MONTANA ENVIRONMENTAL INFORMATION CENTER

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Comments on NorthWestern Energy's Draft 2026 IRP

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I. INTRODUCTION

The Montana Environmental Information Center (MEIC) appreciates the opportunity to comment on NorthWestern Energy's Draft 2026 Integrated Resource Plan (Draft IRP). The Draft IRP is an extremely important planning exercise that lays the foundation for the next 20 years of NorthWestern's Montana electric system and determines whether the system will provide affordable, reliable service for Montanans. These comments are informed by MEIC's participation in NorthWestern's Draft IRP Stakeholder Working Group; attendance at NorthWestern's four public meetings in Great Falls, Missoula, Helena, and Bozeman; and a close review of the Draft 2026 Draft IRP document.

At a high level, this Draft IRP portrays a future for Montana's energy system that conflicts with the desires of NorthWestern's customers. The plan unduly prioritizes expensive and unreliable coal, gas, and nuclear generation, and it is far from a least-cost future. It is recognized around the world that the future of affordable energy lies in wind, solar, and storage resources. Yet, by limiting short- and long-duration storage and using cost estimates for wind, solar, and storage that dramatically exceed standard industry assumptions, these resources have been all but excluded from the Draft IRP. What's more, the Draft IRP fails to adequately reflect the reliability benefits of a balanced resource portfolio that combines wind and solar with both short- and long-duration storage.

Furthermore, MEIC appreciates the Draft IRP's discussion of potential reliability benefits from transmission projects such as the North Plains Connector (NPC) and a future Montana to Idaho path 18 expansion project, but not accounting for the specific capacity benefit of interregional transmission is a major hole in the modelling. This, combined with the model's inability to contemplate future resource and capacity contracts and a black-box planning reserve margin, leads the Draft IRP to project a capacity deficit that isn't reflected in reality.

For example, Portland General Electric assumes 100% capacity contribution from its future share of the NPC based on a study they commissioned by Energy GPS to look at market availability during the utility's peak need. Similarly, Astrapé Consulting conducted an analysis for Grid United that demonstrated the 3,000-MW NPC would unlock 3,550 MW of capacity across the SPP, MISO, and the Western electric grid – greater than the physical capacity of the project itself due to the nature of connecting diverse regions that experience peak electricity demand at different times of day, on different days, or in different seasons.

Given these analyses, and in the absence of NorthWestern's own analysis (which MEIC maintains should have been conducted in this Draft IRP process), NorthWestern should assume that its full 300 MW of capacity on the NPC can be relied on for contributing to its peak capacity needs. Holding all else equal, if 300 MW of capacity are enabled in NorthWestern's service territory by the North Plains Connector, and NorthWestern were to renew its expiring contract with the Judith Gap wind facility (accredited at 24.4 MW summer capacity and 34.8 MW winter capacity), the base case would be resource adequate without any additional resources through 2040 (NorthWestern's capacity forecasts demonstrates a 246 MW summer capacity deficit in 2040 and 323 MW winter capacity deficit in 2039-2040). Factoring in load-shaving and load-shifting measures could reduce the projected peak capacity need even further.

There are countless other improvements that are needed in the Draft IRP, including the need to include NorthWestern's internal analysis for its impending day-ahead energy market decision, which will have extremely relevant implications for future system costs and reliability. It is also outrageous that the entire Draft IRP document completely ignores climate change.

These deficiencies could have been addressed through a more robust Draft IRP development process. MEIC acknowledges and appreciates improvements that have been made by the resource planning team, but upon arriving at this Draft IRP, we're left feeling that deep barriers within NorthWestern's company culture have impeded a truly transparent and collaborative process. From the beginning, it has been pulling teeth to gain even superficial access to this process and the relevant materials that should be publicly available as a given. Moving forward, we hope and expect that NorthWestern will prioritize transparency and public participation from the start, with a fundamental shift in the company's planning ethic to produce a truly collaborative vision for Montana's energy future.

These concerns and others are explained in detail in the comments to follow.

II. MODEL PARAMETERS LEAD TO THE SYSTEMIC EXCLUSION OF WIND AND SOLAR

The Draft IRP has almost completely excluded low-cost wind and solar from its 20-year planning scenarios through arbitrary modeling parameters that do not reflect the reality of these resources. MEIC is frustrated that the Draft IRP's executive summary opens with an acknowledgement of "pressures to transition to lower-carbon resources" and Montana's "renewable potential," expressing NorthWestern's intent to "position[] Montana's system to participate in a more integrated, decarbonizing western grid," but then lays out incredibly carbon-intensive future portfolios with minimal to no new carbon-free wind and solar resources. Figure 18 is demonstrative of NorthWestern's aversion to building and owning wind and solar, showing that 92% of delivered wind and solar energy in 2024 came from contracted resources.

The parameters used in Draft IRP modeling undervalue the ability for wind and solar to supply electricity during NorthWestern's peak electricity demand, which is exacerbated by ignoring solar and wind's ability to provide reliable and complementary electricity when they are built together and combined with short- and long-duration energy storage. While the Draft IRP includes hybrid wind plus short-duration storage and solar plus short-duration storage candidate resources, this neglects to consider the interaction effects of a complementary portfolio combining wind, solar, and short-duration storage for a combined ELCC benefit. What's more, the Draft IRP contains no analysis of the tremendous ELCC benefits of combining long-duration storage with wind and solar resources.

The modeling also falsely puts new-build gas generation on the same timeline as wind, solar, and storage by making all of these resources available beginning in 2030, when realistically wind, solar, and storage projects can be fully developed years faster than the timeline to construct a gas plant – exacerbated by current gas turbine supply constraints. The artificial model constrains on short- and long-duration energy storage, discussed more later on, further limit the model's ability to realistically examine the costs and reliability of building wind and solar on NorthWestern's system.

It has been shown that it is more expensive to continue running the Colstrip plant than to replace it with wind, solar, and storage resources. MEIC remains concerned that the somewhat arbitrary 150 MW overbuild constraint, along with other modeling deficiencies outlined in this section, prevents the model examining a scenario that builds low cost renewable energy to gradually replace the Colstrip plant while that plant still operates at a diminishing capacity (possibly even examining the phased retirement of one unit then the other). Despite NorthWestern's continued assertion that we must have the new bridge in place (i.e. renewables) before eliminating the old one (i.e. Colstrip plant), the model creates a scenario where the plant must be replaced all at once whenever it is retired. Fixing the cost assumptions for wind and solar, as well as addressing cost assumption issues for coal, gas, and nuclear that are addressed later on in these comments, would almost certainly alter the Draft IRP's finding that "selecting fossil-fueled resources after 2035 results in a total portfolio cost of 2% less than the Base Case."

Without providing the source data that NorthWestern supplies to WRAP for calculating the capacity accreditations for wind and solar resource, it remains dubious whether these accreditations acurately reflect these resources' performance in Montana. Furthermore, by treating wind, solar, and storage resources in isolation, the model discredits the ability of these resources to contribute to the utility's peak load. A whole portfolio of variable energy resources is not, but should be, analyzed for its aggregate contribution to resource adequacy. The current Draft IRP model assigns fixed ELCC accreditations to wind (24.5% winter, 19.5% summer) and solar (8.1% winter, 41.8% summer) resources. Concerningly, between the release of a Draft IRP to Stakeholders and the release of a Draft IRP to the public, the winter accreditation for the Judith Gap wind facility in Table 39 was inexplicably cut from 25.5% and 34.8 MW to 0% and 0 MW, simultaneously dropping the overall winter accreditation of NorthWestern's wind resources from 24.5% to 16.6%. This is an error that must be fixed, especially if 16.6% wind accreditation was used in the Draft IRP modeling. The overall winter accreditation for NorthWestern's solar resources was also reduced from 8.1% to 7.9% in Table 40, an erroneous change that is not supported when calculating the overall weighted solar accreditation based on the information in that table.

A better ELCC methodology would show the incremental resource adequacy improvement from each additional resource, encompassing the synergistic benefits of deploying complementary resources into the portfolio and not treating these resources in isolation. ELCC should be a measure of the entire portfolio's resource adequacy, and by isolating individual variable resources, their resource adequacy value is significantly diminished. Therefore, NorthWestern should be assessing portfolio-wide ELCC to capture all interactive effects, urging WRAP to move beyond the opaque and increasingly archaic planning reserve margin.

Unecessarily, Section 7.1.3 VER Candidate Resources includes discussion on landfill disposal of wind turbine blades, citing a resource from American Clean Power from January 2023. However, an October 2024 resource from American Clean Power demonstrates that turbine blades are made from safe, non-toxic inert material and make up a negligibly small portion of total landfil waste, while upwards of 80-94% of a wind turbine's mass is readily recyclable. That NorthWestern felt the need to include this commentary, while completely ignoring climate change and discussion of any public or environmental health impacts of gas, coal, or nuclear generation – especially nuclear waste disposal – throughout the Draft IRP other than cursory discussion of environmental regulations, demonstrates NorthWestern's perverse underlying bias against clean and affordable renewable energy that permiates this entire planning process.

Wind and solar resources can play a vital role in meeting NorthWestern's peak demand when analyzed more holistically for their performance in a full portfolio of complementary resources and in a connected western grid where power can be shared from where it is available to where it is needed. Solar peaks during the day to complement wind's usual evening peak, solar and wind paired with batteries allows for shifting the power generation in time from when it is abundantly available to when it is most needed, and interregional transmission connectivity allows for shifting power generation in space from where it is abundantly available to where it is abundantly needed. Furthermore, with this interregional connectivity and long duration energy storage available for high demand events when wind and solar have low output, Figure 8 paints a different picture. There is a significant cluster of high-VER-output instances when demand is also high, in the roughly 70% to 90% range, demonstrating that wind and solar can provide energy during higher-demand periods.

A. **FLAWS IN COST ASSUMPTIONS**

The Draft IRP further undervalues wind and solar by tacking on exorbitant, unrealistic costs for connecting these resources to the grid. Applying a $1,291,137 per MW network upgrade cost to new resources ignores the opportunity to take advantage of lower costs interconnection opportunities. This includes geographic flexibility for siting renewable generation facilities in locations to cause minimal strain to the transmission system, as well as replacing retiring fossil generation facilities with renewable projects where the infrastructure for grid connection is already available. Most of the new capacity needs identified in Draft IRP follow the retirement of existing resources, especially the Colstrip plant, so wind and solar would be able to replace these resources with minimal interconnection and network upgrade costs.

Meanwhile, NorthWestern recently acquired Avista's 222 MW and Puget Sound Energy's 314 MW shares of the Colstrip plant. While neither of these shares in the plant have undergone prudency reviews and approval processes at the PSC, they are both using NorthWestern's transmission capacity to execute contracts to the benefit of NorthWestern, not the utility's retail customers. While NorthWestern has contracted firm transmission rights from Puget Sound Energy for that share of the plant through at least 2030, those rights could be contracted for moving other lower-cost energy. This transmission capacity should be used to the benefit of NorthWestern's retail customers who pay for transmission infrastructure, and therefore, that transmission capacity should be available for low-cost wind and solar interconnection. Rather than applying interconnection and network upgrade costs to new wind and solar resources in the Draft IRP, those costs should be applied to NorthWestern's additional shares of the Colstrip plant that are crowding out interconnection capacity that otherwise would be available for lower-cost wind and solar resources. Overall, the current structure of the Draft IRP model does not realistically contemplate how wind, solar, and storage could be used to cost effectively replace the Colstrip plant.

As stated previously in MEIC's Stakeholder Group comments, models should be re-run with a fixed allocation each for $0 interconnection and network upgrades for solar and wind resources, similar to how models were run with a ceiling for the amount of storage resources that could be deployed. This would reflect the availability of deploying wind and solar resources where interconnection costs are negligible: close to demand centers and elsewhere that the grid can accommodate those resources. Furthermore, the model should reflect these negligible interconnection and network upgrade costs wherever existing generation resources are slated to retire. At a minimum, interconnection and network upgrade costs should be brought in line with assumptions used by other regional utilities or industry standard estimations from NREL of roughly $100,000 per MW – less than one tenth the cost used in this Draft IRP.

1. O&M COST ASSUMPTIONS

On top of interconnection costs & grid upgrade costs, the baseline cost assumptions used for wind, solar, and storage dramatically exceed standard industry assumptions and preclude the selection of these resources in modeling. Section 7.1.6 Candidate Resource Cost Estimates explains that "O&M costs are assumed to escalate at 2.5% per year consistent with the 2024 NREL ATB," but this completely misrepresents the cost projections laid out in the 2024 NREL ATB. Section 7.8 PCM Results again references this flawed 2.5% operating expenses inflation escalation. While it is true that NREL assumes a 2.5% uniform annual inflation rate, this assumption is used in cost forecasts to present costs in *real*, 2022 dollars, and is not treated as a 2.5% annual increase to O&M costs as the Draft IRP has used it.

These comments will refer to NREL ATB cost projections for utility-scale wind, solar, and battery storage technologies from Class 1, Advanced scenarios because technological advancements have caused historical cost curves to outpace even NREL's most optimistic cost projections. However, MEIC notes that other technology classes explored in NREL's ATB, as well as NREL's moderate and conservative scenarios across these classes, all demonstrate substantial, real reductions to overnight capital costs and fixed O&M costs for utility-scale wind, solar, and battery technologies that are not reflected in the Draft IRP's cost assumptions.

A closer look at NRELs projections show that renewables O&M costs are decreasing drastically in *real* dollars from 2025 to 2045: A 43% decrease for solar and 37% decrease for wind. Using a 2.5% annual inflation rate for year-to-year *nominal* dollar costs still shows an overall 6% <u>*decrease*</u> to solar O&M through the planning horizon, and only a marginal 3% increase to land-based wind O&M. In comparison, assuming a fixed 2.5% annual increase to O&M costs creates completely unrealistic and misleading price projections. Compared to NREL's projection of a 43% *real* dollar *decrease* to solar O&M between 2025 and 2045, a fixed 2.5% escalation leads to a 64% *increase* over that same horizon. This misguided escalation assumption projects solar O&M costs in 2045 that are <u>*254% higher than NREL's projections*</u> in *real*, inflation-adjusted dollars. And compared to NREL's projection of a 37% *real* dollar *decrease* to land-based wind O&M between 2025 and 2045, a fixed 2.5% escalation again leads to a 64% *increase* over that same horizon. This projects wind O&M costs in 2045 that are <u>*203% higher than NREL's projections*</u> in *real*, inflation-adjusted dollars. The same can be said for 4-hour battery O&M costs, where NREL projects a 42% *real* and 5% *nominal* decrease to O&M costs from 2025 to 2045. Yet, using a fixed 2.5% fixed annual increase results in a 64% increase over the planning horizon, resulting in O&M costs in 2045 that are <u>*372% higher than NREL's projections*</u> in *real*, inflation-adjusted dollars.

Not only are the O&M *escalations* for wind, solar, and storage completely off from standard assumptions, but initial O&M cost assumptions used for wind and solar in this Draft IRP for costs in 2025 start off already drastically higher than costs outlined in NREL's 2024 ATB. While the Draft IRP shows fixed O&M costs for solar of $26.26/kW-year in 2025, that is 18% higher than NREL's estimate (adjusted to *real* 2025 dollars) of $22.18/kW-year. The Draft IRP shows fixed O&M costs for wind of $45.02/kW-year in 2025, which is 39% higher than NREL's $32.46/kW-year. The starting point fixed O&M costs for 4-hour battery storage used in the Draft IRP are closer to NREL's projections.

So while O&M costs continue to plummet for wind, solar, and storage, the Draft IRP assumes the exact opposite, artificially escalating costs throughout the planning period. Furthermore, O&M costs of resources in NorthWestern's portfolio beyond 2045 appear to not be captured in the 20-year net present value (NPV) nor the remaining book life charts. Given that the O&M costs of coal, gas, and nuclear infrastructure continue to escalate, while wind, solar, and storage costs continue to fall, this is another benefit of a clean portfolio that is not captured in the Draft IRP.

2. TECHNOLOGY COST ASSUMPTIONS

In addition to inaccurate O&M cost projections for wind, solar, and storage, the Draft IRP uses 2025 installed overnight capital cost estimates for wind, solar, and battery storage that are also inexplicably drastically higher than standard estimates in NREL's 2024 ATB. The Draft IRP shows overnight cost of solar PV at $1,731/kW, which is 24% higher than NREL's 2025 cost of $1,397/kW (in *real* 2025 dollars). Similarly with wind, the Draft IRP shows a $1,871/kW overnight cost, which is 28% higher than NREL's 2025 cost of $1,461/kW (in *real* 2025 dollars). And for 4-hour, 100 MW battery storage, the Draft IRP uses a $2,071/kW overnight cost, which is 55% higher than NREL's 2025 cost of $1,337/kW (in *real* 2025 dollars). Meanwhile, Figure 30: Candidate Resource Cost Curves demonstrates assumptions for costs of wind, solar, battery storage, and combinations thereof to all begin climbing at some point over the planning horizon with no explanation for this escalation. This is completely at odds with historical trends and industry projections that costs for these technologies will continue to fall. This escalation, along with high initial cost estimates, is yet another artificial reason for the model to bias against the selection of wind and solar resources.

Contradicting the assumptions in the rest of the modeling, Section 7.4.3 Power Prices discusses how, similar to what has been observed in other markets that already have relatively high renewables penetration, increased renewable energy in future power markets will put "significant downward pressure on average prices." Section 1.7 of the Executive Summary also acknowledges that "with growing renewables, the model expects near-term price reductions [on the market] followed by a gradual increase in average prices in later years," in part due to "increased natural gas costs." This is the only times that the Draft IRP acknowledges the ability of renewables to provide low-cost electricity to NorthWestern's customers, yet the Draft IRP is completely blind to these benefits for renewables in NorthWestern's own portfolio, demonstrating the profit maximizing incentive that informs this planning. The 2024 average price per MWh of NorthWestern's contracted solar resources in Table 23 is demonstrative of the low costs of solar at scale, with the 80 MW Apex Solar and 80 MW MT Sun projects averaging about $43 per delivered MWh each. And Table 24, showing the average price per MWh of NorthWestern's contracted wind resources demonstrates the low cost of well-sited wind at scale, with the 80 MW South Peak and 80 MW Stillwater projects providing electricity at an average of $22 and $38 per delivered MWh respectively.

III. LOAD & CAPACITY NEED FORECASTS

It is unclear why the load forecast shown in Figures 2 and 3 abruptly jump up in 2028, coinciding with the projected online date for the Trident Solar Hybrid project. Given a uniform load forecast escalation without this unexplained jump, it appears that the addition of the Trident Solar Hybrid project would make the portfolio resource adequate through 2031. Better explanation is needed to justify this jump in demand, particularly since data centers demand growth is modeled as separate sensitivities. Without explanation, it appears that this demand jump is manufactured to portray a portfolio that remains resource inadequate.

MEIC is also concerned that NorthWestern's internal load forecast for the medium- and long-term planning years results in a higher load forecast than the 2023 IRP load forecast. The Draft IRP explains that the 2023 load forecast was based on the WRAP load forecast methodology, as discussed in Section 7.3 Capacity Forecast. Given the deference to WRAP methodology elsewhere in the Draft IRP, it is unclear why WRAP's methodology was abandoned here, and concerning that parting with WRAP methodology leads to projection of greater need for resource investment when this forecasting decision has not been supported.

Comparing Figure 35, which shows the winter load forecast in the 2026 Draft IRP, with Figure 39, which shows the winter load forecast in the 2023 IRP, demonstrates an approximate 100-150 MW load forecast increase between the plans in the later years of the planning horizon. Since data center load growth is treated as its own sensitivity, this increased load forecast between the 2023 plan and 2026 plans seems to serve no purpose other than to show an inflated need for capacity investment.

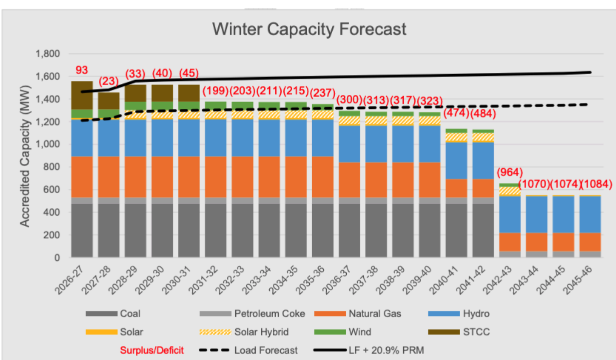


FIGURE 35: NORTHWESTERN'S WINTER CAPACITY FORECAST.

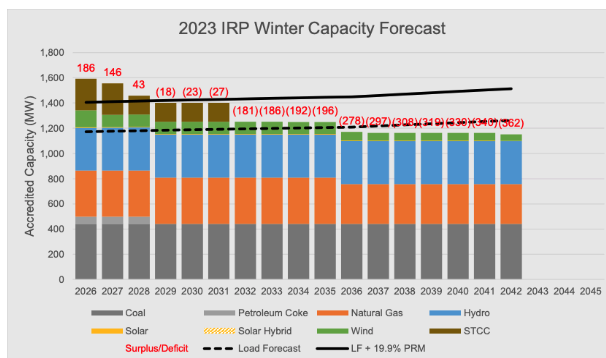


FIGURE 39: NORTHWESTERN'S 2023 IRP WINTER CAPACITY FORECAST.

MEIC's concerns that the Draft IRP's load forecasts and forecasted capacity need may be higher than is warranted are compounded by a recent report from GridStragegies. This report determined that the North American Electric Reliability Corp's 2025 Long-Term Reliability Assessment, which is aggregated from individual utility and balancing authority projections, likely overestimates future load growth and ignores non-firm interregional power flows' ability to contribute to capacity needs. These same national concerns are directly applicable to NorthWestern's load forecasting and capacity need forecasting.

IV. REPRESENTATION OF SHORT-AND LONG-DURATION ENERGY STORAGE

While this Draft IRP has improved its representation of both short-and long-term battery storage compared to 2023, there are further improvements to be made. Understandably, the model was very preferential to selecting short- and long-duration battery storage, and the Draft IRP admits that "[t]he ARS module selects the maximum threshold of 4-hour storage resources and usually the maximum LDES resources in the majority of portfolio outcomes." However, rather than accepting the value of these resources, particularly in their ability to support more low-cost wind and solar resources in the portfolio, arbitrary limits were established to constrain how much of each of these resources could be built (250 MW for short-duration, 150 MW for long-duration). This, in turn, has severely limited the model's ability to select wind and solar since more battery storage can not be selected to increase these resource's abilities to contribute to peak load.

The Draft IRP has attempted to justify the 250 MW short-duration storage limit based on rudimentary modeling that shows introduction of short-duration batteries beyond 250 MW creating a secondary winter peak. However, this is far from how batteries would be operated on the grid in practice, and the electric grid is handling tremendous battery storage deployment elsewhere, particularly in Texas, without issue. Figures 27-29 are intended to demonstrate the advent of this secondary peak, and purport to show that increasing battery deployment beyond the 250 MW limit has negligible impact on reducing peak demand. However, these figures neglect several key considerations that could allow for additional battery deployment and associated benefit. Particularly, these figures assume that 250 MW of 4-hour batteries all charge simultaneously during a given 4-hour period, before all discharging simultaneously over a different 4-hour period.

In practice, batteries could be charged over a longer than 4-hour period at a rate below their max charging capacity. Similarly, batteries could discharge below max discharge capacity to more precisely lower peak demand rather than being constrained to only charging and discharging at their max nameplate 4-hour specifications. Different batteries on the system could also stagger charging and discharging to not create the simultaneous load of all charging at once, and to mimic a lower capacity, longer duration battery when discharging. 4-hour batteries can also be cycled multiple times a day to maximize their benefit, despite the model's limitation on a single charge/discharge cycle per day. 4-hour batteries enable much more flexibility than is allowed in these figures and the 250 MW short-duration battery limitation.

Section 7.1.4 Energy Storage Candidate Resources also explains that the decision was made to not model 8-hour battery energy storage or pumped hydro storage as eligible candidate resources in ARS. While MEIC appreciates that short-duration battery storage and long-duration iron-air battery storage were modeled robustly in the Draft IRP and selected in every scenario and sensitivity, the explanation for excluding 8-hour BESS and pumped hydro storage is unsatisfactory. That 8-hour storage and pumped hydro must be coordinated with 4-hour storage and accommodate longer charging durations is not a reason to exclude those resources from the modeling. Exploring the potential portfolio benefits of these storage resources is particularly important given the limitations established for 4-hour storage and iron-air LDES.

The 150 MW limit on iron-air long duration energy storage is also arbitrary. Form Energy's iron-air LDES technology will be available very soon, with its pilot project slated to come online this year and more projects to follow. This technology is available, and is extremely valuable when paired with wind and solar to create an affordable and reliable portfolio. Limiting LDES therefore arbitrarily limits the model's inclination to select low-cost renewable resources. As mentioned earlier in these comments, hybrid wind + solar + LDES resources should have been modeled in the Draft IRP. The model should have also been run without this 150 MW LDES constraint to show how it would affect the least cost outcome. While the Stakeholder Group was told that this modeling was conducted, it is not contained anywhere within this Draft IRP nor is it in any posted resources from previous ETAC and Stakeholder Group meetings.

In addition to short- and long-duration battery storage limitations, MEIC is concerned that NorthWestern's decision to accredit four-hour battery storage as the minimum accreditation between winter and summer season under WRAP could lead to a mismatch in accreditation values used versus actual seasonal performance of the battery. It is unclear why separate summer and winter accreditations could not be used for batteries as it appears that separate summer and winter capacity accreditations were used for other candidate resources in the Draft IRP. It is also unclear why Table 43: Candidate Resource Capacity Accreditations shows 82.1% winter accreditations for 4-hour batteries, when a WRAP presentation from June 2025 shows energy storage resources in the MidC region, which includes NorthWestern, at nearly 100% accreditation throughout the winter months. The solar/battery hybrid candidate resources in this Draft IRP also appear to have low accreditations at 27.5% for 100 MW solar/50 MW 4-hour storage and 10.6% 100 MW solar/100 MW 4-hour storage. That same WRAP presentation shows solar hybrid resources in MidC with roughly 35-40% qualifying capacity contributions throughout the winter months. It appears that these candidate resources accreditations are lower than what WRAP has demonstrated for the region, but MEIC cannot verify NorthWestern's accreditation values without having greater access to WRAP accreditation data and methodology.

The Draft IRP also indicates in Section 7.6.2.1 Ancillary Services that the model reserves "20 MW of regulation-eligible units" in all hours for frequency regulation, in addition to 3% of total generation for spinning reserve service and 3% of total load for supplemental reserve service. Batteries are capable of providing these ancillary grid services, but is unclear whether the model allows batteries to count toward these requirements. If not, batteries should be included for these functions.

V. IRP ASSUMPTIONS UNDULY FAVOR COAL & GAS

Assumptions made throughout the Draft IRP unduly favor expensive coal and gas. For example, Section 2.2 Changes in the Planning Process and Content asserts that NorthWestern has "refined the base-case scenario to reflect only future resources with executed power purchase agreements or final commission orders." However, the base case includes the Avista share of the Colstrip plant and associated costs of running the plant despite this plant not being in rate base and having received no final order with a prudency determination or otherwise from the commission. This is just one example of many demonstrating the preferential treatment given to Coal and Gas in the Draft IRP modeling.

A. INFLATED RELIABILITY OF COAL & GAS

While undervaluing wind and solar, the Draft IRP has simultaneously greatly overvalued the reliability of coal and gas. An analysis conducted in 2023 demonstrated that the aging Colstrip coal plant faces mounting reliability troubles and should only be accredited for its availability 51% of the time when it's currently needed for peaking events. Yet the Draft IRP still claims a 98.3% summer and 99.5% winter accreditation for the Colstrip plant.

MEIC understands that NorthWestern's previous 222 MW share of Colstrip is in the rate base, so customers currently pay for this plant whether its working or not – and must double pay for replacement power when the plant is broken. Given customers' burden for paying for the Colstrip plant *and* replacement power during peaking events when the plant has gone offline, accurate capacity accreditation for this facility is extremely important. However, MEIC's requests for input data for WRAP resource accreditations have gone unanswered. In July 2025, MEIC raised the concern at a Stakeholder Working Group meeting, in a follow up email, and in a submission to the Draft IRP feedback form that page 70 of the WRAP design document indicates that "planned outages … will not negatively impact [Qualified Capacity Contribution] QCC values [for thermal resource accreditation]."

It is generally understood that planned outages are planned for shoulder seasons when NorthWestern and the greater region experience off-peak demand, in which case these events would not count toward WRAP accreditation anyway. However, one of the units at Colstrip went offline in the January 2024 cold weather event and both units went offline in the July 2024 heatwave, both instances referred to as "planned maintenance." MEIC is concerned that critical outage could be labelled as "planned" and shield colstrip's reliability factor from taking a hit when the plant really was not available when it's power was needed, but these concerns have not been addressed. Instead, contrary to what we have seen in practice for the Colstrip plant, Section 7.6.2 Production Cost Modeling of the Draft IRP claims that "when planned maintenance does occur, NorthWestern plans for the outages of those units during the shoulder seasons." Table 42 in Section 7.2.1 Existing Resources provides the Effective Forced Outage Rates for NorthWestern's existing thermal resources, a relevant factor in determining Colstrip's QCC, but MEIC is concerned that this data for Colstrip specifically is redacted without explanation.

Furthermore, the Draft IRP modeling does no factor in gas resources' reliability challenges in extreme weather due to equipment malfunction and fuel supply challenges. In other jurisdictions, gas plants have repeatedly failed to provide electricity when people need it most, and gas supply is increasingly constrained across the country. When the weather is coldest, using gas to simultaneously heat homes and generate electricity has created supply shortages in other jurisdictions like PJM, with dire consequences. Meanwhile, near-term U.S. LNG exports are increasing alongside rising domestic demand for natural gas which will only continue to exacerbate the gas supply problem. On top of fuel shortages, the Draft IRP only superficially discusses gas turbine supply challenges that limit the ability to build new gas generation resources without incorporating this limitation into the modeling.

B. FUEL COSTS FOR GAS

Since the Draft IRP was published, the EIA issued a Short-Term Energy Outlook projecting that gas prices could increase 30% or more from 2026 to 2027. However, the Draft IRP assumes a more modest escalation of gas prices, with Figure 42 indicating that a 30% increase to 2026 prices forecasts across AECO, CIG, and Malin hubs would not be experienced until the early 2030s. And this forecast was created prior to current geopolitical events leading to more strained global gas supplies and even higher prices. Given the model's heavy reliance on gas generation, gas price forecasts in the Draft IRP should be updated to reflect EIAs most recent projections which could result in major changes to the model's resource selection across scenarios and sensitivities. The Draft IRP also explains that "PowerSIMM's natural gas and and power price simulations follow a forecast and do not adjust with supply and demand imbalances," but this would be an important model consideration given current gas supply issues. In addition to year-to-year gas price increase trends, Figure 41 also demonstrates the volatility of gas prices, especially in extreme winter conditions when gas heating and power generation are at their highest demand. These extreme events are particularly concerning for NorthWestern's non-firm gas supplies to DGGS and Basin Creek. The Draft IRP must be updated to more accurately represent the increasing volatility of gas prices.

Also of great concern to MEIC is the forecasting of "likely revenues" from candidate resources in choosing least cost candidate resources in the Draft IRP. As became abundantly clear in the recent rate case before the Public Service Commission, NorthWestern's PowerSIMM forecasting for energy market sales and associated revenues greatly overestimated the attractiveness of NorthWestern's thermal resources, namely YCGS, in the open market. As a result, NorthWestern proposed a PCCAM base reliant on major increases to market sales revenues that failed to materialize. MEIC's concern is that this Draft IRP appears to have used the same PowerSIMM forecasting of future market sales revenues for candidate resources contemplated in various scenario portfolios, which very well could be reflecting revenue that would not materialize. In fact, the base case modeling projected annual export revenues that *exceed* the revenue projections that never materialized in the rate case's PCCAM base, as can be seen in Figure 77.

It appears that the Draft IRP is projecting that market sales revenues will offset the costs of large thermal gas, coal, and nuclear generation, making those resources more attractive to the model while hiding their true costs to ratepayers. For example, for the base case ARS modeling scenario, the Draft IRP attributes the selection of an SMR in 2043 to "their high capacity accreditation and greater market sales revenues." Sensitivities H and I are particularly demonstrative of this concerning reliance on market sales revenues, as Sensitivity I is modeling a 50% *increase* to gas prices, yet this sensitivity actually models 58 MW *more* gas generation than Sensitivity H that is modeling a 50% *decrease* to gas prices, appearing to be driven by a presumption of increased sales revenues. Figure 87 also raises concerns about revenues projections, as it shows that the projected total portfolio cost *increases* in Sensitivity F that has a 50% *reduction* in market power prices, while the projected total portfolio cost *decreases* in Sensitivity G with a 50% *increase* in market power prices. This least-cost methodology puts a lot of ratepayer eggs in the market sales basket. All of these flawed assumptions around gas reliability and costs lead to the incorrect assertion in the Draft IRP that "the 200 MW SC CT F Class natural gas resources is the least cost resource per accredited capacity," and all the other cost per accredited KW calculations in Table 44, but these are a product of modeling assumptions and not the true least cost outcome.

Additionally, on the topic of gas generation in the Draft IRP, rather than planning for additional gas transmission upgrades (loops, compressor stations, pipeline upgrades, new pipelines, and new storage fields), NorthWestern should be planning for system electrification and the associated leveling and ultimate decline of gas demand that follow. The consideration of gas transmission upgrades neglects to consider near-term fuel availability and price volatility challenges.

In finalizing the Draft IRP, NorthWestern should also update data associated with YCGS from 2024 data to 2025 data to give a fuller picture of the plant's operations, rather than a snapshot into the first two month's of the plant's operation at the end of 2024. This is the case for price per MWh data in Table 16, emissions data in Table 25, the 2024 8.0 Bcf total natural gas supply requirement for electric generation fuel provided in Section 6.9, and anywhere else where data is provided for YCGS. It is also unclear whether Table 16 is providing operational cost per MWh or if it includes rate-based capital costs for plants. Considering that a [2022 PSC staff memo]() indicated total cost per MWh for DGGS was $125.05, dramatically higher than the $39.66 listed in table 16, MEIC is concerned that this table presents misleading cost information for NorthWestern's owned resources. Additionally, MEIC submitted an inquiry earlier this winter about how the YCGS revenue requirement resulting from the rate case in Docket 2024.05.053 has been incorporated into portfolio costs and we are still interested in this information.

C. MISREPRESENTING COSTS OF EARLY COLSTRIP RETIREMENT

The Draft IRP erroneously concludes that "early retirement of Colstrip is expensive to customers," but ignors important costs of continuing to to operate the plant while double counting portfolio costs in early retirement scenarios. This conclusion, apparently central to the Draft IRP's major findings, appears preordained to support NorthWestern's financial interest in continuing to operate the plant and not demonstrative of a truly least-cost outcome for NorthWestern's customers.

1. UNDERESTIMATION OF COLSTRIP COSTS THROUGH 2042

For scenarios and sensitivities that assume the continued operation of the Colstrip plant through 2042, costs of operating Colstrip are severely underestimated. For starters, Section 7.8 PCM Results asserts that "[t]he existing resource partial RR calculations have been simplified such that no additional capital investments are assumed for these assets over the study period." However, it is well-known that the Colstrip plant needs tremendous capital investments to continue operating year-to-year, such as tremendous deferred maintenance needs, regular capital-intensive overhauls, and any unforeseen capital investments needed to address additional issues that will arise with operating an already aging plant for another 17 years. It is unclear whether regular overhauls are considered planned maintenance and included in the Draft IRP's cost estimates, as Section 7.6.2 Production Cost Modeling's explains that "planned maintenance for Colstrip is included in the model because it occurs on a periodic basis."

Additionally, while "fuel" from wind and solar energy is free, the cost of fuel for the Colstrip plant has always been one of the largest drivers of increasing generation costs for Colstrip. NorthWestern passes those costs on to its customers through the PCCAM, so minimizing those cost projections in the Draft IRP can make Colstrip look more affordable when the PCCAM will just be adjusted to recoup actual fuel costs. Section 2.2 Changes in the Planning Process and Content claims that, compared to the 2% annual coal fuel cost escalation used in the 2023 IRP, "NorthWestern implemented a more realistic escalation based on the historical performance of the Colstrip coal contract indices" in the 2026 Draft IRP. However, the "more realistic" coal fuel price escalation methodology in Section 7.4.1 is almost completely redacted.

It is therefore unclear whether the new escalation methodology for coal fuel costs at Colstrip adequately captures the escalations that are reasonably foreseeable at the plant. While the Draft IRP has not disclosed coal costs at Colstrip, NorthWestern's annual, publically available FERC Form 1 filings must retroactively disclose this information. Looking back at these filings, it is apparent that NorthWestern's cost of coal per ton at Colstrip increased by 57% from 2018 to 2024. When NorthWestern entered into a new coal contract at the end of 2019, the average cost per ton of coal jumped by 21%. We know that NorthWestern just entered into a new coal contract that goes into effect this year, with another likely jump in the price of coal, but the details of the contract remain hidden. The 2023 IRP used a 2% annual coal cost increase assumption, but then, according to NorthWestern's FERC Form 1 filings, the cost of coal increased by 9% between 2023 and 2024. Given the previous dramatic underestimation of coal price escalations, the public deserves to know how the current Draft IRP is estimating future price increases and whether those actually are in line with forseable escalations.

On top of all these underestimated costs, there remains tremendous regulatory uncertainty around the need for the Colstrip plant to comply with Montana's regional haze plan and the EPA's mercury and air toxics standards in the next 20 years. Colstrip is a dated plant that has not implemented the modern pollution controls employed at similar coal plants across the country, and it is highly likely that further pollution compliance upgrades will be needed over the next 17 years if NorthWestern continues to operate the plant. Regardless of the outcome of current regulations, it is clear that regulations protecting public health will remain a major factor in the continued operation of Colstrip over the Draft IRP planning horizon.

2. OVERESTIMATING PORTFOLIO COSTS IN EARLY RETIREMENT SCENARIOS

While scenarios and sensitivities involving operating Colstrip through 2042 underestimate the costs of continuing to run the plant, the scenarios looking at early Colstrip retirement overestimate portfolio costs, simultaneously making these scenarios look less attractive. A major modeling flaw that MEIC raised several times in the stakeholder process but was not addressed is the treatment of remaining Coalstrip book value after plant retirement. While ongoing fuel and O&M costs are taken out of the base revenue requirement calculations after Colstrip retirement in those scenarios contemplating early retirement, the Draft IRP assumes that the full rate base for the plant and approved rate of return on that rate base remain in effect through 2042 regardless of whether the plant is operating. So of course these scenarios are more expensive because customers are double paying for a plant that is not used and useful *and* replacement power when the plant retires. This is an erroneous and misleading assumption, because should the Colstrip plant become no longer used and useful, then customers would no longer be obligated to pay for it, and certainly would not be required to pay the full rate base plus 10% return on equity.

Montana's legislature enacted HB 467 in 2019, enabling utilities to securitize stranded generation assets to accelerate depreciation and establish lower financing costs. The Draft IRP should reflect this reality in Colstrip closure scenarios. Instead the Draft IRP assumes that customers would continue to pay the remaining $250 million rate based cost of the plant plus 10% ROE through 2042. Customers would be far better off investing that $250 million at 10% annual ROE by replacing Colstrip with wind, solar, short-/long-duration energy storage, and enhanced geothermal should that technology continue to advance. These assumptions in the Draft IRP, along with inflated cost assumptions for wind, solar, and storage technologies, result in the erroneous conclusion that early Colstrip retirement is "expensive" for customers.

Early Colstrip closure scenarios also neglect to account for the tremendous public health and societal benefits of eliminating harmful particulate and greenhouse gas emissions from the plant. Colstrip plant early closure scenarios represent the lowest total CO2 emissions futures contemplated in the Draft IRP, with Scenario B's 2029 closure representing a 30% decrease to overall portfolio emissions.

3. FAILING TO PLAN FOR COST-EFFECTIVE COLSTRIP TRANSITION

NorthWestern needs to seriously explore Colstrip plant retirement scenarios, planning for replacing its power and grid services, while planning and investing in community transition for the town of Colstrip and its citizens. A recent study from RMI analyzed specifically how NorthWestern's capacity and grid services from this resource (including the acquisition of Puget Sound Energy and Avista's shares) could be cost-effectively replaced by wind, solar, and storage resources. The Colstrip plant retirement scenarios contemplated in the Draft IRP misrepresent portfolio costs, while failing to contemplate comprehensive transition planning for the plant and community.

Analyses such as Energy Innovation's Coal Cost Crossover report have shown that 99% of existing coal plants, including Colstrip, are more expensive to continue running than replacing those resources with new, local wind, solar, and energy storage resources. Not only are these energy resources low-cost, but by siting these resources locally and taking advantage of existing grid interconnections, interconnection and network upgrade costs would become negligible. The model should be reconfigured to be able to reflect and assess this reality and explore how NorthWestern could start investing in wind, solar, and storage resources today to begin the transition at Colstrip.

VI. INTEGRATING ELECTRIC TRANSMISSION PLANNING INTO THE IRP

MEIC appreciates that Section 6 of the Draft IRP includes extensive discussion on NorthWestern's electric transmission system. MEIC highlights the key points made that "[i]nterregional transmission capacity is the key to unlocking interregional resource and load diversification benefits." and that "[i]nterregional transmission capacity could assist NorthWestern in complying with [] RA requirements." MEIC further appreciates discussion of Grid United's North Plains Connector Project in Section 6.5.1 and discussion of a potential Path 18 Montana to Idaho Project (M2I) in Section 6.5.2. Given continued progress on developing the NPC line, upgrading the capacity on the Colstrip Transmission System as discussed in the Draft IRP will also likely be an important transmission investment for ensuring adequate transmission capacity throughout Montana and connecting to neighboring regions. MEIC also notes that Section 6.2.3.4 on MATL could be updated to discuss ongoing plans to upgrade that line. Interregional transmission lines such as the NPC and M2I will be essential for unlocking key reliability and affordability benefits that come with regional connectivity and diversification.

However, as MEIC has raised throughout this process, the model still lacks a representation of discussed resource adequacy benefits from interregional transmission. This could be accomplished by representing transmission as a capacity resource or by otherwise reflecting this RA benefit in the model. As long as the model does not capture these benefits, it will overselect for expensive capacity resources that are not actually needed for resource adequacy in reality.

For example, the Draft IRP recognizes that "winter peaks remain the primary driver of WRAP capacity deficits and the timing of new generation builds." MEIC notes that during our winter peaks Montana has a particularly synergistic relationship with the Southwest U.S., which does not experience a winter peak. Abundant, low-cost solar energy could be more readily moved from the Southwest into Montana with greater interregional transmission connection. Incorporating transmission's capacity benefits in the IRP should be included as a top priority in the IRP's Action Items.

While MEIC acknowledges and appreciates that NorthWestern has approached WRAP to develop a methodology for calculating the resource adequacy benefits of interregional transmission, not having that methodology from WRAP should not preclude NorthWestern from using an accreditation proxy in the current IRP modeling. For example, Portland General Electric's IRP assumes 100% capacity contribution from its future share of the NPC based on a study commissioned from Energy GPS to look at market availability during peak need. Similarly, Astrapé Consulting conducted an analysis for Grid United that demonstrated the 3,000-MW NPC would unlock 3,550 MW of capacity across the SPP, MISO, and the Western electric grid – greater than the physical capacity of the project itself. This is due to the nature of connecting diverse regions that experience peak electricity demand at different times of day, on different days, or in different seasons. GridStrategies' June 2025 Report on the Resource Adequacy Value of Interregional Transmission also lays out how utilities can calculate an ELCC value for a given interregional transmission project.

Given these analyses, and in the absence of NorthWestern's own analysis (which MEIC maintains should have been conducted in this IRP process), NorthWestern should assume that its full 300 MW of capacity on the NPC can be relied on for contributing to peak capacity needs. Sensitivity Q should therefore be re-run with a 300 MW capacity addition from NPC introduced in 2032 to represent the line's targeted in service date. Holding all else equal in this Draft IRP, if 300 MW of capacity are enabled in NorthWestern's Montana service territory by the North Plains Connector, the base case would be nearly resource adequate without any additional resources through 2040 (the capacity forecasts demonstrate a 246 MW summer capacity deficit in 2040 and 323 MW winter capacity deficit in 2039-2040).

NorthWestern should continue improving the integration of its transmission planning into the IRP process in order to identify where transmission upgrades, reconductoring, and new builds can unlock access to lower-cost resources and associated reliability benefits from greater grid connectivity. Planning transmission and generation side-by-side will allow for truly identifying the least-cost energy system to meet the reliability and affordability needs of the system into the future.

Other utilities integrate transmission and resource planning to varying degrees of effectiveness, and NorthWestern Energy has the opportunity to learn from these utilities' efforts. Interwest Energy Alliance released a report in September explaining that utilities across the West can and should integrate transmission planning into integrated resource plan development, and assessing a number of Western utilities' successes and shortcomings in doing so. The report also outlines steps and specific modeling and analytical methods that utilities can use to evaluate transmission expansion opportunities in IRPs. These steps and methods are included below:

Step 1: Represent Transmission Constraints in IRP Models

A. **Resource Expansion Limits** in capacity expansion models – Constrain new resource additions by zone based on known transmission capacity.
B. **Transfer Limits** in production cost models – Apply transfer limits between load/resource zones and market zones to reflect known transmission constraints.

Step 2: Quantify the Value of Transmission Expansion Options

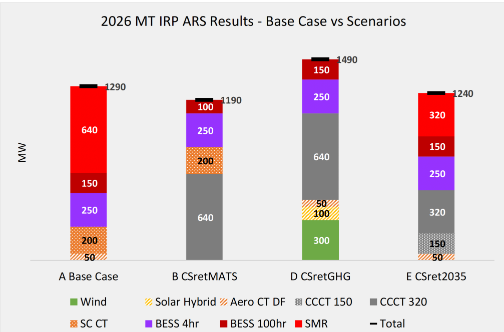
A. **Transmission Scenarios** – Model scenarios with specific transmission changes (e.g., new lines or rebuilds) to assess impacts on portfolio cost and composition.
B. **Transmission Expansion Options** in Capacity Expansion Models – Allow the model to exceed zonal limits by incurring costs that reflect necessary transmission upgrades.
C. **Transmission Planning Studies** Explicitly Integrated with the IRP Analysis – Use transmission planning studies to ensure that IRP models include accurate transmission constraints and upgrade options and that the final portfolio evaluation includes transmission costs required to deliver new resources.

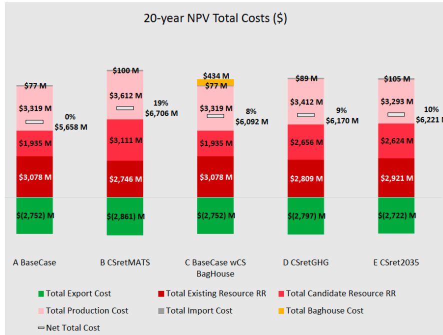
Further integrating transmission planning into the IRP is not only possible, but it is necessary in order for NorthWestern to rise to the challenge of providing reliable and affordable electricity into the future.

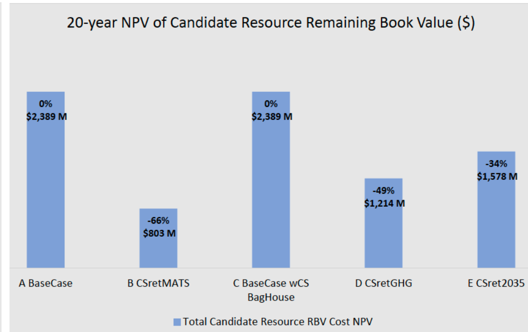
VII. NUCLEAR COSTS AND AVAILABILITY ARE INADEQUATELY REPRESENTED

The Draft IRP models numerous future portfolios with Small Modular Nuclear Reactors, the most expensive energy sources available, even though the technology is not commercially deployable at this time. Not capturing the true costs of a nuclear-heavy portfolio, the Draft IRP portfolio cost estimates only include costs within the 20-year planning horizon. That means that the costs for a nuclear plant built to replace Colstrip in 2043 are almost completely excluded from the total portfolio costs. Since the Draft IRP assumes a 60-year book life for such an asset, only the first three years of amortization are captured in a 20 year NPV cost analysis that looks at costs from 2026 to 2045. Meanwhile, no SMRs have been built and operated to test whether a 60-year book life would actually be feasible for such a facility.

Additionally, the nature of a NPV analysis for total portfolio costs in 2026 means three years of expenses for an SMR built at the end of the planning horizon are shrunk down significantly through 17 years of backward discounting. This is acutely apparent when comparing total portfolio cost 20-year NPV with the remaining book value of the corresponding scenario and sensitivity portfolios. Portfolios including SMR resources, such as the base case scenario, show relatively lower total portfolio costs, but much higher remaining book value, reflecting the remaining 57 years of amortization for SMRs. Examining remaining book value also demonstrates that, under current model assumptions, while more investment is needed up front to replace Colstrip in early retirement scenarios, the remaining costs in the portfolio after the 20-year horizon are much lower. The Draft IRP's 20-year NPV Total Costs graphics should be updated to reflect each portfolios remaining book value so *total* portfolio costs can be more readily examined. This could be accomplished by listing the remaining book value at the top of each 20-year NPV bar chart, or by graphing remaining book values as additional bars alongside each portfolio NPV.







The fact that nuclear is only selected in scenarios and sensitivities with the carbon-emitting resource constraint, despite the high costs of gas alternatives without the carbon-emitting resource constraint, is indicative of the outrageous costs of nuclear energy. If the modeling assumptions discussed above that undermine and limit wind, solar, and storage were rectified, then nuclear would have no place in the Draft IRP's modeling outcomes. And, the modeling assumes that SMRs will even be available over the 20-year planning horizon. This may be the case, but there has yet to be a commercially operational SMR in the U.S., so the reliability of cost estimates and availability of these resources for a future Montana portfolio remain tenuous at best.

Additionally, while the cost estimates used for SMRs in the Draft IRP modeling are much higher than the other candidate resources, they still may be underestimates. For example, the Vogtle nuclear plant's units 3 and 4 that came online in 2023 and 2024 cost as much as $36.8 billion to build, at 2,234 MW total nameplate capacity. That comes out to $16,473 per KW, compared to the $11,015 per KW overnight cost used in the Draft IRP modeling for SMRs. While SMR designs are supposed to bring design costs down through their modularity, pilot projects such as NuScale's failed project at the Idaho National Lab have demonstrated that these types of plants are prone to similar cost overrun issues as traditional larger nuclear facilities. Many analysts have also speculated that SMRs will actually cost more per unit of energy than larger nuclear facilities given lost economies of scale.

Beyond these cost and availability assumptions around nuclear, NorthWestern also makes no acknowledgement of the risks of nuclear power throughout the Draft IRP. Risks surrounding uranium extraction, processing, and transportation are not addressed, nor is nuclear waste disposal. And there is no discussion of workforce safety risks and public health risks from radiation exposure, let alone the potential impacts of a more catastrophic failure at a nuclear facility. These risks are particularly prevalent given the current deregulation of nuclear safety standards at the federal level. These risks should all be addressed in the Draft IRP.

A. ENHANCED GEOTHERMAL AS A MORE VIABLE ALTERNATIVE

Meanwhile, enhanced geothermal systems (EGS), a technology that is arguably a lot further along than SMRs, has not been modelled as a candidate resource in this Draft IRP. Advancements in drilling technologies are allowing developers to drill deeper wells at lower costs in order to access geothermal heat in virtually any geographic location. This creates a major potential for this energy source to expand dramatically in the coming years as costs continue to decline. When done right, enhanced geothermal can be carbon-free, can supply energy on-demand to complement low-cost wind and solar, requires no fuel, has a minimal land footprint, and can utilize existing oil and gas workforce and infrastructure.

Despite the continued struggle to bring a single SMR pilot project online, leading EGS developer Fervo Energy brought its 3.5 MW pilot project online in 2023, and is expanding its operations from there. The developer's Cape Station project is ontrack to bring 100 MW online this year, with another 400 MW on the way in 2028. NV Energy modeled a power purchase agreement with one of Fervo's enhanced geothermal projects in its 2024 Draft IRP at $107 per MWh, similar to the historical performance of NorthWestern's contract with YELP as listed in Table 21, and these enhanced geothermal costs continue to decline. Given the rapid development and emerging availability of this energy resource compared to experimental SMRs, EGS should be considered as a candidate resource in the IRP's 20-year planning scope. At a minimum, enhanced geothermal resource should be included in NorthWestern's next IRP.

VIII. IGNORING CLIMATE CHANGE

As MEIC has raised on multiple occasions, none of the scenarios and sensitivities contemplated in the Draft IRP are in line with NorthWestern's Net Zero by 2050 Vision. This is despite the claim in the Executive Summary that "NorthWestern will … ensur[e] progress toward the Company's 2050 Net Zero goal." The PSC's comments on the 2023 IRP also recommended that NorthWestern evaluate the net zero by 2050 commitment. However, all contemplated portfolios would lead to significant carbon-emitting resources in the electric portfolio beyond 2050, including in scenarios and sensitivities that do not allow carbon-emitting resources to be built after 2035. Even Sensitivity N that allows for no new carbon-emitting resources throughout the entire planning period would still have emissions past 2050 from existing fossil fuel resources such as YCGS, while maintaining tremendous total emissions throughout the planning cycle due to the continued operation of Colstrip. This no-carbon-emitting-resources sensitivity should at a minimum be combined with the early Colstrip plant retirement scenarios, but the IRP also needs to model scenarios that would actually result in a carbon neutral portfolio. Specifically, the IRP should examine scenarios to reach full-portfolio carbon neutrality by 2040 and by 2050, including considerations for early Cosltrip retirement. If NorthWestern does not intend to plan for reaching net zero by 2050, then it should stop claiming this goal when it is beneficial to its public image.

MEIC is extremely concerned that the Draft IRP completely ignores climate change, despite the increasingly apparent impacts of a changing climate on Montana's energy system. The only time that "climate change" shows up in the document is in Section 2.3.2 Comments on 2023 MT Draft IRP, referencing stakeholders' "strong concerns regarding the [2023] Draft IRP's lack of attention to climate change and environmental impacts." Rather than addressing and incorporating those concerns, the 2026 Draft IRP outright omits any discussion of climate change while admitting to having "narrowed the scope of the environmental section." And while the Draft IRP purports that "Sustainability" is one of its three planning objectives, the contemplated future portfolios represent far from a "phased transition toward lower-emission and more efficient resources." Concerningly, this planning objective conflates "sustainable and dependable fuel supplies" with environmental sustainability.

Section 2.3.2 dismisses stakeholders' previous concerns that the IRP must take into account the implications of the *Held v. State of Montana* climate case, falsely claiming that "the Commission addressed the effect of *State of Montana v. Held* in the MEIC's petition for rulemaking in Docket 2024.03.028." However, MEIC reminds NorthWestern that Docket 2024.03.028 remains unresolved before the PSC. While the PSC declined petitioners' request for declaratory ruling in September 2025, petitioners subsequently filed a motion for reconsideration which has not been acted on by the PSC since they suspended their deadline to respond to the motion. Furthermore, the PSC has not yet addressed petitioners' request to initiate rulemaking to incorporate consideration of climate impacts into the PSC's regulation of utilities. Regardless of the final outcome of this docket, NorthWestern has a constitutional obligation to maintain and improve a clean and healthful environment, including a stable climate, for present and future generations.

Despite not acknowledging climate change throughout the Draft IRP, there are many instances where the Draft IRP discusses the impacts of climate change indirectly without calling them what they are. Section 3 Regional Outlook opens with a discussion on "ever-hotter summer heatwaves that push demand even higher," and "a growing threat of prolonged drought," yet fails to acknowledge that these risks are driven by climate change. Section 8.3 further acknowledges that "[e]xtreme weather events are occurring with increasing frequency and severity across the Pacific Northwest, introducing additional uncertainty for both electric demand and resource performance during critical periods," again failing to acknowledge the roll of climate change. A comprehensive consideration of climate risks and mitigation strategies should be incorporated into Chapter 8, discussing climate change explicitly and acknowledging fossil fuel infrastructure's contribution to these risks. This additional IRP section should also incorporate climate resiliency and adaptation planning to anticipate and respond to future climatic changes in Montana.

While the Draft IRP discusses climactic trends, PowerSIMM's simulations for load forecasts and renewable generation do not incorporate these trends. Instead, the models rely on historic weather data to produce inherently skewed future weather projections. This is concerning, particularly given the Draft IRP's assertion that "[w]eather is the primary driver of simulations." The PowerSIMM model's weather forecasts must be adjusted to account for climate trends that will impact future load and renewable generation profiles.

A. GREENHOUSE GAS EMISSIONS

Despite failing to mention climate change, MEIC acknowledges that the Draft IRP does outline the portfolio carbon emissions of each scenario and sensitivity. Notably, the Draft IRP makes no mention of "greenhouse gases," other than referencing EPA's greenhouse gas rules, neglecting to discuss what these emissions are and their implications for a changing climate. Instead, the Draft IRP lays out 2024 CO2 emissions for existing thermal resources, includes emissions rates for SO2, NOx, and CO2 for the various gas candidate resources considered, and graphs CO2 emissions for each contemplated portfolio. Despite the Draft IRP's heavy reliance on gas generation, fueled predominantly by methane, the Draft IRP fails to mention methane emissions associated with leaks in methane extraction, processing, storage, and transmission, nor does it discuss methane's potency as a greenhouse gas with 86 times the climate warming potential per unit of mass compared to CO2 over a 20-year period.

The Draft IRP acknowledges that stakeholders in 2023 requested an analysis of the social cost of greenhouse gases, and that again for this 2026 IRP, "ETAC expressed a desire for NorthWestern to incorporate environmental externalities such as presenting the impact of a social cost of carbon on NorthWestern's portfolio." MEIC is disappointed that despite these requests, a social cost of greenhouse gases analysis is not included in this Draft IRP. This is also despite the requirement in ARM 38.5.2020 that "the cost-effectiveness of all resource acquisitions will be evaluated with respect to long-term total costs, including scenarios based on societal costs." ARM 38.5.2021 defines societal cost as "all costs to a utility plus externalities." So it follows that the Draft IRP should be updated to include a social cost of greenhouse gases analysis for each of its portfolios.

Based on the EPA's 2023 Report on the Social Cost of Greenhouse Gases, the 2026 social cost of greenhouse gas emissions for CO2 in 2020 dollars at a 2.0% near-term Ramsey discount rate is $215 per ton. Adjusting for inflation, that would be $271.07 per ton in 2026 dollars. The social cost of greenhouse gases can then be easily calculated using emissions data such as the data provided in Table 25 in the Draft IRP. However, as mentioned earlier in these comments, 2025 data should be used for YCGS since the plant did not come online until the end of October 2024. The 41,228 tons of CO2 emissions listed in Table 25 for YCGS in 2024 only represents around two months of operations, so an entire year might be closer to 247,368 tons (41,228 * 6). For NorthWestern's existing thermal resources (excluding additional Colstrip shares), that results in a portfolio-wide social cost of CO2 emissions in 2026 of over $825 million. Factoring in a

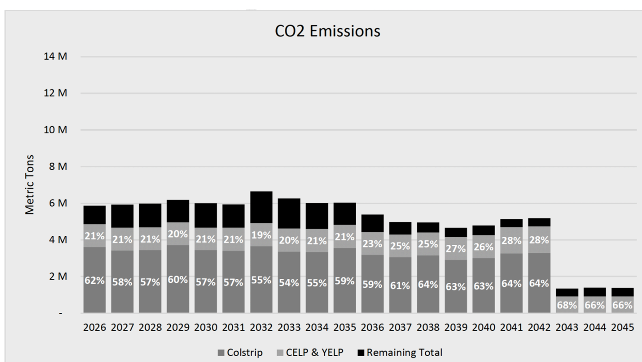
267% increase to Colstrip emissions, proportional to NorthWestern's additional Colstrip shares from Avista and Puget Sound Energy, adds nearly $1 billion to this annual social cost of NorthWestern's portfolio for a total ***$1.813 billion*** annual social cost. This must be represented in the IRP.

Resource	CO_2 (Metric Ton)	Metric Tons of CO_2/MWh
Colstrip	1,364,993	1.03
CELP	391,171	1.36
YELP	673,731	1.76
YCGS	41,228	0.47
Basin Creek	82,795	0.50
DGGS	286,948	0.60

TABLE 25: 2024 HISTORICAL EMISSIONS.

SCGHG Analysis Example	Resource
$370,008,653	Colstrip
$106,034,723	CELP
$182,628,262	YELP
*(247,368 tons) $67,054,044	YCGS
$22,443,241	Basin Creek
$77,782,994	DGGS
$825,951,917	**Total**
$1,812,641,658	**w/Additional Colstrip**

Additionally, emissions graphs outlining the annual and total CO2 emissions of each contemplated portfolio should be broken out with more granularity for each individual generation facility. While Colstrip makes up the biggest share of emissions, the scale of these graphs could be adjusted to fit more information into taller bars and show emissions by source. For example, as can be seen in the base case emissions graph below, the Y-axis scale could be reduced to 8 or 10 million metric tons to break down more granularity in the "remaining total." This scale adjustment would work in all scenarios and sensitivities other than possibly the data center sensitivities that have much higher emissions. At a minimum, the Draft IRP should differentiate between the emissions associated with existing generation infrastructure versus emissions from contemplated new generation infrastructure.



B. PUBLIC HEALTH IMPACTS

In addition to ignoring climate change, the public health impacts of coal, gas, and nuclear power generation are not mentioned or addressed throughout the entire Draft IRP. The closest the Draft IRP comes to discussing these issues is in Section 2.3.2 Comments on 2023 MT Draft IRP. This section relays that in 2023, Tribal representatives expressed concerns that "the harmful environmental and health impacts of continued coal use, particularly on the Northern Cheyenne Tribe, were not addressed." However, the Draft IRP does nothing to incorporate those concerns and completely ignores any public health impacts of its proposed resource portfolios. This is despite the Colstrip plant's highest rate of harmful particulate emissions out of any coal plant in

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the country, and despite the tremendous public health implications of gas and nuclear generation. Analysis of public health impacts must be included in the IRP.

IX. IMPORTANCE OF MODELING DAY AHEAD MARKET PARTICIPATION

NorthWestern faces a critical decision on the horizon on whether to join the Energy Day Ahead Market (EDAM), independently governed in the West, or to join the Southwest Power Pool's Markets+. This decision will have tremendous implications for future electric reliability and affordability in NorthWestern's Montana service territory. As has been requested previously by MEIC, the Draft IRP should include modeling on the the costs and benefits of participating in either market, including the costs of leaving the real-time Western Energy Imbalance Market (WEIM) managed by the same entity as EDAM should it choose Markets+. The Draft IRP acknowledges that participation in WEIM has "proven to be beneficial to customers." In fact, the WEIM has created $202.64 million in benefits to NorthWestern and its customers since joining the market in 2021. Market participation modeling should incorporate costs and other challenges associated with selling power across potential market seams between these overlapping markets.

In a meeting of the Governor's Energy Taskforce, a representative from NorthWestern indicated that the utility has conducted an internal analysis on the costs and benefits of joining EDAM versus Markets+. While consideration of the implications of joining either of these competing day ahead markets should be integrated throughout the IRP, this analysis should be included as an appendix at a minimum.

X. CONTRACT EXTENSIONS & NEW CONTRACTS

MEIC again raises the issue that the IRP model's inability to contemplate future capacity contracts and power purchase agreements leads to a major overestimation of future new-build capacity needs. MEIC appreciates that the Action Items laid out in Table 2 includes "evaluate extensions of contracts," but that evaluation should have happened concurrently with the development of this Draft IRP. Much of the capacity needs identified throughout the Draft IRP are a result of future contract expirations. This is especially true over the first 10 years of the planning horizon where the expiration of Powerex (100 MW) and Heartland (150 MW) capacity contracts and the expiration of renewable energy contracts such as Judith Gap wind facility (39 MW) contribute to more than the entire identified capacity need of 149 MW in summer 2035 and 237 MW in winter 2035-36. Without exploring whether existing contracts can be extended or if new capacity contracts and power purchase agreements can be entered into, the model is not weighing all cost-effective options when selecting to build new generation infrastructure in the next 10 years.

While it has been pointed out that capacity contracts and PPAs would have an opportunity to bid into any future request for proposals resulting from this Draft IRP, neglecting to consider these contracts in the Draft IRP further solidifies a predisposed bias toward expensive new-build projects over contracts that mean more affordable energy for NorthWestern's customers. And this is an ongoing cycle. Previous IRPs have projected the expiration of certain renewable energy contracts, such as the Judith Gap wind facility, demonstrating a looming capacity need. Rather than taking this as an opportunity to proactively negotiate contract extensions and new contracts, this looming capacity need has instead been used to justify, in part, the investment into new expensive resources such as YCGS. However, once these resources have been built or acquired, their expensive surplus capacity has been used to help justify not extending cheaper contracts with existing renewable resources. This happens despite the fact that it would be cheaper to NorthWestern's customers to forego these costly investments into new infrastructure and instead plan to renew contracts from the beginning.

The IRP should contemplate contract renewals for existing low-cost wind and solar resources (such as Judith Gap) that could continue providing energy to NorthWestern at a lower cost than the new-build resources selected throughout the Draft IRP model runs. The IRP should also make clear which of its expiring contracts it intends to renew, such as the contract with the 10.5 MW Broadwater hydro facility that expires at the end of June 2026. These are valuable resources, and NorthWestern should prioritize keeping them in its portfolio rather than planning to build expensive and polluting resources to replace them. Additionally, the IRP model should be re-configured to contemplate new capacity contracts and capacity contract renewals, as well as new renewable energy PPAs.

XI. DEMAND SIDE MANAGEMENT

MEIC appreciates the Draft IRP's inclusion of section 4.2 Demand-Side Management Acquisition and Programs, as well as the inclusion of Sensitivity R to look at a future with increased DSM and NEM. However, the Draft IRP still has a lot of room for improvement in incorporating the tremendous potential for demand side management and energy efficiency to reduce capacity needs.

Regarding NorthWestern's DSM acquisition plan, annual DSM acquisition targets should equal the economically feasible potential DSM determination, rather than the arbitrary "achievable potential." Table 14 demonstrates that NorthWestern's total DSM acquisitions from 2013-2014 to 2024-2015 have exceeded targets by nearly 30 MW, an indication that annual DSM targets could be significantly more ambitious. Figure 109 exemplifies the benefits of increasing DSM measures, showing that Sensitivity R's 20-year NPV total cost is 10% less than the base case (this is displayed incorrectly as 4% in Table 1, which should be corrected). Table 110 furthers this exemplification, showing that the remaining book value for the Sensitivity R portfolio is 27% less than the remaining book value for the base case portfolio.

The biggest shortcoming regarding DSM is the IRP model's absence of any DSM measures specifically targetted at load shifting and load shaving during peaking events. Potential demand response programs are mentioned briefly in Section 4.2, but then promptly dismissed. The Draft IRP should incorporate measures such as large load curtailment agreements and virtual power plant coordination to tactfully shift and shave non-essential electricity demand in times of peak demand throughout the year. Smart meters can help facilitate these measures, but Section 10.3 Advanced Metering Infrastructure only hints at AMI's capabilities for enabling important DSM and DR measures without providing information on how NorthWestern intends to take advantage of these capabilities. The infrastructure is in place and customers are paying for it, so we should know how NorthWestern intends to make these a worthwhile investment rather than an acknowledgment that this technology *could* assist DSM and DR. Modeling the ability of DSM measures to lower peaks will prevent NorthWestern from overbuilding expensive generation infrastructure.

Section 2.2.1.2 ETAC Comments on 2026 Draft IRP references comments from ETAC that demand response has been underutilized as a resource, and that NorthWestern should use third-party DR aggregators to take advantage of this potential. MEIC is disappointed that NorthWestern's response to these comments dismisses behavioral and direct load control options as "difficult to scale during Montana's extreme cold winters where safety is important." MEIC agrees that safety is important during Montana's extreme cold winters, but disagrees that scaling DLC options is incompatible with maintaining safety. As brought up by ETAC, NorthWestern should consult with third-party DR aggregators – or virtual power plant providers – before dismissing this option as infeasible for winter peak conditions. While space heating and domestic hot water are essential in extreme winter conditions, other significant household loads such as EV charging and operation of high-demand appliances such as washing machines, dryers, and dishwashers could all be coordinated through a VPP to shift non-essential electricity uses away from peaking hours.

MEIC is also concerned with the Draft IRP's use of a Net Cost of New Entry (CONE) methodology rather than Gross CONE for determining avoided-cost calculations for DSM acquisitions. Given that neighboring utilities generally use a Gross CONE methodology, it is unclear why this switch was made. Similar to previous concerns raised in these comments around PowerSIMM's forecasts for energy market sales revenues, it appears Net CONE calculations could also be swayed by inacurate forecasts. If the model projects that generation alternatives to DSM acquisitions will offset their capital costs through energy sales revenue, but then those energy sales revenues never materialize, then customers could be stuck paying for more expensive resources despite the model's assertion that a given alternative beats out DSM acquisitions based on a Net CONE calculation. NorthWestern should rectify PowerSIMM's market sales projection methodology before incorporating anticipated revenues into avoided-cost calculations. Until then, a Gross CONE methodology should be used.

Finally, Section 2.2 claims that "NorthWestern's changes to its planning process and the content result in an IRP that satisfies the Commission's rules adopted in 2023." However, this ignores the two ARM waiver requests that NorthWestern has submitted to the PSC regarding certain DSM data. One of these waiver requests is acknowledged in Appendix B, but not the more recent waiver request for ARM 38.5.2022 (1) (f) (iii). MEIC will refrain from rehashing our concerns with those requests here, as we have laid those out in PSC Docket 2025.05.038. However, MEIC is concerned that these waiver requests are not mentioned in the DSM section of the Draft IRP. In light of these waiver requests, the claim that the IRP satisfies the Commission's rules is misleading.

XII. PLANNING RESERVE MARGIN

Explanation around the Draft IRP's summer and winter planning reserve margins remains significantly lacking. This is concerning considering the implication of the PRM on the Draft IRP's identified capacity need. For example, the 20.9% winter PRM adds over 250 MW to the peak capacity requirement on top of the roughly 1,200 MW load forecast for 2026-27. While NorthWestern has indicated that the PRM comes from WRAP and is outside the utility's control, the Draft IRP should provide better explanation on how this number is determined.

Currently, Section 7.2 Resource Accreditation defines PRM as "the difference between the total resource accredited capacity and the peak load forecast, all divided by the peak load forecast." This is an unhelpful definition that gives the mathematical relationship between the PRM and the peak load forecast without providing any insight into how the PRM percentage is actually determined. Presumably, the PRM percentage is determined as a function of load forecasts across WRAP regions to determine a necessary reserve margin of accredited resource capacity on top of that load forecast threshold, but this definition does nothing but confuse the origin of the PRM percentage.

Table 36 shows WRAP PRMs for 2025 summer months, and the Draft IRP should include a similar table with WRAP PRMs for winter months. A [WRAP presentation] from June 2025 showed winter 2026-27 PRM values for the MID C region (which includes NorthWestern) of 29.4% in November, 12.7% in December, 13.2% in January, 10.6% in February, and 18.8% in March with similar month-to-month PRMs looking forward to winter 2029-2030. While WRAP currently defines the winter season as November 1 - March 15, the Draft IRP acknowledges that the WRAP PRM Task Force has proposed changing the winter season to November 20 - February 28/29. This makes sense considering that NorthWestern's historic winter peaking events generally occur in December, January, and February. It is unclear where the 20.9% winter PRM in the Draft IRP comes from, but WRAP's winter PRMs for December, January, and March would indicate that NorthWestern's winter PRM should fall between 10.6% and 13.2%. That could amount to a significant difference in demonstrated capacity need in the Draft IRP upwards of 100 MW.

Whether or not the PRM percentages used in the Draft IRP come from WRAP, much more detailed explanation is needed on how these percentages are determined. The Draft IRP should explain and share what information NorthWestern shares with WRAP for calculculating PRMs, as well as explaining WRAP's methodology for determining PRMs. Further explanation should also be provided as to why NorthWestern uses uniform seasonal PRMs rather than using the more granular month-to-month PRMs provided by WRAP. Simply asserting that a 20.9% winter PRM means NorthWestern needs an additional 250 MW of accredited generation capacity in excess of its load forecast without any supporting justification is extremely troubling. Upon improving clarity around the PRM's used in the Draft IRP, the ARS capacity modeling result figures should be updated to show lines for load forecast without PRM in addition to LF + PRM lines, similar to the capacity need figures used earlier in the Draft IRP.

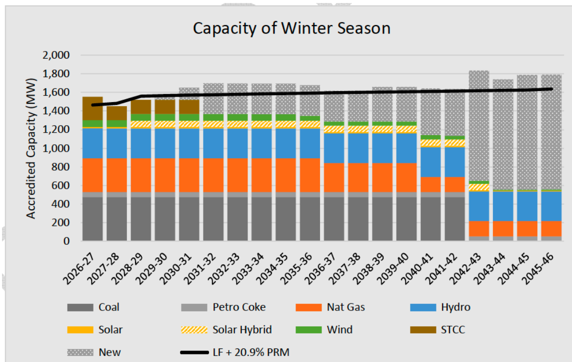

FIGURE 50: WINTER CAPACITY FORECAST WITH AN OVERBUILD CONSTRAINT.

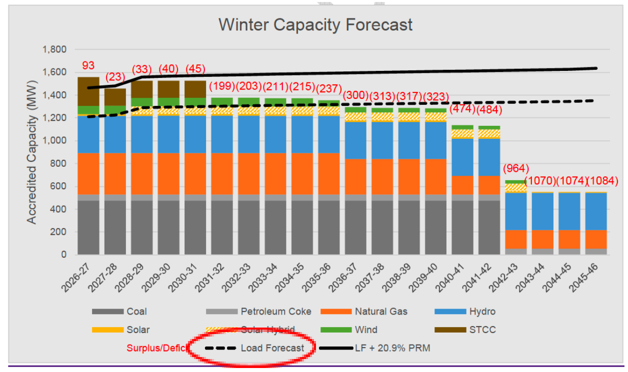

FIGURE 3: NORTHWESTERN'S WINTER CAPACITY FORECAST.

XIII. DATA CENTERS

MEIC believes that examining data center demand growth through specific sensitivities rather than as part of the base case assumptions makes sense as it is unclear whether data center demand will materialize, the magnitude of demand they will create, and how quickly that demand will show up. However, major data center announcements have been made for NorthWestern's system that amount to as much as 1,400 MW of known developments, significantly more than the 1,160 MW explored in the largest data center development sensitivity. This data center load growth also has the potential to be even greater with as many as 11 other data centers in discussion with NorthWestern for projects in Montana or South Dakota. With this in mind, additional 1,400 MW and 2,000 MW data center sensitivities should be run to show the system-wide impacts of this magnitude of data center development. The IRP should also explore load flexibility requirements from such large loads during peak events to examine how those measures could reduce the overall portfolio capacity need. Additionally, as has been requested previously by MEIC, NorthWestern's existing letters of intent and related agreements with data centers, as referenced in the Draft IRP, should be appended, unredacted, to the final IRP.

The Draft IRP also discusses the "opportunity" that data centers present to Montana's energy system to "increase utilization of existing assets, and improve overall system load factors." While NorthWestern continues trying to characterize data center load growth as an "opportunity," the company has still provided no binding assurances that this load growth will not negatively impact existing customers and the overall reliability and affordability of Montana's electric system. This is despite the readily apparent information in the Sensitivity L model outcomes that show a nearly doubling of portfolio emissions and a more than doubling of total portfolio costs with 1,160 MW of data center deployment. These costs are particularly concerning given the potential for existing customers to be left on the hook to pay for infrastructure investments in the case that projected data center load growth never materializes. The Draft IRP also does not discuss the risk of data center demand further constraining the transmission system, particularly during critical peak times.

A recent study from Berkeley Lab and The Brattle Group has often been cited as a justification for supporting data center build out. This study identified historic links between load growth and lower electricity costs, but arguments pointing to this study as justification for data center build out gloss over a number of key details. First off, the study focussed on past load growth trends, clarifying that rapid and significant load growth from data centers very well could result in different results, including potential upward pressure on retail electricity rates. A significant finding of this study that has been overlooked is that residential customers and customers of investor-owned utilities have experienced greater rate increases than other customer classes and customers of coops and public utilities.

A 2024 report also published by the Berkeley Lab acknowledges that "ratepayers could be unduly burdened by cost recovery" if "investments are made on the grid side" to serve data centers "but the expected load fails to show up." This risk is apparent from American Electric Power (AEP) Ohio's recent implementation of a large load tariff that requires data centers to pay for at least 85% of their projected energy needs regardless of whether that need fully materializes to cover infrastructure costs to supply electricity to these facilities. This assurance to existing customers, along with the introduction of a load study tariff for data center proposals, called the hollow bets of fly-by-night data center developers, and as a result AEP Ohio's interconnection requests dropped by *17 GW*. Montanans do not have such assurance that data centers will have to pay for stranded infrastructure costs, and we cannot afford to pay for giggawatts of unused generation infrastructure. The data center sensitivities in NorthWestern's IRP should examine the costs to customers if investments are made to serve projected data center load but then those loads never materialize.

Some amount of data center development might lead to higher utilization of existing grid infrastructure and therefore decrease per unit system-wide costs by spreading total costs over more customers. However, even if this is the case, this leaves the question of how these costs are spread among customer classes and whether data centers are being subsidized by residential customers. The study from Berkeley Lab and The Brattle Group found that despite commercial customers driving recent load growth, residential customers have disproportionately born increasing system costs. MEIC is concerned that without proper guardrails, data center load growth will similarly and unfairly drive up residential electric bills. When data center development necessitates major energy infrastructure investments then those facilities certainly can and do increase system-wide costs and the costs for existing customers. This is supported by the Draft IRP's modeling of Sensitivity L, which shows that system-wide costs per MWh increase with 1,160 MW of data centers deployed. The Draft IRP should include more detail on how NorthWestern intends to protect existing customers, particularly existing residential customers, from increased costs associated with serving new large data centers.

Additionally, the way that data center sensitivities have been structured in this Draft IRP makes it challenging to compare those sensitivities with the other scenarios and sensitivities explored in the Draft IRP. Other than Sensitivity O that assumes Puget Sound Energy's Colstrip share is used for serving retail load, the data center sensitivities are the only model runs that include this share of the Colstrip plant. This makes it difficult to understand the implications of portfolio cost information for the data center sensitivities compared to outcomes in other model runs. In claiming that, for the data center sensitivities, "the resulting system-average cost per megawatt-hour generally declines or remains relatively stable relative to the Base Case portfolio," is therefore an apples to oranges comparison. Factoring in the issues around Colstrip cost and reliability assumptions addressed earlier in these comments, these data center load growth sensitivities are likely significantly underestimating total portfolio costs and per MWh costs by relying on the assumption of acquiring the PSE share at $0, despite tremendous unrepresented costs for that portion of the plant. Without illusory projections for data center load growth, there is no justification for NorthWestern's acquisition of additional Colstrip shares, and existing customers should not be on the hook for the tremendous and unnecessary risks associated with these acquisitions.

XIV. BLACK HILLS ENERGY MERGER NOT ADDRESSED

MEIC is also concerned that the Draft IRP includes no mention of NorthWestern's proposed merger with Black Hills Energy. This topic was brought up in both ETAC and Stakeholder Working Group meetings, but NorthWestern had expressed that it would not change anything related to the 2026 Draft IRP. However, this potential merger has tremendous potential to influence NorthWestern's future electric planning. At a minimum, MEIC believes a section discussing this development and its potential implications for NorthWestern's future Montana electric system should be included in the Draft IRP.

XV. IRP PROCESS

While MEIC acknowledges and appreciates improvements to transparency and public participation that have been made by the resource planning team, there is still a long way to go. There are countless assumptions and decisions in this Draft IRP that were not made clear until the release of the draft, and it would have been tremendously beneficial for ETAC and Stakeholders to have been given a greater role in influencing these decision as the plan was developed. This is supported by the ETAC discussion referenced in the Draft IRP around "the need for earlier, clearer communications with stakeholders and the public." The Draft IRP claims that "NorthWestern engaged ETAC and stakeholders early in the 2026 Draft IRP planning process to ensure an understanding of modeling inputs and cost assumptions," but that was not exactly the case for stakeholder engagement as explained further below. With earlier proactive input, issues in the Draft IRP laid out throughout these comments could have been tweaked prior to running any of the modeling. Having worked through the stakeholder process to now have a draft IRP in hand, it is clear that deep barriers within NorthWestern's company culture have impeded a truly transparent and collaborative process.

From the beginning, it has often been pulling teeth to gain even superficial access to this process and the relevant materials that should be publicly available as a given. With acquisitions of Avista and Puget Sound Energy's Colstrip shares already in motion, it is hard to feel that this process determined a least-cost portfolio rather than simply retroactively justifying decisions already made by NorthWestern's executives.

A. ETAC & THE STAKEHOLDER WORKING GROUP

Opportunities for public engagement in the Draft IRP's development remained minimal, with access to ETAC severely limited compared to previous IRP cycles. After holding closed meetings without public notice for the first three ETAC meeting, ETAC's structure was only marginally improved in response to requests from the PSC. While the public was granted view-only access, meetings were frequently not given adequate notice, often posted to the resource planning webpage only a day or so in advance; meeting materials were not available in advance, and often would not become available until weeks after a meeting took place; and agendas and meeting minutes were minimal. With that in mind, the Draft IRP's assertion that NorthWestern's resource planning website was "comprehensive" feels somewhat disingenuous.

In lieu of direct public participation in ETAC meetings, the public was directed to a feedback form on the resource planning website, but that feedback and any responses to it currently do not appear to be reflected in the Draft IRP. The Draft IRP does include discussion on topics raised by ETAC, though many of the concerns that ETAC raised are subsequently dismissed and it is unclear whether engagement with ETAC substantially steered the development of the Draft IRP. It remains crucially important that NorthWestern identify accountability mechanisms to ensure that issues and ideas raised in public comments, ETAC meetings, and Stakeholder meetings are recorded and incorporated into the IRP.

On top of all this, ETAC membership remains inadequate. After carving important stakeholders out of the process in assembling this cycle's ETAC in 2023, it took many months of prodding from stakeholders, and eventually the PSC sending multiple letters to NorthWestern, before the Stakeholder Working Group was finally stood up in mid-2025 for those stakeholders who had not been invited to participate in ETAC to finally have a voice in the Draft IRP's development. However, by mid-2025, the Draft IRP had already been under development for nearly a year and a half.

The first ETAC meeting took place a year and a half before the establishment of the Stakeholder Working Group, but the Draft IRP asserts that the Stakeholder Working Group was established "in parallel" with ETAC to "provide early feedback from non-technical and community-oriented participants." MEIC contends that this forum did not allow for the opportunity for *early* feedback as the Draft IRP cycle was already halfway through. Participants in the Stakeholder Working Group also demonstrated considerable technical understanding of the IRP process and Montana's electric system, despite the characterization in the Draft IRP that this was a group of "non-technical voices."

MEIC has highlighted throughout the Draft IRP's development that the current ETAC membership is not adequately broad-based as required by Mont. Code Ann. § 69-3-1208, lacking representation for Montana-based NGOs and concerned ratepayers throughout the state. A truly broad-based advisory committee would accommodate participation from all qualified and interested government officials and relevant parties, including but not limited to large and small-scale energy developers, low and fixed-income customer advocates, independent economists, Montana-based energy-focused NGOs, regional market representatives, academics, and qualified members of the public. It remains unclear why a distinction was made between ETAC and the Stakeholder Working Group.

The Draft IRP includes summaries of concerns raised by ETAC for the 2026 Draft IRP, as well as concerns raised by stakeholders in 2023, but the current draft does not include any discussion of concerns raised by the stakeholder group in the current planning process. Presumably that will be included in the final IRP, but MEIC is concerned that issues raised throughout the stakeholder process are not being given adequate weight in shaping the IRP. To that end, the cursory discussion of concerns raised by ETAC and stakeholders contributes to the feeling that these processes served more as forums for the planning team to relay what what had already been decided rather than forums for stakeholders to truly influence the IRP's development.

B. ACCESS TO ADDITIONAL INFORMATION

Stakeholders and the public should also be given greater transparency and access to the PowerSIMM modeling platform to provide accountability around model inputs, assumptions, constraints, and results. It is unclear why ETAC members were given access to PowerSIMM but members of the Stakeholder Working Group were not. Section 7.6.3 outlines the Process to Obtain Data for Alternative Modeling, but it concerns MEIC that this data was not available earlier in the IRP process and that it is not included with the public Draft IRP as a given. While MEIC requested this information shortly after beginning to review the Draft IRP, accessing this information was not an option until March – despite the March 12 deadline for submitting comments to NorthWestern on the Draft IRP. Additionally, a publicly available data set should be included with the IRP, rather than requiring a protective order to get any more details on modeling data.

Appendix H also indicates a number of attachments and supporting data, which should be publicly available with the Draft IRP. MEIC particularly requests Aion's candidate resorce report, as well as the comprehensive table of all of NorthWestern's resources referenced in Section 5.1. However, it is concerning that these attachments were not included by default with the Draft IRP.

As has been referenced throughout these comments, MEIC is concerned at the extensive degree of redaction contained in this Draft IRP and is unfamiliar with NorthWestern's IRP ever having redactions in the past. It is unclear why these redactions have been made, including redactions of the cost per MWh contract price for Judith Gap wind facility in Table 24 and Table 53, despite this information being available for every other contracted resource; redactions of cost information for coal and gas fuel in Section 7.4; redaction of the Colstrip plant's EFOR percentage in Table 42; redaction of the 2024 cost per MWh for Colstrip in Table 16; redaction of the future Colstrip variable cost per MWh projections in Table 49; redaction of the 2024 average price per MWh from NorthWestern's capacity contracts in Table 26; and other redactions throughout the Draft IRP.

In future IRP processes, MEIC hopes and expects that NorthWestern will prioritize transparency and public participation from the start, with a fundamental shift in the company's planning ethic to produce a truly collaborative vision for Montana's energy future.

XVI. OTHER ERRORS, INCONSISTENCIES, AND REVISION CONCERNS

In addition to substantial concerns discussed up to this point in these comments, MEIC also noticed a number of errors, typos, inconsistencies, and broken links throughout the Draft IRP that should be polished for the final version of the Draft IRP. MEIC appreciates that NorthWestern provided a version of the Draft IRP that tracks changes between the version originally shared with the Stakeholder Working Group and the version shared with the public several weeks later, and notes that some of these issues were introduced through this set of revisions to the Draft IRP document. MEIC also has some questions and concerns about certain revisions that were made.

A. QUESTIONS AND CONCERNS ABOUT REVISIONS

Regarding revisions, Table 37 includes an updated maximum delivered capacity for YCGS of 165 MW down from 172 MW, then inreases the sumer and winter capacity accreditations to result in the same total MW of accreditation. MEIC has two questions around this: 1) Why was the max delivered capacity decreases, and does it have something to do with the two units that did not initially come online? 2) If YCGS is only capable of delivering 165 MW of max capacity, it does not make sense that accreditation would just increase to offset this change in delivered capacity. What is the explanation for increasing the WRAP accreditation percentages for YCGS?

As discussed earlier in these comments, Table 39 reduces the Winter Accreditation of Judith Gap wind facility from 25.8% to 0% without explanation, in turn reducing the winter accredited capacity from 34.8 MW to 0 MW. This reduction artificially reduces the overall winter accreditation of NorthWestern's wind resource portfolio from 24.5% to 16.6%, a substantial difference. MEIC also notes an inconsistency, where this table showed a 34.8 MW winter accreditation for Judith Gap, but Figure 37: Winter Capacity Retirements represents Judith Gap's winter accreditation as 39 MW. The revision to Table 39 appears to be an error and should be changed, as it is unduly reducing the winter accreditation for wind resources. In Figure 33, it also appears that the Judith Gap wind facility's winter accredited capacity has been removed from the total winter capacity accreditation without explanation.

Similar to this change to the Judith Gap Winter Accreditation, Table 40 updated the Winter Accreditation of solar from 8.1% to 7.9%. However, a weighted calculation of those various solar resources based on maximum delivered capacity and each individual winter accreditation results in an overal winter accreditation of 8.1%. It is unclear why the winter accreditation was reduced to 7.9% and this appears to be an erroneous change.

It is also unclear why NorthWestern felt the need to add the unsupported qualification to Table 46 Sensitivity R (increased NEM and DSM) that "the costs associated with increased NEM participation, including potential system and cost-shift impacts … are not reflected in this sensitivity." "Cost-shift" qualifications were also added to discussion about Sensitivity R elsewhere in the Draft IRP, but no where does the Draft IRP attempt to explain what this cost-shift would be. Particularly given the lack of discussion around cost-shifting from data center loads, MEIC is concerned that it appears these qualification were added to discredit the fact that Sensitivity R showed a viable cost reduction opportunity rather than based on any substantiated cost shif concern.

B. TYPOS & ERRORS

MEIC did not take note of every typo and minor error throughout the Draft IRP, but a number of those are highlighted here with page numbers referencing the Public Draft version of the Draft IRP.

- Page 19, Section 1.9: "Based on conservative long-term planning assumptions and illustrated the Base Case Capacity Forecast … ." This is missing a linking preposition.
- As mentioned previously in these comments, Table 1 on Page 21 of the Public Draft says that the $5,090 M 20-year NPV for Sensitivity R represents a 4% reduction compared to the base case, but this is actually a 10% reduction. This is correctly displayed in Figure 109 on page 197 of the Public Draft.
- Page 21, Section 1.11: "Over the 20-year planning horizon, the capacity increase further as generating units reach the end of their book lives, …." This should say "capacity need increases."

- Page 22, Section 1.11: "...in the 150MW scenario, a 2% reduction cost per MWh." Missing space, and should say "reduction in cost."
- Page 24: "...and policymakers, and ensures that every decision move Montana's energy future forward responsibly." This should say "moves."
- Page 32, Table 5 does not contain the correct times for when public meetings took place.
- Page 48: "... all utilities meeting regional planning reserves margins … ."
- Page 77: "ATC is the amount of transfer capability left after taking nto … ."
- On page 80 there is a duplicative Figure 20 subheading underneath the 6.2.2 Transmission Interconnections with Other BAs section title. The opening sentence of the following paragraph also appears to have been poartially chopped off: "18 below depicts the amount, as rated by WECC, of TTC at the major interconnections of NorthWestern's system with other transmission systems."
- Figure 21 on page 84 has a computer cursor in the upper right corner.
- Page 99, in addition to concerns raised earlier about this section, the following text is repeated: "blades are large, durable pieces of fiberglass that are challenging to cut, bend, or otherwise repurpose. While the growth of wind generation is expected to continue into the future, it is important to acknowledge that the majority of spent blades are currently disposed of in landfills."
- Page 127, the first paragraph appears to be misformatted.
- Page 130, "The winter PRM was calculated by WRAP for the 2026-2026 Winter FS … ."
- The keys for Figure 106, 107, and 108 are unclear on which color bars represent exports from NorthWestern and which colors represent imprts.
- Page 21, 205: "Over the 20-year planning horizon, the capacity increase further as generation units reach the end of their book lives … ." Capacity *need* increases.
- Page 210: "Consistent the Act, the Commission will select … ."
- Page 213: "... the AMI platform is expected to support an explained set of analytical capabilities … ."
- A number of footnote links throughout the draft also lead to dead ends, including 37, 52, 53, 54, 55, 57.

XVII. CONCLUSION

While the 2026 Draft IRP contains improvements compared to the 2023 IRP, and the resource planning team has taken steps to improve the overall IRP development process, there remain numerous flaws in the current Draft IRP's modeling that prevent the determination of a truly least-cost portfolio. MEIC appreciates this opportunity to lay out these issues and make recommendations for improving the plan, and hopes NorthWestern will incorporate these recommendations before submitting a final IRP to the PSC at the end of April. That said, MEIC also recognizes that the planning team is reluctant to re-run its models at this stage of the process. MEIC appreciates the time and resources that running these models entails, but also expresses our frustration that we have not had the opportunity to sift through so many assumptions and model parameters until a substantial Draft IRP was already pulled together.

Throughout the IRP's development, MEIC has advocated for more transparency and participation up front to avoid ending up in this position. Unfortunately, now we have a Draft IRP that expresses a capacity need that appears to be much higher than reality, relying heavily on expensive coal, gas, and nuclear infrastructure to meet that need while severely discounting the tremendous value of wind and solar combined with short- and long-duration energy storage. It would have been extremely beneficial for ETAC and Stakeholders to have been given a greater voice in the development of model assumptions and parameters so that issues in the Draft IRP laid out throughout these comments could have been addressed prior to running any of the modeling. While revisiting Draft IRP modeling is somewhat resource intensive, it is far less resource intensive than investing in costly energy infrastructure that is not the least-cost option for Montanans. MEIC therefore requests that NorthWestern invests the time and resources up front to correct the issues in this Draft IRP so we can conclude this process with a final IRP that sets Montana's electric system on track for a truly least-cost future.

MEIC thanks the resource planning team for its consideration of these comments and requests that when a final IRP is filed at the PSC at the end of April, a version is shared that tracks changes between the publicly available draft released January 16 and the final IRP filed at the PSC.

Sincerely,

Nick Fitzmaurice

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