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ENERGY FUTURES GROUP

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

energyfuturesgroup.com

A Clean Energy Alternative for Minnesota Power

Prepared by:

Chelsea Hotaling, Energy Futures Group

Tyler Comings, Applied Economics Clinic

Joshua Castigliego, Applied Economics Clinic

Anna Sommer, Energy Futures Group

Prepared for:

Fresh Energy

Clean Grid Alliance

Minnesota Center for Environmental Advocacy

Sierra Club

April 2022

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1 Clean Energy Organizations' EnCompass Modeling Runs

Energy Futures Group and Applied Economics Clinic were asked to conduct an independent technical review of Minnesota Power's IRP, making corrections (as deemed appropriate in our professional opinions) to MP's EnCompass modeling assumptions, and exploring alternative combinations of unit retirements and additions that would better fit the policy preferences outlined in Commission orders and state statutes.

The following sections discuss the modifications that we made to Minnesota Power's ("MP") EnCompass database to perform the Clean Energy Organizations ("CEO") modeling runs. CEO modeling runs were performed using EnCompass version 5.1.3.0.

Our modeling approach was to examine two portfolios with different capacity expansion plans:

1) A re-optimized "Revised Minnesota Power Preferred Plan" that includes MP's recently announced Nemadji Trail Energy Center Combined Cycle ("NTEC CC") 20 percent share of the proposed plant, and

2) an all renewable, storage, and demand side management ("DSM") expansion plan that we call the "CEO Preferred Plan."

We evaluated these portfolios under a central set of assumptions that involved making minor corrections and changes to Minnesota Power's modeling assumptions, along with updating the cost of new renewable and storage resources. We decided to re-optimize Minnesota Power's Preferred Plan to ensure that there would be an apples-to-apples cost comparison between a portfolio with the NTEC CC at a 20 percent share and a portfolio without the NTEC CC share. We also modeled these portfolios under five of Minnesota Power's sensitivities: "low load", "high load", "low gas", "high gas", and "higher gas".

Our findings are that the EnCompass modeling described in this report demonstrates that a portfolio of renewable, storage, and energy efficiency resources with no new fossil generation has costs comparable to a portfolio that includes Minnesota Power's share of the NTEC CC.

1.1 Updates and Other Corrections to Minnesota Power's EnCompass Modeling

The changes we made to Minnesota Power's modeling are discussed in the sections that follow. Except where otherwise noted, these changed inputs went into modeling of both expansion plan portfolios.

1.1.1 Minnesota Power's NTEC Ownership Share

Minnesota Power's initial and supplemental Integrated Resource Plan ("IRP") filings contained the assumption that 50% of the NTEC CC, about 296 MWs, would be added to Minnesota Power's portfolio in 2025. Minnesota Power modeled the NTEC CC as an existing resource that was assumed to come online in 2025 and therefore was not a part of the new resources built in the optimized capacity expansion for its Preferred Plan. However, during the review period for this IRP, the Company issued a press release[1] on September 28, 2021, announcing that the Company was selling a portion of its ownership to Basin Electric Power Cooperative. This sale reduced MP's share from 50% to 20% of the project.

Since this update happened after Minnesota Power filed its IRP, but before stakeholder comments on the IRP were due, the CEOs decided to reflect this change in the EnCompass modeling, as the 50% share of the project no longer applied. The Department of Commerce submitted a request to Minnesota Power asking the Company to create EnCompass inputs that would reflect a 20% share of NTEC; but Minnesota Power elected not to do so. The Company provided the following response:

> *The NTEC facility is currently modeled as the full facility in EnCompass with a 50% share of the benefits and costs attributed to Minnesota Power. The EnCompass input are located in the file "RES-Nemadji Trail CC.xlsx" included with the companies February 1st and April 1st modeling files. The ownership share can be adjusted by modifying the cell D30 on the tab "Main Inputs" of the "RES-Nemadji Trail CC.xlsx" modeling input file. The current value is "0.5", but should be adjusted to "0.2" to reflect a 20% ownership share. Changing the "Ownership Ratio" value in this location will update the appropriate timeseries inputs throughout the workbook.*[2]

The CEO Encompass modeling includes the input change that Minnesota Power outlined in its response to the Department of Commerce. This change was also included in the CEO's re-optimization of MP's Preferred Plan.

1.1.2 Transmission Upgrade Costs for Boswell 3

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[1] *ALLETE Announces Third Partner in Nemadji Trail Energy Center Project*, ALLETE (Sep. 28, 2021) *available at* https://investor.allete.com/news-releases/news-release-details/allete-announces-third-partner-nemadji-trail-energy-center.

[2] Minnesota Power Response to Department of Commerce IR 007, Minn. Pub. Utils Comm'n, Docket No. E015/RP-21-33.

Table 1. Minnesota Power Assumptions for Boswell 3 and 4 Replacement

Replacement Options	Boswell 3 Replacement	Boswell 4 Replacement
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Minnesota Power set the S1 Transmission project cost at $144 million, the S2 Transmission project cost at $770 million, and the S3 Transmission project at $803 million. The details of these projects are provided in Table 11 of Appendix F[3] to the IRP.

CEOs contracted with Telos to review the reasonableness of Minnesota Power's transmission project cost estimates. As discussed in greater detail in the Telos Report attached to CEOs' comments, Telos Energy found that a more reasonable cost estimate for the Boswell 3 transmission upgrade (the S1 Transmission project) is $25 million.[4] Our CEO modeling therefore kept the transmission constraints regarding the retirement of Boswell 3 and 4 in place, but incorporated Telos's cost estimate of $25M for the S1 Transmission project in both the CEO Preferred Plan and the Revised MP Preferred Plan modeling runs.

The modeling contained in this report assumes the same December 31, 2029 retirement date for Boswell 3 that Minnesota Power included in its Preferred Plan. For Boswell 4, we note that in its IRP, Minnesota Power said that "The Company is committed to ceasing coal-fired operations at Minnesota Power's BEC Unit 4 in 2035."[5] However, in the modeling, Minnesota Power's Preferred Plan does not retire Boswell 4 in 2035 or include any costs associated with preparing for that retirement. CEOs similarly did not retire Boswell 4 in their modeling because including the reliability mitigation costs of retiring that unit, as well as the costs of adding replacement resources, in the CEO Preferred Plan when these costs were not included in the Minnesota Power Preferred Plan would have prevented an apples-to-apples comparison of the plans' costs and obscured other findings from that comparison.

1.1.3 CO_2 Regulatory Cost and Environmental Externality Costs

Minnesota Power modeled six different environmental future scenarios that evaluated different assumptions around the cost and treatment of CO_2 and the other criteria pollutants. Minnesota Power's

[3] Minnesota Power 2021 IRP, Appendix F: Transmission Planning Activities, Table 11 at 64.
[4] Telos Report, Attachment 2 at 10.
[5] Minnesota Power 2021 IRP, 58.

Preferred Plan uses the Reference Case Future, which is based on the mid environmental and regulatory cost for CO_2, and the mid environmental cost for other criteria pollutants. Table 2 shows the differences between the Reference environmental scenario and the High environmental scenario.

Table 2. Environmental Futures Modeled by Minnesota Power[6]

	Carbon Dioxide (CO_2)				Other Criteria Pollutants
	Prior to 2025		2025 and Thereafter		
	Environmental Cost	Regulatory Cost	Environmental Cost	Regulatory Cost	Environmental Costs
Reference Case	Mid	-	-	$15/Ton	Mid
High Case	High	-	-	$25/Ton	High

In the CEO Preferred Plan and the Revised MP Preferred Plan, we used the High Environmental Cost and High Carbon Regulation Cost Future. This included the high environmental cost of CO_2 prior to 2025, the CO_2 regulatory cost starting at $25/ton in 2025, and the high environmental costs for other criteria pollutants. We believe that this is a reasonable assumption that is closer to the proposed Social Cost of Carbon number estimated by the Obama administration.

1.1.4 Changes to Minnesota Power's Wind, Solar, and Battery Storage Cost Assumptions

We identified several concerns with Minnesota Power's approach to modeling renewable and battery storage resources, including:

1) Using outdated forecasts to develop renewable and battery storage costs,
2) applying an outdated Investment Tax Credit ("ITC") for solar resources,
3) not considering Power Purchase Agreements,
4) not considering solar resources outside of Minnesota
5) not modeling solar-battery hybrid resources.

Minnesota Power's modeling lacked rigor in its treatment of renewable and battery storage resources which we remedied for the CEO modeling. First, the forecasts that MP relied upon for renewable and storage costs were outdated. Second, because the Company's IRP was filed in February 2021, the Company's treatment of the Investment Tax Credit ("ITC") did not account for the 2020 extension of that credit. Third, the Company only modeled self-build renewable and storage options and neglected to consider whether it might use a tax equity partnership or a power purchase agreement ("PPA") to allow the ITC to be credited in the first year of the project rather than "normalized" over the life of the resource, which significantly reduces the value of the ITC. Fourth, the Company understated the capacity factor of solar PV resources that it could access outside of Minnesota. Finally, the Company failed to model solar and battery hybrid resources at all despite these being an attractive energy and capacity replacement option. CEO's modeling corrected all of these flaws and found that a clean portfolio replacement is similar in cost to a portfolio that includes the NTEC plant.

[6] Minnesota Power 2021 IRP, Table 2 at 33.

1.1.4.1 Minnesota Power Used Outdated Cost Forecasts for Renewable and Battery Storage Resources

The Encompass modeling selects the lowest-cost portfolio of resources to build when there is a capacity need. This makes the resource cost assumptions one of the most important modeling inputs. Unfortunately, the bases for the Company's cost assumptions for future renewable and storage resource additions were outdated; the forecasts used by the Company were published in 2019 and 2020. The Company's solar PV and wind capital cost assumptions use both the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") forecasts from 2020 and proprietary forecasts from IHS Global from **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**.[7] MP's battery storage forecasts take the average of those two sources along with the Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") forecast from 2019.[8]

In order to capture more up-to-date market intelligence, CEOs modeling instead uses the NREL ATB 2021 (released in July 2021) and EIA AEO 2021 (released in February 2021).[9] The effect of this update is shown below in Figures 1 through 3. On average, the updated capital cost estimates for solar PV and battery storage are 8 percent lower than MP's, while the updated wind capital cost estimate is slightly higher, showing a 5 percent average increase. Importantly, the changes shown in Figures 1-3 are only to the baseline capital costs, and do not reflect our adjustments to tax credits. Later, we discuss other adjustments to these baseline costs that we applied in our modeling, including updating available tax credits, using a more reasonable capacity factor for solar PV, and allowing for PPAs to be represented in the model—as opposed to only self-build resources. We also used these costs as a baseline for the solar PV and battery storage hybrid resources in our model, which MP neglected to include as a resource option.

[7] Minnesota Power 2021 IRP, Appendix J: Assumptions and Outlooks, 9.
[8] Id. at 10.
[9] We used the NREL ATB 2021 and EIA AEO 2021 which were not available to the Company at the time of its modeling, but Minnesota Power still could have used more up-to-date versions of some of its sources' forecasts, as the Company's modeling was done in "the last half of 2020." Minnesota Power Response to CEO IR 038b, Minn. Pub. Utils Comm'n, Docket No. E015/RP-21-33.

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[10] Attachment to CEO IR 3.8, "2020IRP_New Renewable Alternatives Cost Curves_CEOIR3.8_TS."
[11] Id.

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1.1.4.2 The Investment Tax Credit ("ITC") MP Applied to Solar PV is Outdated

The Investment Tax Credit ("ITC") is a key assumption because it reduces the costs of solar PV installations passed on to ratepayers. The solar PV capital costs shown above in Figure 1 exclude this cost reduction. MP later applied the ITC as a percentage reduction to its solar PV capital costs;[13] but this assumption was outdated as of December 2020 when the credit was expanded by Congress.[14] As shown in Table 3, the current law drastically reduces the costs of 2024 and 2025 solar installations by more than doubling the ITC available in those years. As it stands, the IRP includes the much lower and outdated tax credits, which lead it to highly overestimate the costs of solar PV installations.

[12] Id.

[13] Minnesota Power 2021 IRP, 43-44.

[14] See U.S. Dep't of Energy, Residential and Commercial ITC Factsheets (Feb. 5, 2021) *available at* https://www.energy.gov/eere/solar/articles/residential-and-commercial-itc-factsheets.

Table 3: Solar PV Investment Tax Credit (%)

First year of operation	MP	CEO (current ITC)
2023	26%	26%
2024	10%	26%
2025	10%	22%
2026-2035	10%	10%

The CEO's modeling applies the current ITC to solar PV resources, as shown above. However, our use of the current law should be viewed as conservative in light of further potential cost reductions from future federal legislation.[15]

1.1.4.3 MP Did Not Consider Power Purchase Agreements ("PPAs") for Renewables and Battery Storage Resources

The Company overstates the cost of renewable energy and storage options by assuming that there is no mechanism to monetize the ITC upfront.[16] One of the goals of IRP modeling is to optimize resources on a cost basis; the model is incapable of choosing a less expensive resource if such a resource is not offered to it. Alternative ownership and/or financing arrangements such as PPAs could offer reduced prices by allowing the developer (and, by extension, the buyer) to monetize the ITC for solar or solar-battery hybrids immediately, rather than "normalize" the tax credit by spreading the credit over the project life—as the Company assumes in its modeling. In the interest of pursuing a least-cost plan for ratepayers, the CEOs used the cost structure of a PPA by calculating the levelized cost for wind, solar, and battery resources in our modeling instead of rate-basing these resources. This is consistent with the treatment of these costs in two recent IRP's in Minnesota—Xcel and Otter Tail Power—in which those companies modeled all renewable and storage resources as PPAs—i.e. levelized costs.[17]

1.1.4.4 Minnesota Power Did Not Model Solar Outside of Minnesota

Minnesota Power can access resources outside of Minnesota if it is advantageous to do so; but the Company elected to only model in-state solar projects.[18] The CEOs' modeling has expanded the diversity of solar PV resources available using the energy profile from a MISO Zone 1 solar PV project, leading to a 2 percent increase in capacity factor from the Company's assumption. We used a list of sites in Minnesota and the Dakotas in Xcel, Otter Tail Power and Great River Energy service territories, that MISO has used to characterize the likely build out of solar. This profile produces an average 25.5% capacity factor, which is nearly identical to the 22-year average of the NREL ATB's projection of solar

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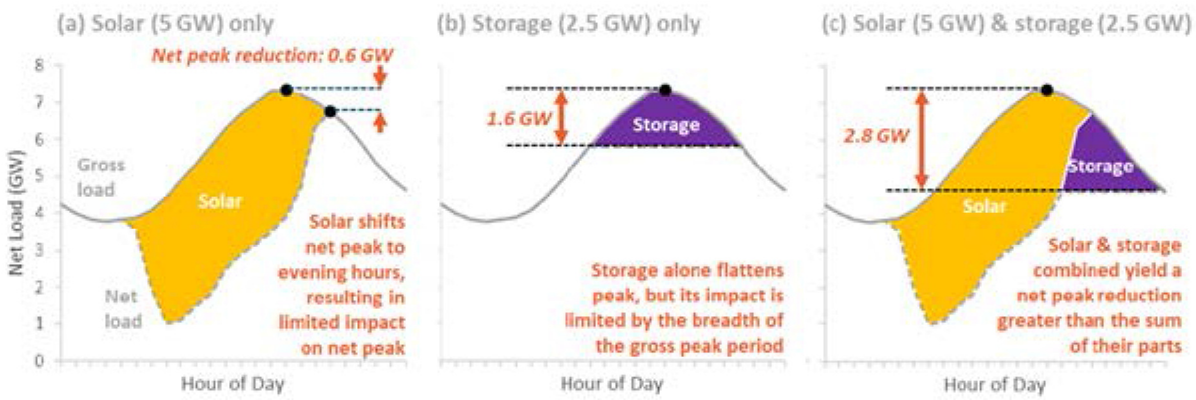
[15] Utility Dive, PMN, AEP executives, other utiity leaders meet with Biden to push clean energy tax measures (Feb. 10, 2022) *available at* https://www.utilitydive.com/news/pnm-aep-utility-executives-biden-clean-energy-renewable-tax-credits/618630.
[16] Minnesota Power Response to CEO IR 131, Minn. Pub. Utils Comm'n, Docket No. E015/RP-21-33.
[17] Otter Tail Power 2022-2036 IRP (Docket No. E017/RP-21-339), Appendix F at 4-6; 2020-2034 Upper Midwest Resource Plan Supplement (Docket No. E002/RP-19-368), Attachment A at 72-74.
[18] Minnesota Power 2021 IRP, Appendix J at 9.

capacity factors (25.4%). However, this change only applies to generic solar PV, not the "net zero" solar resources where MP has specified that the resource is tied into an existing generator's interconnection which would necessarily be in Minnesota.

1.1.4.5 Minnesota Power Did Not Model Solar-Battery Hybrid Resources

Solar-battery hybrid resources offer significant potential value as replacement resources—especially in light of available tax credits and the resources' energy and capacity value. Yet Minnesota Power has neglected to include them as a replacement option for the model to choose.[19] Battery storage resources paired with solar resources receive the same tax credit as the solar, to the extent that the solar power is used to charge the battery. In addition to the ITC benefits, when paired together, solar and battery storage are also mutually beneficial as a capacity resource. For instance, Public Service Company of New Mexico ("PNM") is replacing the retiring San Juan coal plant with solar and battery hybrids, and PNM plans to do the same for its share of the Palo Verde nuclear plant. PNM illustrated the value and complementarity of solar and battery storage hybrids in providing capacity below:



Source: Copy of Figure NS-3 from Direct Testimony of Nicolai Schlag, Before the New Mexico Regulation Commission, Case No. 21-04-02-UT, p.11.

We frequently see solar/battery hybrid included in IRP preferred plans, and Minnesota Power should have at the very least included them as an option. To rectify this, CEO modeled a solar-battery hybrid option using the combination of our solar and battery storage costs.

1.1.5 Minnesota Wind Constraints

In its modeling, Minnesota Power assumed that new Minnesota wind resources could be selected starting in 2023. We decided to make a more conservative assumption that new Minnesota wind would not be available until 2026, given transmission and MISO queue constraints.

[19] Minnesota Power 2021 IRP at 31-32.

1.1.6 Minnesota Power Assumed No New Energy Efficiency Savings After 2029

Minnesota Power modeled two levels of energy efficiency that could be selected as a new resource within the EnCompass model. The savings and cost information for these additional levels of energy efficiency were developed from the 2020-2029 Minnesota State Demand Side Management Potential Study ("MPS").[20] Minnesota Power modeled a "High" level of energy efficiency which corresponds to the midpoint between the Very High and Baseline scenarios from the MPS. Minnesota Power also modeled a "Very High" level of energy efficiency within EnCompass and that corresponds to the Max Achievable scenario from the MPS.

Since the MPS projected energy savings only for the years 2021-2029, the energy efficiency resources modeled in EnCompass assume that there are no new energy efficiency savings after 2029. As Minnesota Power stated in the IRP: "All three EE scenarios therefore assume new program implementation (and new savings) each year through 2029, after which no new saving programs were assumed."[21] We do not think it is reasonable to assume there will be no new energy efficiency savings after 2029 for these resources modeled in EnCompass.

The CEO modeling includes MP's High level of energy efficiency as a new resource, and we assumed that the savings that exist for 2029 for the High energy efficiency resource continue until 2035. The high level of energy efficiency savings included in the CEO modeling are shown in Table 4, below.

Table 4. High Level of EE in CEO Preferred Plan

Year	Energy (GWH)[22]	Peak (MW)
2024	11	2
2025	21	4
2026	32	5
2027	43	7
2028	55	9
2029	66	11
2030	66	11
2031	66	11
2032	66	11
2033	66	11
2034	66	11
2035	66	11

[20] Minnesota Energy Efficiency Potential Study: 2020-2029 (Dec. 4, 2018) *available at* https://mn.gov/commerce-stat/pdfs/mn-energy-efficiency-potential-study.pdf.
[21] Minnesota Power 2021 IRP, Appendix B at 3.
[22] Savings are modeled at the generator.

1.1.7 Hibbard Retirement

The CEO Preferred Plan includes the retirement of the Hibbard unit at the end of 2023 for the reasons described in CEO's comments. Minnesota Power's modeling assumed that Hibbard continues to operate, and we held that same assumption for the Revised Minnesota Power Preferred Plan expansion plan.

1.1.8 Partial Selection for Battery Storage Resources

Minnesota Power modeled new battery storage resources at a size of 100 MW, such that the model could only select battery storage in 100 MW increments. For the two expansion plans, we utilized the partial unit setting in EnCompass which allows units to be selected in a size greater than or equal to 0.1 MWs. We believe it is more appropriate to model battery storage resources with this partial unit setting, given the modular nature of the resource.

1.1.9 Unserved Energy Price

Minnesota Power set up a tiered market structure for the interaction with the MISO market modeled within EnCompass. Table 5, below, gives the inputs that Minnesota power used in EnCompass for the four Market price forecast tiers.

Table 5. MP's MISO Market Price Tier EnCompass Modeling Inputs

MISO Market Tier	Hourly Imports (MW)	Hourly Exports (MW)	Market Price
	[TRADE SECRET BEGINS…		
MISO1			
MISO2			
MISO3			
MISO4			
			…TRADE SECRET ENDS]

For the fourth and last market tier, Minnesota Power set the market price for that tier to be the same as the Company's cost of unserved energy[23]. In runs using Minnesota Power's assumptions, when EnCompass evaluated the costs of unserved energy against acquiring energy from a resource (new build, market purchases, etc.), the model tended to choose unserved energy rather than the most expensive market energy. We believe this unrealistic choice occurred because Minnesota Power set the cost for unserved energy to be identical to its fourth MISO market tier. Put another way, EnCompass sees no reason to prefer market purchases over unserved energy. In order for EnCompass to recognize a difference between unserved energy and market purchases, we changed the unserved energy price to $10,000/MWH so that EnCompass would economically prefer purchases from the fourth MISO market tier over unserved energy.

[23] In EnCompass, unserved energy occurs during any hour where load cannot be met by the available resources including owned and contracted generation and market purchases.

1.1.10 Demand Response Product B

Minnesota Power included, among other potential demand response resources, an option for 100 MW of industrial sector demand response called "Demand Response Product B". This DR project was optimally selected by EnCompass in the modeling runs conducted to determine the CEO Preferred Plan. However, when we examined the results of hourly simulations using these parameters, we realized EnCompass was not enforcing the intended operational constraints.

It is our understanding that the Demand Response Product B modeled by Minnesota Power is intended to represent a demand response product option for large industrial customers that Minnesota Power previously submitted through a petition to the Commission. This program had the following operational parameters[24]:

- Maximum of 600 hours of Firm Load Control hours per year
- Maximum of 2 Firm Load Control periods per day
- Maximum of 12 hours of Firm Load Control periods per day
- Maximum of 12 hours for Firm Load Control duration per occurrence
- Minimum of 4 hours for Firm Load Control duration per occurrence
- No more than four Firm Load Control periods in any seven days of the week

Minnesota Power attempted to capture these parameters by applying the EnCompass settings to this resource outlined in Table 6, below:

Table 6. Demand Response Product B Modeling Inputs

Parameter	Input Category	Input Value	Calculation
600 Hour Annual Maximum	Max Annual Energy	**[TRADE SECRET BEGINS…**	
2 Control periods per day	Max Daily Starts		
4 Hour Minimum for Control Duration	Minimum Uptime		
4 Control Period Maximum per Week	Max Weekly Starts		
4 Control Period Maximum per Week	Max Weekly Energy		**…TRADE SECRET ENDS]**

[24] Minnesota Power Petition for Approval, Minn. Pub. Utils. Comm'n, Docket No. E-015/M-18-735 (Dec. 7, 2018).

In our initial modeling run, we realized that EnCompass was dispatching Demand Response Product B resource without enforcing its four-hour minimum uptime. This was occurring because Minnesota Power had not set a minimum capacity for this resource in EnCompass. After setting the minimum capacity, we reran the model and still observed some issues with the manner in which the resource was dispatched. Despite the inputs reported in Table 6, we could see that in some instances the resource was violating both the Max Annual Energy and the Max Weekly Energy constraint by operating at over 600 hours per year and for longer than 12 consecutive hours. Because the resource seemed to add value to an optimized portfolio, we attempted to correct this issue in the model. However, EnCompass does not currently have the settings necessary to fully prevent the resource from violating these parameters. We spoke with the vendor of EnCompass and confirmed that there were no other inputs within EnCompass that could be used to ensure that the resource did not dispatch for more than 12 hours at a time while also allowing the model to choose when to dispatch the resource.

While we think there is a good chance additional demand response would add value to Minnesota Power's system, we chose to entirely prevent EnCompass from selecting this resource given that model setting issues and client resource and time constraints would not permit the kind of iterating necessary to further reduce the violations of the dispatch parameters.

1.1.11 Additional Battery Storage and Minnesota Wind

Due to the challenges we encountered with the dispatch of the Demand Response project outlined in Section 1.1.10, we decided to look at replacing Demand Response Product B with a mix of resources for the CEO Preferred Plan. Our modeling suggested that EnCompass found this demand response resource to be economic, and due to the resource frequently operating for long durations at a time, we decided to include a 100 MW 10 hour Lithium-ion battery storage[25] project in the CEO Preferred Plan, coming online in 2030. In addition to the battery, we also included an additional 100 MW of Minnesota wind in 2030. These two resources are comparable projects to add in place of the demand response project, given the timing of when EnCompass tended to dispatch the demand response project as well as the fact that it seemed to preferred a relatively long duration of dispatch.

2 CEO Modeling Methodology

The changes described above were then used to develop the two capacity expansion resource portfolios presented in this report. This approach was chosen to allow for an apples-to-apples comparison of costs between the CEOs Preferred Plan (which does not include NTEC) and MP's preferred plan with a 20% share of NTEC.

[25] Costs for the 10-hour battery storage project were based on the NREL 2021 ATB moderate case.

To develop the CEO Preferred Plan, we removed the 20 percent NTEC share and allowed the model to select a fully optimized[26] plan with the updates that were outlined in the prior section. We also allowed the model to re-optimize Minnesota Power's preferred plan under the updated CEO modeling assumptions described in the previous section and the updated assumption that Minnesota Power has a 20% share of NTEC. We refer to this plan as the "Minnesota Power ("MP") Revised Preferred Plan". We believe that the Revised MP Preferred Plan is the proper benchmark to compare costs between a plan with an NTEC 20% share ("Revised MP Preferred Plan") and a plan that does not include an NTEC 20% share ("CEO Preferred Plan") given the change in MP's NTEC share since the IRP was filed. Since MP's share for NTEC decreased from 50% to 20%, re-optimization of the expansion plan was required to determine the resources that would be added to fill the gap left from the decrease in the NTEC share.

Table 7 shows a breakdown of the specific changes made to each of the scenarios and portfolios we created on CEOs' behalf.

The resource expansion plans and cost comparisons that result from these runs are discussed in Section 3.

Table 7. Summary of CEO Modeling Changes

Modeling Changes	MP Revised Preferred Plan	CEO Preferred Plan
NTEC Included (at 20% share)	✓	-
Boswell 3 Retires 2029	✓	✓
High CO_2 Regulatory Cost, High Environmental Cost	✓	✓
CEO Transmission Upgrade Cost for Boswell 3	✓	✓
CEO Solar, Wind, and Battery Storage Costs	✓	✓
Add Solar-Battery Hybrid Resources as a New Resource Option	✓	✓
MISO Zone 1 Solar Hourly Shape [27]	✓	✓
Wind Constraint	✓	✓
MP's "High" Level of Energy Efficiency	-	✓
Retire Hibbard Plant in 2023	-	✓
Selection of "Partial" Battery Storage Resources	✓	✓
Change "Unserved Energy" Price	✓	✓
Demand Response Product B Excluded	✓	✓
Include 10 Hour Battery Storage and 100 MW Wind in 2030	-	✓

[26] The model was allowed to optimize new wind, solar, battery storage, solar hybrids, new thermal resources modeled by MP, energy efficiency, and demand response resources.
[27] This change was made only to the generic solar resource option, not the "net-zero" interconnection solar option.

2.1 Setting up the CEO Modeling Runs

The primary model runs we performed are described in this section.

Figure 4 illustrates how modeling runs were performed in EnCompass. In short, we used the assumption changes described above to create two new capacity expansion resource portfolios as described in Section 1 above: the MP Revised Preferred Plan, which includes the NTEC CC (at 20 percent share), and the CEO Preferred Plan, which does not include the NTEC CC or any new fossil generation. We also replicated five of Minnesota Power's sensitivities with our new resource portfolios to test their robustness under changing conditions.

EnCompass differs from Strategist, Minnesota Power's prior IRP software, in several ways. Strategist performed capacity expansion and simplified dispatch using a representative sample of days, and then mapped the results onto the entirety of each year. EnCompass creates capacity expansion plans in the same manner, but there is a second step that is not part of Strategist. The modeler redispatches the optimized plan while simulating all 8760 hours in a year. The combination of the capital costs from the first run and the production costs from the re-dispatching of the plan are used to create the plan costs. For Minnesota Power, the Present Value of Societal Costs ("PVSC") is derived from the EnCompass revenue requirements plus the externality costs of the criteria pollutants—as shown in Figure 4.

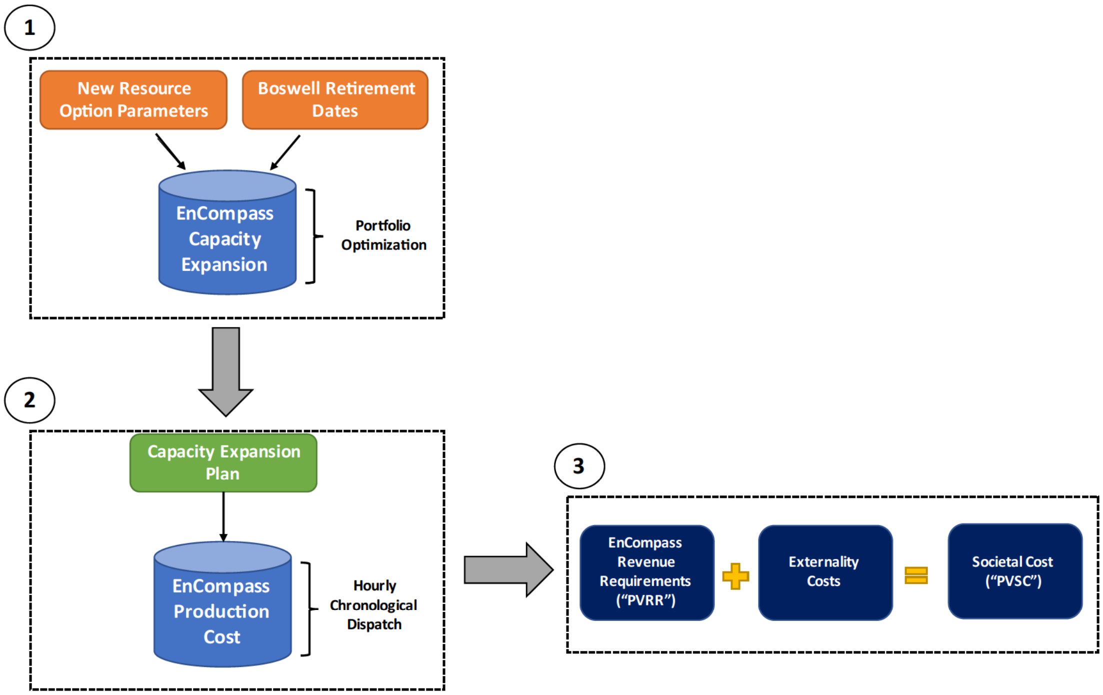


Figure 4. EnCompass Modeling Process

The modeling we performed on behalf of the CEOs satisfies the same hourly demand curve as was modeled by MP and uses the same modeling tool and overall analytical approach.

3 CEO Modeling Results

3.1 Capacity Expansion Portfolio Results

Figure 5 shows a comparison of the cumulative installed capacity in MWs from 2024 to 2035 for the CEO Preferred Plan and the Revised MP Preferred Plan. Both plans add the maximum amount of "net-zero" solar[28] that Minnesota Power allowed over the planning period - 300 MW. Both plans are also similar with regards to the amount of wind that is selected over the planning period. The CEO Preferred Plan also selects a solar-battery hybrid project added in 2030, which the Revised MP Preferred Plan does not select. The Revised MP Preferred Plan selected some four-hour battery storage, but it is less than the amount of four-hour battery storage selected in the CEO Preferred Plan.

Other differences based on modeling assumptions discussed in Section 2 above include, that the Revised MP Preferred Plan contains the 20% NTEC CC share - approximately 118 MW. The CEO Preferred Plan includes the high level of energy efficiency whereas the MP Revised Preferred Plan has MP's base level of energy efficiency. The CEO Preferred Plan also contains the fixed Minnesota Wind and ten-hour battery storage resources in 2030, which was added to remedy modeling flaws with the Demand Response Product B, as discussed above.

[28] "Net-zero" solar is a solar resource MP made available to the model that does not include an interconnection cost because it utilizes existing interconnection from MP's existing generating plants and therefore does not go through the normal MISO interconnection process for new generation. However, because of this unique interconnection strategy, this solar resource does not have accredited capacity where it is assumed to interconnect behind a thermal generator as is the case in MP's assumption.

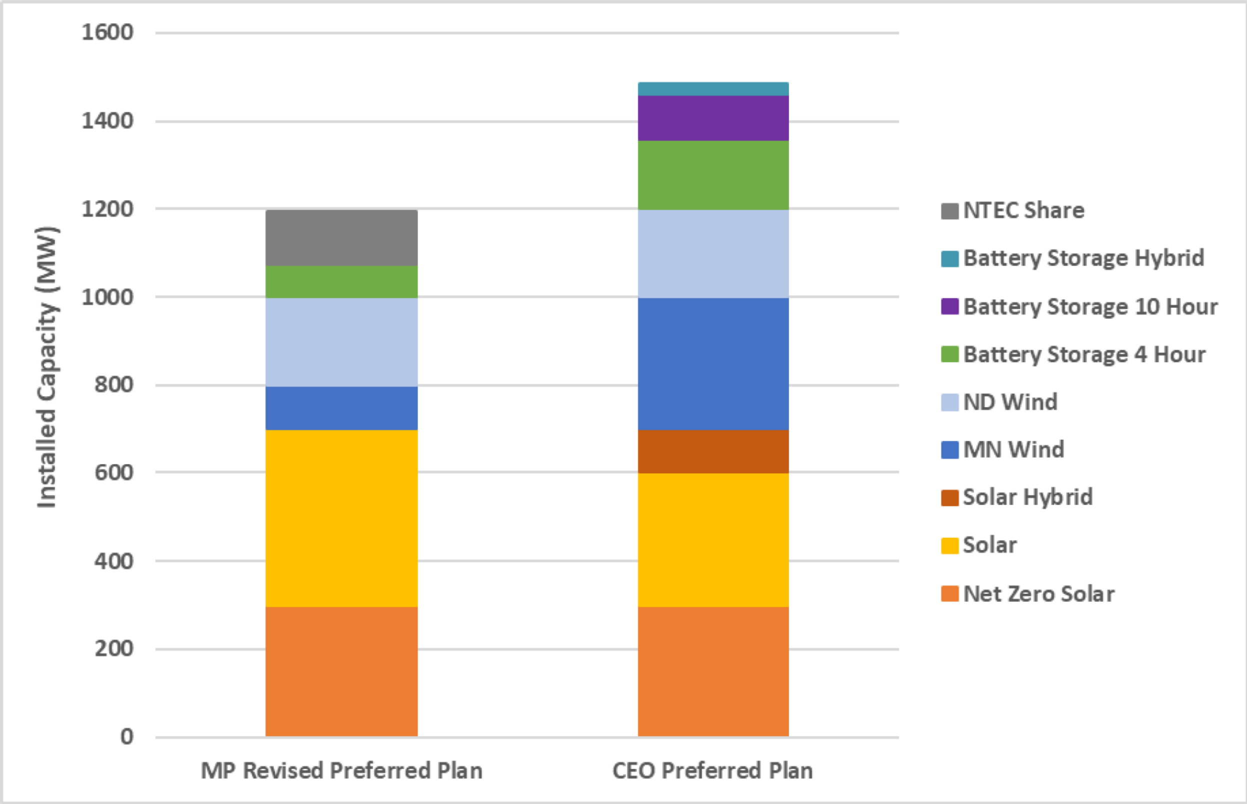


Figure 5. Cumulative Installed Capacity (MW) Between 2024 and 2035

Table 8 and Table 9 show the annual resource additions in installed capacity ("ICAP") and retirements for the CEO Preferred Plan and the Revised MP Preferred Plan, respectively, between 2023 and 2035.

Table 8. CEO Preferred Expansion Plan (ICAP[29] MW)

New Resource Additions:	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Zero Solar	0	200	100	0	0	0	0	0	0	0	0	0	0
Solar	0	0	300	0	0	0	0	0	0	0	0	0	0
MN Wind	0	0	0	0	0	0	0	200	0	0	0	0	100
ND Wind	0	0	0	0	0	0	100	100	0	0	0	0	0
Battery Storage 4 Hour	0	0	0	0	0	0	0	143	0	0	0	0	16
Battery Storage 10 Hour	0	0	0	0	0	0	0	100	0	0	0	0	0
Solar Hybrid	0	0	0	0	0	0	0	100	0	0	0	0	0
Battery Storage Hybrid	0	0	0	0	0	0	0	25	0	0	0	0	0
Energy Efficiency		2	4	5	7	9	11	11	11	11	11	11	11
Retirements:													
Hibbard	-44												
Boswell 3							-350						

[29] Installed Capacity ("ICAP")

Table 9. Revised Minnesota Power Cumulative Expansion Plan (ICAP MW) (re-optimized plan that includes 20% share of NTEC)

New Resource Additions:	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Zero Solar	0	200	100	0	0	0	0	0	0	0	0	0	0
Solar	0	0	300	0	0	0	0	100	0	0	0	0	0
MN Wind	0	0	0	0	0	0	0	100	0	0	0	0	0
ND Wind	0	0	0	0	0	0	0	200	0	0	0	0	0
Battery Storage 4 Hour	0	0	0	0	0	0	0	31	1	0	0	0	43
NTEC Share	0	0	118	0	0	0	0	0	0	0	0	0	0
Retirements:													
Boswell 3							-350						

Both tables show that EnCompass added the maximum amount of net-zero solar resources, or 300 MWs, by 2025. The CEO Preferred Plan and the Revised Minnesota Power Preferred Plan both add 300 MWs of generic solar in 2025. Both plans also indicate that the model selects the maximum amount of ND wind projects available, which is 200 MW. The CEO Preferred Plan does have 300 MW of MN wind, while the Revised Minnesota Power Preferred Plan only has 100 MW. The CEO Preferred Plan contains a higher level of four-hour battery storage at 159 MW, compared to the Minnesota Power Revised Preferred Plan's 75 MW. The CEO Preferred Plan includes a solar hybrid project in 2030 with 100 MW of solar with 25 MW paired battery storage. The CEO Preferred Plan includes the high level of energy efficiency, which starts having savings in 2024. No additional energy efficiency beyond that captured in its load forecast is included in the Revised MP Preferred Plan.

3.2 Present Value Societal Cost ("PVSC") and Present Value Revenue Requirement ("PVRR") Cost Results

In this section we provide the cost results for our two new resource portfolios – Revised Minnesota Power Preferred Plan and the CEO Preferred Plan. To calculate the PVSC results, Minnesota Power performs one post-processing step in order to adjust the revenue requirements coming out of EnCompass to account for the externality costs of emissions. Minnesota Power adds in the externality costs of emissions since those costs are not part of the optimization within EnCompass. The steps that Minnesota Power takes to perform this post-processing adjustment are:

EnCompass Revenue Requirement
+ Externality Costs
= Post-Processing Revenue Requirement or the PVSC

Table 10, below, shows the PVSC and PVRR net present value ("NPV") for the Revised MP Preferred Plan and the CEO Preferred Plan for the period 2021 – 2035. These results indicate that a plan that does not rely on the NTEC CC or additional fossil fuel-based generation is available to Minnesota Power at a slightly lower cost.

Table 10. PVRR and PVSC Results for CEO Modeling ($000)

	Revised MP Preferred Plan	CEO Preferred Plan
PVRR	$6,402,903	$6,391,441
Externality	$1,839,387	$1,849,611
PVSC	**$8,242,290**	**$8,241,052**

3.3 Carbon Emissions

The level of carbon emissions reduction between the CEO Preferred Plan and the Revised MP Preferred Plan is another important factor to consider when evaluating the plans. Table 11 provides the CO_2 emissions comparison between the Revised MP Preferred Plan and the CEO Preferred Plan.

Table 11. CO_2 Emission Comparison (Tons)

Year	Revised MP Preferred Plan	CEO Preferred Plan
2021	5,538,719	5,569,799
2022	4,964,703	4,989,758
2023	4,460,408	4,499,462
2024	4,437,314	4,301,762
2025	1,851,215	2,153,912
2026	1,860,234	2,257,351
2027	2,098,749	2,483,209
2028	2,162,244	2,442,054
2029	2,100,623	2,111,941
2030	1,445,283	1,118,664
2031	1,351,279	1,031,120
2032	1,344,305	1,128,925
2033	1,368,242	1,089,725
2034	1,272,580	998,924
2035	1,300,535	962,104
Total	**37,556,432**	**37,138,708**

While emissions under the CEO Preferred Plan are higher than the Revised MP Preferred Plan in about half the years modeled, the overall total is slightly lower. This is because in the initial years when NTEC comes online and Boswell 3 is retired, the model dispatches Boswell 4 more often. However, this table does not reflect the longer-term reduction in greenhouse gases under the CEO Preferred Plan because the planning period ends in 2035, well before the intended end of NTEC's operating lifetime. It also does not reflect the climate impact of upstream methane emissions associated with NTEC's fuel (which, as discussed in CEO's comments, are significant).[30] Moreover, this table does not reflect the greenhouse gas emission reductions could be achieved by retiring the Boswell 4 coal unit sooner than 2035.

[30] Alvarez, R.A., et al. (2018). Assessment of Methane Emissions from the US Oil and Gas Supply Chain. Supplementary Material. *Science*, *361*(6398), 186-188.

3.4 Sensitivities

We also reran both resource expansion portfolios, the Revised MP Preferred Plan and the CEO Preferred Plan, under several of the sensitivities Minnesota Power developed in its IRP Filing. These sensitivities included low load, high load, low gas price, high gas price, and higher gas price. We followed the same approach that Minnesota Power used for its sensitivities and did not reoptimize the capacity expansion plans. We took the Revised MP Preferred Plan and the CEO Preferred Plan and re-dispatched those resources under each sensitivity. Table 12 shows the PVSC results for these runs.

Table 12. PVRR and PVSC NPV Results for MP Defined Sensitivities ($000)

Revised MP Preferred Plan ($000)					
	Higher Gas	**High Gas**	**Low Gas**	**High Load**	**Low Load**
PVRR	$6,559,049	$6,507,445	$6,412,047	$6,729,602	$6,212,887
Externality	$1,853,225	$1,835,066	$1,848,781	$2,123,541	$1,659,805
PVSC	$8,412,273	$8,342,511	$8,260,828	$8,853,143	$7,872,691
CEO Preferred Plan ($000)					
	Higher Gas	**High Gas**	**Low Gas**	**High Load**	**Low Load**
PVRR	$6,503,941	$6,473,381	$6,423,085	$6,714,988	$6,197,756
Externality	$1,850,871	$1,851,573	$1,844,640	$2,108,737	$1,677,527
PVSC	$8,354,812	$8,324,955	$8,267,724	$8,823,726	$7,875,283
PVSC % Difference	**-0.68%**	**-0.21%**	**0.08%**	**-0.33%**	**0.03%**

4 Summary of Findings

The EnCompass modeling described in this report demonstrates that a resource portfolio of additional renewable, battery storage, energy efficiency, and without a share of NTEC CC can have comparable costs to a portfolio that includes MP's revised NTEC CC share.

Technical Appendix: Levelized Costs of Solar, Wind, and Battery Storage

We calculated the levelized cost of energy ("LCOE") of solar PV, wind, and battery resources as inputs for the Encompass model to select, if economically optimal. The LCOE includes capital and operations costs over the project life, represented as a cost per MWh (for solar PV and wind) or kW-month (for battery storage). Table 13 below shows our levelized costs of solar, wind, and battery storage resources which are based on our updated capital costs, updated treatment of Investment Tax Credit ("ITC") to match current law, applying the ITC to solar PV capital costs upfront, and our addition of a MISO Zone 1 solar PV resource. (Support for these assumptions is discussed in detail in Section 1.1.4.)

Table 13: CEO's Levelized Cost Estimates by Resource Type

[TRADE SECRET BEGINS…

…TRADE SECRET ENDS]

Levelized costs of each technology were calculated by dividing the net present value revenue requirements ("NPVRR") across the project life by the net present value of generation (in MWh) or capacity (in kW) over that period.[31] Minnesota Power's revenue requirements model[32] produces the net present value of revenue requirements for each technology based on the Company's capital structure and before-tax weighted average cost of capital ("WACC") of 7.07 percent. To calculate the net present value of each technology's capital costs for each installation year, we utilized MP's NPV methodology but with our updated capital costs for solar, wind, and battery storage. To calculate the net present value of each technology's operating costs, we utilized the Company's fixed operation and maintenance ("O&M") cost forecasts[33] for each technology type. Each technology's generation (in MWh) and capacity (in kW) were sourced from the Company's input files in its IRP documentation—apart from the MISO Zone 1 solar resource which was our addition.[34]

Technical Appendix: Stranded Costs of NTEC

The table below shows the values of remaining rate base for the Company's 20 percent share of NTEC for given retirement years. As discussed in the main comments, these represent the potential "stranded costs" if the plant is retired prior to its useful life.

Table 14: MP's Remaining Ratebase at NTEC with Early Retirement[35]

Retirement Year	Remaining MP Rate Base ($mil)
2035	**[TRADE SECRET BEGINS…**
2040	
2045	
2050	
	…TRADE SECRET ENDS]

[31] The levelized cost of energy (LCOE) for energy storage technologies (commonly referred to as the levelized cost of storage or LCOS) is generally measured in $/kW-mo, while the LCOE for other electric generating technology, such as solar and wind, are measured in $/MWh.
[32] Attachments to CEO IR 030 (TS), Minn. Pub. Utils Comm'n, Docket No. E015/RP-21-33.
[33] Attachment to DOC IR 1, "DOC IR01 TS Attach - FINAL FEB1 IRP2020 MODEL."
[34] Attachment to DOC IR 1, "DOC IR01 TS Attach - FINAL FEB1 IRP2020 MODEL."
[35] Minnesota Power's Response to CEO IR 63.01 (TS), Minn. Pub. Utils Comm'n, Docket No. E015/RP-21-33. Assuming MP's 20% ownership of NTEC and starting operations in 2027.