	($753,720)
GRE2 GPV1 BD618 ND118	$0	($369,576)	($626,448)	($815,368)	($747,012)	[redacted]	$0	($777,844)	[redacted]	$0	($710,244)	[redacted]	$0	($658,148)	[redacted]	$0	($746,644)
GRE2 GPV1 BD617 ND118	$0	($318,716)	($573,348)	($763,408)	($686,872)	[redacted]	$0	($718,980)	[redacted]	$0	($679,604)	[redacted]	$0	($599,464)	[redacted]	$0	($744,156)
GRE2 ICT2 ICT1	$0	($347,740)	($606,520)	($785,152)	($714,608)	[redacted]	$0	($784,168)	[redacted]	$0	($697,444)	[redacted]	$0	($610,748)	[redacted]	$0	($753,672)
GPV1 ND118 ND219	$0	($367,600)	($627,752)	($814,944)	($746,792)	[redacted]	$0	($778,656)	[redacted]	$0	($707,248)	[redacted]	$0	($657,176)	[redacted]	$0	($744,528)
GRE1 GPV1 ND118 ND219	$0	($368,648)	($631,644)	($818,608)	($749,440)	[redacted]	$0	($778,768)	[redacted]	$0	($710,436)	[redacted]	$0	($661,828)	[redacted]	$0	($744,564)

GRE2 GPV1 ND118 ND219	$0	($368,692)	($631,920)	($818,984)	($749,840)	[redacted]	$0	($778,936)	[redacted]	$0	($710,788)	[redacted]	$0	($662,152)	[redacted]	$0	($744,916)
GPV1 CCC1 BD619	$0	($341,964)	($604,012)	($720,084)	($643,012)	[redacted]	$0	($678,124)	[redacted]	$0	($653,884)	[redacted]	$0	($577,340)	[redacted]	$0	($763,852)
GPV1 CCC1 BD618	$0	($341,788)	($603,764)	($719,796)	($642,780)	[redacted]	$0	($698,172)	[redacted]	$0	($653,468)	[redacted]	$0	($576,800)	[redacted]	$0	($763,580)
GPV1 CCC1 BD617	$0	($304,376)	($579,552)	($653,780)	($589,996)	[redacted]	$0	($634,944)	[redacted]	$0	($609,312)	[redacted]	$0	($519,468)	[redacted]	$0	($740,380)
BD617 ND119 ND219	$0	($265,524)	($529,220)	($701,752)	($636,496)	[redacted]	$0	($680,100)	[redacted]	$0	($631,660)	[redacted]	$0	($554,952)	[redacted]	$0	($728,052)
BD618 ND119 ND219 GRE1	$0	($367,812)	($641,208)	($804,356)	($738,308)	[redacted]	$0	($732,416)	[redacted]	$0	($704,836)	[redacted]	$0	($666,396)	[redacted]	$0	($752,812)
BD617 ND119 ND219 GRE1	$0	($316,032)	($584,352)	($762,076)	($693,344)	[redacted]	$0	($688,968)	[redacted]	$0	($683,044)	[redacted]	$0	($611,492)	[redacted]	$0	($728,528)
BD619 ND119 ND219 GRE2	$0	($367,440)	($641,160)	($804,692)	($738,104)	[redacted]	$0	($733,400)	[redacted]	$0	($705,088)	[redacted]	$0	($667,092)	[redacted]	$0	($753,788)
BD618 ND119 ND219 GRE2	$0	($367,540)	($640,984)	($804,416)	($738,032)	[redacted]	$0	($732,832)	[redacted]	$0	($704,852)	[redacted]	$0	($666,544)	[redacted]	$0	($752,832)
BD617 ND118 ND218	$0	($305,232)	($571,368)	($749,760)	($681,020)	[redacted]	$0	($681,920)	[redacted]	$0	($665,768)	[redacted]	$0	($601,796)	[redacted]	$0	($727,408)
BD618 ND118 ND218 GRE1	$0	($365,952)	($635,672)	($800,368)	($734,980)	[redacted]	$0	($753,352)	[redacted]	$0	($696,452)	[redacted]	$0	($664,464)	[redacted]	$0	($753,024)
BD617 ND119 ND219 GRE2	$0	($332,552)	($600,964)	($787,296)	($720,328)	[redacted]	$0	($721,336)	[redacted]	$0	($703,848)	[redacted]	$0	($634,624)	[redacted]	$0	($728,272)
ND119 ND219 ICT1	$0	($324,280)	($587,976)	($760,508)	($695,252)	[redacted]	$0	($728,628)	[redacted]	$0	($672,196)	[redacted]	$0	($611,332)	[redacted]	$0	($754,380)
GPV1 ICT2 BD619	$0	($350,980)	($595,896)	($777,780)	($702,972)	[redacted]	$0	($774,448)	[redacted]	$0	($682,272)	[redacted]	$0	($616,008)	[redacted]	$0	($750,968)
BD617 ND118 ND218 GRE1	$0	($331,260)	($597,352)	($783,972)	($718,240)	[redacted]	$0	($720,456)	[redacted]	$0	($695,472)	[redacted]	$0	($633,440)	[redacted]	$0	($727,972)
GPV1 ICT2 BD618	$0	($350,464)	($595,308)	($777,136)	($702,444)	[redacted]	$0	($773,596)	[redacted]	$0	($681,620)	[redacted]	$0	($615,064)	[redacted]	$0	($750,116)
BD618 ND118 ND218 GRE2	$0	($365,688)	($635,432)	($800,452)	($734,664)	[redacted]	$0	($753,764)	[redacted]	$0	($696,476)	[redacted]	$0	($664,628)	[redacted]	$0	($753,068)
GRE1 ND119 ND219 ICT1	$0	($342,696)	($611,016)	($788,740)	($720,008)	[redacted]	$0	($737,432)	[redacted]	$0	($694,872)	[redacted]	$0	($640,856)	[redacted]	$0	($754,552)
BD617 ND118 ND218 GRE2	$0	($330,988)	($597,144)	($784,068)	($717,968)	[redacted]	$0	($720,928)	[redacted]	$0	($695,440)	[redacted]	$0	($633,656)	[redacted]	$0	($727,736)
ND118 ND218 ICT1	$0	($334,516)	($600,652)	($779,044)	($710,304)	[redacted]	$0	($730,180)	[redacted]	$0	($684,740)	[redacted]	$0	($630,980)	[redacted]	$0	($753,908)
BD618 ND118 ICT1	$0	($335,652)	($599,384)	($779,556)	($708,676)	[redacted]	$0	($729,464)	[redacted]	$0	($686,216)	[redacted]	$0	($626,368)	[redacted]	$0	($752,840)
GRE2 ND119 ND219 ICT1	$0	($359,052)	($627,464)	($813,796)	($746,828)	[redacted]	$0	($769,744)	[redacted]	$0	($715,504)	[redacted]	$0	($663,932)	[redacted]	$0	($754,596)
GRE1 ND118 ND218 ICT1	$0	($360,824)	($626,916)	($813,536)	($747,804)	[redacted]	$0	($768,652)	[redacted]	$0	($714,496)	[redacted]	$0	($662,712)	[redacted]	$0	($754,176)
BD617 ND118 ICT1	$0	($306,328)	($564,136)	($744,896)	($678,236)	[redacted]	$0	($709,196)	[redacted]	$0	($664,088)	[redacted]	$0	($586,608)	[redacted]	$0	($757,904)
GRE1 ICT1 BD618 ND118	$0	($362,016)	($628,176)	($815,996)	($748,112)	[redacted]	$0	($772,060)	[redacted]	$0	($717,412)	[redacted]	$0	($660,896)	[redacted]	$0	($753,092)
GRE2 ND118 ND218 ICT1	$0	($360,416)	($626,572)	($813,496)	($747,396)	[redacted]	$0	($769,104)	[redacted]	$0	($714,432)	[redacted]	$0	($662,968)	[redacted]	$0	($754,236)
GPV1 ICT2 ICT1	$0	($343,660)	($604,848)	($775,256)	($711,608)	[redacted]	$0	($772,440)	[redacted]	$0	($682,784)	[redacted]	$0	($621,560)	[redacted]	$0	($760,044)
GRE1 ICT1 BD617 ND118	$0	($323,012)	($581,728)	($761,992)	($695,856)	[redacted]	$0	($719,984)	[redacted]	$0	($679,756)	[redacted]	$0	($602,348)	[redacted]	$0	($757,804)
GRE2 ICT1 BD618 ND118	$0	($361,584)	($627,796)	($815,848)	($747,704)	[redacted]	$0	($772,504)	[redacted]	$0	($717,232)	[redacted]	$0	($661,004)	[redacted]	$0	($753,112)
BD617 ND118 ND219	$0	($307,356)	($574,780)	($753,076)	($683,844)	[redacted]	$0	($679,540)	[redacted]	$0	($674,664)	[redacted]	$0	($603,088)	[redacted]	$0	($727,412)
BD618 ND118 ND219 GRE1	$0	($367,240)	($640,480)	($803,736)	($737,656)	[redacted]	$0	($731,804)	[redacted]	$0	($704,288)	[redacted]	$0	($665,720)	[redacted]	$0	($752,048)
GRE1 GPV1 ICT2 ICT1	$0	($343,468)	($604,428)	($775,684)	($712,120)	[redacted]	$0	($772,540)	[redacted]	$0	($682,944)	[redacted]	$0	($621,656)	[redacted]	$0	($760,000)
GRE2 ICT1 BD617 ND118	$0	($322,920)	($581,684)	($762,300)	($695,856)	[redacted]	$0	($720,196)	[redacted]	$0	($679,656)	[redacted]	$0	($602,424)	[redacted]	$0	($757,768)
BD617 ND118 ND219 GRE1	$0	($332,608)	($600,688)	($786,816)	($720,284)	[redacted]	$0	($720,372)	[redacted]	$0	($703,652)	[redacted]	$0	($634,288)	[redacted]	$0	($727,956)
BD618 ND118 ND219 GRE2	$0	($366,972)	($640,264)	($803,776)	($737,372)	[redacted]	$0	($732,224)	[redacted]	$0	($704,256)	[redacted]	$0	($665,808)	[redacted]	$0	($751,852)
GRE2 GPV1 ICT2 ICT1	$0	($343,656)	($604,728)	($776,076)	($712,292)	[redacted]	$0	($773,040)	[redacted]	$0	($683,188)	[redacted]	$0	($621,884)	[redacted]	$0	($760,568)
BD617 ND118 ND219 GRE2	$0	($332,344)	($600,416)	($786,852)	($720,044)	[redacted]	$0	($720,812)	[redacted]	$0	($703,560)	[redacted]	$0	($634,412)	[redacted]	$0	($727,432)
BD619 ND119 ND219	$0	($359,316)	($628,104)	($796,600)	($734,436)	[redacted]	$0	($738,368)	[redacted]	$0	($697,272)	[redacted]	$0	($657,096)	[redacted]	$0	($753,400)
BD619 ND119 ND219 GRE1	$0	($371,268)	($633,896)	($815,744)	($750,872)	[redacted]	$0	($738,656)	[redacted]	$0	($708,776)	[redacted]	$0	($665,828)	[redacted]	$0	($753,724)
BD618 ND119 ND219	$0	($370,316)	($632,364)	($814,268)	($749,108)	[redacted]	$0	($737,616)	[redacted]	$0	($707,756)	[redacted]	$0	($664,528)	[redacted]	$0	($752,572)
BD619 GPV1	$0	($358,120)	($614,140)	($800,400)	($723,328)	[redacted]	$0	($745,360)	[redacted]	$0	($695,336)	[redacted]	$0	($650,776)	[redacted]	$0	($755,156)
BD618 ND118 ND218	$0	($365,708)	($623,128)	($804,768)	($739,928)	[redacted]	$0	($744,800)	[redacted]	$0	($706,900)	[redacted]	$0	($652,308)	[redacted]	$0	($752,680)
BD619	$0	($371,652)	($637,996)	($813,292)	($747,424)	[redacted]	$0	($770,224)	[redacted]	$0	($707,792)	[redacted]	$0	($651,408)	[redacted]	$0	($762,240)
BD619 GRE1	$0	($372,756)	($639,256)	($815,328)	($749,600)	[redacted]	$0	($770,624)	[redacted]	$0	($709,580)	[redacted]	$0	($657,212)	[redacted]	$0	($762,580)
BD618	$0	($371,648)	($637,580)	($813,760)	($747,752)	[redacted]	$0	($769,476)	[redacted]	$0	($708,540)	[redacted]	$0	($655,868)	[redacted]	$0	($761,428)
ND119 ND219	$0	($361,060)	($624,756)	($797,288)	($732,032)	[redacted]	$0	($769,276)	[redacted]	$0	($692,160)	[redacted]	$0	($650,052)	[redacted]	$0	($746,516)
ND119 ND219 GPV1	$0	($368,236)	($628,428)	($815,440)	($747,272)	[redacted]	$0	($769,908)	[redacted]	$0	($707,784)	[redacted]	$0	($657,840)	[redacted]	$0	($745,212)
ND119 ND219 GRE1	$0	($367,576)	($635,896)	($813,620)	($744,888)	[redacted]	$0	($769,740)	[redacted]	$0	($711,752)	[redacted]	$0	($671,588)	[redacted]	$0	($746,836)
ND118 ND218	$0	($366,824)	($632,960)	($811,352)	($742,612)	[redacted]	$0	($770,520)	[redacted]	$0	($709,388)	[redacted]	$0	($668,132)	[redacted]	$0	($741,796)

ICT1	$0	($341,304)	($607,980)	($778,568)	($714,196)	$0	($730,396)	$0	($693,540)	$0	($625,792)	$0	($788,160)
BD618 ND118	$0	($368,828)	($632,560)	($812,732)	($741,852)	$0	($769,544)	$0	($710,892)	$0	($661,988)	$0	($739,480)
GPV1 FVP	$0	($344,132)	($613,636)	($783,740)	($719,956)	$0	($733,868)	$0	($681,504)	$0	($638,020)	$0	($744,584)
GRE1 ICT1	$0	($349,936)	($617,192)	($787,704)	($723,536)	$0	($739,176)	$0	($702,240)	$0	($634,400)	$0	($788,416)
GPV1	$0	($344,124)	($613,628)	($783,736)	($719,952)	$0	($733,868)	$0	($681,504)	$0	($638,016)	$0	($744,588)
GRE1 GPV1	$0	($344,596)	($614,420)	($784,544)	($720,664)	$0	($734,552)	$0	($682,020)	$0	($638,628)	$0	($744,732)
GPV1 FVP DGRD	$0	($353,040)	($622,676)	($792,860)	($729,176)	$0	($739,144)	$0	($691,712)	$0	($650,908)	$0	($762,824)
GPV1 DEGRADE	$0	($353,036)	($622,668)	($792,856)	($729,176)	$0	($739,148)	$0	($691,712)	$0	($650,900)	$0	($762,824)
GRE2 ICT1	$0	($357,516)	($625,000)	($795,748)	($731,176)	$0	($748,140)	$0	($709,448)	$0	($641,948)	$0	($788,452)
BD618 ND118 ND219	$0	($370,232)	($632,436)	($813,940)	($748,896)	$0	($737,064)	$0	($707,012)	$0	($663,620)	$0	($751,724)
GRE2 GPV1	$0	($344,500)	($614,968)	($785,332)	($721,384)	$0	($734,704)	$0	($682,532)	$0	($639,244)	$0	($744,916)
GRE1	$0	($376,604)	($643,860)	($814,372)	($750,204)	$0	($770,840)	$0	($712,200)	$0	($648,492)	$0	($762,868)
GRE2	$0	($376,220)	($643,704)	($814,452)	($749,880)	$0	($771,648)	$0	($712,368)	$0	($648,872)	$0	($762,820)
MAX		($265,524)	($529,220)	($653,780)	($589,996)		($634,944)		($609,312)		($519,468)		($724,976)
MIN		($376,604)	($648,428)	($821,836)	($754,868)		($802,344)		($720,996)		($677,700)		($788,452)

DOC Calculaton of Xcel's RES Compliance w/ Proposed Wind Additions

	System GWh	MN	MN Sales (MWhs)	RES %	RES Req.	annual Gen.			REC Surplus/ (Deficit)	MWh Additions from Proposed Wind at 40% CP	REC Surplus/(Deficit) w/ Proposed Wind
2013	45569	74%	33,721,060	18%	6,069,791	5,674,803	5,225,699	Beg. Bal.	4,830,711		4,830,711
2014	45901	74%	33,966,740	18%	6,114,013	5,674,803			4,391,501		4,391,501
2015	46243	74%	34,219,820	18%	6,159,568	5,674,803			3,906,737		3,906,737
2016	46628	73%	34,038,440	25%	8,509,610	5,674,803			1,071,930	2,628,000	3,699,930
2017	46838	73%	34,191,740	25%	8,547,935	5,674,803			(1,801,202)	2,628,000	3,454,798
2018	47137	73%	34,410,010	25%	8,602,503	5,674,803			(4,728,902)	2,628,000	3,155,098
2019	47416	73%	34,613,680	25%	8,653,420	5,674,803			(7,707,519)	2,628,000	2,804,481
2020	47720	73%	34,835,600	30%	10,450,680	5,674,803			(12,483,396)	2,628,000	656,604
2021	48020	73%	35,054,600	30%	10,516,380	5,674,803			(17,324,973)	2,628,000	(1,556,973)
2022	48236	73%	35,212,280	30%	10,563,684	5,674,803			(22,213,854)	2,628,000	(3,817,854)
2023	48466	73%	35,380,180	30%	10,614,054	5,674,803			(27,153,105)	2,628,000	(6,129,105)
2024	48747	73%	35,585,310	30%	10,675,593	5,674,803			(32,153,895)	2,628,000	(8,501,895)
2025	49060	72%	35,323,200	30%	10,596,960	5,674,803			(37,076,052)	2,628,000	(10,796,052)
2026	49404	72%	35,570,880	30%	10,671,264	5,674,803			(42,072,513)	2,628,000	(13,164,513)
2027	49738	72%	35,811,360	30%	10,743,408	5,674,803			(47,141,118)	2,628,000	(15,605,118)
2028	50089	72%	36,064,080	30%	10,819,224	5,674,803			(52,285,539)	2,628,000	(18,121,539)
2029	50430	72%	36,309,600	30%	10,892,880	5,674,803			(57,503,616)	2,628,000	(20,711,616)
2030	50792	72%	36,570,240	30%	10,971,072	5,674,803			(62,799,885)	2,628,000	(23,379,885)
2031	51141	72%	36,821,520	30%	11,046,456	5,674,803			(68,171,538)	2,628,000	(26,123,538)

2012 Existing Generation	4,906,523
2013 Additions:	
Prairie Rose	648,658
Big Blue Wind	119,622
Total Est. Annual Generation	5,674,803
Unretired RECs	5,225,699

☐ **Non Public Document – Contains Trade Secret Data**
☒ **Public Document – Trade Secret Data Excised**
☐ **Public Document**

Xcel Energy		
Docket No.:	E002/M-13-603 & E002/M-13-716	
Response To:	Department of Commerce Information Request No.	005
Requestor:	Christopher Shaw and Craig Addonizio	
Date Received:	August 21, 2013	
Date Received:	September 4, 2013 (Via Phone Discussion)	**SUPPLEMENT**

Question:

Trade Secret Attachment E of Xcel's petition includes the results of the initial screen of RFP responses. Please explain:

a. How the range of levelized costs for each project was determined, including the difference between the high and low end of the range and whether all costs, including interconnection costs, where included in the levelized cost calculation.
b. For projects that offered a PPA or ownership option, how Xcel determined which option was preferred.
c. For each project that was below the $29/MWh cutoff, an explanation of why that project was not selected.

Response:

a. The levelized $/MWh results in Attachment E are shown by project, and presented as a cost range in situations where bidders submitted multiple bids for the same project. In many instances, the bidder offered multiple proposals for the same project including PPA or ownership options, with multiple variations in MW size and price. Rather than listing the levelized $/MWh for each option of a given project, results were combined into a range from the lowest priced option to the highest priced option for that project. The levelized $/MWh from the initial screening encompassed all costs as provided in each bidder's proposal (including interconnection costs), plus internal estimates for certain other costs such as O&M and ongoing capital.

b. Of the projects identified from the initial screening process as meeting the \$29/MWh threshold requirement, Business Development identified five projects that appeared attractive from an ownership perspective, two of which were also identified by the Purchase Power group as attractive from a PPA perspective. Business Development initiated discussions with the bidders on all five projects regarding high level terms and conditions for a build/transfer transaction. Simultaneously, Purchased Power initiated discussions with the bidders on the two projects that had also offered a PPA option. As those PPA discussions progressed, the project owner for those two projects became less interested in negotiating terms and conditions acceptable for a build/transfer transaction.

c. Each build/transfer project below the \$29/MWh cutoff was assessed by Business Development to determine its potential viability from an ownership perspective using multiple variables. As a result, certain projects appeared to be more attractive from a build/transfer perspective for multiple reasons, including experience, capabilities and financial viability of the proposing entity, the transmission/interconnection ability for the project, turbines being proposed, etc.

   Each PPA project below the \$29/MWh cutoff was assessed by the Purchased Power group. The two PPA projects identified by the Purchased Power group to move forward with in negotiations offered lower priced options than those PPAs offered by the other bidders with the exception of project number W002, identified in Attachment E. Project W002 was not selected due to **[BEGIN TRADE SECRET END TRADE SECRET]**.

<u>SUPPLEMENTED QUESTION</u>:

The following questions were requested during a phone discussion with Mr. Shaw on September 4, 2013. Trade Secret Attachment E of Xcel Energy's Petition includes the results of the initial screen of RFP responses. Please provide:

a. The basis for not selecting projects W026, W002, W039 and W011

b. Further explanation of how the levelized \$/MWh price ranges per Attachment E were established.

c. The main drivers that changed the levelized cost calculations from the initial screening to the final results for the four projects selected.

<u>SUPPLEMENTED RESPONSE</u>:

d. The following table provides the primary basis for not selecting projects W026, W002, W039 and W011.

Project #	Primary Basis for Not Selecting
	[Begin Trade Secret…
W026	
W002	
W039	
W011	
	…End Trade Secret]

e. The range of levelized costs for each project per Attachment E represents the lowest cost and highest cost options where a bidder submitted multiple proposals for the same project. As an example, Geronimo submitted PPA, ownership or combination PPA/ownership proposals with numerous variations in size, turbine type and price structure for most of their projects. We calculated the levelized cost for each option offered and presented results as a range per Attachment E. As it relates to Geronimo's Courtenay project, the lowest cost option came in at **[Begin Trade Secret …End Trade Secret]** and the highest cost option was priced at **[Begin Trade Secret… …End Trade Secret]**. All other options offered for the Courtenay project fell within the range of **[Begin Trade Secret… …End Trade Secret]**.

f. The table below provides a comparison of the levelized cost from the initial screening to the final results for the selected proposals along with the main driver behind the change in cost.

Project	**Proposal Selected**	**$/MWh Initial Screen**	**$/MWh Final**	**Main Driver**
		[Begin Trade Secret…	**[Begin Trade Secret…**	**[Begin Trade Secret…**
Courtenay	200 MW PPA Escalating Price			
Odell	200 MW PPA Escalating Price			
Pleasant Valley	200 MW Build / Transfer			
Border	150 MW Build/Transfer			
		…End Trade Secret]	**…End Trade Secret]**	**…End Trade Secret]**

Portions of this response have been redacted and designated as "Non-Public." The redacted portions contain "trade secret" information that includes private data on individuals not generally known or readily ascertainable by others. Consistent with past treatment of similar information, Xcel Energy maintains this information as trade secret.

Preparer:	Stan Dufault
Title:	Senior Analyst – Resource Planning
Department:	Resource Planning
Telephone:	612-215-4577
Date:	August 27, 2013

SUPPLEMENTED: September 6, 2013

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Public Comments

Docket No. E002/M-13-603 and E002/M-13-716

Dated this **9th** day of **September, 2013**

/s/Sharon Ferguson

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