STATE OF MINNESOTA

BEFORE THE PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Application for Approval of its 2021-2035 Integrated Resource Plan	**PUC Docket No. E015/RP-21-33**

CLEAN ENERGY ORGANIZATIONS' REPLY COMMENTS

On Behalf Of
Fresh Energy
Clean Grid Alliance
Sierra Club
Minnesota Center for Environmental Advocacy

August 29, 2022

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SUMMARY OF ARGUMENT

Despite the massive new influx of federal support[1] that will drive down the cost of building new wind, solar, storage and other carbon-free technologies, and despite the clear and present danger of intensifying catastrophic climate change, Minnesota Power (MP or the Company) remains wedded to the belief that constructing and operating the proposed Nemadji Trail Energy Center (NTEC) is a good idea and a prudent use of capital. It is neither.

These Reply comments address several points raised by the April initial comments by the parties as well as by the revised modeling submitted by the Department of Commerce (Department or DOC) on July 29. This submission is jointly filed by the nonprofit organizations Fresh Energy, Clean Grid Alliance, Sierra Club, and the Minnesota Center for Environmental Advocacy (collectively, the Clean Energy Organizations, or CEOs), and relies, in part, on a new sensitivity modeling run and analysis[2] conducted by Anna Sommer[3] and Chelsea Hotaling[4] of Energy Futures Group (EFG) and Tyler Comings[5] of Applied Economics Clinic. The CEOs additionally collaborated with the Union of Concerned Scientists in the preparation of these comments.

In Part I of these comments, CEOs note that the Office of the Attorney General Residential Utilities Division (OAG) largely agrees with CEOs' legal analysis of the PUC's authority to re-

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[1] *See* Part VI *infra*.
[2] Minn. Pub. Utils. Comm'n, Minnesota Power 2021 Integrated Resource Plan, *A Clean Energy Alternative for Minnesota Power: A Supplemental Report*, Docket No. E015/RP-21-33, (July 29, 2022) [hereinafter "EFG Supp. Report"].
[3] Anna Sommer is a Principal of Energy Futures Group and has supported the CEOs' work on integrated resource planning and related issues before this Commission since 2005.
[4] Chelsea Hotaling is a Consultant with Energy Futures Group and has conducted EnCompass modeling for IRP and certificate of need cases in several states.
[5] Tyler Comings is a Senior Researcher at the Applied Economics Clinic. He focuses on energy system planning (including integrated resource plans), costs of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. He has provided testimony on these topics in Arizona, Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Ohio, Oklahoma, Maryland, Michigan, Missouri, New Jersey, Nova Scotia (Canada), and West Virginia.

evaluate and reverse its now 4-year old decision approving the NTEC agreements. In Part II of these comments, CEOs explain that even when the current inflationary environment is taken into consideration, the CEOs' Preferred Plan remains cost effective and sufficient to meet load. In Part III, CEOs respond to the DOC's recently filed revised modeling and commentary. CEOs note that the DOC does not model a future without NTEC and that CEOs' Preferred Plan successfully retires Boswell 3 without the need for any new thermal resources. In addition, CEOs argue that the record in this docket supports CEOs' position that planning must begin now to build sufficient transmission or other reliability mitigations to retire Boswell 4. In Part IV, CEOs support the arguments of Citizens Utility Board (CUB) that high and volatile fossil gas prices increase the financial risks to ratepayers of MP's reliance on NTEC. And in Part V, CEOs support the position of Atlas Infrastructure, Inc., a major ALLETE institutional shareholder, that building NTEC is inconsistent with widely accepted pathways to 1.5 degrees and presents a significant risk that the investment in NTEC will become stranded. In Part VI, CEOs discuss how the recently-enacted Inflation Reduction Act, with its generous subsidies for renewables and storage, supports the positions of all parties opposing NTEC.

CEOs' recommendations to the Commission are reiterated in detail at the end of this document. We respectfully request that the Commission: 1) modify Minnesota Power's Preferred Plan by removing NTEC, ordering the retirement of Hibbard, and finding the need for more solar power; 2) order the retirement of Boswell 3 by the end of 2029 (as proposed by Minnesota Power); 3) order Minnesota Power to commence planning sufficient to maintain the option of retiring Boswell 4 by 2030; 4) order Minnesota Power to work with stakeholders to identify steps needed to avoid foreclosing the ability to operate in alignment with 1.5°C pathways in its next IRP; 5) order Minnesota Power to commence stakeholder outreach to develop a modeling construct that enables the utility to model solar-powered generators connected to the company's distribution grid, take steps to better align distribution and resource planning, and account for local community generation goals for distributed generation in its next IRP; 6) order that Minnesota Power's next IRP analyze public health impacts; and 7) order Minnesota Power to establish a stakeholder group to address equity issues, including disproportionate energy burdens.

I. CEOS AGREE WITH THE OAG THAT THE COMMISSION HAS THE LEGAL AUTHORITY TO NOT APPROVE NTEC, AND THAT IT IS IN THE PUBLIC INTEREST FOR THE COMMISSION TO DO SO

A. The OAG Correctly Finds That The Commission Has The Legal Authority To Not Approve NTEC.

The most imminent major resource choice presented by Minnesota Power's IRP is whether the company should continue to pursue the NTEC project. However, Minnesota Power has made no effort in this docket to show that NTEC is in the public interest today, instead treating NTEC as an approved resource that does not need to be examined. CEOs explained at length in our initial comments why in fact the project's approval in 2018 does not relieve Minnesota Power of the duty to show that NTEC is in the public interest in 2022, especially given how circumstances have changed materially.[6] Nor does that 2018 approval deprive the Commission of authority to amend Minnesota Power's resource plan to remove NTEC.

The OAG similarly argues that the law "authorizes the Commission to remove NTEC from Minnesota Power's resource plan, as long as doing so is in the public interest. Minnesota law also authorizes the Commission to revisit the NTEC Order and rescind those portions of the order approving the NTEC affiliated-interest agreements ("AIAs")."[7] The OAG cites the same three distinct statutory bases of authority that CEOs cite – the Commission's authority under the

[6] Minn. Pub. Utils. Comm'n, Minnesota Power 2021 Integrated Resource Plan, CEOs' Initial Comments, Docket No. E015/RP-21-33, 14-36 (Apr. 29, 2022) [hereinafter "CEO Initial Comments"].

[7] Minn. Pub. Utils. Comm'n, Minnesota Power 2021 Integrated Resource Plan, OAG's Initial Comments, Docket No. E015/RP-21-33, 8 (Apr. 29, 2022) [hereinafter "OAG Initial Comments"].

resource planning statute,[8] its authority under the affiliated interest agreement statute,[9] and its general authority to rescind, alter, or amend any prior order.[10] And like CEOs, the OAG concludes that the Commission can implement its authority in this docket, without additional notice or evidence-taking, given the notice and robust evidentiary record already provided by this docket.[11]

B. The OAG Presents Additional Changed Circumstances That Warrant The Commission's Exercise Of Its Authority To Not Approve NTEC.

CEOs stressed in our initial comments how dramatically circumstances have changed since NTEC's approval, including: more ambitious climate protection goals that are incompatible with new gas plants, the growing risk that gas plants will end up as stranded investments given the long-term trend of falling renewable energy and battery prices, and Minnesota Power's sale of most of its share of NTEC.[12] The OAG identifies additional changed circumstances that also undermine the former case for NTEC:

- Minnesota Power's 2017 load forecast, on which the NTEC approval was based, overestimated actual capacity and energy need, and today's forecasts show no need for NTEC;[13]
- NTEC can no longer be seen as a hedge against market prices given that market energy costs and renewable energy costs are now projected to be lower than previously projected;[14] and
- Gas prices have experienced extreme volatility since NTEC was approved, increasing the fuel price risk to which Minnesota Power's customers are exposed.[15]

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[8] Minn. Stat. § 216B.2422, subds. 2(a) and 4.
[9] Minn. Stat. § 216B.48, subd. 6.
[10] Minn. Stat. § 216B.25. In addition to these ample sources of authority, CEOs have pointed to the Commission's authority over rates and its long line of cases holding that utilities seeking rate recovery are obliged to consider whether continued investment in a project is prudent when circumstances have changed. CEOs Initial Comments, Part II(B).
[11] OAG Initial Comments, 9.
[12] CEO Initial Comments, 28-36.
[13] OAG Initial Comments, Part I(A).
[14] OAG Initial Comments, 3-6.
[15] OAG Initial Comments, 6-7.

CEOs urge the Commission to include all of these compelling factors in its consideration of NTEC and to find that NTEC is not in the public interest.

C. Upgrades To The Square Butte Line Would Provide Access To More Low-Cost Renewable Power, Further Undermining The Need For NTEC.

Another material changed circumstance that undermines the need for NTEC and increases its cost relative to renewable power is Minnesota Power's plan to modernize its aging Square Butte HVDC line. This power line was originally built in the 1970s to deliver coal power from North Dakota. Minnesota Power bought it in 2010, and it has now been repurposed, with approximately 600 MW of North Dakota wind now relying on it.[16] However, the line's two converter stations are a decade beyond their designed lifetime, and it is increasingly difficult to procure spare parts for them. Minnesota Power therefore needs to modernize the converter stations, and that need presents what MP calls a "once-in-a-generation opportunity" to simultaneously enhance the line.[17] MP is therefore considering increasing the capacity of the line from 550 MW to 900 MW.

The OAG notes that this capacity upgrade presents Minnesota Power with a unique opportunity to minimize interconnection costs for new generation.[18] CEOs agree that the upgraded line would open the door to less expensive and likely readily-accessible new renewable projects, making NTEC even less comparatively economic. Moreover, upgrading this new line could also help alleviate the transmission reliability concerns associated with the retirement of Boswell 4, as the Telos Energy analysis noted.[19]

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[16] Minn. Pub. Utils. Comm'n, Minnesota Power 2021 Integrated Resource Plan, Initial Filing, Docket No. E015/RP-21-33, App. F, 11, (Feb. 1, 2021) [hereinafter "MP IRP"].
[17] *Id.*
[18] OAG Initial Comments, 4-5.
[19] CEO Initial Comments, Attachment 2 "*Transmission Reliability Analysis of Minnesota Power's Integrated Resource Plan*" [hereinafter "Telos Report"], 23.

II. CEOS' PREFERRED PLAN IS ROBUST, EVEN WHEN ASSUMING A HIGHER COST FUTURE BASED ON CURRENT INFLATIONARY CONDITIONS

In our initial comments, CEOs presented the CEOs' Preferred Plan, which excludes NTEC, retires the Hibbard plant, adds near-term solar, increases energy efficiency, retires Boswell 3 in 2029, and replaces Boswell 3 with a combination of renewables and storage. We also tested our plan against several of MP's sensitivities, including three gas price and two load sensitivities.[20] Given recent price and volatility trends throughout the energy sector that have continued since our initial filing, CEOs filed supplemental modeling testing our Preferred Plan under a "high-cost" sensitivity, where costs are increased for all new generation resources in our plan, and cost assumptions for coal, natural gas, and electricity prices are also increased, using reasonable public information. The results of this sensitivity run are that significant price increases across the board did not change the results from our initial filing -- the CEOs' Preferred Plan without NTEC or new fossil generation remains lower cost, lower risk, and with fewer CO2 emissions in comparison to the Revised MP Preferred Plan that includes NTEC.[21]

The "high cost" sensitivity includes capital cost increases to solar, lithium-ion battery storage, and wind and are detailed in Energy Futures Group (EFG) and Applied Economics Clinic (AEC) *Supplemental Report*, filed July 29, 2022 (EFG Supplemental Report). For new generation, the biggest changes are that solar costs are 29 percent higher than CEOs' base case and battery storage costs are 22 percent higher.[22] Table 1 in the EFG Supplemental Report shows the new costs in levelized terms and is provided below. It is worth noting that these renewable and storage price forecasts do not incorporate the recently enacted Inflation Reduction Act that can be expected

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[20] CEO Initial Comments, Attachment 1 "*A Clean Energy Alternative for Minnesota Power*" [hereinafter "EFG Initial Report"], Section 3.4.
[21] EFG Supp. Report, Sections 2.2, 2.3.
[22] EFG Supp. Report, Section 2.1.

to put significant downward cost pressure on renewables, storage, and other carbon-free generation, as discussed in Part VI. Already, Xcel Energy is crediting the Inflation Reduction Act with reducing the cost of the Sherco solar project by 20 percent, with yet additional benefits due under the law because of its location at a retiring coal plant.[23]

Table 1. CEO's Levelized Cost Estimates by Resource Type under High-Cost Sensitivity[24]
[TRADE SECRET BEGINS….

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For fuel cost and electricity price inputs, EFG and AEC compared different gas price forecasts and determined that MP's "higher" gas and electricity price forecasts were reasonable, as gas and electricity prices are highly correlated.[25] A comparison of MP gas price forecasts and Henry Hub and MN Citygate historic prices is provided in Figure 4 of the EFG Supplement Report, which shows MP's "higher" forecast could be considered a conservative choice for this sensitivity.

[23] Kirsti Marohn, "Climate Law Could Shrink Price of Sherco," *MPR News,* Aug. 22, 2022, https://www.mprnews.org/story/2022/08/22/climate-law-could-shrink-price-of-sherco-solar-project.
[24] EFG Supp. Report, Section 2.1.
[25] *Id.*

Figure 1. Natural Gas Price Forecasts and Actuals ($/MMBtu)[26]

[TRADE SECRET BEGINS…

…TRADE SECRET ENDS]

For coal prices, we used the recent changes in long-term forecasts of Powder River Basin (PRB) coal prices from the EIA's most recent Annual Energy Outlook. This forecast increased PRB prices by roughly 11 percent on average (for the period of 2021 through 2035) from the previous year's forecast.[27]

After developing the "high cost" sensitivity cost changes, EFG tested the CEOs' Preferred Plan and the MP Revised Preferred Plan under the higher cost conditions. EFG and AEC developed the "Revised MP Preferred Plan" as part of CEOs' initial modeling in order to allow for an "apples to apples" comparison of cost and emissions between MP's Plan and the CEOs' Preferred Plan.

[26] EIA actual Henry Hub and MN Citygate gas prices, available at: https://www.eia.gov/natural gas/data.php#prices. Note that data was unavailable for MN Citygate gas prices in September and November of 2021; Please see DOC IR01 TS Attach - FINAL FEB1 IRP2020 MODEL for MP's modeled natural gas prices.
[27] EFG Supp. Report, Section 2.1.

As we explained in our Initial Comments, "while updating the modeling to reflect Minnesota Power's 20% NTEC share, EFG ran EnCompass to create an optimal plan with CEOs' changes to modeling cost inputs [such as costs for new renewables] but including specific thermal resources that are in Minnesota Power's Preferred Plan – namely, NTEC and Hibbard."[28] In this way, the comparison between the two plans can be thought of as more narrowly focusing on the impacts of NTEC, and to a lesser degree, Hibbard, in MP's resource plan. As described in CEOs' initial comments, the CEOs' Preferred Plan was developed by EFG and AEC such that it meets the same energy and capacity requirements that MP modeled and is dispatched against the same 8760 hourly, chronological profile that MP used, in order to demonstrate that load can be met throughout all years of the planning period.[29]

The results of the comparison between the CEOs' Preferred Plan and the Revised MP Preferred Plan under the "high cost" sensitivity are consistent with all of the modeling in our initial filing: the CEOs' Preferred Plan is slightly lower in cost and has lower CO2 emissions through 2035 than the MP Revised Preferred Plan, which includes NTEC and Hibbard.[30]As such, this sensitivity provides evidence that the CEOs' Preferred Plan is robust in a high-cost and volatile commodity environment. Moreover, with the Inflation Reduction Act, we expect that renewable, storage, and other carbon-free generation will be less susceptible to continued price increases and volatility compared to coal and gas. Therefore, CEOs continue to recommend the Commission adopt CEOs' recommended modifications to MP's resource plan based on the CEOs' Preferred Plan.

[28] CEO Initial Comments, 37.
[29] CEO Initial Comments, 37.
[30] EFG Supp. Report, Section 2.2 and 2.3.

III. THE DEPARTMENT'S ENCOMPASS MODELING DOES NOT EVALUATE A SCENARIO WITHOUT NTEC, DOES NOT FULLY CONSIDER REPLACEMENT OPTIONS FOR BOSWELL 3, AND HIGHLIGHTS THE IMPORTANCE OF PLANNING NOW FOR BOSWELL 4'S RETIREMENT IN 2030

In its initial and supplemental comments, the Department provides EnCompass modeling analysis, but does not offer final recommendations on approval or modifications to MP's resource plan.[31] DOC states that its modeling suggests that MP should: retire Boswell 3 in 2025 and Boswell 4 in 2030; replace Boswell 3 with 282 MW of a peaking resource by 2026; add 200-300 MW of wind in 2024-25; acquire 100 MW of solar sited at Boswell in the post-2030 time frame using existing Boswell interconnection rights; potentially acquire demand-response and wind resources in the post-2030 time frame; and ensure that the approved MP MISO Long Range Transmission Project Iron Range – Benton – Cassie's Crossing transmission line (Iron Range line) continues to be a sufficient Boswell 4 retirement mitigation measure. DOC notes that if the Iron Range line is insufficient to mitigate the effects of the retirement of Boswell 4, MP should acquire 593 MW of gas combined cycle resource.[32] DOC did not do any modeling without NTEC and so did not evaluate whether the NTEC proposal should be abandoned.

As DOC explicitly did not make recommendations to the Commission in its supplemental comments, CEOs' reply focuses on DOC's modeling suggestions, highlighting two central issues. First, that DOC's modeling does not address the issue of whether NTEC should be included in MP's Preferred Plan, as some portion of MP NTEC ownership was included in all DOC modeling. Second, we address DOC's modeling suggestions regarding Boswell replacement. DOC's

[31] Minn. Pub. Utils. Comm'n, Minnesota Power 2021 Integrated Resource Plan, DOC's Initial Comments, Docket No. E015/RP-21-33, 77-78 (Apr. 29, 2022) [hereinafter "DOC Initial Comments"]; Minn. Pub. Utils. Comm'n, Minnesota Power 2021 Integrated Resource Plan, DOC's Supplemental Comments, Docket No. E015/RP-21-33, 53-54 (July 29, 2022) [hereinafter "DOC Supp. Comments"].
[32] DOC Supp. Comments, 53.

modeling results include an analysis with the recently MISO Board-approved Iron Range – Benton – Cassie's Crossing 345 kV transmission project (Iron Range line), which it believes will be sufficient to mitigate transmission reliability impacts of retiring the Boswell units.[33] Because DOC's modeling results suggest that the Iron Range line would negate the need for a gas combined cycle plant to replace Boswell 4, and because the line has been approved by the MISO Board, and MP and Great River Energy have filed an intent to build the line[34], we focus on DOC's modeling suggestion of replacing Boswell 3 with 282 MW of a peaking resource. Finally, we discuss how DOC's modeling underscores the need for planning for reliable Boswell 4 retirement to begin as soon as possible.

A. Like MP, The Department Hardwired NTEC Into All Its Modeling Runs.

Like MP's modeling, DOC's modeling included NTEC in all runs.[35] While MP only modeled NTEC at its previous 50% share, DOC conducted runs with both MP's previous 50% share and its new 20% share.[36] While DOC does acknowledge that MP's NTEC ownership percentage is "highly uncertain" and may include a "no ownership level,"[37] DOC did not do any modeling without NTEC.[38] As CEOs' discuss in our initial comments, MP must show that its plan, including NTEC, is in the public interest.[39] The fact that NTEC was approved by the Commission years ago does not shield the proposed plant from examination under today's very different circumstances. The Department's inclusion of NTEC in all its modeling runs means that its

[33] DOC Supp. Comments, 2.
[34] Minn. Pub. Utils. Comm'n, In re Application of Minnesota Power and Great River Energy for a Certificate of Need for the Northland Reliability Project 345 kV Transmission Line, *Notice of Intent to Construct, Own, and Maintain the Iron Range – Benton County – Cassie's Crossing Transmission Project*, Docket No. E015, ET2/CN-22-416 (Aug. 1, 2022).
[35] DOC Supp. Comments, 74-75.
[36] *Id.*
[37] DOC Supp. Comments, 53.
[38] *Id.*
[39] CEO Initial Comments, Part II.

modeling, like MP's, sheds no light on whether NTEC is in the public interest today.[40] Thus, the only modeling before the Commission that does shed light on that crucial question is CEOs' modeling, which shows that the public interest is better served by a plan without NTEC.[41]

In contrast, CEOs' Preferred Plan modeling removes NTEC from MP's plan and adds no new fossil resources. Moreover, as described in our initial comments, CEOs' Preferred Plan is marginally less expensive than MP's Plan and has far less economic risk, while meeting the same energy, capacity, and transmission reliability planning targets as MP's Plan.

B. CEOs' Modeling Does Not Select A New CT For Boswell Unit 3 Replacement.

The Department states that its modeling suggests that MP replace Boswell 3 with 282 MW of a peaking resource by 2026.[42] The basis for this modeling suggestion is that: "[t]ypically, the Department found that under base conditions (Mid Forecast, 50% NTEC, and No LRTP), EnCompass tends to select transmission in 2026; however, if the forecast, NTEC ownership level, or LRTP is changed from these conditions, EnCompass tends to select a gas CT unit in 2026."[43] CEOs appreciate that the Department characterizes the combustion turbine in its modeling as a generic peaking resource for the purposes of stating the modeling result. Still, our modeling results do not find a new CT is an optimal replacement for Boswell 3.

First, it is worth noting that while DOC's modeling did select a CT in the "Fast Exit" scenario (Boswell 3 in 2025 and Boswell 4 in 2030), when the LRTP line was included, its modeling did *not* select a CT or any new gas resources in any of the other four retirement scenarios,

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[40] It is notable that MP stated on August 12, 2022 that NTEC can be delayed until 2030 without affecting MP's ability to meet load. See Minnesota Power Response to LPI IR 041, Docket No. E015/RP-21-33 (Aug. 12, 2022).
[41] CEOs' Initial Comments, Part III.
[42] DOC Supp. Comments, 53.
[43] DOC Supp. Comments, 52.

which include: "status quo", "early Boswell 3", "early Boswell 4", or "MP's Preferred Plan".[44] In other words, when LRTP is included in the modeling, DOC's model does not select a new CT (or any new gas for that matter) in three out of the four scenarios that test Boswell retirements – it only selects the new CT in the Fast Exit retirement scenario.

CEOs' modeling results, on the other hand, do not replace Boswell 3 with a gas CT, but instead add wind, solar, stand-alone storage, and solar-battery hybrids.[45] One explanation for this difference is that CEOs' modeling made key adjustments to MP's modeling input assumptions, while the Department did not. As the Department states, it "made minimal changes to the inputs and assumptions made by MP."[46] The Department did not add any new generation resource options or make changes to the new generation resource options available to the model.[47] The Department describes its three changes as: "hydroelectric [run of river] capacity changes, a heat rate assumption change [Young Plant], and end effects treatment."[48]

As explained in our initial comments, our experts found that MP's assumptions unrealistically constrained the availability of renewables, energy storage, and demand response. CEOs' therefore made several changes to MP's modeling assumptions for new resources available to the model. The most significant of these changes in relation to the Department's peaking replacement result, is that CEOs' added solar-battery hybrid resources as a selectable resource in the model.[49] MP did not include a solar-battery hybrid resource as a resource option in any of its modeling runs, and neither did the Department because the Department did not make any additional resources available to the model beyond those assumed by MP. Making solar-battery

[44] DOC Supp. Comments, 29-30, Figures 7A, 7B, 7C, 7D.
[45] EFG Initial Report, 21, Table 8.
[46] DOC Initial Comments, 63.
[47] DOC Initial Comments, 52, 63.
[48] DOC Initial Comments, 63
[49] EFG Initial Report, Section 1.1.4.5

hybrids available to the model was a meaningful addition as these resources were selected by EnCompass in the CEOs' modeling in 2030 when Boswell 3 goes off-line.[50] In addition, CEOs also updated assumptions around cost, location, and operational characteristics for wind, solar, battery storage, energy efficiency, and demand response.[51] Again, the Department did not make any adjustments to the operational or cost assumptions for new generation resources.

In short, the Department has not offered any evidence showing that NTEC is needed nor provided robust evidence for a suggested need for a new peaking resource in 2026. CEOs continue to recommend our Preferred Plan as it includes an analysis without NTEC and replaces Boswell 3 without new gas generation, commensurate with the costs and reliability of MP Preferred Plan.

C. The Department's Comments Underscore The Importance Of Minnesota Power Starting Now To Plan Any Additional Transmission Upgrades And/Or Other Reliability Solutions Needed To Retire Boswell By 2030.

CEOs appreciate the added attention the Department brings to the importance of accelerating the retirement of the Boswell coal units, and the Department's comments illustrate the importance of requiring Minnesota Power to immediately start the transmission upgrade and reliability mitigation planning needed to allow Boswell to be entirely retired by 2030.

Regarding a Boswell unit 4 2030 retirement, the Department states that the MISO-approved Iron Range line "could serve as a reliability mitigation measure for certain Boswell unit retirements. This would mean that MISO would trigger the costs of the line and recover the costs

[50] EFG Initial Report, Section 3.1, 21.

[51] EFG Initial Report, Section 1.1. As described in the EFG Initial Report at Section 1.1.11, the Demand Response Product B that MP developed as a resource option was selected in our model but was not operating correctly in EnCompass and we were unable to find a solution after working with the EnCompass vendor. To replace the demand response product, EFG substituted 100 MW of 10-hour battery storage, using a relatively conservative cost assumption – the "mid" assumption from the 2021 NREL ATB – and 100 MW of wind, in 2030. We note this here because while the 10-hour battery storage resource was added as a substitute for the faulty DR product, we did not include the 10-hour storage resource as a new generic resource that the model could select.

per its tariff, rather than MP's IRP triggering the transmission line and the entire cost falling on MP ratepayers. From a modeling perspective, this drastically reduces the costs of the transmission Boswell constraint options, meaning that EnCompass should have a tendency to favor transmission over natural gas generation as a Boswell reliability mitigation option."[52] CEOs are optimistic that this line will resolve a significant portion, if not the vast majority, of transmission reliability issues regarding Boswell unit 4 retirement. Indeed, Telos Energy's transmission reliability analysis found it likely that MISO's proposed line would "significantly reduce the cost and extent of additional mitigations required for the retirement of Boswell 4."[53]

The Iron Range line is not the only factor that could greatly reduce the transmission upgrade needs and costs Minnesota Power would face to retire Boswell 4. CEOs' initial comments identify several other ways in which Minnesota Power's estimate of transmission upgrade costs can and should be reduced.[54] These include considering operational and/or contractual adjustments that would prevent MP from exporting power to Manitoba during winter peak demand – something which should be done anyway to prevent situations where Minnesota would be exporting power during our most stressed periods.[55] The need for a more thorough understanding of what is needed and what is possible within the timeframe to do it is why CEOs are recommending that the Commission require Minnesota Power to immediately begin planning the transmission upgrades and other grid reliability mitigation options needed to retire Boswell 4 by 2030 and to make annual

[52] DOC Supp. Comments, 26.
[53] Telos Report, 24.
[54] CEO Initial Comments, 49-50.
[55] CEO Initial Comments, 57.

reports to the Commission.[56] Fortunately the MISO approval of the Iron Range line made this task more certain and much less expensive for MP customers.

IV. CUB CORRECTLY ARGUES THAT THE RISK POSED BY HIGH AND VOLATILE NATURAL GAS PRICES HAS BEEN SERIOUSLY UNDERESTIMATED IN THIS IRP AND IN THE NTEC APPROVAL DOCKET, AND THAT RISK FALLS ENTIRELY ON RATEPAYERS

As the Citizen's Utility Board (CUB) points out, natural gas prices have recently been far higher and more volatile than Minnesota Power's gas price predictions.[57] Indeed, gas prices have experienced extreme price volatility in 2021 and 2022, and especially during the 2022 summer. Shortly after this IRP was filed, as a result of winter storm Uri in February 2021, the spot market for natural gas prices briefly shot to around $200/MMBtu at two of the gas market hubs serving Minnesota, a historically unprecedented event with painful consequences for Minnesota consumers.[58] Now factors beyond weather, including the war in Ukraine, are causing a more sustained period of volatility. The Energy Information Administration (EIA) recently reported that U.S. natural gas price volatility reached an all-time high in the first quarter of 2022.[59] In May of this year monthly Henry Hub natural gas prices rose to a 14-year high, at $8.14/MMBtu, with prices having nearly tripled from the previous year.[60] The Energy Information Administration (EIA) recently reported that U.S. natural gas price volatility reached an all-time high in the first

[56] CEOs Initial Comments, Part V(C) and Part IX(C). The other reason CEOs urge this immediate transmission planning process is because Minnesota Power estimated that the transmission upgrades would take ten years (MP IRP, Appendix P, at 30), threatening the ability to retire Boswell 4 in 2030 unless it is replaced with a new on-site gas plant.
[57] CUB Initial Comments, at 13, 19-20.
[58] ALJ Findings of Fact, Conclusions of Law, and Recommendation, *In the Matter of the Petitions for Recovery of Certain Gas Costs, Docket No. G-008/M-21-138,* at 22.
[59] EIA, "Natural gas price volatility reached an all-time high in first-quarter 2022," Aug. 10, 2022, https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/08_11/.
[60] EIA, Henry Hub Spot Prices, available at: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

quarter of 2022.[61] In May of this year, monthly Henry Hub natural gas prices rose to a 14-year high, at $8.14/MMBtu, with prices having nearly tripled from the previous year.[62]

Figure 2. Natural Gas futures prices since 2008[63]

By contrast, in this IRP Minnesota Power is forecasting gas prices ranging from $3.42/MMBtu in 2021 rising to $4.84/MMBtu in 2035.[64] In its Energy*Forward* filing, through which it sought and obtained approval of NTEC, Minnesota Power was even more optimistic about low and stable future gas prices. When MP discussed the risk factors the NTEC project faced, it said this about gas price risk: "With natural gas prices currently ranging between $2.50/MMBtu and $3.00/MMBtu and likely to remain lower than historical values for the foreseeable future, and given the availability of diverse natural gas supply options, the risks related to natural gas pricing

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[61] EIA, "Natural gas price volatility reached an all-time high in first-quarter 2022," Aug. 10, 2022, https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/08_11/.
[62] EIA, Henry Hub Spot Prices, available at: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm
[63] *Id.*
[64] MP IRP Appendix J, at 3.

and reliability with respect to NTEC are low."[65] Clearly, NTEC now faces much higher fuel price risks than originally estimated, making this risk yet another dramatically changed circumstance that warrants the Commission asking whether NTEC makes sense in 2022.

The fact that NTEC is now exposed to much higher and unpredictable gas prices is particularly notable given that a chief reason cited for the project's approval was to provide protection from volatile market forces. In its order approving NTEC, the Commission said, "[e]ven if Minnesota Power experiences no capacity needs, it will be purchasing energy from the MISO market, and NTEC provides a hedge against spikes in market prices and reduces overall costs by providing an economic source of energy."[66]

Moreover, as CUB notes,[67] the risk of high-cost natural gas will not be shared by Minnesota Power and its ratepayers. Rather, it will be borne entirely by ratepayers as a result of automatic adjustment provisions under which the Commission may allow a public utility to automatically adjust its rates to reflect fuel cost changes.[68] The automatic fuel price adjustment directly undermines Minnesota Power's financial incentive to change its decision to pursue NTEC in the face of striking new increases and volatility in natural gas prices. This makes it all the more important that the Commission seriously consider the risk that NTEC -- dependent as it will be for decades on unpredictably-priced fuel -- would pose to ratepayers.

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[65] Minn. Pub. Utils. Comm'n, In the Matter of Minnesota Power's Petition for Approval of the Energy*Forward* Resource Package, Docket No. E015/M/AI-17-568, (July 28, 2017) ["NTEC Petition"], 6-47.
[66] Minn. Pub. Utils. Comm'n, In the Matter of Minnesota Power's Petition for Approval of the Energy*Forward* Resource Package, ORDER APPROVING AFFILIATED INTEREST AGREEMENTS WITH CONDITIONS, Docket No. E015/M/AI-17-568, (January, 24, 2019), 6-47.
[67] CUB Initial Comments, 14.
[68] Minn. Stat. § 116B.16, subd. 17; Minn. R. 7825.2390-.2850.

V. CEOS AGREE WITH THE CONCERNS EXPRESSED BY ATLAS INFRASTRUCTURE, A MAJOR SHAREHOLDER OF ALLETE, INC

In our initial comments, CEOs discussed the financial and regulatory risks faced by Minnesota Power and other utilities by not moving rapidly enough towards decarbonization. This stranded-asset risk derives from the global commitment to pursue steps to limit warming to 1.5 degrees C., which the science tells us requires the world to cut emissions roughly in half by 2030 and to push for net zero emissions by midcentury.[69] This commitment is reflected our nation's Nationally Determined Contribution (NDC), where the US pledged to the world to cut US carbon emissions to 50-52% below 2005 levels by 2030 and then to reach net zero by 2050.[70] The Biden Administration has set the goal of a 100% carbon-free electric grid by 2035.[71] Studies charting out the least-cost pathways for the US to meet its emission-cutting commitments, discussed in CEOs' initial comments, show that operating coal plants beyond 2030 and building unmitigated new gas plants are incompatible with these goals.[72]

By investing in NTEC, Minnesota Power saddles ratepayers with the risk that the plant may be forced to retire by 2035 or earlier to meet emission reduction goals. This risk is emphasized by the comments submitted to the Commission by one of ALLETE's major shareholders, Atlas Infrastructure.[73] Atlas Infrastructure urges the Commission to rescind its approval of NTEC and

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[69] *Global Warming of 1.5°C: Special Report*: *Summary for Policymakers*, IPCC (2018) *available at* https://www.ipcc.ch/sr15/chapter/spm/

[70] *Fact Sheet: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies*, U.S. White House (Apr. 22, 2021), *available at* https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-goodpaying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/.

[71] *Id.*

[72] CEO Initial Comments, Part I(B).

[73] P. Burfitt, Atlas Infrastructure, public comment, *In the Matter of Minnesota Power's Application for Approval of its 2021-2035 Integrated Resource Plan,* Docket No. E015/RP-21-33 (filed June 6, 2022).

to ask Minnesota Power to model non-fossil fuel replacements for the Boswell units. As part of its investment due diligence process, Atlas Infrastructure did its own analysis of Minnesota Power's future emissions and compared them to carbon budgets for the internationally-agreed greenhouse gas reduction targets. Atlas Infrastructure concluded, like CEOs, that Minnesota Power's plan is not in alignment with global climate goals. CEOs are not aware of any institutional shareholder of a utility ever submitting comments to the Commission urging it to deny the utility's plan to build a fossil fuel plant.

Atlas Infrastructure is a member of multiple climate initiatives, including one, Net Zero Asset Managers, whose hundreds of members have more than $57 trillion in assets under management.[74] Clearly, taking seriously the globally-agreed climate targets and their emissions implications is becoming mainstream among private investors. CEOs submit that the Commission has an even greater obligation to take global climate targets seriously, given its duty to determine if resources are in the public interest and its other obligations under the law.[75]

VI. THE RECENT ENACTMENT OF THE INFLATION REDUCTION ACT STRENGTHENS THE CASE OF ALL PARTIES OPPOSED TO NTEC

The landmark Inflation Reduction Act (IRA) was signed into law on August 16, 2022.[76] The IRA, which invests $369 billion in the clean energy transition, has been hailed as the most aggressive response to climate change in US history[77] and as a "monumental" boost to clean

[74] *Id.,* 1.
[75] *See, e.g.,* Minn. Stat. § 216B.2422 subds. 2, 4; Minn R. 7843.0500, subp. 3; Minn. Stat. § 116D.02, subd. 2; Minn. Stat. § 216H.06.
[76] The Inflation Reduction Act was enacted as H.R. 5376. The official text of H.R. 5376, published by the Government Publishing Office, is available here: https://www.govinfo.gov/content/pkg/BILLS-117hr5376enr/pdf/BILLS-117hr5376enr.pdf. *See also* Congressional Research Service, *Tax Provisions in the Inflation Reduction Act of 2022 (H.R.5376),"* Aug. 10, 2022, [hereinafter "CRS Report"], https://crsreports.congress.gov/product/pdf/R/R47202.
[77] White House, "Remarks by President Biden at Signing of H.R. 5376, the Inflation Reduction Act of 2022," Aug. 6, 2022. https://www.whitehouse.gov/briefing-room/speeches-remarks/2022/08/16/remarks-by-president-biden-at-signing-of-h-r-5376-the-inflation-reduction-act-of-2022/.

energy.[78] The US currently has over 211 gigawatts ("GW") of clean power capacity; under the IRA this is now expected to *more than triple* by 2030 to 750 GW, with a "transformative impact . . . on the country's electric grid."[79] Analysts at Princeton University who have modeled the law's impacts project that it will greatly accelerate U.S. decarbonization, closing two-thirds of the emissions gap between current policy and the ambitious 2030 emission reduction target.[80] It achieves these goals largely through reducing the cost of clean energy in the power sector.[81]

Under the IRA, both a $25/MWh production tax credit (PTC) and a 30% investment tax credit (ITC) for wind and solar have been extended through 2024,[82] after which renewables will have access to technology-neutral PTCs or ITCs continuing through 2032 at least.[83] Under the law's revisions, investor-owned utilities will be better able to take advantage of the tax credits for utility-scale solar projects.[84] For the first time, the 30% ITC is also available for stand-alone battery storage facilities.[85] An additional 10% tax credit is available for renewable and storage facilities certifying that certain steel, iron, and manufactured products used in the facility were produced in the US.[86] And of particular relevance to Minnesota Power, yet another 10% tax credit is provided

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[78] John Engel, *Inflation Reduction Act: Clean Energy Industry Cheers 'Monumental' Vote by Senate*, Renewable Energy World (Aug. 8, 2022), https://www.renewableenergyworld.com /solar/inflation-reduction-act-clean-energy-industry-cheers-monumental-passage-by-senate/#gref.

[79] John Hensley, *It's a Big Deal for Job Growth and for a Clean Energy Future*, The Power Line (Aug. 5, 2022), https://cleanpower.org/blog/its-a-big-deal-for-job-growth-and-for-a-clean-energy-future/.

[80] Jesse D. Jenkins, et al., *Preliminary Report: The Climate and Energy Impacts of the Inflation Reduction Act of 2022*, at 9-10, Princeton University Zero Lab, Aug. 2022, https://repeatproject .org/docs/REPEAT_IRA_Prelminary_Report_2022-08-04.pdf.

[81] *Id.*

[82] H.R. 5376, §§ 13101 and 13102. *See also* CRS Report, p. 5-7.

[83] H.R. 5376, §§ 13701 and 13702. *See also* CRS Report 18-19.

[84] John Weaver, *What's in the Inflation Reduction Act for the solar industry?*, pv magazine (August 15, 2022), https://www.pv-magazine.com/2022/08/15/whats-in-the-inflation-reduction-act-for-the-solar-industry/.

[85] H.R. 5376, §§ 13102 and 13702.

[86] *Id.*

if these carbon-free technologies are built in an "energy community," which includes a community in which a coal-fired electric generating unit has been retired after 2009.[87] The Boswell site, where units 1 and 2 were retired in 2018, would presumably already qualify for this additional credit. These subsidies and the new economic landscape they usher in strengthen the arguments of all parties opposing NTEC and pushing for greater reliance on renewables and storage, including the OAG, Atlas Infrastructure and the CEOs. These new and extended subsidies are designed to cut carbon emissions by increasing the economic advantage of clean energy and storage enough that they substantially displace fossil fuel generation, and analysts expect the law will indeed succeed in transforming the energy grid. The IRA therefore represents yet another material (perhaps monumental) change in circumstances warranting the Commission to modify Minnesota Power's IRP by excluding NTEC.

VII. RECOMMENDATIONS

We reiterate[88] CEOs recommendations and respectfully request that the Commission:

A. Modify Minnesota Power's IRP by:

1. ordering Minnesota Power to withdraw from the NTEC project and revoking the Commission's approval of the related affiliate interest agreements;
2. ordering retirement of the Hibbard plant in 2023; and
3. finding the need for approximately 600 MW of solar by 2026.

B. Order the retirement of Boswell 3 by the end of 2029.

C. Order that Minnesota Power:

1. commence planning the transmission system reliability mitigations needed to maintain the option of retiring the Boswell facility entirely, including unit 4, by no later than 2030; and

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[87] *Id.*

[88] The following list no longer includes CEOs' earlier recommendation that the Commission commence a proceeding to update its estimated future carbon costs under Minn. Stat. § 216H.06 because that proceeding has recently been commenced. *In the Matter of Establishing an Updated Estimate of the Costs of Future Carbon Dioxide Regulations on Electricity Generation Under Minn Stat. § 216H.06,* Docket No. E999/DI-22-236.

2. submit annual reports to the Commission beginning one year from the date of this order and continuing until the filing of the next IRP. Such reports must:
   i. describe work done to date and work yet to be completed, providing a schedule of expected milestones, and estimating the earliest date for completion of the transmission system reliability mitigations; and
   ii. specifically evaluate converting Boswell 3 to a synchronous condenser upon retirement.

D. Order that Minnesota Power work with stakeholders to include an analysis in the next IRP that identifies the near-term steps needed to ensure Minnesota Power meets its customers' needs in a fashion compatible with 1.5°C pathways.

E. Order that Minnesota Power:[89]

1. work with stakeholders to develop a modeling construct that enables Minnesota Power, as part of its next resource plan, to model solar-powered generators connected to the company's distribution grid as a resource. Minnesota Power and stakeholders shall address the following factors in developing the modeling construct:
   i. using a "bundled" approach as is used to model energy efficiency and demand response;
   ii. the costs borne by the utility and the costs borne by the customer;
   iii. cost effectiveness tests; and
   iv. other topics as identified by stakeholders.

2. take steps to better align distribution and resource planning, including:
   i. set the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan;
   ii. conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level;
   iii. proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources;
   iv. improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Minnesota Power can take advantage of distributed energy resources to address discrete distribution system costs; and
   v. plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.

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[89] Similar language was recently adopted in by the Commission: Minn. Pub. Utils. Comm'n, *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company, d/b/a Xcel Energy,* Order Approving Plan with Modifications and Establishing Requirements for Future Filings, Docket No. 19-368 para. 15 (April 15, 2022).

3. account for local clean energy goals, in aggregate, in forecasting and modeling. In particular, the plan should include consideration of local community generation goals for distributed generation in its next IRP.

F. Order that Minnesota Power's next IRP include an analysis of the public health impacts, over the 15-year planning period, of its current generation fleet, its proposed plan, and other resource scenarios studied. The public health analysis should at minimum evaluate and quantify the health costs associated with fine particulate matter from coal and biomass power plants.

G. Order Minnesota Power to, prior to the next IRP, conduct community outreach and establish a stakeholder group to:[90]

H. provide input on the public health analysis for the next IRP, including the methodology, results, and implications for Minnesota Power's resource plan;

inform the design of electricity services and programs that improve equitable electricity delivery, improve customer access to energy efficiency and load-shaping programs, and improve customer access to DG and renewable energy. These services and programs should particularly focus on reducing disparities in energy burden, ensuring equitable access to low-income residents, and ensuring equitable access to Black, indigenous, and communities of color that have disproportionately borne costs of unjust and inequitable energy decisions;

I. Order Minnesota Power, in its next IRP docket, and in a separate docket to be established by the Executive Secretary, to file details describing stakeholder outreach and progress on the above requirements in H, (above) by January 1, 2024, and annually thereafter.

Dated: August 29, 2022

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[90] CEOs also relied on the Commission's language in its recent Xcel order for this recommendation. *Id.* para. 25 (Apr. 15, 2022).