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A Clean Energy Future for Xcel: Supplemental Report

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1 Clean Energy Organizations' EnCompass Modeling Initial Comments

In our report attached to the Clean Energy Organizations' ("CEO") February 11, 2021 comments, we discussed the three portfolios we modeled:

1) Xcel's Preferred Plan as filed,
2) a reoptimized Revised Xcel Preferred Plan that includes the Sherco CC, and
3) an alternative, all renewable and storage expansion plan we call the CEO Preferred Plan.

Our findings demonstrated that a portfolio of renewable and storage resources with no new fossil generation has:

1. Consistently similar or lower costs than a portfolio that includes the Sherco CC;
2. Offer similar levels of reliability as a portfolio that includes the Sherco CC; and
3. Offers further, material CO_2 emission reductions.

This supplemental report addresses several additional technical points that we were not able to include in our original report due to lack of time as well as some items of interest that we learned subsequent to the filing of CEO's Direct Comments.

2 Clean Energy Organizations' Supplemental EnCompass Modeling

The focus of the EnCompass modeling for the supplemental comments is to further explore the "unserved energy" that was discussed in Sections 1.1.4 and 3.3 of the EFG report filed with the CEO's comments in February. Due to the significant number of resources retiring between 2040 and 2045, especially the Monticello nuclear unit in 2040 in our modeling, a dramatic uptick in the amount and costs of "purchases" could be seen in the modeling results between 2040 and 2045. This drove a significant difference in overall revenue requirements between our two primary capacity expansion plans: the CEO Preferred Plan and the Revised Xcel Preferred Plan. Those "purchase" costs included significant quantities of "unserved energy", which Xcel prices at **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**/MWh. This "unserved energy" result was also partially driven by Xcel's assumption limiting the total amount of MISO market purchases along with the volume of resource retirements including that of the Monticello nuclear unit in 2040.

For this supplemental modeling, we explored two additional mechanisms to analyze and/or address the "unserved energy" that we observed in the CEO Preferred Plan. The first run held constant the resources in Xcel's Preferred Plan as filed, with the exception of the Sherco Combined Cycle ("CC") unit, which was replaced with CEO's alternative to the Sherco CC in the CEO Preferred Plan. That is, adding 1000 MWs of hybrid solar and 250 MWs of battery storage hybrid resources in 2027 to replace the Sherco CC. We also evaluated a run that looked at continuing the energy efficiency savings for the bundles selected in EnCompass after 2034. The sections below discuss the results of each of the runs.

2.1 Replacing the Sherco Combined Cycle with Solar Hybrid Resources in 2027

This run froze the resources in Xcel's Preferred Plan with one change: 1000 MWs of hybrid solar and 250 MWs of battery storage hybrid resources were added in place of the Sherco Combined Cycle ("CC") unit in 2027. We substituted this volume of solar hybrid and hybrid storage resources for the Sherco CC in 2027 since that is the capacity that was selected by EnCompass under the CEO Preferred Plan. There are two key results from this run.

First, we can directly compare the CEO's alternative to the Sherco CC in Xcel's Preferred Plan. Consistent with the findings of our initial report, replacing the Sherco CC with CEO's alternative resources is less expensive.

Table 1. PVSC Under Xcel Corrected Base Case

Run Name	PVSC
Xcel Preferred – Replace Sherco with Solar Hybrid 2027	$40,501
Xcel Fixed Preferred Plan	$40,801

The second finding is in regards to the "unserved energy" issue. This run with the CEO alternative to the Sherco CC results in a *de minimus* amount of unserved energy of 718 MWH in 2043, but all the other years in the planning period have no unserved energy. Table 2 shows the comparison of the unserved energy in the CEO Preferred Plan compared to Xcel's Preferred Plan with the hybrid solar and battery storage replacing the Sherco CC in 2027.

Table 2. Unserved Energy (MWH) Comparison

Year	CEO Preferred Plan	Xcel Preferred with Hybrid Solar 2027
2037		
2038		
2039		
2040		
2041	1,995	
2042	7,605	
2043	11,121	718
2044	22,137	
2045	4,317	

This finding illustrates that the "unserved energy" in the out-years of the CEO Preferred Plan is not caused by creating a plan without the Sherco CC and is consistent with our finding that the primary drivers are the significant number of resources retiring between 2040 and 2045, especially the

Monticello nuclear unit in 2040, the unrealistic drop-off in energy efficiency savings in Xcel's modeling (discussed in the next section), and Xcel's modeling limits on MISO imports.

2.2 Continuation of Energy Efficiency Savings After 2034

As discussed in the Minnesota Department of Commerce's ("Department") filed comments,[1] Xcel modeled no new energy efficiency savings after 2034. We concur with the Department that this assumption is unrealistic because it would mean a cessation of Xcel's longstanding energy efficiency efforts. **Figure** *1* and **Figure** *2*, below, show the generation and firm capacity of new energy efficiency resources, respectively. These are cumulative savings so the steep decline reflects the expiration of previously installed measures. We believe that this combination of assuming energy efficiency programs stop, numerous existing unit retirements, and the limitations of time sampling that must occur in the capacity expansion step are driving the levels of unserved energy that we observed in our modeling runs.

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Figure 1. Generation (GWH) from New Energy Efficiency Resources

[1] Minnesota Department of Commerce Public Comments. Docket No. E002/RP-19-368. P. 56 – 57.

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Figure 2. Firm Capacity (MW) of New Energy Efficiency Resources

In order to evaluate the impact that the energy efficiency savings have on the "unserved energy", we froze the energy efficiency savings and firm capacity at the 2034 level for the years 2035 to 2045 as the Department did in its own runs. We reoptimized the CEO Preferred Plan with these energy efficiency assumptions. When the energy efficiency savings are frozen, the result is that there is less "unserved energy" in the plan. Table 3 below shows the comparison of the "unserved energy" (MWH) in the CEO Preferred Plan compared to the run that maintains the 2034 level of energy efficiency savings for 2035 to 2045 ("EE Freeze").

Table 3. Unserved Energy (MWH) Comparison

Year	CEO Preferred Plan	EE Freeze
2037		5,023
2038		2,853
2039		
2040		3,056
2041	1,995	
2042	7,605	
2043	11,121	7,107
2044	22,137	
2045	4,317	

The results of these modeling runs, in addition to the impact of flow batteries added to the CEO Preferred Plan, indicate that the unserved energy in the EnCompass modeling is not a foregone outcome, but rather a product of the resource choices that Xcel will make in the 2030s and beyond.

2.3 Nuclear Scenarios

All of the EnCompass analysis in our initial report included Xcel's proposed 10-year extension of the Monticello nuclear unit. The CEOs wanted to explore additional contingencies related to extending the life of the Monticello unit compared to retiring the unit at the end of its current license in 2030. In order to evaluate those contingency costs, we compared the CEO Preferred Plan as discussed in the February 2021 EFG report, the CEO Preferred Plan with additional contingency costs for extending Monticello until the end of 2040, and a run in which the Monticello unit retires at the end of 2030.

The CEO Preferred Plan with life extension contingency costs was run to gauge the impact of modeling additional operation and maintenance ("O&M") and capital costs for Monticello under a ten year extension. These costs are greater than the costs assumed by Xcel. The capital costs were created by experts at the Union of Concerned Scientists ("UCS") and the additional O&M costs were based on the Department's assumptions as noted below. The additional costs are explained further in the CEO's reply comments.

Xcel's methodology for modeling nuclear capitalized maintenance and plant balances was to run the costs through the Capital Expenditure and Recovery module of Strategist and then model the resulting stream as fixed costs in EnCompass. It's our understanding that Xcel used this approach because at the time EnCompass did not have the financial capabilities Xcel needed. For our modeling, we modeled the additional O&M and capital expenditures developed by UCS as a separate stream of costs that are additive to Xcel's inputs. The additional O&M was modeled as a fixed cost and the additional capital was input as a stream of annual capital expenditures that are rate based. We used our "CEO Base" cost scenario for these runs and the details of the CEO Base cost scenario are in Section 1.2 of the Initial EFG Report.

The costs recommended by UCS included the DOC's assumption of an additional one percent increase in O&M costs[2], a 25 percent increase in annual capital expenditures for years 2024 to 2039 to reflect higher contingency costs, plus a $3 million dollar per year increase from 2021 to 2025 to capture additional costs to submit the license renewal application to the NRC for a ten year life extension.[3] Table 4 presents the Present Value of Societal Cost ("PVSC") results for these three runs.

Table 4. PVSC Comparison of Monticello Runs Under the CEO Base Case (Millions of Dollars)

Run Description	CEO Base Case
CEO Preferred Plan Additional Nuclear Costs	$38,719
CEO Preferred Plan	$38,482
No Monticello Extension	$38,605

Including the additional O&M and capital expenditure assumptions for the Monticello unit increases the cost of the CEO Preferred Plan by about 0.6 percent. When comparing the CEO Preferred Plan (Monticello retiring at the end of 2040) with the No Monticello Extension run that retires Monticello at the end of 2030, the CEO Preferred Plan is slightly lower in cost (0.3%).

3 Department of Commerce Sherco CC Analysis

While the Department used both a different model, Strategist, and developed different assumptions than the CEOs, the Department's analysis has some important similarities in its results. Specifically, like the CEOs' modeling, the Department's runs without the Sherco CC were slightly lower cost than the runs with the Sherco CC. Table 5 provides the PVSC results in millions of dollars for the Department's Scenario 134, with the Sherco CC, and Scenario 134a, without the Sherco CC. Scenario 134a was lower cost than Scenario 134 across each of the different scenarios modeled by the Department. The Department's modeling results support the CEOs' finding that there are alternative portfolios without the Sherco CC that are lower in cost than portfolios that contain the Sherco CC.

[2] Minnesota Department of Commerce Public Comments. Docket No. E002/RP-19-368. P. 56 – 58.
[3] The 25 percent annual capital cost increase was based on UCS' assessment of the DOC Global report and other industry sources. The license renewal application costs was based on estimates in the DOC Global report.

Table 5. Department's Strategist PVSC Modeling Results (Millions of Dollars)[4]

	Scenario 134 (with Sherco CC)	Scenario 134a (without Sherco CC)	Difference
Base Case	$36,814	$36,609	-$205
Mid Externalities, No CO_2 Internal Cost	$39,358	$38,607	-$751
High Externalities, No CO_2 Internal Cost	$42,857	$41,734	-$1,123
High Externalities, CO_2 Internal Cost	$38,574	$38,376	-$198
Low Externalities, No CO_2 Internal Cost	$35,853	$35,420	-$433
Low Externalities, Use CO_2 Internal Cost	$34,794	$34,586	-$208
No Externalities, Use CO_2 Internal Cost	$33,654	$33,452	-$202
No Externalities, No CO_2 Internal Cost	$33,654	$33,452	-$202
Low Solar Price	$36,190	$35,868	-$322
High Solar Price	$37,251	$37,177	-$74
Low Wind Price	$36,444	$36,221	-$223
High Wind Price	$36,819	$36,623	-$196
Low Forecast	$35,829	$35,585	-$244
High Forecast	$39,705	$39,599	-$106
Low Coal Cost	$36,771	$36,566	-$205
High Coal Cost	$36,857	$36,651	-$206
Low Gas Price	$36,472	$36,086	-$386
High Gas Price	$36,657	$36,465	-$192
Low Nuke Cost	$36,238	$36,033	-$205
High Nuke Cost	$37,389	$37,184	-$205
High Market Price	$36,629	$36,562	-$67
Low Market Price	$36,690	$36,359	-$331
Low Market Capacity	$36,847	$36,680	-$167
No Market	$37,053	$37,029	-$24

[4] Minnesota Department of Commerce Public Comments. Docket No. E002/RP-19-368. Scenario 134 Strategist Outputs provided in Attachment 1. Scenario 134a Strategist Outputs provided in Attachment 3.

4 Xcel's Modeling of Demand Response

The EnCompass modeling for Xcel's Supplemental IRP filing included a dispatch adder,[5] essentially a hurdle rate for utilization of all new Demand Response ("DR") programs. When the CEOs asked Xcel for the rationale underlying this dispatch adder, Xcel responded by saying:

> *A dispatch cost adder was applied to the Demand Response programs to ensure they were the final resources to be dispatched in the model during a peak load / capacity shortfall event to reflect actual operational practices.*[6]

Xcel further explained that a dispatch adder was used over a maximum annual energy input field ("MaxAnnEn") that can limit the annual output of a resource because of difficulties in making that setting work as intended. Xcel said:

> *The 'MaxAnnEn' data field only works correctly when a full annual run is performed (all 8,760 hours are calculated in a single simulation) so that the model can accurately allocate the energy across all months of the year. Since the Company performed production costing runs using a rolling 28-day simulation period, we utilized the 'MaxWeekEn' data field instead to limit the dispatch to the assumed program max limits. The Company notes, however, that this limit was relatively non-binding – in other words, the DR programs were actually dispatched in the model at much lower levels than the imposed max limit.*[7]

With the dispatch adder, we observed that in Xcel's modeling, DR is generally NOT utilized. In most of Xcel's modeling runs, the new Demand Response programs are not dispatched until 2037. That demand response is currently the last resource to be utilized during a shortfall event is not a reasonable justification for a DR dispatch adder in modeling; rather, DR is a resource that should be optimized around its attributes like any other resource. Moreover, we do not think this assumption is consistent with the Commission's intention in ordering Xcel, in prior Resource Plan orders, to evaluate additional demand response.

We understand that there is uncertainty in fairly representing all resources in IRP models, but we don't believe the methodology Xcel has used allows its model to accurately capture the full value of demand response. And with increasing decarbonization and electrification it will be increasingly important to capture the potential for load flexibility in IRPs. We would like to see Xcel explore other methodologies that will allow it to do just that.

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[5] **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** for the remainder of the planning period.
[6] Xcel response to CEO IR 130a. Docket No. E002/RP-19-368.
[7] Xcel response to CEO IR 130b. Docket No. E002/RP-19-368.

5 Battery Storage Cost

Section 1.2 of the initial EFG report discussed several of the changes that the CEOs used to create the "CEO Base Case" scenario of different modeling assumptions.[8] One of the changes was to modify the costs for new battery storage resources. EFG used project pricing information from project bids received by the Public Service Company of New Mexico ("PNM"). Utilizing the PNM bids as a source for modeling battery storage costs in the CEO modeling runs is reasonable since the cost reflects actual bids received for battery projects. We have not seen battery prices submitted in response to Request for Proposals that have significant differences across different regions. As such, we would expect these bid prices to be generally applicable to Minnesota utilities.

Since EFG's report, PNM has received additional pricing information related to battery projects in PNM's service territory. Table 6 shows the project pricing information with the two new projects that PNM has received bids for. The average cost per kW-month is even lower with the addition of the two new projects. These additional projects provide further support for CEO's battery storage cost assumptions.

Table 6. PNM Battery Storage Pricing with New Projects

	With ITC $/kW-Mo	No ITC $/kW-Mo
Jicarilla	$9.97	$13.47
Arroyo	$7.46	$10.08
Bidder #5	$7.99	$10.80
Bidder #2	$7.70	$10.41
New Bid	$6.68	$9.03
New Bid	$7.56	$10.22
Avg	**$7.89**	**$10.67**

[8] Section 1.2 of the Initial EFG Report.